ATTACHMENT G: WELL CONSTRUCTION AND TESTING

CTV III

Facility Information

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Introduction

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]

Figure 1: Map showing the location 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 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.

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

No stimulation program is proposed at this time.

Well 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 [redacted], 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.

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 [redacted]. Casing is planned to be set at [redacted]. 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 [redacted] 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.

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.

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.

CO_2 Injectate and Formation Fluids

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 [redacted], 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: 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 [redacted].

A 100% CO2 injectate stream has been assumed for computational modeling and for the well performance modeling. Table 1 summarizes the injectate properties at downhole conditions for the injectors over the life of the project.

Table 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 2 provides estimated formation fluid properties.

Table 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

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.

Pre-Injection Testing Plan – Injection Wells

The following tests and logs will be acquired during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The testing activities described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in the Testing and Monitoring document.

Deviation Checks

Deviation measurements will be conducted approximately every 120’ during construction of the well.

Tests and Logs

The following logs will be acquired during the drilling or prior to the completion of the C1, C2, E1, E2, W1, and W2 wells:

- Dual Induction Laterolog
- Spontaneous Potential
- Gamma Ray
- Caliper
- Compensated Neutron
- Formation Density
- Mud Log
- Acoustic Cement Bond Log

Demonstration of Mechanical Integrity

Below is a summary of the tests to be performed prior to CO_2 injection:

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT - Internal	SAPT	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Temperature Log	Prior to operation

Annulus Pressure Test Procedures

1. The tubing/casing annulus (annulus) will be filled with liquid. The volume of fluid required will be measured.

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test.

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less equal to or greater than the highest annular pressure specified in the Operating Procedures document. Following pressurization, the annular system must be isolated from the source (annulus tank) by a closed valve.

4. The annulus system must remain isolated for a period of no less than 60 minutes. During the period of isolation, measurements of pressure will be made at ten-minute intervals. The annulus system must remain isolated for a period of no less than 60 minutes. During the period of isolation, measurements of pressure will be made at ten-minute intervals.

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

Injectivity and Pressure Fall-Off Testing for Injection Wells

Injectivity testing using brine compatible with formation fluids and formation mineralogy will provide assurance of wellbore connectivity with the reservoir and can be used to forecast CO_2 injection rate. The benefit of completing a pressure fall-off test is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV will complete injectivity and pressure fall off testing prior to CO_2 injection, pursuant to 40 CFR §146.87(e).

CTV will consider pressure fall-off testing throughout the injection phase to complement reservoir monitoring if injection rate decreases along with a simultaneous injection pressure increase outside the results from computational modeling.

Pressure fall-off testing procedures are described below:

1. Injection rate will be held constant prior to shut in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.

2. Upon shutting in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.

3. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.

A surface gauge at the wellhead and a downhole gauge set above the packer with real-time surface readout capability will be used for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

Pre-Injection Testing Plan – Monitoring Wells M1 and M2

Monitoring wells proposed for the CTV storage project will be drilled prior to CO_2 injection. CTV will install monitoring equipment and ensure well integrity in the well construction and completion process. The testing activities described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in Attachment C.

Deviation Checks

Deviation measurements for M1 and M2 will be recorded approximately every 120' for each well during construction of the well.

Tests and Logs

The following logs will be acquired during the drilling and prior to the completion of these wells:

- Dual Induction Laterolog
- Spontaneous Potential
- Gamma Ray
- Caliper
- Compensated Neutron
- Formation Density
- Acoustic Cement Bond Log

Demonstration of Mechanical Integrity

CTV will run mechanical integrity logs and tests prior to CO_2 injection operations.

Annulus Pressure Test Procedures

1. The tubing/casing annulus (annulus) will be filled with liquid. The volume of fluid required will be measured.

2. Temperature stabilization of the well and annulus liquid will be verified prior to conducting the test.

3. The annulus of the well will be pressurized to a surface pressure of no less than 500 PSI. Following pressurization, the annular system will be isolated from the source (annulus tank) by a closed valve.

4. The annulus system must remain isolated for a period of no less than 60 minutes. During the period of isolation, measurements of pressure will be made at ten-minute intervals.

Pre-Injection Testing Plan – USDW Monitoring Wells:

USDW monitoring wells proposed for the CTV storage project will be drilled prior to CO_2 injection. CTV will ensure well integrity in the well construction and completion process. The testing activities described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in Attachment C.

Deviation Checks

Deviation measurements will be recorded approximately every 120' for each well during construction of the well.

Tests and Logs

The following logs will be acquired during the drilling and prior to the completion of these wells:

- Dual Induction Laterolog
- Spontaneous Potential
- Gamma Ray
- Caliper
- Compensated Neutron
- Formation Density
- Acoustic Cement Bond Log

Demonstration of mechanical integrity

CTV will pressure test the casing before perforating and baseline sampling, prior to CO_2 injection operations.