Carbon TerraVault III
Class VI Permit Application
Narrative Report

Submitted to:
U.S. Environmental Protection Agency Region 9
San Francisco, CA

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ATTACHMENT A: CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(a)

Carbon TerraVault III

1.0 Project Background and Contact Information

Carbon TerraVault Holdings LLC (CTV), a wholly owned subsidiary of California Resources Corporation (CRC), proposes to construct and operate two CO_2 geologic sequestration wells at CTV III located in San Joaquin County, California. This application was prepared in accordance with the U.S. Environmental Protection Agency's (EPA's) Class VI, in Title 40 of the Code of Federal Regulations (40 CFR 146.81) under the Safe Drinking Water Act (SDWA). CTV is not requesting an injection depth waiver or aquifer exemption expansion.

CTV will obtain the required authorizations from applicable local and state agencies, including the associated environmental review process under the California Environmental Quality Act. Appendix A1 outlines potential local, state and federal permits and authorizations. Federal act considerations and additional consultation, which includes the Endangered Species Act, the National Historic Preservation Act and consultations with Tribes in the area of review, are presented in the Federal Acts and Consultation attachment.

CTV forecasts the potential CO_2 stored in the [redacted] at an average rate of [redacted] million tonnes annually for [redacted] years. CO_2 will be sourced from direct air capture and other CO_2 sources in the project area.

The Carbon TerraVault III (CTV III) storage site is located in the Sacramento Valley, [redacted]. The project will consist of six injectors, surface facilities, and monitoring wells. This supporting documentation applies to the six injection wells.

CTV will actively communicate project details and submitted regulatory documents to County and State agencies:

1. Geologic Energy Management Division (CalGEM)
   District Deputy
   Mark Ghann-Amoah: (661) 322-4031

2. CA Assembly District 13
   Assemblyman Carlos Villapudua
   31 East Channel Street – Suite 306
   Stockton, CA 95202
   (209) 948-7479

3. San Joaquin County
   District 3 Supervisor –Tom Patti
   (209) 468-3113

tpatti@sjgov.org

4. San Joaquin County Community Development
Director – David Kwong
1810 East Hazelton Avenue
Stockton, CA 95205
(209) 468-3121

5. San Joaquin Council of Governments
Executive Director – Diane Nguyen
555 East Weber Avenue
Stockton, CA 95202
(209) 235-0600

6. Region 9 Environmental Protection Agency
75 Hawthorne Street
San Francisco, CA 94105
(415) 947-8000

2.0 Site Characterization

2.1 Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]

2.1.1 Geologic History

The CTV III storage site is located [redacted]

[redacted]

Figure 2.1-1. Location map of the project area with the proposed injection AoR (red) in relation to the Sacramento Basin. CO_2 plume boundary shown in blue.

2.1.2 Site Geology Overview

The CTV III project area lies within the Sacramento Basin in northern California (**Figure 2.1-2**). The Sacramento Basin is the northern, asymmetric sub-basin of the larger, Great Valley Forearc. This portion of the basin, that contains a steep western flank and a broad, shallow eastern flank, spans approximately 240 miles in length and 60 miles wide (Magoon 1995).

[redacted]

Figure 2.1-2. Location map of California modified from (Beyer, 1988) & (Sullivan, 2012). The Sacramento Basin regional study area is outlined by a dashed black line. B – Bakersfield; F – Fresno; R – Redding.

2.1.2.1 Basin Structure

The Great Valley was developed during mid to late Mesozoic time. The advent of this development occurred under convergent-margin conditions via eastward, Farallon Plate subduction, of oceanic crust beneath the western edge of North America (Beyer 1988). The convergent, continental margin, that characterized central California during the Late Jurassic through Oligocene time, was later replaced by a transform-margin tectonic system. This occurred as a result of the northward migration of the Mendocino Triple Junction (from Baja California to its present location off the coast of Oregon), located along California's coast (**Figure 2.1-3**). Following this migrational event was the progressive cessation of both subduction and arc volcanism as the progradation of a transform fault system moved in as the primary tectonic environment (Graham 1984). The major current day fault, the San Andreas, intersects most of the Franciscan subduction complex, which consists of the exterior region of the extinct convergent-margin system (Graham 1984).

[redacted]

Figure 2.1-3. Migrational position of the Mendocino triple junction (Connection point of the Gorda, North American and Pacific plates) on the west and migrational position of Sierran arc volcanism in the east (Graham, 1984). The figure indicates space-time relations of major continental-margin tectonic events in California during Miocene.

2.1.2.2 Basin Stratigraphy

The structural trough that developed subsequent to these tectonic events, that became named the Great Valley, became a depocenter for eroded sediment and thereby currently contains a thick infilled sequence of sedimentary rocks. These sedimentary formations range in age from Jurassic to Holocene. The first deposits occurred as an ancient seaway and through time were built up by the erosion of the surrounding structures. The basin is constrained on the west by the Coast Range Thrust, on the north by the Klamath Mountains, on the east by the Cascade Range and Sierra Nevada and the south by the Stockton Arch Fault (**Figure 2.1-2**). To the west the Coastal Range boundary was created by uplifted rocks of the Franciscan Assemblage (**Figure 2.1-4**). The Sierra Nevadas, that make up the eastern boundary, are a result of a chain of ancient volcanos.

[redacted]

Figure 2.1-4. Schematic W-E cross-section of California, highlighting the Sacramento Basin, as a continental margin during late Mesozoic. The oceanic Farallon plate was forced below the west coast of the North American continental plate.

Basin development is broken out into evolutionary stages at the end of each time-period of the arc-trench system, from Jurassic to Neogene, in **Figure 2.1-5**. As previously stated, sediment infill began as an ancient seaway and was later sourced from the erosion of the surrounding structures. Sedimentary infill consists of Cretaceous-Paleogene fluvial, deltaic, shelf and slope sediments. Due to the southward tilt of the basin

[redacted]

[redacted]

[redacted] This area is a minor structural trap with a slight dip of about 2.8 degrees to the west leaving the area mostly flat.

2.1.2.3. Submarine Canyons

[redacted]

2.1.3 Geological Sequence

[redacted] The injection zone is shown in red [redacted] The average injection depth is approximately [redacted] TVDSS.

[redacted]

Following its deposition, the [redacted] was buried under the [redacted] which carries throughout most of its distribution. This formation serves as the upper confining zone for the [redacted] reservoir due to its low permeability, thickness, and regional continuity that spans beyond the AoR (**Figure 2.1-7**). Above the [redacted] is the [redacted] and [redacted].

[redacted]

2.2 Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]

<u>2.2.1 Data</u>

To date, 46 wells have been drilled to various depths within the project AoR. Along with an extensive database of wells in this field, seismic coverage, core and reservoir performance data such as production and pressure give an adequate description of the reservoir (**Figure 2.2-1**).

[redacted]

[redacted]

Well data are used in conjunction with three-dimensional (3D) and two-dimensional (2D) seismic to define the structure and stratigraphy of the injection zone and confining layers (**Figure 2.2-2**). **Figure 2.2-3** shows outlines of the seismic data used and the area of the structural framework that was built from these seismic surveys. The 3D data in this area were merged using industry standard pre-stack time migration in 2013, allowing for a seamless interpretation across the seismic datasets. The 2D data used for this model were tied to this 3D merge in both phase and time to create a standardized datum for mapping purposes. The following layers were mapped across the 2D and 3D data:

- A shallow marker to aid in controlling the structure of the velocity field
- The approximate base of the [redacted] which is unconformable with the Eocene strata below
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

The top of the [redacted] was used as the base of this structural model due to the depth and imaging of Basement not being sufficient to create a reliable and accurate surface. Interpretation of these layers began with a series of well ties at well locations shown in **Figure 2.2-3**. These well ties create an accurate relationship between wells which are in depth and the seismic which is in time. The layers listed above were then mapped in time and gridded on a 550 by 550 foot cell basis. Alongside this mapping was the interpretation of any faulting in the area which is discussed further in the Faults and Fracture section of this document.

The gridded time maps and a sub-set of the highest quality well ties and associated velocity data are then used to create a 3D velocity model. This model is guided between well control by the time horizons and is iterated to create an accurate and smooth function. The velocity model is used to convert both the gridded time horizons and interpreted faults into the depth domain. The result is a series of depth grids of the layers listed above which are then used in the next step of this process.

The depth horizons are the basis of a framework which uses conformance relationships to create a series of depth grids that are controlled by formation well tops picked on well logs. The grids are used as structural control between these well tops to incorporate the detailed mapping of the seismic data. These grids incorporate the thickness of zones from well control and the formation strike, dip, and any fault offset from the seismic interpretation. The framework is set up to create the following depth grids for input in to the geologic and plume growth models:

- [redacted]
- [redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

2.2.Site Stratigraphy

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

2.2.2.5 [redacted]

Above the [redacted] which is separated by a widespread surface of transgression and acts as a secondary confining zone to the [redacted] Overlying the [redacted], this shale acts as a seal throughout most of the southern Sacramento and northern San Joaquin Basins.

[redacted]

2.2.3 Map of the Area of Review

As required by 40 CFR 146.82(a)(2), **Figure 2.2-7** shows surface bodies of water, surface features, transportation infrastructure, political boundaries, and cities. [redacted] **Figure 2.2-8** indicates the locations of State- or EPA-approved subsurface cleanup sites. This cleanup site information was obtained from the State Water Resources Control Board's GeoTracker database, which contains records for sites that impact, or have the potential to impact, groundwater quality. Water wells within and adjacent to the AoR are discussed in Section 2.7.7 of this document.

[redacted]

2.3 Faults and Fractures [40 CFR 146.82(a)(3)(ii)]

2.3.1 Overview

A combination of 3D and 2D seismic, along with well control, were used to define faulting within the area (**Figure 2.2-3**). [redacted]

[redacted]

[redacted]

Our geologic model shows an average [redacted] thickness within the CO_2 plume boundary to be 210 ft. [redacted]

As discussed in the Injection and Confining Zone Details section, mineralogy data will be collected for the [redacted], but based on data from the [redacted] we expect the [redacted] to be clay rich and therefore continue to provide a vertical seal to the [redacted] within the fault zone. The [redacted] above the [redacted] will be monitored as part of the monitoring and testing plan. **Figure 2.3-2** shows a schematic cross-section across this fault based upon the seismic interpretation.

[redacted]

[redacted]

The AoR is bound [redacted]

[redacted]

[redacted]

[redacted] Our modeling has the [redacted] **Table 2.3-1** shows the average initial, maximum (14 years after initial injection), and 100 years post injection pressure at these locations. An average pressure increase is also provided, and these numbers are averages across the [redacted] The natural seismic history of this area is discussed in the Seismic History section of this document and Attachment C of this application details the seismicity monitoring plan for this injection site.

[redacted]

[redacted]

2.4 Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]

2.4.1 Mineralogy

No quantitative mineralogy information exists within the AoR boundary. Mineralogy data will be acquired across all the zones of interest as part of pre-operational testing. Several wells outside the AoR have mineralogy over the respective formations of interest, and that data is presented below.

2.4.1.1 [redacted]

The [redacted] outside the AoR has x-ray diffraction (XRD) data for the [redacted] (see **Figure 2.4-1** for well locations). Reservoir sand from four samples within this well averages 33% quartz, 42% plagioclase and potassium feldspar, and 24% total clay (see **Table 2.4-1**). The primary clay minerals are kaolinite and mixed layer illite/smectite. Calcite & dolomite were not detected in any of the samples.

[redacted]

[redacted]

2.4.1.2 [redacted]

Mineralogy data is available for the [redacted] from three wells in the [redacted]. The [redacted] has FTIR, while the other two wells have XRD data. Nine samples show an average of 29% total clay, with mixed layer illite/smectite being the dominant species, with kaolinite and chlorite still prevalent. They also contain 32% quartz, 39% plagioclase and potassium feldspar, minimal pyrite, and less than 1% calcite & dolomite.

2.4.1.3 [redacted]

Mineralogy data is available for the [redacted] from the [redacted] well. Nine samples show an average of 46% total clay, with mixed layer illite/smectite being the dominant species, with kaolinite and chlorite still prevalent. They also contain 23% quartz, 29% plagioclase and potassium feldspar, 2% pyrite, and 1% calcite & dolomite.

<u>2.4.2 Porosity and Permeability</u>

2.4.2.1 [redacted]

Wireline log data was acquired with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, compressional sonic, resistivity as well as neutron porosity and bulk density.

Formation porosity is determined one of two ways: from bulk density using 2.65 g/cc matrix density as calibrated from core grain density and core porosity data, or from compressional sonic using 55.5 µsec/ft matrix slowness and the Raymer-Hunt equation.

Volume of clay is determined by spontaneous potential and is calibrated to core data.
Log-derived permeability is determined by applying a core-based transform that utilizes capillary pressure porosity and permeability along with clay values from x-ray diffraction or Fourier transform infrared spectroscopy. Core data from two wells with 13 data points was used to develop a permeability transform. An example of the transform from core data is illustrated in **Figure 2.4-2** below.

[redacted]

Comparison of the permeability transform to log generated permeability (Timur-Coates method) from a nuclear magnetic resonance (NMR) log in the [redacted] is almost 1:1 and matches rotary sidewall core permeability over the [redacted] interval (**Figure 2.4-3**). See **Figure 2.4-1** for location of [redacted].

[redacted]

In the well [redacted], for the [redacted], the porosity ranges from 1.5% - 34% with a mean of 26.5% (**Figure 2.4-4**). The permeability ranges from 0.003 mD - 697 mD with a log mean of 68 mD (**Figure 2.4-5**).

[redacted]

A log plot for the [redacted] is included in **Figure 2.4-6**.

[redacted]

The average porosity for the [redacted] is 27.0%, based on 18 wells with porosity logs and 30487 individual logging data points. See **Figure 2.4-7** for location of wells used for porosity and permeability averaging.

The geometric average permeability for the [redacted] is 75.4 mD, based on 18 wells with porosity logs and 30073 individual logging data points.

[redacted]

2.4.2.2 [redacted]

The average porosity of the upper confining zone [redacted] is 29.3%, based on 17 wells with porosity logs and 10044 individual logging data points.

The geometric average permeability of the upper confining zone [redacted] is 0.34 mD, based on the [redacted] NMR permeability from the Timur-Coates method (see **Figure 2.4-1** for well location).

2.4.2.3 [redacted]

The average porosity of the lower confining zone [redacted] is 21.4%, based on 16 wells with porosity logs and 31279 individual logging data points.

The geometric average permeability of the lower confining zone [redacted] is 0.49 mD, based on 16 wells with porosity logs and 30853 individual logging data points.

2.4.3 Injection Zone and Confining Zone Capillary Pressure

Capillary pressure is the difference across the interface of two immiscible fluids. Capillary entry pressure is the minimum pressure required for an injected phase to overcome capillary and interfacial forces and enter the pore space containing the wetting phase.

No capillary pressure data was available for the [redacted]. This data will be acquired as part of pre-operational testing.

No capillary pressure data was available for the [redacted] (Injection zone) in the project area. For computational modeling purposes, capillary pressure data obtained in the similar geologic age and setting [redacted] in the nearby [redacted] was used. Site and zone specific Capillary pressure data will be obtained as part of pre-operational testing. **Figure 2.4-8** shows the capillary pressure data used for the computational modeling.

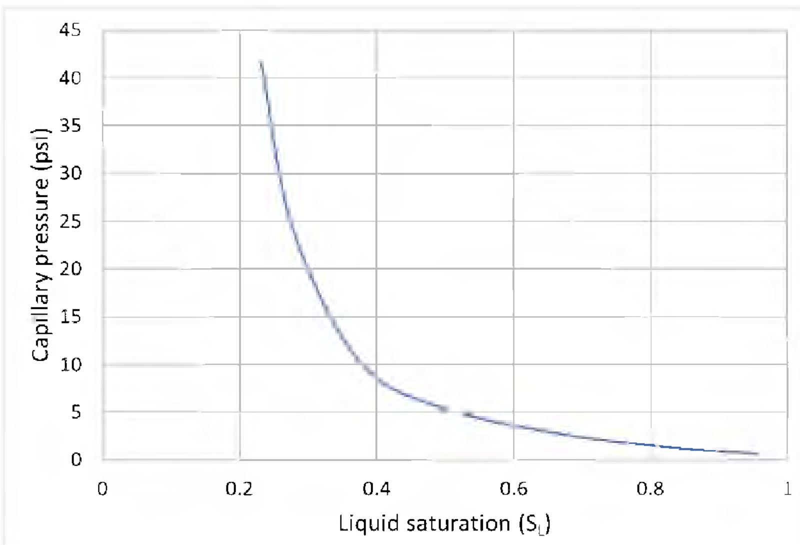

Figure 2.4-8. Injection zone Capillary pressure used for Computational modeling.

2.4.4 Depth and Thickness

Depths and thickness of the [redacted] reservoir and [redacted] confining zone (**Table 2.4-2**) are determined by structural and isopach maps (**Figure 2.4-9**) based on well data (wireline logs). Variability of the thickness and depth measurements is due to:

1. [redacted]
2. The [redacted] remains consistent throughout the AoR both structurally and stratigraphically.
3. [redacted]

Table 2.4-2: [redacted] gross thickness and depth within the AoR.

Zone	Property	Low	High	Mean
Upper Confining Zone	Thickness (feet)	100	360	207
[redacted]	Depth (feet TVD)	4,954	6,164	5,582
Reservoir	Thickness (feet)	316	1,336	1,024
[redacted]	Depth (feet TVD)	5,044	10,281	7,395

[redacted]

2.4.5 Structure Maps

Structure maps are provided in order to indicate a depth to reservoir adequate for supercritical-state injection.

2.4.6 Isopach Maps

Spontaneous potential (SP) logs from surrounding gas wells were used to identify sandstones. Negative millivolt deflections on these logs, relative to a baseline response in the enclosing shales, define the

sandstones. These logs were baseline shifted to 0mV. Due to the log vintage variability, there is an effect on quality which creates a degree of subjectivity within the gross sand, however this will not have a material impact on the maps.
Variability in the thickness and depth of either the [redacted] will not impact confinement. CTV will utilize thickness and depth shown when determining operating parameters and assessing project geomechanics.

2.5 Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]

2.5.1 Caprock Ductility

Ductility and the unconfined compressive strength (UCS) of shale are two properties used to describe geomechanical behavior. Ductility refers to how much a rock can be distorted before it fractures, while the UCS is a reference to the resistance of a rock to distortion or fracture. Ductility generally decreases as compressive strength increases.

Ductility and rock strength calculations were performed based on the methodology and equations from Ingram & Urai, 1999 and Ingram et. al., 1997. Brittleness is determined by comparing the log derived unconfined compressive strength (*UCS*) vs. an empirically derived UCS for a normally consolidated rock (UCS_{NC}).

$$\log UCS = -6.36 + 2.45\log(0.86V_p - 1172) \quad (1)$$

$$\sigma' = OB_{pres} - P_p \quad (2)$$

$$UCS_{NC} = 0.5\sigma' \quad (3)$$

$$BRI = \frac{UCS}{UCS_{NC}} \quad (4)$$

Units for the UCS equation are *UCS* in MPa and V_p (compressional velocity) in m/s. OB_{pres} is overburden pressure, P_p is pore pressure, σ' is effective overburden stress, and *BRI* is brittleness index.

If the value of BRI is less than 2, empirical observation shows that the risk of embrittlement is lessened, and the confining zone is sufficiently ductile to accommodate large amounts of strain without undergoing brittle failure. However, if BRI is greater than 2, the "risk of development of an open fracture network cutting the whole seal depends on more factors than local seal strength and therefore the BRI criterion is likely to be conservative, so that a seal classified as brittle may still retain hydrocarbons" (Ingram & Urai, 1999).

2.5.1.1 [redacted]

Within the AoR, six wells had compressional sonic and bulk density data over the [redacted] to calculate ductility, comprising 3,769 individual logging data points, see pink squares in **Figure 2.4-1**. 15 wells had compressional sonic data over the [redacted] to calculate UCS, comprising 9413 individual logging data points, see black circles in **Figure 2.4-1**. The average ductility of the confining zone based on the mean value is 1.50. The average rock strength of the confining zone, as determined by the log derived UCS equation above, is 2,091 psi.

An example calculation for the well [redacted] is shown below (**Figure 2.5-1**). UCS_CCS_VP is the UCS based on the compressional velocity, UCS_NC is the UCS for a normally consolidated rock, and BRI is the calculated brittleness using this method. Brittleness less than two (representing ductile rock) is shaded red.

[redacted]

Within the [redacted], the brittleness calculation drops to a value less than two. Additionally, the [redacted] above the [redacted] has a brittleness value less than two. As a result of the [redacted] ductility, there are no fractures that will act as conduits for fluid migration from the [redacted].

2.5.2 Stress Field

The stress of a rock can be expressed as three principal stresses. Formation fracturing will occur when the pore pressure exceeds the least of the stresses. in this circumstance, fractures will propagate in the direction perpendicular to the least principal stress (**Figure 2.5-2**).

[redacted]

Stress orientations in the Sacramento basin have been studied using both earthquake focal mechanisms and borehole breakouts (Snee and Zoback, 2020, Mount and Suppe, 1992). The azimuth of maximum principal horizontal stress (S_{Hmax}) was estimated at [redacted] by Mount and Suppe, 1992. Data from the World Stress Map 2016 release (Heidbach et al., 2016) shows an average S_{Hmax} azimuth of [redacted] once several far field earthquakes with radically different S_{Hmax} orientations are removed (**Figure 2.5-3**), which is consistent with Mount and Suppe, 1992. The earthquakes in the area indicate a strike-slip/reverse faulting regime.

[redacted]

In the project AoR there is no site specific [redacted] fracture pressure or fracture gradient. A [redacted] step rate test will be conducted as per the pre-operational testing plan. However, several wells in the [redacted] have formation integrity tests (FIT) for the [redacted]. Two wells recorded minimum fracture gradients of 0.75-0.76 psi/ft based on FIT in the [redacted], see **Figure 2.5-**[redacted]). For the computational simulation modeling and well performance modeling, a frac gradient of 0.76 psi/ft was assumed for now.

[redacted]

In the project AoR there is no site specific [redacted] fracture pressure or fracture gradient. A [redacted] step rate test will be conducted as per the pre-operational testing plan. In the interim, CTV is making the assumption that the [redacted] will have a similar fracture gradient as the [redacted].

The overburden stress gradient in the reservoir and confining zone is 0.91 psi/ft. No data currently exists for the pore pressure of the confining zone. This will be determined as part of the preoperational testing plan.

2.6 Seismic History [40 CFR 146.82(a)(3)(v)]

[redacted]

[redacted]

The United States Geologic Survey (USGS) provides an earthquake catalog tool (https://earthquake.usgs.gov/earthquakes/search/) which can be used to search for recent seismicity that could be associated with faults in the area for movement. A search was made for earthquakes in the greater vicinity of the project area from 1850 to modern day with events of a magnitude greater than three. **Figure 2.6-2** shows the results of this search. **Table 2.6-1** summarizes some of the data taken from them. [redacted]

[redacted]

[redacted]

Event 8 appears to be isolated from the fault zones at a depth of 6km. Reviewing the 3D seismic data in that area there may be a structural feature at the level of seismic basement, but it is not well imaged. The event does not continue into the shallower sediments that are thousands of feet deeper than the proposed injection zone. Similar can be said for event 13, another deep (6km) event that is outside of the AoR.

For the [redacted], event numbers 2 and 7 are clearly related to the fault trace. Event 7 was a significant distance from the AoR and event 2 was significantly deeper (14.55km) than the proposed injection zone. Finally, events 3, 12, and 14 are in the closest proximity to the [redacted]. Event 14 appears to align with the [redacted], a mapped fault by the CGS that may be a splay of the [redacted] and [redacted]. Event 12 is interpreted to be at a significant depth (14.95km) away from the injection zone and far beneath the sedimentary section of the basin. Event 3 is likely the most concerning, this earthquake happened in 2002, at the approximate seismic basement level which is interpreted to be around 16,000 ft (4.88km). The average depth of prior seismic events in the region based on these data (**Table 2.6-1**) is approximately 9.3km, far deeper than the proposed injection zone and sedimentary section.

[redacted] Our modeling shows the [redacted] to be under-pressured across the AoR, which will be confirmed in pre-operational testing. [redacted] As stated previously, given that other formations around these faults have held back hydrocarbons at pressures above hydrostatic, we believe this to be a safe standard for fault stability.

Lund-Snee and Zoback (2020) published updated maps for crustal stress estimates across North America. **Figure 2.6-4** shows a modified image from that work highlighting the CTV III area. This work agrees with previous estimates of maximum horizontal stress in the region of approximately [redacted] in a strike-slip to reverse stress regime (Mount and Suppe, 1992) and is consistent with World Stress map data for the area (Heidbach et al, 2016). Attachment C of this application discusses the seismicity monitoring plan for this injection site.

[redacted]

2.6.2 Seismic Hazard Mitigation

[redacted] This document defines the confining zone, beginning with the [redacted], that separate the [redacted] injection interval from USDW.

The following is a summary of CTVs seismic hazard mitigation for CTV III:

The project has a geologic system capable of receiving and containing the volumes of CO_2 proposed to be injected

- [redacted]

[redacted]

Will be operated and monitored in a manner that will limit risk of endangerment to USDWs, including risks associated with induced seismic events

- Injection pressure will be lower than the fracture gradient of the sequestration reservoir with a safety factor (90% of the fracture gradient)
- Injection and monitoring well pressure monitoring will ensure that pressures are beneath the fracture pressure of the sequestration reservoir and confining zone. Injection pressure will be lower than the fracture gradients of the sequestration reservoir and confining zone with a safety factor (90% of the fracture gradients)
- A seismic monitoring program will be designed to detect events lower than seismic events that can be felt. This will ensure that operations can be modified with early warning events, before a felt seismic event

Will be operated and monitored in a way that in the unlikely event of an induced event, risks will be quickly addressed and mitigated

- Via monitoring and surveillance practices (pressure and seismic monitoring program) CTV personnel will be notified of events that are considered an early warning sign. Early warning signs will be addressed to ensure that more significant events do not occur
- CTV will establish a central control center to ensure that personnel have access to the continuous data being acquired during operations

Minimizing potential for induced seismicity and separating any events from natural to induced

- Pressure will be monitored in each injector and sequestration monitoring well to ensure that pressure does not exceed the fracture pressure of the reservoir or confining zone
- Seismic monitoring program will be installed pre-injection for a period to monitor for any baseline seismicity that is not being resolved by current monitoring programs
- Average depth of prior seismic hazard in the region based on reviewed historical seismicity has been approximately 9.3km. Significantly deeper than the proposed injection zone

2.7 Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

The California Department of Water Resources has defined 515 groundwater basins and subbasins with the state. [redacted] **Figure 2.7-1** shows the AoR, [redacted], and the surrounding areas. The Subbasin encompasses an area of about [redacted] (DWR 2006).

[redacted]

2.7.1 Hydrologic Information

Major surface water bodies within the [redacted] consist of the [redacted]. **Figure 2.7-1** shows the location of these surface water bodies. The [redacted] makes up almost the entire eastern boundary of the Subbasin and it feeds water into the [redacted], which is located just west of the Subbasin.

[redacted] In addition to the major natural waterways there is a large network of irrigation canals, which convey surface water to agricultural properties.

2.7.2 Base of Fresh Water and Base of USDWs

The owner or operator of a proposed Class VI injection well must define the general vertical and lateral limits of all USDWs and their positions relative to the injection zone and confining zones. The intent of this information is to demonstrate the relationship between the proposed injection formation and any USDWs, and it will support an understanding of the water resources near the proposed injection wells. A USDW is defined as an aquifer or its portion which supplies any public water system; or which contains a sufficient quantity of ground water to supply a public water system; and currently supplies drinking water for human consumption; or contains fewer than 10,000 mg/l total dissolved solids; and which is not an exempted aquifer.

2.7.2.1 Base of Fresh Water

The base of fresh water (BFW) helps define the aquifers that are used for public water supply. [redacted] Luhdorff & Scalmanini (2016) performed a study that focused on the geologic history of freshwater sediments from which groundwater is extracted for beneficial uses as defined and regulated under SGMA.

[redacted] In most of western San Joaquin County in the Delta the fresh groundwater aquifers are limited to relatively shallow depths of 500 to 700 feet bgs in the [redacted], and to 1,600 feet bgs in the [redacted].

[redacted] performed a study of over 500 well logs in eastern [redacted] groundwater for [redacted]. The focus of this study was the uppermost 500 feet, where most water wells were completed. Subsequently [redacted] used logs also examined for the nature of geologic units at greater depths to better define the BFW. The top of the geophysical logs tended to be at 800 feet or greater depths. These logs generally show fine-grained geologic units with few sand beds. The depth to base of fresh water was difficult to discern in available geophysical logs because of the lack of sand beds. The elevation of the base of freshwater aquifers determined from logs were plotted on a base map (see **Figure 2.7-2**). Contour lines of one hundred feet were drawn, but are variable based on well control.

[redacted]

2.7.2.2 Calculation of Base of Fresh Water and USDW

CRC has used geophysical logs to investigate the USDWs and the base of the USDWs. The calculation of salinity from logs used by CRC is a four-step process:

(1) converting measured density or sonic to formation porosity

The equation to convert measured density to porosity is:

$$POR = \frac{(Rhom - RHOB)}{(Rhom - Rhof)} \tag{5}$$

Parameter definitions for the equation are:

POR is formation porosity

Rhom is formation matrix density grams per cubic centimeters (g/cc); 2.65 g/cc is used for sandstones

RHOB is calibrated bulk density taken from well log measurements (g/cc)

Rhof is fluid density (g/cc); 1.00 g/cc is used for water-filled porosity

The equation to convert measured sonic slowness to porosity is:

$$POR = -1\left(\frac{\Delta tma}{2\Delta tf} - 1\right) - \sqrt{\left(\frac{\Delta tma}{2\Delta tf} - 1\right)^2 + \frac{\Delta tma}{\Delta tlog} - 1} \quad (6)$$

Parameter definitions for the equation are:

POR is formation porosity

Δtma is formation matrix slowness (µs/ft); 55.5 µs/ft is used for sandstones

Δtf is fluid slowness (µs/ft); 189 µs/ft is used for water-filled porosity

Δtlog is formation compressional slowness from well log measurements (µs/ft)

(2) calculation of apparent water resistivity using the Archie equation,

The Archie equation calculates apparent water resistivity. The equation is:

$$Rwah = \frac{POR^m R_t}{a} \quad (7)$$

Parameter definitions for the equation are:

Rwah is apparent water resistivity (ohmm)

POR is formation porosity

m is the cementation factor; 2 is the standard value

R_t is deep reading resistivity taken from well log measurements (ohmm)

a is the archie constant; 1 is the standard value

(3) correcting apparent water resistivity to a standard temperature

Apparent water resistivity is corrected from formation temperature to a surface temperature standard of 75 degrees Fahrenheit:

$$Rwahc = Rwah\frac{TEMP+6.77}{75+6.77} \quad (8)$$

Parameter definitions for the equation are:

Rwahc is apparent water resistivity (ohmm), corrected to surface temperature

TEMP is down hole temperature based on temperature gradient (DegF)

(4) converting temperature corrected apparent water resistivity to salinity.

The following formula was used (Davis 1988):

$$SAL\_a\_EPA = \frac{5500}{Rwahc} \quad (9)$$

Parameter definitions for the equation are:

SALa_EPA is salinity from corrected Rwahc (ppm)

The base of fresh water and the USDW are shown on the geologic Cross Section A-A' (**Figure 2.2-4**) The base of fresh water and based of the lowermost USDW is at a measure depth of approximately 1100 ft and 2500 ft respectively.

[redacted]

2.7.3.1 Alluvium

The Alluvium (Q) includes sediments deposited in the channels of active streams as well as overbank deposits and terraces of those streams. They consist of unconsolidated silt, sand, and gravel. Sand and gravel zones in the younger alluvium are highly permeable and yield significant quantities of water to wells. The thickness of the younger alluvium in the [redacted] is less than 100 feet (DWR 2006).

2.7.3.2 Flood Basin and Intertidal Deposits

The Flood Basin Deposits [redacted] and Intertidal Deposits (Qi) are in the Delta portions of the Subbasin. These sediments consist of peaty mud, clay, silt, sand and organic materials. Stream-channel deposits of coarse sand and gravel are also included in this unit. The flood basin deposits have low permeability and generally yield low quantities of water to wells due to their fine-grained nature. Flood basin deposits generally contain poor quality groundwater with occasional zones of fresh water. The maximum thickness of the unit is about 1,400 feet (DWR 2006).

2.7.3.3 Alluvial Fan Deposits

Along the southern margin of the Subbasin, in the Non-Delta uplands areas of the Subbasin are fan deposits (Qf) from the Coast Ranges. These deposits consist of loosely to moderately compacted sand, silt, and gravel deposited in alluvial fans during the Pliocene and Pleistocene ages. The fan deposits likely interfinger with the Flood Basin Deposits. The thickness of these fans is about 150 feet (DWR 2006).

[redacted]

[redacted]

[redacted]

[redacted]

2.7.3.6 Undifferentiated Non-marine Sediments

The upper Paleogene and Neogene sequence begin with the [redacted] which represents fluvial deposits that blanket the entire southern Sacramento Basin. The unconformity at the base of the [redacted] marks a widespread Oligocene regression and separates the more deformed Mesozoic and lower Paleogene strata below from the less deformed uppermost Paleogene and Neogene strata above. The undifferentiated non-marine sediments contain approximately 3,000 - 10,000 milligrams per liter (mg/l) TDS water and is the lowermost USDW in the AoR (**Figure 2.2-3**).

[redacted] The soil profiles show the subsurface relationships and location of the formations and coarse-grained sediments that comprise the principal aquifers. [redacted]

[redacted]

Geologic Cross Section B-B' (**Figure 2.7-4**) runs [redacted] portions of the [redacted]

[redacted]

Geologic Cross Section C-C' (**Figure 2.7-5**) runs a [redacted]. This geologic section illustrates the types of sediments, the estimated base of freshwater, the possible location of the [redacted]. Where the clay location is uncertain, no wells were present that penetrated deep enough to confirm its presence or absence. The base of fresh water varies throughout the Subbasin and is shown on the sections. It is as shallow as -400 feet mean sea level (msl) to as much as -2,000 feet msl (GEI 2021).

[redacted]

[redacted]

2.7.5.1 Upper Aquifer
The Upper Aquifer is used by domestic, community water systems, and for agriculture. The Upper aquifer also supports native vegetation where groundwater levels are less than 30 feet bgs (GEI 2021). The Upper Aquifer is an unconfined to semi-confined aquifer. It is present above the [redacted]

There are multiple coarse-grained sediment layers that make up the unconfined aquifer, however the water levels are generally similar. Generally, the aquifer confinement tends increase with depth becoming semi-confined conditions. There is also typically a downward gradient in the [redacted]; the gradient ranges from a few feet bgs to as much as 70 feet bgs. The groundwater levels in the Upper Aquifer are usually 10 to 30 feet higher than in the Lower Aquifer. The groundwater levels [redacted]

The hydraulic characteristics of the unconfined aquifer are highly variable. The USGS estimated horizontal hydraulic conductivity values for organic sediments ranging from 0.0098 ft/d to 133.86 ft/d (Hydrofocus 2015). Wells in the unconfined aquifer produce 6 to 5,300 gpm. The transmissivity of the unconfined aquifers, ranges between 600 to greater than 2,300 gallons per day per foot (gpd/ft). The storativity is about 0.05 (GEI 2021).

Water quality in the Upper Aquifer is mostly transitional, with no single predominate anion. Most water are characterized as sulfate bicarbonate and chloride bicarbonate type [redacted]. The TDS of these transitional water ranges between 400 to 4,200 mg/L. Nitrate is generally high in the Upper aquifer in the [redacted] portions of the Subbasin. Nitrate is generally low in the Delta portions of the Subbasin (GEI 2021).

2.7.5.2 Lower Aquifer

The Lower Aquifer is typically used by community water systems [redacted] and agriculture. The Lower Aquifer is mainly comprised of the lower portions of the [redacted] and extends to the base of fresh water. The clay is present in the southern third of the Subbasin; the clay's extent to the west and north is uncertain and has been estimated to have a vertical permeability ranging from 0.01 to 0.007 feet per day (Burow et al. 2004).

The groundwater levels are generally deeper than water levels in the Upper Aquifer (Hotchkiss and Balding 1971). Groundwater levels in the confined aquifer are about -25 to -75 feet msl. The groundwater levels are normally 60 to 200 feet above the top of the [redacted].

Wells in the Lower Aquifer produce about 700 to 2,500 gpm. The transmissivity typically ranges from 12,000 to 37,000 gpd/ft, but can be 120,000 gpd/ft. The storage coefficient or storativity has been measured to be 0.0001 (Padre 2004).

Water quality in the Lower Aquifer in the western portions are chloride type water but mostly transitional type of sulfate chloride near the valley margins and sulfate bicarbonate and bicarbonate sulfate near the [redacted]. In general, the TDS ranges between 400 and 1,600 mg/L. Nitrate is typically low in the Lower Aquifer. Wells completed below the Corcoran Clay sometimes have elevated levels sulfate and total dissolved solids above the drinking water MCLs. Only at one deep location, [redacted], are chloride levels elevated (GEI 2021).

2.7.6 Potentiometric Maps

The [redacted] used groundwater level measurements in over 226 wells, which have been reported to DWR's CASGEM or Water Data Library systems. To evaluate groundwater levels, the GSP only used wells with known total depths and construction details so that the wells were assigned to a principal aquifer. To supplement data from these wells, additional monitoring wells were located that were being used for other regulatory programs.

2.7.6.1 Upper Aquifer

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

2.7.6.2 Lower Aquifer

The [redacted] extends throughout the [redacted], at [redacted]. Groundwater contours for the Lower Aquifer were developed using data from the CASGEM monitoring wells that are constructed below the [redacted] and supplemented by data from municipal wells (**Figure 2.7-8**). Groundwater monitoring well data were used from the [redacted].

[redacted]

[redacted]

The groundwater gradient in Fall 2019 from the [redacted] and the [redacted] is estimated to be 0.0009 foot/foot into the [redacted]. Due to the pumping depression, the gradient increases around the [redacted]. The gradient near the western edge of the subbasin cannot be determined to the lack of monitoring wells constructed below the [redacted].

2.7.7 Water Supply Wells

The California State Water Resources Control Board Groundwater Ambient Monitoring Assessment Program (GAMA), and the Department of Water Resources (DWR) public databases were searched to identify any water supply wells within a one-mile radius of the AOR. A total of 155 water supply wells were identified within one mile of the AoR. A map of well locations and table of information are found in **Figure 2.7-9** Water Well Location Map and the attached **Table 2.7-1** Water Well Information, respectively.

[redacted]

Groundwater in the Subbasin is used for municipal, industrial, irrigation, domestic, stock watering, frost protection, and other purposes. The number of water wells is based on well logs filed and contained within public records may not reflect the actual number of active wells because many of the wells contained in files may have been destroyed and others may not have been recorded.

[redacted]

[redacted]. The known water well depths and other information are included in the attached **Table 2.7-1.** Some well depths are unknown, but all water supply wells completion intervals are expected to be much shallower than the injection zone.

2.8 Geochemistry [40 CFR 146.82(a)(6)]

2.8.1 Formation Geochemistry

[redacted]

[redacted]

[redacted]

2.8.2 Fluid Geochemistry

[redacted] The well [redacted] was sampled in 1980 (see **Figure 2.5-4** for well location). The measurement of total dissolved solids (TDS) for the sample is 13,889.4 mg/L. The complete water chemistry is shown in **Figure 2.8-1**.

[redacted]

Salinity calculations were also performed on logs from wells within the AoR, and these showed TDS in the [redacted] being approximately 14,000 – 16,000 ppm. A conservative TDS of 15,500 ppm was used for the computational model.

[redacted]

2.8.3 Fluid-Rock Reactions

[redacted]

2.9 Other Information (Including Surface Air and/or Soil Gas Data, if Applicable)

No additional information to add.

2.10 Site Suitability [40 CFR 146.83]

Sufficient data from both wells and seismic demonstrate the integrity through lateral continuity of the reservoir as well as the confining zone. [redacted]

[redacted]

[redacted]

[redacted]

CTV's estimates storage for the project area is up to [redacted]. This was arrived through computational modeling.

3.0 AoR and Corrective Action

CTV's AoR and Corrective Action plan pursuant to 40 CFR 146.82(a)(4), 40 CFR 146.82(a)(13) and 146.84(b), and 40 CFR 146.84(c) describes the process, software, and results to establish the AoR, and the wells that require corrective action.

AoR and Corrective Action GSDT Submissions
GSDT Module: AoR and Corrective Action ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Tabulation of all wells within AoR that penetrate confining zone ***[40 CFR 146.82(a)(4)]*** ☒ AoR and Corrective Action Plan *[40 CFR 146.82(a)(13) and 146.84(b)]* ☒ Computational modeling details ***[40 CFR 146.84(c)]***

4.0 Financial Responsibility

CTV's Financial Responsibility demonstration pursuant to 140 CFR 146.82(a)(14) and 40 CFR 146.85 is met with a line of credit for Injection Well Plugging and Post-Injection Site Care and Site Closure and insurance to cover Emergency and Remedial Responses.

Financial Responsibility GSDT Submissions
GSDT Module: Financial Responsibility Demonstration ***Tab(s):*** Cost Estimate tab and all applicable financial instrument tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Demonstration of financial responsibility ***[40 CFR 146.82(a)(14) and 146.85]***

5.0 Injection and Monitoring Well Construction

CTV plans to drill six new injectors for the CTV III storage project. New injection wells C1, C2, E1, E2, W1, and W2 are planned and designed specifically for CO_2 sequestration purposes. These wells will target selective intervals within the injection zone to optimize plume development and injection conformance. Additionally, three new monitoring wells are required to support the storage project. M1 and M2 will be injection zone monitoring wells, and D1 will be an above-zone monitoring well. Two USDW monitoring wells, US1 and US2, will also be constructed prior to injection. Figure 1 shows the location of the new wells.

[redacted]

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure non-endangerment of USDW. Due to the depth of the base of USDW, an intermediate casing string will be utilized to isolate the USDW. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of USDW using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

Appendix C-1: Injection and Monitoring Well Schematics provides casing diagram figures for all injection and monitoring wells with construction specifications and anticipated completion details in graphical and/or tabular format.

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

5.1 Proposed Stimulation Program [40 CFR 146.82(a)(9)]

There are no proposed stimulation programs currently.

5.2 Construction Procedures [40 CFR 146.82(a)(12)]

Injection and monitoring wells will be drilled during pre-operational testing, and no abnormal drilling and completion challenges are anticipated. The drilling histories of nearby wells provide key information to drilling professionals and identify the expected conditions to be encountered. The wells will be constructed with objectives to achieve target CO_2 injection rates, to prevent migration of fluids out of the injection zone, to protect the shallow formations, and to allow for monitoring, as described by the following:

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

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

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

Well materials follow the following standards:

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

As required by §146.86(b)(1), casing and tubing material sizes, thicknesses, and grades were selected by evaluating the proposed well design internal pressures, external pressures, and axial loads that the well will be expected to withstand throughout construction and operations. Load cases identified using oil and gas industry best practices as well as specific CO_2 injection loads were modeled using industry-accepted casing design software, StrinGnosis. Load scenarios were calculated for the intermediate casing, the injection casing/liner, and the tubing string with the assumption of 87.5% remaining body wall thickness (manufacturer's tolerance for new pipe). Load types assessed in the load scenarios include burst, collapse, axial (tensile and compressive), and triaxial (Von Mises Equivalent). Temperature effects under static or dynamic conditions, based on load scenario, have been incorporated into the modelling results. The design results indicate the materials selected have strengths sufficient to withstand all worst-case load scenarios and include industry-standard safety factors.

Well materials will be reviewed following final determination of CO_2 stream design specification and again after testing the composition, properties, and corrosiveness of the CO_2 stream. If actual CO_2 specification requires material selection to be changed, the new material size, thickness, and grade will be sufficient to meet all load scenarios including safety factors.

5.2.1 Casing and Cementing

Well-specific casing diagrams including casing specifications are presented in Appendix C-1: Injection and Monitoring Well Schematics to meet the requirements of 40 CFR 146.86(b)(1)(iv). These specifications allow for the safe operation at bottomhole injection conditions not to exceed the maximum allowable operating pressure (MAOP) of 0.684 psi/ft specified in the Appendix: Operating Procedures.

[redacted]. These conditions are not extreme, and standard cementing and casing best practices are sufficient to ensure successful placement and isolation. Industry standard practices and procedures for designing and placing primary cement in the casing annuli will be utilized to ensure mechanical integrity of cement and casing. Staged cementing is not an anticipated requirement.

Surface casing will be designed to protect the base of fresh water at a depth of around 400' TVD. Casing is planned to be set at 600'. Class G portland cement – an API grade cement – meets API standard specifications for this application. Accelerator additives will be used to speed up the thickening time of the cement, lost circulation additive may be used as macro plugging material, and extender additives may be used to protect shallow formations by reducing the weight of cement.

The intermediate casing will be set at a depth sufficient to cover the USDW. The depth to the base of USDW is expected to be encountered at approximately [redacted]. Casing will be set or below [redacted] to ensure protection of the USDW. Class G portland cement will be circulated to surface with retarding additives (depending on pump time) to decrease the speed of cement hydration as well as friction reducer additives to improve upon the flow properties of the cement slurry. Anti-foam additives, fluid loss additives, lost circulation material, dispersants, and extenders may also be considered based on industry best practices for slurry design to ensure effective placement of cement.

The long casing string will be set 120' into the lower confining layer. A combination of Class G portland lead slurry and Class G portland tail slurry with CO_2 resistant additives will be used to cement the long string. The tail slurry will be circulated from TD into the confining layer. The lead slurry will provide isolation of the long string casing in and above the confining layer to surface. Anti-foam additives, fluid loss additives, lost circulation material, dispersants, and extenders may also be considered based on industry best practices for slurry design to ensure effective placement of cement, along with considering the addition of silica flour for strength retrogression.

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

5.2.2 Tubing and Packer

The information in the tables provided in Appendix C-1: Injection and Monitoring Well Schematics is representative of completion equipment that will be used and meets the requirements at 40 CFR 146.86(c). Tubing and packer selection and specifications will be determined during pre-operational testing and will be sufficient to withstand all load scenarios considering internal pressure, external pressure, axial loading, and temperature effects.

5.2.3 Annular Fluid

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

5.2.4 Injectate and Formation Fluid Properties

CTV is planning to construct a carbon capture and sequestration "hub" project (*i.e.*, a project that collects carbon dioxide (CO_2) from multiple sources over time and injects the CO_2 stream(s) via a Class VI UIC permitted injection well(s)). Therefore, CTV is currently considering multiple sources of anthropogenic CO_2 for the project. The potential sources include capture from existing and potential future industrial sources, as well as Direct Air Capture (DAC). The CO_2 stream from the source(s) will consist of a minimum of 95% CO_2 by volume. Incidental substances in associated with the CO_2 stream may include, for example, water content (<25 lb/mmscf), oxygen, H_2S, and SO_x compounds. CTV would expect the CO_2 stream will be sampled at the transfer point from the source and analyzed according to the analytical methods described in the "CTV III – QASP" (Table 4) document and the "Attachment C – CTV III Testing and Monitoring plan" (Table 1) document. Should the injectate not meet the minimum requirements, it will be rejected. The anticipated injection temperature at the wellhead is 90 – 130° F.

A 100% CO2 injectate stream has been assumed for computational modeling and for the well performance modeling. Table 5.1 summarizes the injectate properties at downhole conditions for the injectors.

Table 5.1: Injectate properties at downhole conditions (Assuming 100% CO2 injectate)

Injectate property at downhole conditions	Injector C1	Injector C2	Injector E1	Injector E2	Injector W1	Injector W2
Viscosity, cp	0.066	0.071	0.062	0.065	0.063	0.067
Density, lb/ft^3	48.65	50.69	46.14	47.99	46.53	48.88
Compressibility factor, Z	0.433	0.487	0.426	0.473	0.434	0.487
Injection rate, mmscfpd (Average)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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

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

Geochemical analysis of the connate formation water has been provided in section 2.8 of the Attachment A narrative document. Figure 2.8-1 provides water geochemistry representative of the project area and does not indicate corrosiveness to standard cement and casing materials. A formation water analysis will be obtained during pre-operational testing and reviewed to ensure compatibility with well construction materials. Table 5.2 provides estimated formation fluid properties.

Table 5.2: Formation fluid properties

Formation Fluid Property	Estimated Value/Range
Density, g/cm^3	1.01
Viscosity, cp	1.26
TDS, ppm	~14,000-16,000

5.2.5 Alarms and Shut-Off Devices

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

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

The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

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The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

6.0 Pre-Operational Logging and Testing

CTV has attached a pre-operational logging and testing plan pursuant to 40 CFR 146.82(a)(8) and 40 CFR 146.87.

Pre-Operational Logging and Testing GSDT Submissions
GSDT Module: Pre-Operational Testing ***Tab(s):*** Welcome tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Proposed pre-operational testing program ***[40 CFR 146.82(a)(8) and 146.87]***

7.0 Well Operation

CTV has provided detailed operating procedures for each injection well. These procedures are provided for all injectors in the Appendix – Operational Procedures document. The operational procedure for planned injector C1 is included below.

7.1 Operational Procedures [40 CFR 146.82(a)(10)]

For a target rate of [redacted], bottom hole and surface pressures have been estimated for injector C1 over the life of the project. These pressures were estimated using results from the Plume simulation as an input into the multiphase well nodal analysis software – PROSPER by Petroleum Experts Ltd. PROSPER has been used extensively in CO_2 EOR to model CO_2 injection wells. The pressures have been currently calculated assuming a 100% CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

At the start of injection, a surface and bottom hole injection pressure of 1,240 psi and 2,934 psi respectively, are required to inject. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface and bottom hole pressures required are 1,300 psi and 3,050 psi respectively, which is the maximum pressure CTV expects to operate the well under target rate conditions.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 4,224 psi (calculated at the top perforation). The injection well will be controlled using automation to never exceed this maximum BHP.

The expected pressures for injector C1 over the life of the project are summarized in Table 7.1.1 and in the Operational Procedures Appendix.

Table 7.1.1. Proposed operational procedures for Injector C1.

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Allowable Pressure	Using 0.76psi/ft frac gradient with 10% safety factor	
Surface	2243	psig
Downhole	4224	psig
Average (/ Target) Injection Rate	[redacted]	Mmscfpd Tons/day
Injection Pressure @ Average (/ Target) rate	Expected range over project	
Surface - Start / End / Average	1240 / 1300 / 1270	psig
Downhole - Start / End / Average	2934 / 3050 / 2992	psig
Maximum Proposed Injection Rate	[redacted]	mmscf/d Tons/d
Injection Pressure @ Maximum Proposed Rate		
Surface – Start / End / Average	1440 / 1500 / 1470	psig
Downhole – Start / End / Average	2983 / 3075 / 3029	psig
Annulus Pressure	Expected range over project	
Surface - Start / End	100 / 315	psig
Downhole - Start / End	2725 / 1940	psig
Annulus / Injection Tubing Pressure Differential	>100	psig

7.1.1 Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to Attachment C: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure, as needed.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4% KCl is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in Table 7.1.1 are suitable to the well design and will not impact the well integrity or induce formation fracture.

7.1.2 Target Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate.

At this time, for injection well C1, CTV expects a target injection rate of [redacted] which the maximum expected bottom hole injection pressure is 3,050 psi. A threshold of 10% over these values will be used to configure automation and alarms, which equates to [redacted] and 3,355 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

7.1.3 Shutdown Procedures

Under routine shutdowns (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of [redacted]

7.1.4 Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is seen or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.

7.2 Proposed Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

There are currently multiple sources of anthropogenic CO_2 being considered for the project. These include capture from existing and potential future industrial sources in the Sacramento Valley area, as well as Direct Air Capture (DAC). The carbon dioxide stream will consist of a minimum of 95% CO_2 by volume. Other key constituents that will be controlled for corrosion mitigation include water content (<25 lb/mmscf), oxygen, H2S, and SOx compounds. The Injectate stream will be sampled at the transfer point from the source and analyzed according to the analytical methods described in the "CTV II – QASP" (Table 4) document and the "Attachment C: Testing and Monitoring plan" (Table 1) document. Should the injectate not meet the minimum requirements it will be rejected. The anticipated injection temperature at the wellhead is 90 – 130° F.

Corrosiveness of the CO_2 stream is very low as long as the entrained water is kept in solution with the CO_2. This is ensured by the < 25 lb/mmscf injectate specification referred to above. Injectate water solubility will vary with depth and time as temperature and pressures change. The water specification is conservative to ensure water solubility across super-critical operating ranges. CRA tubing will be used in the injection wells to mitigate this potential corrosion impact should free-phase water be present. CTV may optimize the maximum water content specification prior to injection based on technical analysis.

8.0 Testing and Monitoring

CTV's Testing and Monitoring plan pursuant to 40 CFR 146.82 (a) (15) and 40 CFR 146.90 describes the strategies for testing and monitoring to ensure protection of the USDW, injection well mechanical integrity, and plume monitoring.

Testing and Monitoring GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Testing and Monitoring tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Testing and Monitoring Plan [40 CFR 146.82(a)(15) and 146.90]

9.0 Injection Well Plugging

CTV's Injection Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials and methodology for injection well plugging.

Injection Well Plugging GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Injection Well Plugging tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Injection Well Plugging Plan [40 CFR 146.82(a)(16) and 146.92(b)]

10.0 Post-Injection Site Care (PISC) and Site Closure

CTV has developed a Post-Injection Site Care and Site Closure plan pursuant to 40 CFR 146.93 (a) to define post-injection testing and monitoring.

At this time CTV is not proposing an alternative PISC timeframe.

PISC and Site Closure GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** PISC and Site Closure tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ PISC and Site Closure Plan [40 CFR 146.82(a)(17) and 146.93(a)]

PISC and Site Closure GSDT Submissions
GSDT Module: Alternative PISC Timeframe Demonstration ***Tab(s):*** All tabs (only if an alternative PISC timeframe is requested) Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Alternative PISC timeframe demonstration ***[40 CFR 146.82(a)(18) and 146.93(c)]***

11.0 Emergency and Remedial Response

CTV's Emergency and Remedial Response plan pursuant to 40 CFR 164.94 describes the process and response to emergencies to ensure USDW protection.

Emergency and Remedial Response GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Emergency and Remedial Response tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Emergency and Remedial Response Plan *[40 CFR 146.82(a)(19) and 146.94(a)]*

12.0 Injection Depth Waiver and Aquifer Exemption Expansion

No depth waiver or Aquifer Exemption expansion is being requested as part of this application

Injection Depth Waiver and Aquifer Exemption Expansion GSDT Submissions
GSDT Module: Injection Depth Waivers and Aquifer Exemption Expansions ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Injection Depth Waiver supplemental report ***[40 CFR 146.82(d) and 146.95(a)]*** ☐ Aquifer exemption expansion request and data ***[40 CFR 146.4(d) and 144.7(d)]***

13.0 Reference

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NARRATIVE REPORT - FIGURES

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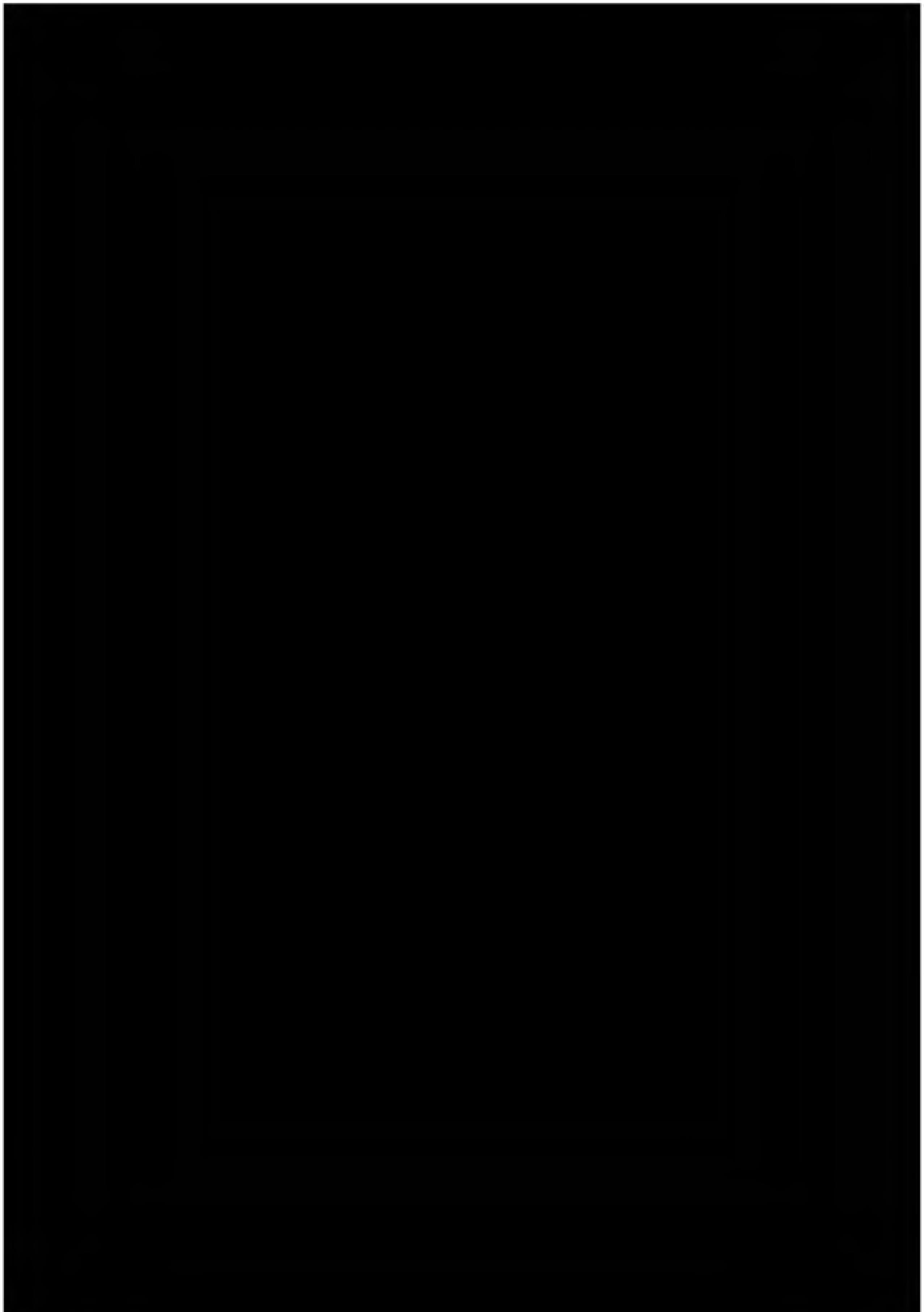

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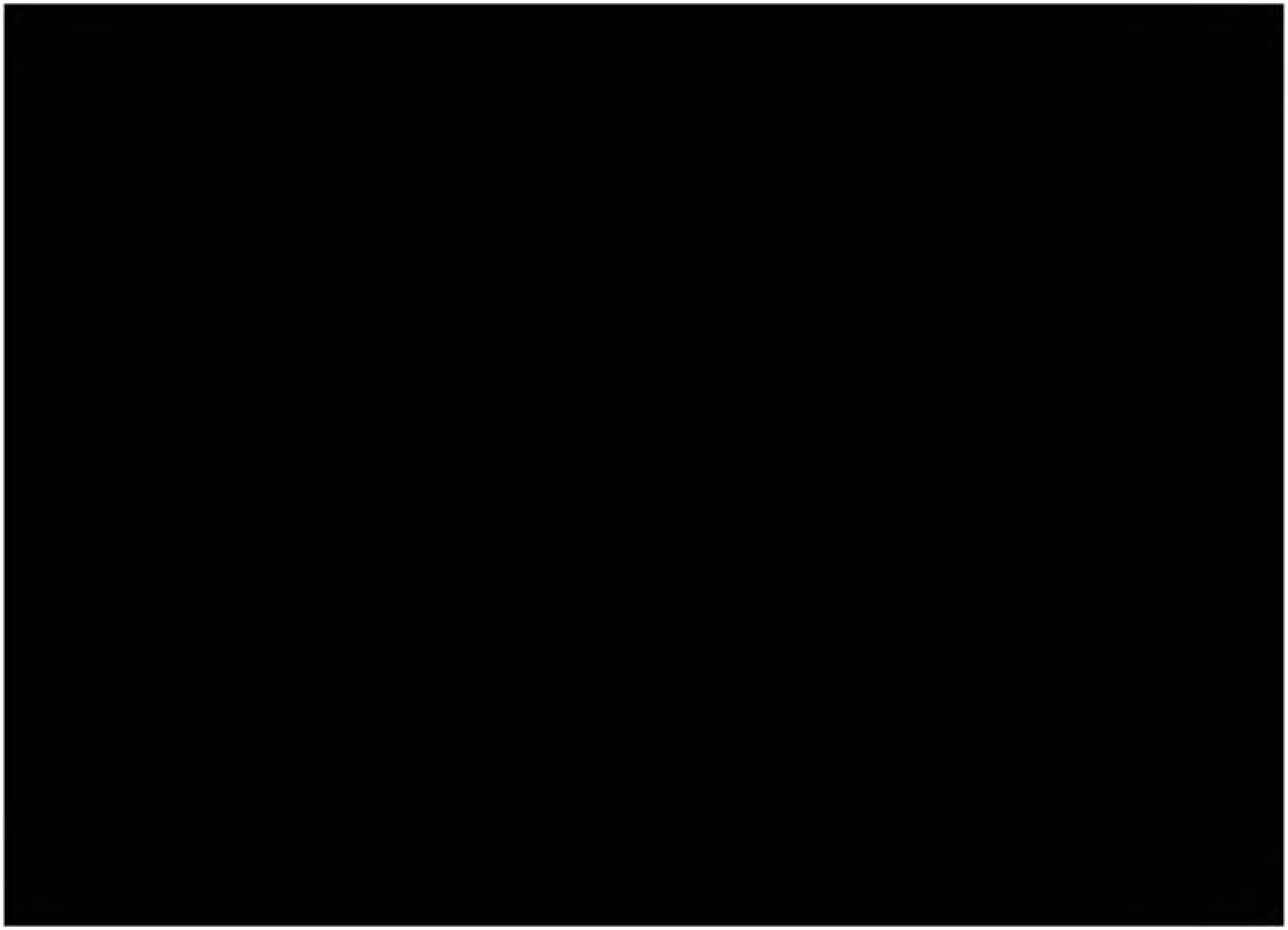

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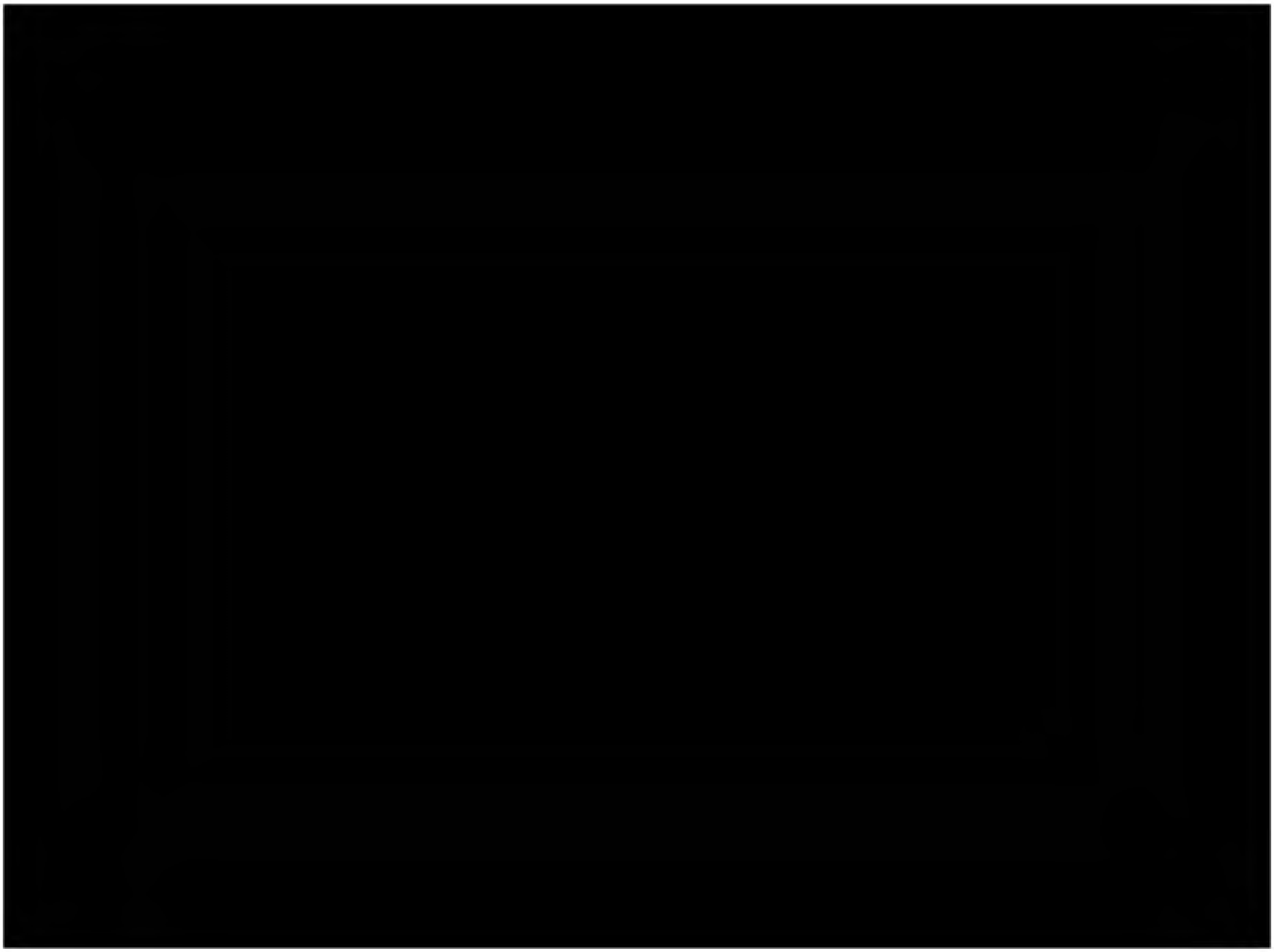

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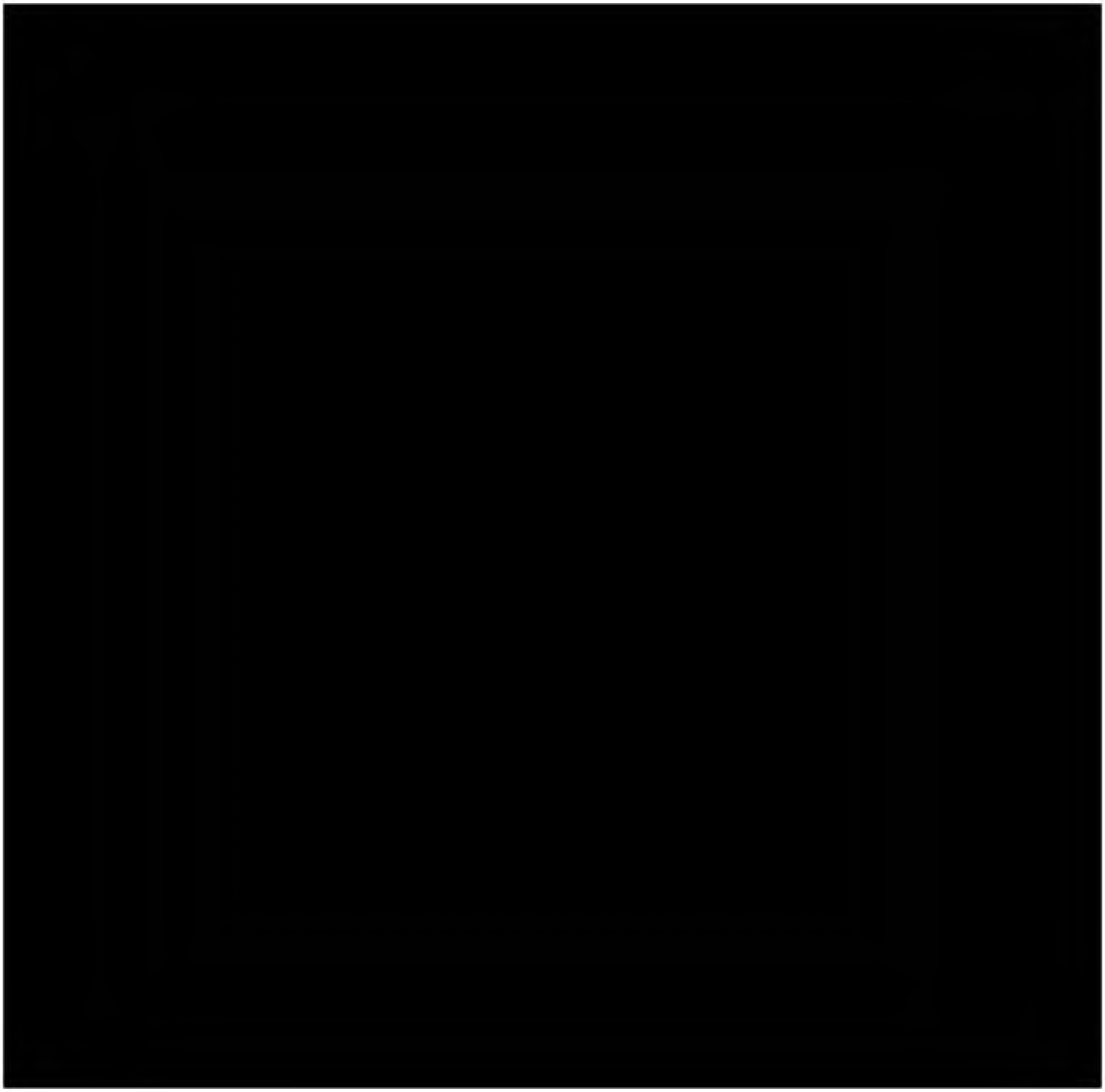

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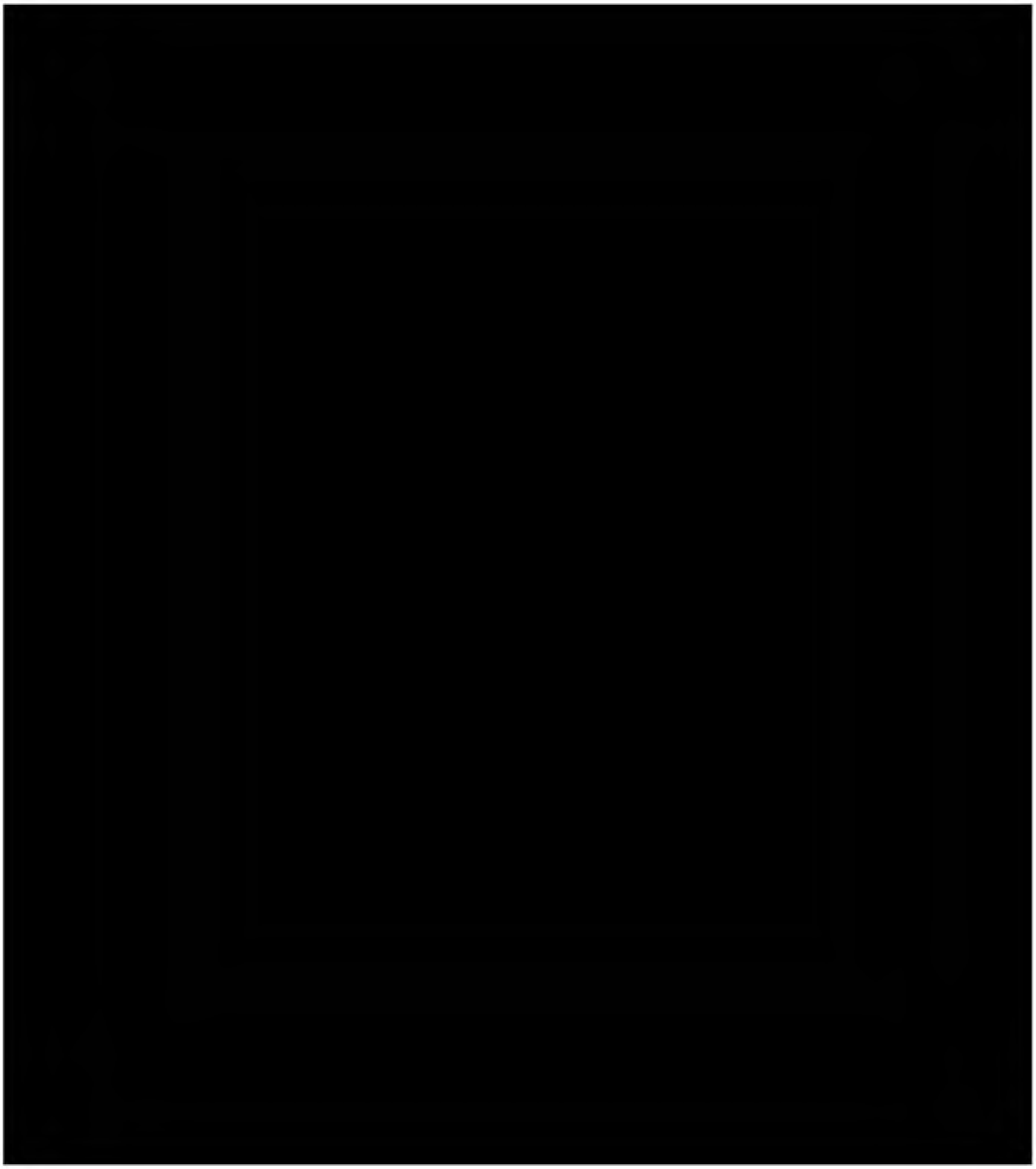

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NARRATIVE REPORT - TABLES

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[redacted]

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Table 2.6-1. Data from USGS earthquake catalog for faults in the region of CTV III.

[redacted]

[redacted]

[redacted]

1= All depths are based on feet below ground surface
WCR= Department of Water Resources Well Completion Report
LAT= Latitude
LONG= Longitude
T= Township
R= Range
S= Section
APN= Assessor Parcel Number
NA= Data is not available or not applicable
GAMA= State Water Board's GAMA website