ATTACHMENT A2: CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(a)

Elk Hills A1-A2 Storage Project

CTV plans to utilize existing injectors, 357-7R and 355-7R, for the Elk Hills A1-A2 Storage project.

Wells 357-7R and 355-7R are 1,300 feet apart and will inject CO_2 into the Monterey Formation A1-A2 reservoir. Plume development from each of the wells will coalesce into the larger Monterey Formation A1-A2 AoR. The following documents provided for injector 357-7R are valid for injector 355-7R and will not be resubmitted:

> Attachment A: Narrative Site Characterization (with exception of the well construction and operating procedures.)
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> Attachment B: AoR and Corrective Action Plan
>
> Attachment C: Testing and Monitoring Plan
>
> Attachment E: Post Injection Site Care and Site Closure Plan
>
> Attachment F: Emergency and Remedial Response Plan, and
>
> Quality Assurance and Surveillance Plan

Submission for well 355-7R includes Attachment A2: Narrative for an overview of 355-7R well construction and operational procedures, Attachment G2: Construction Details, and Attachment D2: Injection Well Plugging Plan.

Injection Well Construction

CTV plans to utilize existing injectors, 357-7R and 355-7R, for the Elk Hills A1-A2 Storage project. These injectors are currently approved by CalGEM for Class II injection of up to 50 million cubic feet per day gas (up to 44% CO_2) for the purpose of reservoir pressure maintenance. These wells have been engineered for the injection of CO_2 with appropriate materials able to minimize corrosion and to ensure that the wellbore stresses are within specifications and standards given the planned operating conditions. Previous and current injectors used to maintain reservoir pressure injected 175 billion cubic feet of natural gas with injection rates as high as 30 million cubic feet per day for individual wells.

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

Injectate Migration Prevention:

355-7R was drilled in 1973, at which time there were no drilling and completion issues. The well was constructed to prevent migration of fluids out of the Monterey Formation, protect the shallow formations, and allow for monitoring, as described by the following:

1. Well design exceeds criteria of all anticipated load cases including safety factors
2. Multiple cemented casing strings protect potential shallow USDW-bearing zones from contacting fluids within the production casing
3. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement. 13-3/8" and 9-5/8" casing string were cemented with 30 cubic feet and 35 cubic feet returns to surface, respectively.
4. Cement bond log (CBL) indicates presence of cement in the production casing annulus well above the Reef Ridge Shale confining layer and consistent with cementing operations results. Cement is present throughout the entire CBL logging interval, from base of 7" casing to ~5200 feet.
5. Upper completion design enables monitoring devices to be installed downhole, cased hole logs to be acquired, and Mechanical Integrity Testing (MIT) to be conducted
6. Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions
7. 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

Materials:

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

1. Tubing – material selection consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
2. Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
3. Packer – corrosion resistant alloy material or coating and hardened rubber
4. Casing and Cement - N-80 and K-55 casing with 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 with good cement bond between formation and casing into the Reef Ridge Shale

The well will be reconfigured with corrosion resistant materials and will be tested for mechanical integrity prior to injection.

Standards:

Well materials follow the following standards:

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

Casing and Cementing

Casing:

Monterey Formation A1-A2 temperature is approximately 240 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet standards. Temperature differences between the CO_2 injectate and reservoir will not affect well integrity.

Casing specifications are presented in Table 5. These specifications show that the well was engineered to standards that allow for the safe operation at the conditions outlined in Table 8 in operating parameters. Wells with similar construction methods have been used in Elk Hills for gas injection with no operational issues related to the structural strength.

Table 5: Casing Specifications for the 355-7R injector.

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14 - 60	20.000	19.5	52	H-40	Short	31	875	90
Surface	14 - 500	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	14 - 520 520 - 3,393	9.625	8.835	40	N-80 K-55	Long	31	5,750 3,950	3,090 2,570
Long-string	14 – 43 43 – 4,089 4,089 – 5,796 5,796 – 8,363 8,363 – 9,500	7.000	6.184 6.366 6.276 6.276 6.184	29 23 26 26 29	N-80 K-55 K-55 N-80 N-80	Long	31	8,160 4,360 4,980 7,240 8,160	7,020 3,270 4,320 5,410 7,020

Cement:

Class G Portland cement has been used to complete the well. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The cement returns were to surface for the 13-3/8" and 9-5/8" casing strings. Cement bond log

(CBL) indicates the top of cement is above 5,200 feet (top of CBL logged interval), which is well above the top of the upper confining layer.

Protection of USDW:

The USDW and all strata overlying the injection zone will be protected by the following:

1. A CBL log was run on the well post completion to ensure adequate bond to casing and formation.
2. SAPT tests that pressure the well annulus to 500 PSI for 30 minutes have been acquired through time. All SAPT's demonstrate that the production casing (and packer) has mechanical integrity, with no casing or packer leaks. SAPT will be acquired before the start of injection and every five years thereafter.
3. If there are mechanical integrity issues in the future, CTV will run a casing inspection log to assess casing thickness.

Tubing and Packer:

The information in this table meets the minimum requirements at 40 CFR 146.86(c). Tubing specifications in Table 6 are for the current well configuration. CTV plans to configure the well with corrosion resistant tubing.

Table 6. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	8,398	00	3.920	135	L-80	Long	9,020	8,540

Table 7. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Baker-Hornet, Ni plated	8,403	95.4	23-29	6.000	2.920

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
100,000	8,000	8,000	6.466	6.184

Well Operation

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

Injectors will be operated to inject the desired rate of super-critical (SC) phase CO_2. For attaining SC flow, surface injection pressure will be a minimum of 1,200 PSI. As the depleted oil reservoir fills up, a higher surface injection pressure will likely be required. Final reservoir pressure target is 4,000 PSI. It is assumed that at shut-in, the downhole injection pressure will be ~4,500 PSI.

Table 8 values shown below for average injection pressure are an average of initial conditions and final conditions. As the reservoir fills up with CO_2 it will pressure up, thus creating a continually changing reservoir and injector condition over injection life. A downhole injection pressure of ~4,500 PSI is assumed to occur at shut-in timing when reservoir pressure has reached its final level at 4,000 PSI. This translates to a surface injection pressure of ~1,600 PSI, which will be achieved via a surface booster pump.

The final/maximum values for surface and downhole injection pressures are far below (~2,000 psi) those associated with the Class II permitted fracture gradients of 0.8 psi/foot with a 10% safety factor. 40+ years of gas and water injection experience into the Monterey Formation A1-A2 reservoir supports that these operating limits are appropriate and effective. Additionally, the final reservoir pressure target of 4,000 PSI is significantly below the Reef Ridge confining shale estimated minimum geomechanical failure pressure of ~7,500 PSI.

Table 8. Proposed operational procedures.

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure	UIC Class II frac gradient 0.8 psi/ft (with 10% Safety factor)	
Surface	2,900	psig
Downhole	6,108	psig
Injection Pressure	Average over time	
Surface Average / Maximum	1,400 / 1,600	psig
Downhole Average/ Maximum	4,300 / 4,516	psig
Maximum Injection Rate	30 per well	mmscfpd
Average Injection Rate	10-15 per well	mmscfpd
Maximum Injection Volume and/or Mass	10 million	tonnes
Average Injection Volume and/or Mass	8 million	tonnes
Annulus Pressure	3,720 @ packer	psig
Annulus Pressure/Tubing Differential	578 @ packer @ average injection condition	psig

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 Monterey Formation A1-A2 sequestration. These include capture off of the Elk Hills NGCC Power Plant as well as 3rd party existing and proposed industrial sources in the Southern San Joaquin Valley area. 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#/mmscf) and oxygen level (<50 ppm).

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#/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. In early injection time, it is likely that gas phase CO_2 will exist towards the lower depths of the tubing string. Tubing with metallurgy appropriate for the CO_2 stream specification will be selected in the injection wells to mitigate this potential corrosion impact should free-phase water be present.

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)]***