ATTACHMENT G2: SONOL SECURITIES 3 CONSTRUCTION AND PLUGGING PLAN

CTV II – Storage Project

Injection Well Sonol Securities 3

1. Version History

File Name	Version	Date	Description of Change
Att G – Well Construction details	1	5/3/22	Original submission for CTV II project.
Att G – Well Construction and Testing_CTV II V2	2	8/4/22	Updated submission to address EPA administrative review request dated 6/9/22.
Att G2 – CP – Inj - Sonol 3	3	12/14/22	Generated separate construction and plugging for repurposed Sonol Securities 3 well
Att G2 – CP – Inj - Sonol 3	3.1	2/2/23	Updated to correct typos

2. Introduction

CTV plans to utilize three existing gas wells as injectors (Sonol Securities 1-A, Sonol Securities 3, and Pool B-2) and drill two new injection wells (UI-Inj-1 and UI-Inj-2) for a total of five injection wells for the CTV II storage project. The wells are in Sections 10, 16 and 21 within the unit boundary of the Union Island Gas Field. Sonol Securities 1-A, Sonol Securities 3, and Pool B-2 are 6', 7', and 0' above mean sea level, respectively. These injectors are currently approved by CalGEM as gas producers. Figure 1 identifies the location of injection wells and monitoring wells.

Proposed injection well Sonol Securities 3 (API #04-077-20171) is an oil and gas production well that was drilled in 1972 and is currently inactive. CTV understands the well to be appropriately located, constructed, and in suitable mechanical condition to be re-used for injection in 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.

Appendix 5 - 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.

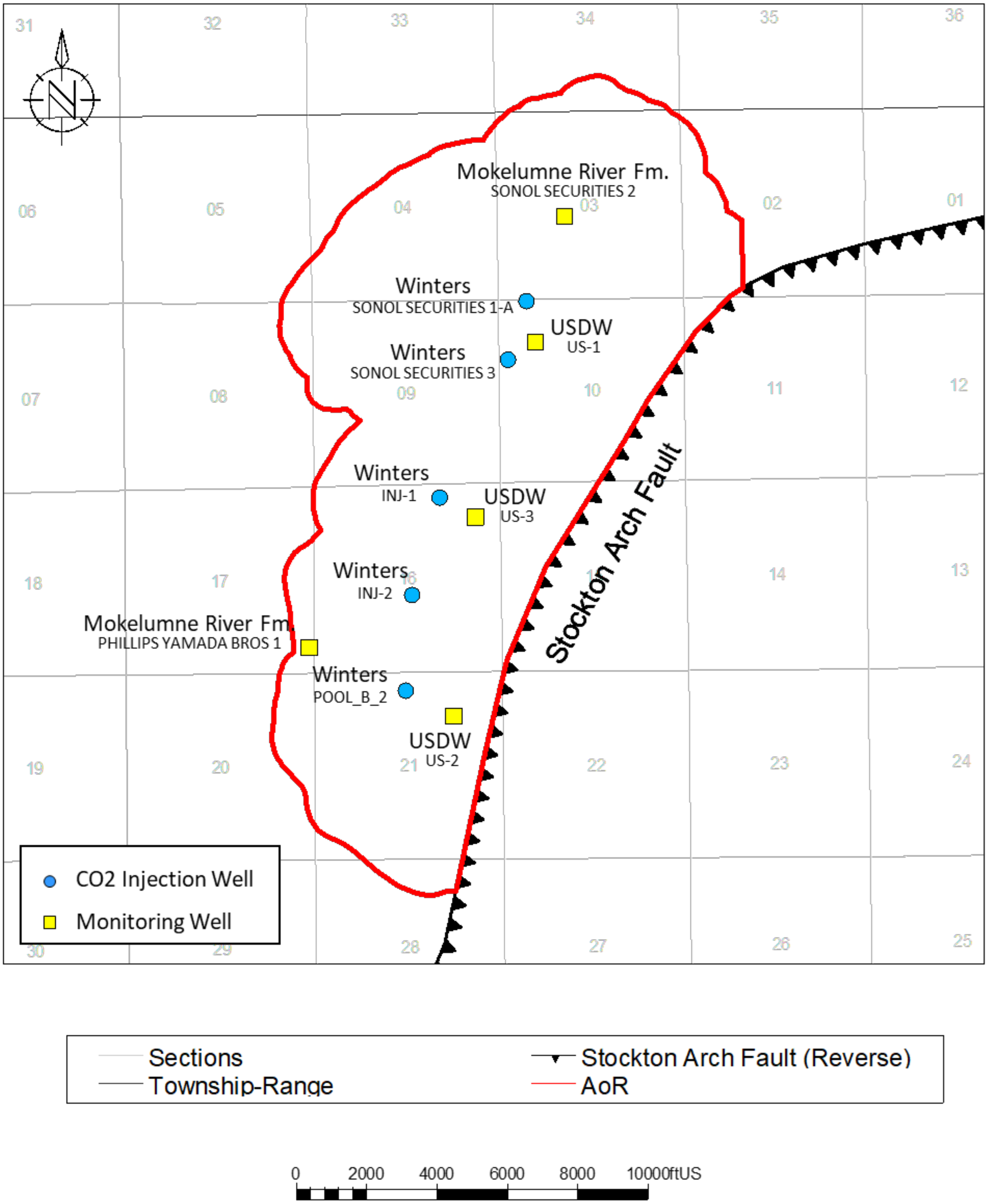

Figure 1. Map showing the location of injection and monitoring wells that will monitor zones above the upper confining zone.

3. <u>Construction Details (40 CFR 146.82(a)(12)</u>

3.1. Injectate Migration Prevention and Protection of the USDWs

Sonol Securities 3 was drilled in 1972, at which time there appears to have been some minor drilling and completion issues (casing damage and junk in hole), none of which should impact well usage. The base of the USDW is located at 2,374' MD & TVD in this well. The well was constructed 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 USDWs and all strata overlying the injection zones are-described by the following:

- Well design exceeds criteria of all anticipated load cases including safety factors
- Multiple cemented casing strings protect potential shallow USDW-bearing zones from contacting fluids within the production casing
- 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 the surface. The intermediate casing string was cemented with cement returns to the surface. The long-string casing was cemented with a calculated top of cement at approximately 7,700'.
- 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.
- Standard annular pressure tests (SAPT) will be performed as noted in Section 5 below). 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.
- Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms will provide 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

The Sonol Securities 3 injection well was constructed using industry standards and recommended practices. Existing and future well materials comply with the following specifications.

- API Spec 5CT / ISO 11960 – Specification for Casing and Tubing
- API Spec 5CRA / ISO 13680 – Specification for Corrosion-Resistant Alloy Seamless Tubes for use as Casing, Tubing, and Coupling Stock
- API Spec 10A / ISO 10426-1 – Cements and Materials for Cementing

- API Spec 11D1 / ISO 14310 – Downhole Equipment – Packers and Bridge Plugs
- API Spec 6A / ISO 10423 – Specification for Wellhead and Tree Equipment

3.2. Materials

Well materials utilized will be compatible with the CO_2 injectate to prevent loss of mechanical integrity in the well:

- Tubing – corrosion-resistant alloy (CRA) consistent with accepted industry practices for corrosion mitigation based on a mixture of formation fluids and injectates.
- Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on a mixture of formation fluids and injectates.
- Packer – corrosion resistant alloy material or coating and hardened rubber elastomer element material.
- Casing – the standard N-80 casing which is currently installed will be demonstrated to be compatible with the CO_2 injectate through corrosion coupon monitoring as discussed in the Testing and Monitoring document.
- Cement- portland cement has been used extensively in enhanced oil recovery (EOR) producers for decades. Data acquired from existing wells supports that the cement is compatible with CO_2 when good cement bond between formation and casing exists within the Winters Injection and Starkey-Sawtooth Confining Zones.

3.3. Casing

Winters formation temperature is approximately 218 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. 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. 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.

Table 1. Casing details

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)
Surface	0-1,007’	13.375	12.615	54.5	K-55	Short	2.62	2,730	1,130
Intermediate	0-5,618’	9.625	8.755	43.5	N-80	Long	2.62	6,330	3,810
Long String	0-9,927’	5.5	4.778	20	N-80	Long	2.62	8,990	8,830

Subsidence in the region 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 Union Island Gas Field. As shown in Figure 2, recent subsidence data demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

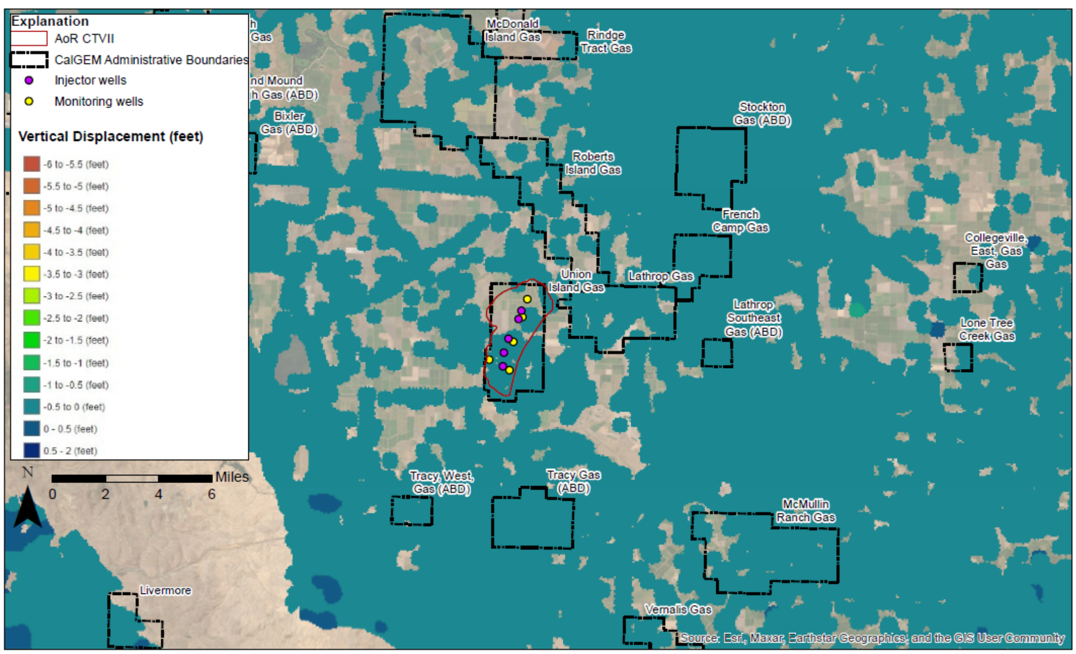

Figure 2. Subsidence in the Union Island Field is -0.5 to 0 feet for June 2015 to July 2022. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

3.4. Cement

Class G portland and Poz D cement were used to cement the well. These cements are 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 surface casing. The intermediate casing string was also cemented to surface. The long-string casing string was cemented in place with Class G portland cement with a calculated top of cement at approximately 4,213'. The liner was cemented in place with the top of cement at approximately 9,352 feet, the top of the liner. Subsequently, a CBL was reported to be run from 9,878 to 7,700', the top of cement.

3.5. Tubing and Packer

The information in the tables provided in Table 2 and Table 3 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 may be modified prior to conversion during pre-operational testing.

Table 2 provides injection tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c). The tubing and packer that are currently installed will be removed prior to injection. A suitable corrosion-resistant alloy will be installed once the CO_2 stream impurities and impurity concentrations have been determined. The grade identified in Table 2 is anticipated to be acceptable.

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	9,570	3.5	2.992	9.3	L-80 CRA	Premium	10,160	10,530

At the beginning of CO_2 injection, CO_2 may be in direct contact with free phase water in the wellbore because of well work, until the free phase water is displaced into the formation. After initial displacement, no free phase water is expected in the wellbore. Tubing integrity is maintained with minimal and acceptable corrosive impact due to the CRA material selection and very limited duration of multi-phase injection.

Table 3 provides specifications of a sealbore 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 depths are within a cemented interval of the long-string 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)
Permanent Sealbore Packer, CRA	9,540	30.3	23-32	5.687	3.25

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
200,000	7,500	7,500	6.366	6.049

3.6. 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 long-string casing and external corrosion of the tubing.

3.7. Injectate and Formation Fluid Properties

Details about the proposed Injectate composition and properties can be found in Section 7.2 of the Narrative document. Similarly, the formation fluid composition and properties can be found in Section 2.8.2 of the Narrative document.

The anticipated injection temperature at the wellhead is 90 – 130° F.

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 a <25 lb/mmscf 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 (Section 2.8.2 of the Narrative Document) does not indicate corrosiveness to standard cement and casing materials.

Injectate and formation water analysis will be obtained during pre-operational testing and reviewed to ensure compatibility with well construction materials

3.8. Alarms and Shut-off devices

As described in the Testing and Monitoring Plan, injection wells will be configured with real-time injection rates, 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 EPA Preamble to the Class VI Rule states (Federal Register Vol.75, No.237, p.77258): "EPA believes that requiring automatic surface shut-off devices instead of down-hole devices provides more flexibility to owners or operators when performing required mechanical integrity tests. Additionally, this requirement addresses concerns about risks associated with routine well workovers that may be complicated by the presence of down-hole devices while still maintaining USDW protection." For these reasons CTV will design Sonol Securities 3 with a surface shut-off valve at the wellhead and not a down-hole device.

4. <u>Existing Logging and Testing</u>

Logging and testing data that was acquired during initial well construction is provided in the following discussion. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be acquired during pre-operational testing. Appendix 6.2 includes copies of previously acquired logs.

- Dual Induction-Laterolog: A Dual Induction-Laterolog was acquired during drilling to 9,962 feet.
- Cored: Core log was acquired during drilling from 9,692 feet to 9,723 feet.

5. <u>Pre-Operational Logging and Testing</u>

The following tests and logs will be conducted prior to converting the gas well into an injection well, in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The tests are listed below and methods are described in the Testing and Monitoring Plan. 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
Sonol Securities 3	Cement Bond Log	Along the long-string casing to surface
	Casing Inspection Log	Along the long-string casing to surface
	Internal MI: SAPT	Casing/tubing annulus above packer
	External MI (at least one of): Oxygen Activation Log Noise Log	Along the long-string casing to surface
	Pressure Fall-off Testing	Injection Zone

6. Well Operation

Injection operation conditions of Sonol Securities 3 are detailed in the document titled Appendix 4 - Operational Procedures_V2.

7. 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.

7.1. Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottom hole pressure gauge. During plugging operations, the weighted cement slurry displacement fluids will be overbalanced to the reservoir pressure ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

7.2. Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity prior to plugging the injection well as required by 40 CFR 146.92(a). A temperature log will be run over the entire depth of each sequestration well. Data from the logging runs will be evaluated for anomalies in the temperature curve, which would be indicative of fluid migration out of the injection zone. Data will be compared to the data from temperature logs performed prior to injection of CO_2. Deviations between the temperature log performed before, after and during injection may indicate issues related to the integrity of the well casing or cement.

7.3. Information on Plugs

CTV will use the materials and methods noted in Table 5 to plug the injection 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 with specifications consistent with API Spec 10A 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 consistent with the properties of Class G portland cement used in well construction, 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 5, 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 14' MD due to the depth reference to the kelly bushing 14' above ground level during drilling.

Table 5. Plugging details.

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (inches)	4.778	8.835	8.835	8.835
Depth to bottom of tubing or drill pipe (feet)	9,865	4,112	2,399	25
Sacks of cement to be used	40	46	46	9
Slurry volume to be pumped (bbl)	8.19	9.42	9.42	1.84
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (feet)	9,499	3,987	2,274	0
Bottom of plug (feet)	9,865	4,112	2,399	25
Type of cement or other material	Class G	Class G	Class G	Class G
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or Coiled-Tubing Plug			

7.4. 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 updated Injection Well Plugging Plan, if applicable.

7.5. 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, 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.