ATTACHMENT G3: CONSTRUCTION AND PLUGGING PLAN
INJECTION WELL UI-INJ-3
CTV II

Version History

File Name	Version	Date	Description of Change
Att G – Well Construction details	1	5/3/2022	Original submission for CTV II project.
Att G – Well Construction and Testing_CTV II V2	2	8/4/2022	Updated submission to address EPA administrative review request dated 6/9/22.
Att G3 – CP – Pool B2	3	12/14/2022	Generated separate construction and plugging for repurposed Pool B2 well
Att G3 – CP – Pool B2	3.1	2/2/2023	Updated to correct typos
Att G3 - CP - Inj – UI INJ 3 - DBS	4	11/26/2024	Updated to new drill UI-INJ-3; Response to August 29, 2024 EPA Comments

1. Introduction

CTV plans to drill five new injection wells (UI-INJ-1, UI-INJ-2, UI-INJ-3, UI-INJ-4, and UI-INJ-5) 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. **Figure G3-1** identifies the locations of injection wells and monitoring wells.

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 carbon dioxide (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 logging while drilling (LWD) and mud logs to ensure protection of shallow formations. The surface casing strings will provide multiple barriers of protection for underground sources of drinking water (USDWs) and shallow formations using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

Appendix 5: Injection and Monitoring Well Schematics (**Appendix 5**) provides casing diagram figures for all injection and monitoring wells with construction specifications and anticipated completion details in graphical and/or tabular format.

2. Construction Details (40 CFR 146.82(a)(12)

2.1 Injectate Migration Prevention and Protection of the USDWs

New well construction will occur during the pre-operational testing phase, 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 Winters Formation, to protect USDWs and the shallow formations, and to allow for monitoring, as described by the following:

- Well designs will exceed criteria of all anticipated load cases including safety factors.
- Multiple cemented casing strings will protect shallow USDW-bearing zones from contacting injection fluid within the production tubing.
- All casing strings will be cemented in place using industry-proven recommended practices for slurry design and placement. The surface casing will be cemented with cement returns to surface. The surface 2 and long-string casing will be cemented with a theoretical volume to surface.
- Cement bond logging (CBL) will be used to verify the 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 (injection tubulars, packer, and wellhead) enables monitoring devices to be installed downhole, cased hole logs to be acquired, samples to be obtained and MIT to be conducted.
- Standard annular pressure tests (SAPTs) demonstrate that the long string casing, tubing, packer and wellhead will 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 USDWs.
- Real-time surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual visibility to potential anomalous injection conditions. As specified in Attachment F: Emergency and Remedial Response Plan, Section 4.1, Automatic shutdown devices are activated when:
    - ◇ Wellhead pressure exceeds the shutdown pressure specified in the permit.
    - ◇ Annulus pressure indicates a loss of external or internal well containment.
- 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 UI-INJ-4 injection well will be 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

2.2 Materials

Well materials used will be compatible with the carbon dioxide (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: CRA 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 **Attachment C**.
- Cement: Portland cement has been used extensively in enhanced oil recovery (EOR) producers for decades. Data acquired from existing wells support 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.

2.3 Casing

Winters Formation temperature is approximately 218°F. 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 that the current condition of the casing will withstand the operational load associated with maintaining annular fluid and pressure. The casing specifications in **Table G3-1** 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.

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 G3-2**, recent subsidence data demonstrate no appreciable subsidence in the area of review (AoR). Therefore, subsidence does not pose a risk to well integrity within the storage project.

2.4 Cement

Class G portland cement will be used to cement 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 will be to surface for the Surface 1 casing. The Surface 2 casing string will also be cemented to surface. The long-string casing string will be cemented in place with Class G portland cement to surface. Subsequently, a CBL will be run to confirm annular isolation throughout and above the injection and confining formations (Section 5).

2.5 Tubing and Packer

The information in **Appendix 5** 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 during pre-operational testing.

Table G3-2 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). A suitable CRA will be selected and installed once the CO_2 stream impurities and impurity concentrations have been determined. The packer setting depth refers to the center of the element.

2.6 Annular Fluid

A 4 percent potassium chloride (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 bottom-hole temperatures to prevent internal corrosion of the long-string casing and external corrosion of the tubing.

2.7 Injectate and Formation Fluid Properties

Details about the proposed injectate composition and properties can be found in Section 7.2 of **Attachment A: Application Narrative** (**Attachment A**). Similarly, the formation fluid composition and properties can be found in Section 2.8.2 of **Attachment A**.

The anticipated injection temperature at the wellhead is 90 to 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 pounds per million standard cubic feet (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 supercritical 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 **Attachment A**) 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.

2.8 Alarms and Shut-Off Devices

As described in **Attachment C**, injection wells will be configured with real-time injection rates, injection pressure, and annular pressure monitoring and alarms. **Appendix 4: Operational Procedures** (**Appendix 4**) 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 used 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 UI-INJ-3 with a surface shut-off valve at the wellhead and not a downhole device.

3. Pre-Operational Logging and Testing

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. The tests are listed below and methods are described in **Attachment C** and **Attachment I: Pre-Operational Testing Plan** (**Attachment I**). **Table G3-3** summarizes the pre-injection logging data and tests that CTV will acquire during the pre-operational testing and construction phase.

CTV will notify EPA least 30 days prior to conducting mechanical integrity and formation tests and provide a detailed description of the testing procedure. Notice and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

4. Well Operation

Injection operation conditions are detailed in **Appendix 4**.

5. 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.

5.1 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.

5.2 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 (**Table G3-4**). 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.

5.3 Information on Plugs

CTV will use the materials and methods noted in **Table G3-5** 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 pounds per square inch (psi) compressive strength and a maximum liquid permeability of 0.1 millidarcy (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 G3-5**, 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.

5.4 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.

5.5 Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is used 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 downhole 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) 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 total depth (TD) during rig operations. Subsequent operations are carried out using a CTU.
4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100 feet' inside of the cement plug and is pulled uphole 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 uphole 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 uphole 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:

- Bottom-hole 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 (USDW defined as a non-exempt aquifer that has <10,000 milligram per liter [mg/L] total dissolved solids [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.

Figures

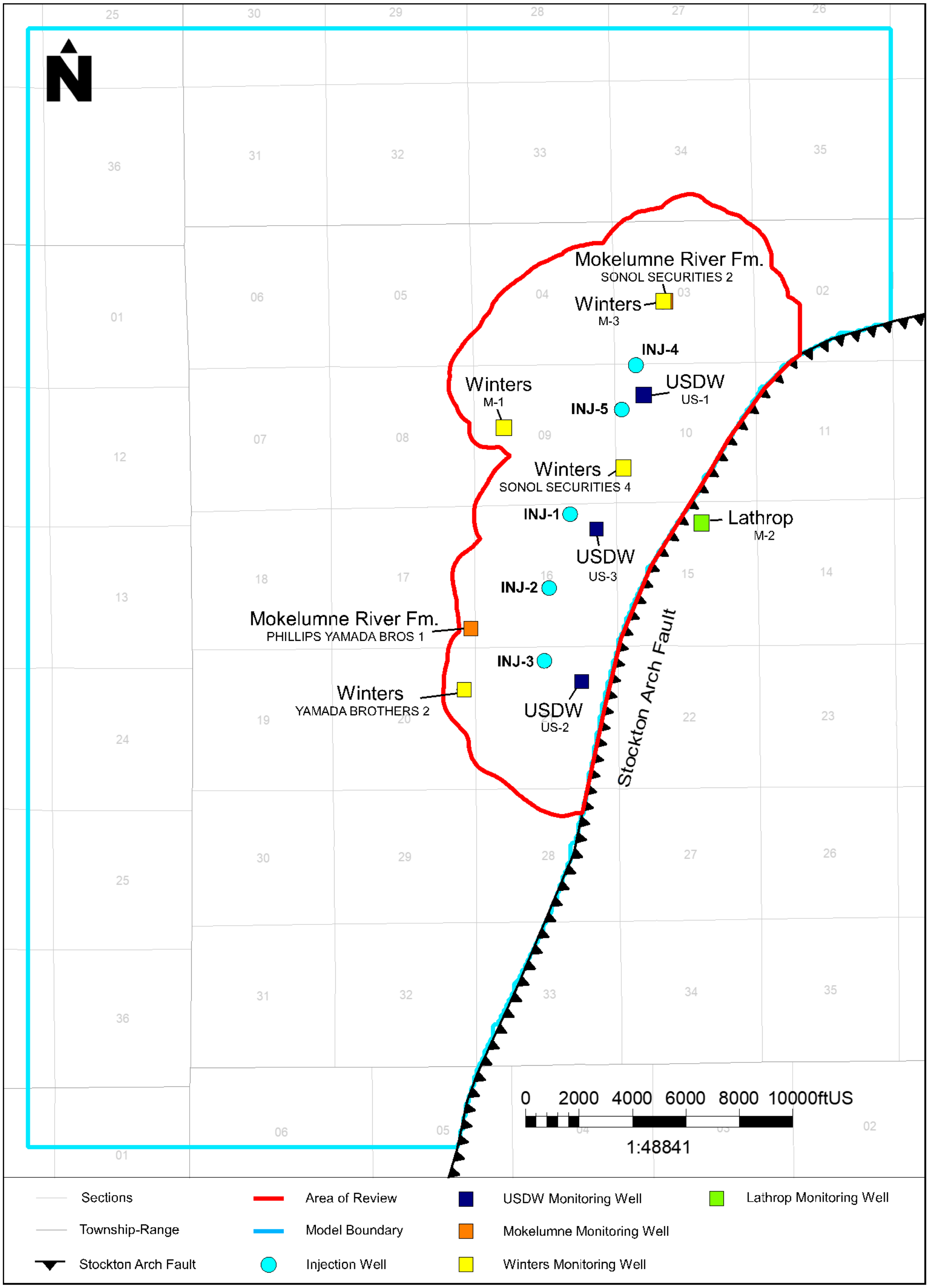

Figure G3-1. Map showing the locations of injection and monitoring wells.

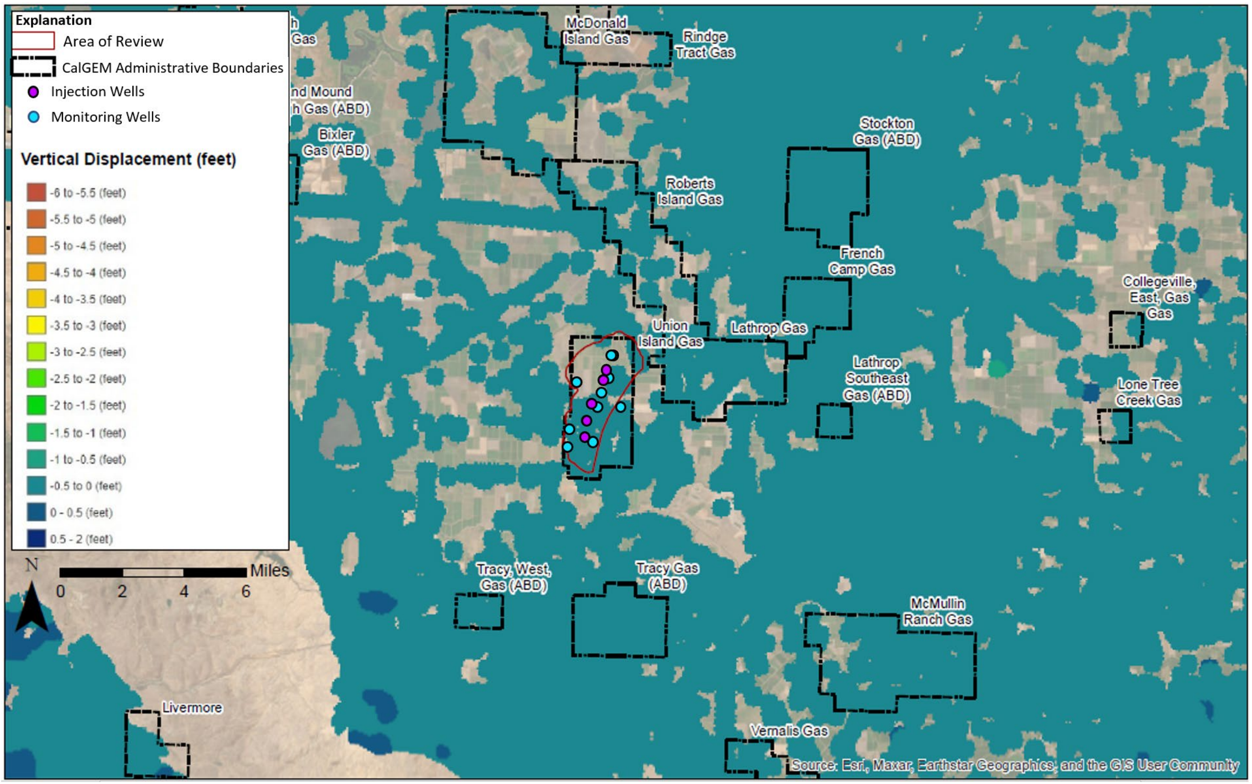

Figure G3-2. Subsidence in the Union Island Field is -0.5 to 0 feet for June 2015 to July 2022. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Tables

Table G3-1. Casing Details, UI-INJ-3

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	14-54	20	19.124	94	--	--	2.62	--	--
Surface 1	14-600	13.375	12.615	54.5	K-55	Short	2.62	2,730	1.130
Surface 2	14-4,450	9.625	8.755	43.5	N-80	Long	2.62	6,330	3,810
Long String	14-9,700 9,700-10,350	7	6.276	26	N-80 L-80 CRA	Long	2.62	7,240	5,410

API = American Petroleum Institute
BTU/ft hr °F = British Thermal Unit per foot, per hour, per degree Fahrenheit
CRA = corrosion resistant alloy
lb/ft = pound per foot
psi = pound per square inch

Table G3-2. Tubing and Packer Details, UI-INJ-3

Components	Setting Depth Interval and Units (feet)	Tensile Strength/ Rating (lb)	Burst Strength/ Rating (psi)	Collapse Strength/ Rating (psi)	Material (e.g., weight/grade/connection)
Tubing 3½-inch	9,830	207,220	10,160	10,530	6.5 lb/ft, L-80 CRA, Premium
Packer	9,800	200,000	7,500	7,500	Permanent Sealbore Packer, CRA

lb = pound
psi = pound per square inch
lb/ft = pound per foot
CRA = corrosion resistant alloy

Table G3-3. Pre-Operational Logging and Testing, UI-INJ-3

Data Collection Location(s)	Logging or Testing Activity	Spatial Coverage or Depth
UI-INJ-3	Deviation checks	Every 120 feet during drilling operations
	Dual induction laterolog	During drilling operations
	Gamma ray	During drilling operations
	Caliper	During drilling operations
	Compensated neutron	During drilling operations
	Formation density	During drilling operations
	Mud log	During drilling operations
	Cement bond log	Along all casing strings to surface
	Casing inspection log	Along the long-string casing to surface
	Internal MIT: SAPT	Casing/tubing annulus above packer
	External MIT (at least one of): Oxygen activation log Noise log	Along the long-string casing to surface
	Injectivity test	Injection Zone
	Pressure fall-off testing	Injection Zone

Table G3-4. Planned MITs, UI-INJ-3

Test Description	Location
Temperature	Entire length of sequestration well

Table G3-5. Plugging Details, UI-INJ-3

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be placed (inches)	6.276	6.276	6.276	6.276
Depth to bottom of tubing or drill pipe (feet)	10,000	5,563	2,363	37
Sacks of cement to be used	90	23	23	8
Slurry volume to be pumped (bbl)	18.43	4.71	4.71	0.93
Slurry weight (lb/gal)	15.8	15.8	15.8	15.8
Calculated top of plug (feet)	9,518	5,443	2,238	14
Bottom of plug (feet)	10,000	5,568	2,363	39
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			

bbl = barrel
lb/gal = pound per gallon