MONITORING WELL CONSTRUCTION AND PLUGGING DETAILS

Elk Hills A1-A2 Storage Project

Above Zone Monitoring Well, 327-7R-RD1

Facility Information

Facility Name: Elk Hills A1-A2 Storage Project
327-7R-RD1 Above Zone Monitoring Well

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Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – CP Details_327-7R-RD1	1	11/4/22	Original document, combines well construction, and plugging plan into monitoring well narrative document.
Attachment G – CP Details_327-7R-RD1	2	05/14/2023	In response to EPA questions 03/2023

Introduction

CTV requires three monitoring wells for the Elk Hills A1-A2 Storage Project. CTV intends to repurpose two existing wells for monitoring of both the injection interval and one above zone monitoring. Figure 1 identifies the wells proposed for monitoring the storage project. This document describes the construction, recompletion, logging, testing, operating, and plugging plans for above zone monitoring well 327-7R-RD1.

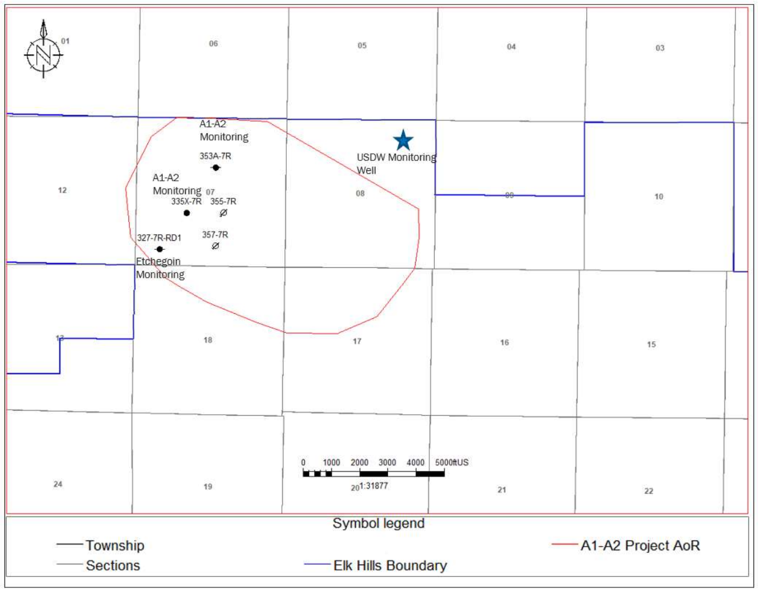

Figure 1: Map showing the location of injection wells and monitoring wells.

Monitoring well 327-7R-RD1 is an existing oil and gas production well that was drilled in 2000 and is currently inactive. CTV understands the well to be appropriately located, constructed, and in suitable mechanical condition to be re-used for monitoring this sequestration project. As specified in the Testing and Monitoring Plan, CTV plans to conduct an evaluation of mechanical integrity during pre-operational testing to ensure internal and external mechanical integrity.

The *Appendix: A1-A2 Injection and Monitoring Well Schematics* document provides casing diagram figures for all monitoring wells with construction specifications and anticipated completion details in graphical and/or tabular format.

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

Injectate Migration Prevention and Protection of USDW

327-7R-RD1 was drilled in 2000, at which time there were no drilling and completion issues. The base of USDW is located at 849’ MD & TVD in this well. The well was constructed in such a way as to prevent migration of fluids out of the injection zone and allow for monitoring required in the Testing and Monitoring Plan. Well construction details that support the protection of USDW and all strata overlying the injection zone are described by the following:

1. Surface Casing is set and cemented across the base of the USDW interval to surface such that, in combination with the 9-5/8” production casing, multiple casing strings protects shallow USDW-bearing zones from contacting fluids within the production tubing.

2. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement. The surface casing was cemented with cement returns to surface. The 9-5/8" casing string was cemented with a theoretical volume to surface, but cement returns were not observed. The 5-1/2" liner was cemented successfully and will be isolated with cement plugs internally and above as part of the recompletion to monitor the reservoir above the confining layer.
3. Upper completion design (injection tubulars, packer, and wellhead) enables monitoring devices to be installed downhole, cased hole logs to be acquired, samples to be obtained, and Mechanical Integrity Testing (MIT) to be conducted.
4. Standard annular pressure tests (SAPT) demonstrate that the long string casing, tubing, packer, and wellhead have mechanical integrity. Internal MIT will be performed before the start of injection and any time the packer is reset to demonstrate isolation and integrity of primary barriers (tubing, packer, wellhead) and secondary barriers (casing, wellhead) for the protection of potential USDW. 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.
5. Realtime surface monitoring equipment with alarms and remote connectivity to a centralized facility provides continual awareness to potential anomalous pressure conditions.

The 327-7R-RD1 monitoring well was constructed using industry standards and recommended practices. Existing and future well materials comply with the following specifications.

1. API Spec 5CT / ISO 11960 – Specification for Casing and Tubing
2. API Spec 5CRA / ISO 13680 – Specification for Corrosion-Resistant Alloy Seamless Tubes for use as Casing, Tubing, and Coupling Stock
3. API Spec 10A / ISO 10426-1 – Cements and Materials for Cementing
4. API Spec 11D1 / ISO 14310 – Downhole Equipment – Packers and Bridge Plugs
5. API Spec 6A / ISO 10423 – Specification for Wellhead and Tree Equipment

Materials

Current well materials are compatible with the Etchegoin formation fluids and are suitable for the monitoring purposes intended.

1. Tubing – standard N-80 grade carbon steel tubing is appropriate and is consistent with accepted industry practices and field experience.
2. Wellhead – standard grade carbon steel material
3. Packer – standard carbon steel and elastomer material consistent with accepted industry practices.
4. Casing – the standard grade N-80 and P-110 casing is appropriate and is consistent with accepted industry practices and field experience

5. Cement – Class G and Class C portland cement used in constructing the well is appropriate for monitoring in the reservoir above the confining layer.

Casing

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at expected bottomhole monitoring conditions.

The Etchegoin Formation temperature is approximately 170 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet industry standards. Logging data to assess casing corrosion to be collected during pre-operational testing will be used to ensure the current condition of the casing will withstand the operational load associated with maintaining annular fluid and pressure.

Table 1: Casing Specifications for the 327-7R-RD1 Monitoring Well

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	20' - 60'	20	19.124	94	-	-	2.62	-	--
Surface	20' - 2337'	13.375	12.515	61	K-55	Short	2.62	3090	1540
Long-String	20' - 6382' 6382' - 8245'	9.625	8.755 8.681	43.5 47	N-80 P-110	Long	2.62	6330 9440	3810 5300
Liner	8059’ – 9842’	5.5	4.892	17	N-80	Long	2.62	7740	6390

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

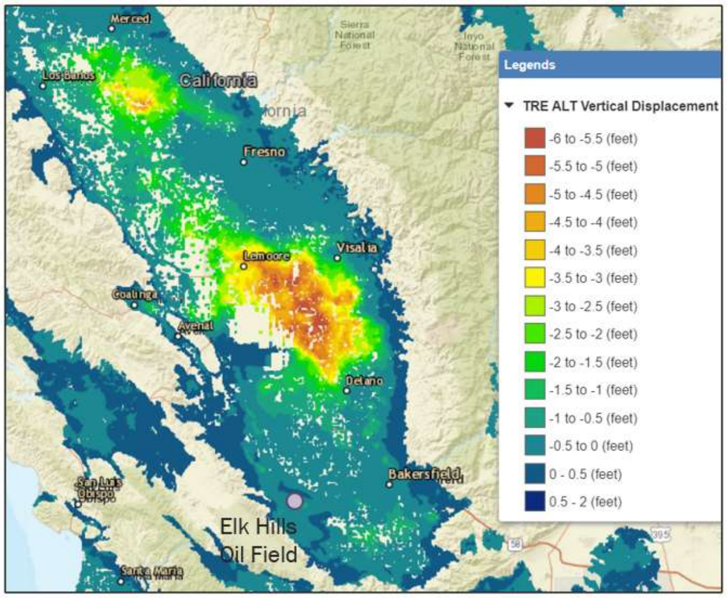

Figure 2: Subsistence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Cement

Portland cements have been used to cement the well. Portland cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The 13-3/8" casing was cemented using Class C portland cement with 60 bbls returns to surface. The 9-5/8" production casing was cemented using Class G portland cement with circulation throughout the job and no cement returns. No cement evaluation log was acquired at the time of installation. Cement evaluation logging will be performed to ensure annular isolation and well integrity during conversion activities for Etchegoin reservoir monitoring.

Tubing and Packer

Table 2 provides monitoring tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c).

Table 2. 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	3762'	2.875	2.441	6.5	N-80	Short	10,570	11,170

Table 3 provides specifications of a hydraulic packer suitable to use in this application. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel. The proposed packer setting depth is within a cemented interval of the 9-5/8" casing string.

Table 3. 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)
Hydraulic, low carbon alloy steel	3732'	30.3	40-47	8.452	2.416

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
50,000	10,000	10,000	8.835	8.681

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 9-5/8" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, monitoring wells will be configured with realtime downhole pressure, temperature, and annular pressure monitoring and alarms. Monitoring wells will have wellhead equipment sufficient to prevent leakage at surface. The wellhead tree will include redundant valves. Safety valves or other automatic shut-off devices are not required for monitoring wells in general.

Logging and Testing

Logging and testing data that was acquired during initial well construction is provided below. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be acquired during pre-operational testing. Table 4 summarizes the pre-injection logging data and tests that CTV will acquire during the pre-operational testing and construction phase.

Table 4: Summary of Remaining Pre-Operational Logging and Testing

Data Collection Location(s)	Logging or Testing Activity	Spatial Coverage or Depth
327-7R-RD1	Cement Bond Log	Along the 9-5/8" casing to surface
	Casing Inspection Log	Along the 9-5/8" casing to surface
	Internal MI: SAPT	Casing/tubing annulus above packer
	External MI (at least one of): Oxygen Activation Log Noise Log	Along the 9-5/8" casing to surface

Deviation Checks During Drilling

Deviation checks were acquired during drilling at varying frequency from ~1007’ feet measured depth (MD) to bottom hole at 9843’ feet MD (Table 5).

Table 5: Deviation checks during drilling for the 327-7R-RD1 well.

MD	INC	AZI	TVD		MD	INC	AZI	TVD
0	0	0	0		8767	22.9	202.7	8714.7
1007	2	357	1006.8		8799	23.8	205.1	8744.1
1505	2	0.88	1504.5		8831	24.6	207.9	8773.2
2307	1.75	358	2306.1		8862	25.6	211.4	8801.3
2838	1.75	13	2836.8		8894	27.5	215	8829.9
3331	2.25	5	3329.5		8926	28.9	218.5	8858.1
3841	2.75	12	3839		8957	30.3	223	8885.1
4328	3	15	4325.4		8987	32.1	225.5	8910.8
4876	3.75	22	4872.5		9019	34.2	227.3	8937.6
5627	3	26	5622.2		9050	36.5	228.7	8962.8
6114	1	49	6108.8		9082	38.8	231.1	8988.2
6619	1.5	150	6613.8		9114	41.4	232.2	9012.7
7125	2	178	7119.5		9145	43.9	233.9	9035.5
7567	2	163	7561.3		9177	46.5	235	9058
7807	2.4	164.7	7801.1		9208	47.8	236.8	9079.1
7870	6.1	179.8	7863.9		9239	48.7	236.8	9099.7
7933	11.5	183.3	7926.1		9303	50.5	236.7	9141.2
7995	16.4	187.2	7986.3		9365	51.7	236.1	9180.1
8058	18	188.2	8046.5		9426	55.3	237.8	9216.4
8121	18.6	186.8	8106.3		9489	55	237.8	9252.4
8185	18.9	185.8	8166.9		9521	53	238.5	9271.2
8245	19.19	183.79	8223.6		9551	51.2	238.5	9289.7
8401	18.5	178	8371.3		9614	51.2	239.2	9329.1
8433	18.8	179.5	8401.6		9646	52.9	241.3	9348.8
8496	19.2	178.4	8461.2		9677	54	242	9367.3
8559	19.5	186.8	8520.6		9741	53.7	242	9405
8622	20.7	190.4	8579.8		9800	54	242	9439.8
8684	21.1	196.3	8637.7		9843	54	242	9465.1
8748	22.4	199.5	8697.1					

Open Hole Log Analysis

Open hole wireline log data was acquired prior to installation of the long string casing. Figure 3 provides the results of these measurements that include spontaneous potential, natural gamma ray, and resistivity.

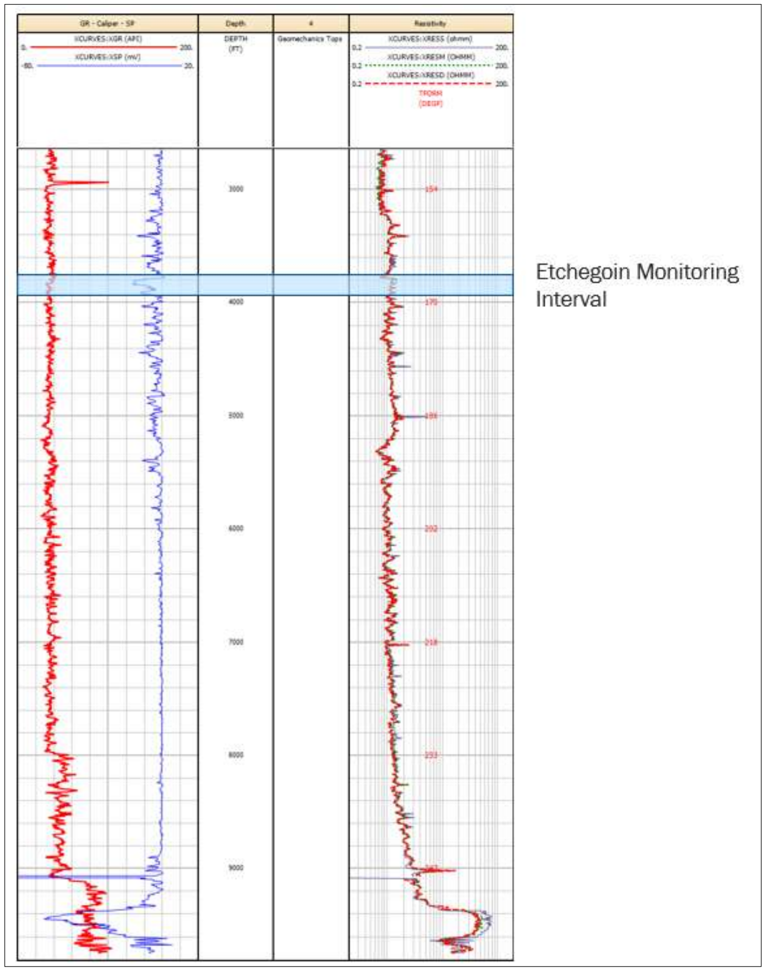

Figure 3: Open-hole well logs for 327-7R-RD1

Cement Evaluation

The cement bond log amplitude and variable density log (VDL) acquired at the time of construction was not logged across the entire confining layer. Cement was observed at the top of the liner interval, but no cement bond log was run on the 9-5/8" casing. The Pre-Operational Testing plan document specifies additional cement evaluation logging to be performed across the entire 9-5/8" casing string during pre-operational testing.

MIT – Internal: Standard Annular Pressure Test (SAPT)

SAPT is conducted to demonstrate that the tubing/packer/casing annulus system is presently not leaking and can provide a sufficient secondary barrier in the event of a tubing or packer leak. The SAPT test pressure and duration will be consistent with EPA-approved SAPT requirements and procedures. This testing will occur during installation of tubing string prior to injection, and this procedure is described in the Testing and Monitoring document.

MIT – External: Noise Log or Oxygen Activation Log

Noise logs and oxygen activation logs are approved forms of external mechanical by the EPA. An approved log would indicate tubing integrity and show no migration of injectate through the casing cement above the top perforation. An evaluation of external MIT using at least one of these approved methods will be performed during pre-operational testing and establish a baseline survey to support future external MIT evaluations during injection. These logging procedures are described in the Testing and Monitoring document.

Monitoring Well Plugging Plan

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

Planned Tests or Measures to Determine Bottomhole Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottomhole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity test prior to plugging the monitoring well as required by 40 CFR 146.92(a). A temperature log or other approved external MIT will be run over the entire depth. The external MIT method will be a temperature log or other approved external MIT, and the procedure will be EPA-approved and consistent with procedures outlined in the Testing and Monitoring Plan. If a temperature log is run for external MIT, the temperature data will be evaluated for anomalies in the temperature profile by comparing to baseline temperature data acquired prior to injection of CO_2 and during the injection phase. If another approved external MIT method is used, it will be compared to baseline pre-injection data and/or other data acquired throughout the injection phase which the EPA has deemed acceptable.

Information on Plugs

CTV will use the materials and methods noted in Table 6 to plug the monitoring well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. 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 wells will have this cement placed as detailed in Table 6, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures. Note that ground level corresponds to 20' MD due to the depth reference to the kelly bushing 20' above ground level during drilling.

Table 6: Plugging details

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	8.681	8.755	8.755	8.755
Depth to bottom of tubing or drill pipe (ft)	8059	3934	1484	45
Sacks of cement to be used (each plug)	224	412	268	10
Slurry volume to be pumped (bbl)	45.88	84.38	54.89	2.05
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	7433	2802	749	20
Bottom of plug (ft)	8059	3934	1484	45
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or Coiled-Tubing Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Monitoring Well Plugging Plan, if applicable.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.
2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.
3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).
4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up hole while cementing operations continue.
5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.
6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.
7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.
8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.

- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L TDS):

    - If there is cement behind the casing across the base of USDW (if present), a 100-foot cement plug shall be placed inside the casing across the interface.

    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.

- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.