4.0 INJECTION WELL CONSTRUCTION PLAN

40 CFR 146.86

CAPIO MOUNTAINEER SEQUESTRATION PROJECT

Facility Information

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Well name:	MCCLINTIC SEQUESTRATION 001
Well location:	MASON COUNTY, WEST VIRGINIA Latitude: [redacted] Longitude: [redacted]

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<u>4.0 Injection Well Construction Plan ((146.86 (a)(1,2,3))</u>

This section describes how a single, newly drilled injection well (MCCLINTIC SEQUESTRATION 001) will be constructed at the Capio Mountaineer project in Mason County, West Virginia, to meet the requirements of 40 CFR 146.86.

Figure 4-1 shows a base map of the project area and the proposed location of the injection well and the Area of Review (AoR). The injection well will deviate from vertical between the surface to total depth (TD) locations. The injection well construction plan is designed to prevent the movement of fluids into or between underground sources of drinking water (USDWs) or into any unauthorized zones and to permit the use of appropriate testing devices and workover tools. The design also accommodates continuous monitoring of the annulus space between the injection tubing and long string casing ((146.86 (a)(1,2,3)). The proposed injection well diagram is shown in **Figure 4-2**. The well will be deviated below the surface casing, building a tangent interval and then dropping back to vertical before cutting into the top of the caprock formation. The proposed deviation plan is shown in **Figure 4-3**.

A comprehensive suite of wireline logs, core, fluid samples and reservoir testing will be acquired during the drilling of the well.

Table 4-1 details the depths of the geological formations of interest at the site based on available regional data ((146.86 (b)(1)(i)). Refer to the AoR and Corrective Action Plan (Permit Section 2) for further details on these formations.

The well design is described in detail in the following sections, including the drilling phase, materials to be used, and the design itself. Formation and casing depths for the injection well have been determined using regional data and will be confirmed and updated if required based on data collected in this well during drilling.

No completion stimulation beyond an acid-wash to clean up near wellbore drilling mud and cement invasion is planned at this time because the expected reservoir quality is sufficient for the planned injection volumes. The maximum injection volumes for this project are detailed in the Project Narrative (Permit Section 1.0). No oil or gas zones are anticipated to be encountered at this location.

[redacted]

Table 4-1: Formations of Interest and estimated depths at the MCCLINTIC SEQUESTRATION 001 well location based on available regional data.

[redacted]

Figure 4-1: Map of Capio Sequestration project showing injection well (MCCLINTIC SEQUESTRATION 001) and AoR.

[redacted]

Figure 4-2: MCCLINTIC SEQUESTRATION 001 injection wellbore diagram based on offset information.

[redacted]

Figure 4-3: MCCLINTIC SEQUESTRATION 001 wellbore deviation path.

4.1 Casing and Cementing (146.86 (b))

The proposed well design is shown in **Figure 4-2**. The lithology of the storage formation and confining zones are shown with the injection depth, hole sizes and casing sizes and depths. These are described below.

4.1.1 Corrosiveness of the CO_2 Stream and Formation Fluids (146.86 (b)(1)(v)(vi))

Prior to injection, the actual chemical and physical characteristics of the injectant will be confirmed using appropriate analytical methods. The current planned composition of the injectant is shown in **Table 4-2**.

[redacted]

Table 4-2: Planned CO_2 stream composition for the Capio Mountaineer Sequestration project.

Table 4-3 presents the analytical parameters that will be measured in the injection well to assess the corrosivity of the formation waters in the storage formation. The pH, conductivity, and total dissolved solids (TDS) data represent analytical results from a commercial laboratory, the oxidation-reduction potential (ORP) data are field measurements made at the time the brine samples are collected, and the temperature value is the temperature measured at the mid-point of the formation through wireline logging at the injection well (40 CFR 146.86 (b)(1)(vi)).

Parameter	Value
Average pH	TBD
Average Conductivity	TBD
Average TDS	TBD
Average ORP	TBD
Mid-Point Temperature	TBD

Table 4-3: Chemical parameters of storage formation brine to be used for corrosivity assessment.

4.1.2 Casing/Tubing

The well will be designed using carbon steel for the casing and tubulars that are not expected to be in contact with a mixture of the injectant (CO_2) and water. That is, the conductor, surface and intermediate casing sections will all be carbon steel. The deep casing string will be constructed with corrosion-resistant chrome (13CR) from the reservoir through the confining zone and carbon steel from above the confining zone to surface. This section of the wellbore is expected to have intermittent exposure to CO_2-formation water mixed fluids especially in the initial phases of injection and intermittently when well workovers are performed throughout the project's life. Although the expected water content of the injectant stream will be less than 30 parts per million (ppm), the injection tubing string and flow-wetted injection tree components will be composed of corrosion-resistant materials or coatings.

All selected casing and tubing grades and weights will be adequate for handling anticipated stress loads and pressures throughout the life of the project. The downhole tubulars were analyzed to ensure their ability to withstand the anticipated loads they may undergo. This analysis reviewed loads during installation, drilling, injection, workover, and subsequent abandonment. Additionally, effects due to cyclical loading, temperature, well bore deviation, and exposure to well bore fluids were also assessed.

Table 4-4 summarizes the casing program for the injection well. All casing strings will be cemented to the surface and any changes to the final well design will be discussed with the UIC Director or representative. **Table 4-5** details the minimum recommended tubulars and descriptions of key loads that were assessed. The design is robust, meeting industry accepted minimum safety factors with significant margin. American Petroleum Institute (API) minimum safety factors are based on 1.125 for collapse, 1.1 for burst and 1.6 for axial loading.

The deepest USDW will be confirmed from the fluid sampling program in the STW. Surface casing will be set through the deepest USDW, and the intermediate and production casings will provide additional layers of protection to the USDW.

[redacted]

Table 4-4: Injection well casing details.

[redacted]

Table 4-5: Injection Well tubular performance details.

4.1.3 Tubular Stress Conditions (146.86 (c))

Surface

The surface casing will be the first string of casing installed by the drilling rig. The surface casing will be isolated behind two casing strings during injection operations, so the only applicable load conditions are during the installation of the surface casing and during drilling of the intermediate hole section. The highest evaluated burst load occurs when pressure testing the casing, which results in a 1.28 safety factor (SF) and meets design criteria. Axial loading will be minimal due to shallow setting depth, and all evaluated axial load cases result in SF that exceed 2.56 and meets design criteria. The worst-case collapse loading for the surface casing would be if returns are lost while drilling the intermediate hole interval resulting in full evacuation; however, this results in a 1.26 SF and meets design criteria.

Production String

The production string is the final casing string that will be installed and will be exposed to installation and injection load cases. The upper portion of the string will be isolated by a tubing and packer completion allowing for use of carbon steel. The lower portion of the string that will be across the storage formation and confining zone will use a corrosion-resistant alloy (13CR) as this string will be providing long-term well integrity after the injection phase is completed and the well is plugged. The production casing will be centralized with one centralizer per joint with solid body centralizers through the confining zone interval and bowspring throughout the remainder of the well.

The burst load when pressure testing the casing results in a 2.89 SF and meets design criteria. During normal operations, the burst loading on the long string casing due to applied annular pressure results (high) in a SF above 1.72. In the event the tubing develops a leak and maximum injection pressure is applied on a column of annular fluid, the resulting SF is 1.67; however, this will be a short-term event due to safety systems. Axial loading will be minimal due to setting depth and minimal temperature fluctuations. All evaluated axial load cases result in SF that exceed 2. The worst-case collapse loading for the long string casing is a full evacuation to air which results in a SF of 1.35 and meets design criteria. This annulus will be filled with packer fluid (to minimize corrosion) and monitored to check for leaks; thus, this evacuated load case is extremely unlikely. A Von mises analysis was also performed resulting in a minimal SF of 1.968.

Injection Tubing

The injection tubing will be the final string of tubulars installed. The injection tubing will be the primary tubular in contact with injected fluids. During a workover event, the tubing may be removed from the well and can be replaced if any wall loss or damage has taken place. The highest burst load evaluated occurs when the tubing is pressure tested. This load results in a 1.4 SF which meets design criteria. Burst load during normal injection operations (maximum injection pressure, low annular pressure) results in a SF greater than 3. Burst load during injection with an annular pressure loss event results in a SF that exceeds 2.0. The highest collapse load assessed assumes that the tubing is evacuated during a high annular pressure event, but still results in a SF of 1.4 and meets design criteria.

4.1.4 Cement (146.86 (b))

The cemented casing strings (three in total) for the proposed injection well will all be cemented back to surface. The surface and intermediate strings will be cemented using Class L cement. The injection string will be installed using a CO_2 resistant cement system as the tail mix in the storage formation and confining zone intervals with Class L cement back to surface. **Table 4-6** gives a summary of the cement types to be used for each casing string.

[redacted]

Table 4-6: Summary of cement types and corresponding casing strings.

Class A cements are adequate for providing zonal isolation in behind-pipe environments to prevent the movement of formation fluids between zones. Class A cements have been applied in shallow oil and gas wells and water disposal wells for many decades and are an accepted best practice. In a typical, non-corrosive subsurface environment (i.e., aquifer or oil/gas reservoirs) Class A cement will perform well throughout the service life of most wells.

Class C cements are ground finer than Class A cements with a higher Tricalcium Silicate (C_3S) content both contributing to a higher strength cement and quicker curing than Class A are the design choice for the injection well.

Class G or H cements are generally intended for use in deeper onshore wells and will have improved performance characteristics under higher temperature and pressure conditions, as compared to Class A cements (Guner & Ozturk, 2015). Reservoir temperatures and anticipated operating pressures are relatively low at the injection well.

Joppa Class L is a low CO_2 (lower environmental impact) oil well cement designed for normal slurry applications for cementing oil and gas wells. In 2019, the API added the Class L designation to Annex B of Specification 10A. Class L composite well cement is manufactured by inter-grinding Portland cement clinker and one or more forms of gypsum with pozzolanic material. Fly ash, silica fume, and natural pozzolans all qualify as pozzolanic materials. API also allows the addition of suspension agents in Class L cements.

Class L blend of cement "meets or exceeds the ASTM International C 150, Type I, II or III Standard or API Specification 10" when used in accordance with the manufacturer's specifications and standards for well cementing. This determination has been made based on a detailed review of laboratory testing data for the blend and a comparison of laboratory performance to Class A blends
CO_2 resistant cement slurries which have key properties of low reactivity and near zero permeability are used beside any casing section set across from storage or confining layers.

All casing strings will be cemented to the surface. **Table 4-7** describes the type of cement, estimated volumes, and weight of the mixture pounds-per-gallon (ppg). Additives may change slightly based on laboratory testing. Volumes may be adjusted based on expected hole enlargement during drilling operations.

[redacted]

Table 4-7: Injection well cement program.

4.1.5 Downhole Completion Equipment (146.86 (a) (2,3)

Completion equipment will exceed the ratings of the injection tubing and will be suitable for downhole conditions. Completion equipment will be designed such that a profile plug can be set, and the tubing released from the on-off tool for workover activities.

[redacted] Tubing tail pipe will be present below the packer to allow installation of a tubing plug and for pressure/temperature sensors to be set, as warranted throughout the life of the well. A perforated joint of tubing may be required for the pressure/temperature sensors, and this will be determined in the final design. Positive external pressure will be applied to the tubing string throughout the service life of the well from the annular fluid system.

The final packer selection for this well will be determined prior to completion. However, preliminary plans suggest a packer similar to Baker Hughes' SC-2 retrievable production packer may be used for this application. The Baker SC-2 packer is designed for higher temperature and pressure environments where a high differential pressure (i.e., from above and below) may be present. Although a high-pressure differential will not be observed in this well, the design of this packer provides additional assurance of a positive seal. The exposed components of the packer will be specially constructed from CO_2-resistant materials including 13CR in addition to specially designed polymers for the elements. During the initial startup phase of injection, the packer may be exposed to CO_2-saturated brine from below until it is fully displaced from the wellbore by the CO_2.

4.1.6 Completion Strategy

The completed interval of this injection well will encompass the Copper Ridge [redacted] The casing will be perforated using 4-inch wireline conveyed guns, with 20 shots per foot. An acid wash will be used to remediate the formation damage imparted from the perforations or remedial cement contamination in the injection zone.

4.1.7 Wellhead Design

The injection wellhead design is shown below in **Figure 4-3**. The injection well tree will be constructed with CO_2 resistant materials/coatings on all surfaces to be in contact with the injection stream. The design has dual master valves for redundancy and a crown valve to allow rigup of wireline even under pressured situations.

[redacted]

Figure 4-4: MCCLINTIC SEQUESTRATION 001 wellhead design.

4.2 Drilling Contingencies

To further understand the subsurface underlying the McClintic site location, an assessment of the local hydraulic and hydrogeologic conditions was completed. This included a review of the stratigraphy, hydrogeology, and salinity of shallow and deep aquifers underlying the project site.

Fresh water aquifers in the region include shallow alluvium aquifers along the Ohio and Kanawha Rivers and bedrock aquifers within the Upper and Lower Pennsylvanian formations. Unconsolidated clastics ranging from clay, silt, sand, gravel and boulders comprise alluvial aquifers. Alluvium aquifers along the Kanawha River are found to contain higher proportions of clay and silt (Kozar and Mathes, 1991). Bedrock aquifers of the Pennsylvanian are primarily comprised of carbonate rocks, specifically dolomite and limestone. These aquifers have little primary porosity and capacity is largely dependent on fracture number, extent and aperture (Kozar and Mathes, 1991). Groundwater capacity is low in bedrock aquifers and salinity rapidly increases with depth.

The deepest documented USDW within western West Virginia is the Lower Pennsylvanian Berea Sandstone. Water samples from the United State Geological Survey (USGS) database show that in Mason County the Pennsylvanian sandstones have salinities of more than 100,000 ppm which would classify them as saline aquifers, not sources of fresh water. However, the Berea Sandstone was still evaluated at the primary site. The base of the sandstone, which marks the base of the Pennsylvanian system, is at a depth of ~1,350 ft, which is shallower than the regional confining unit, the Black River Limestone. The top of the Black River is expected to be present at a depth of ~5,870 ft MD at the site. There would be over 6,000 ft of rock and multiple confining layers separating the potential storage reservoirs and the deepest USDW. No sole source aquifers are present in Mason County nor any other county in West Virigina (EPA, 1989).

In the event of lost circulation issues, Lost Circulation Material (LCM) will be added to the drilling fluid and in extreme cases an LCM pill will be mixed and pumped. The addition of a cementing stage tool may be required in situations where losses cannot be alleviated by LCM.

Although elevated pressures or hydrocarbons are not expected, blow out prevention equipment (BOPE) will be installed prior to drilling below the surface casing. Periodic drills and training will be performed to ensure the crews are educated in how to react to a well control event.

4.3 Annular Fluid System

This section presents the injection tubing-casing annular fluid system to be used in the injection well after drilling and casing. The injection tubing-casing annular fluid will be a dilute salt solution such as potassium chloride (KCl), sodium chloride (NaCl), or similar. The fluid will be mixed on site from dry salt and good quality (clean) fresh water, or it will be acquired pre-mixed. The fluid will also be filtered to ensure that solids do not interfere with the packer or other components of the annular protection system. The likely density of the annular fluid will be approximately 9.2 ppg. The final choice of fluid will depend on availability and wellbore conditions.

The annulus fluid will contain additives and inhibitors including: a corrosion inhibitor, biocide (prevent growth of harmful bacteria), and an oxygen scavenger. Example additives and inhibitors are listed below along with approximate mix rates:

- Corrosion inhibitor for carbon steel tubulars – 10 gallons (gal) per 100 barrels (bbls) packer fluid
- Corrosion inhibitor for use with 13CR stainless steel tubulars or a combination of stainless steel and carbon steel tubulars – 20 gal per 100 bbls packer fluid
- Biocide – 1 gal per 100 bbls packer fluid
- Non-sulfite oxygen scavenger – 10 gal per 100 bbls packer fluid

Actual products and supplier will be determined closer to project execution.

4.4 Stimulation Program

No stimulation program is being planned as the expected injectivity of the Copper Ridge should be adequate for the planned injection volumes. The Fidelis site location is suitable for CO_2 sequestration due to the favorable lithologies of the storage and confining formations. The storage formation, the Copper Ridge, is mostly composed of medium grained arkose, lithic arkose, and subarkose sandstones intermixed with conglomerates with 18% measured porosity (Handford and Dutton, 1980). The most common mineral in the sandstones of this formation is quartz followed by feldspar and lithic rock fragments. Additionally, quartz overgrowth cements are seen in this formation (Handford and Dutton, 1980). The prevalence of quartz cement has positive implications for CO_2 injection because quartz-cemented rocks are naturally resistant to the potentially corrosive effects of long-term exposure to injected CO_2. Furthermore, although neither the CO_2 stream nor formation waters are expected to be highly corrosive, the injection well materials that come in contact with the CO_2 stream and/or reservoir brines will be constructed of corrosion-resistant materials, such as 13CR steel, or similar. For example, the casing string across the Copper Ridge formation, the packer, and deep portions of the tubing will be constructed with corrosion-resistant materials or coatings. The thickness, porosity and permeability of the Copper Ridge storage formation make this site location optimal for CO_2 sequestration with a large CO_2 storage capacity. A small volume of acid may be required to "clean the formation face and near wellbore region" prior to injection to remove drilling fluid and cement contamination in the matrix.

4.5 Demonstration of Mechanical Integrity

Pressure testing and logging will be performed to confirm the casing was installed correctly and cemented adequately.

Refer to the Pre-Operational Testing Plan (Permit Section 5) and the Testing and Monitoring Plan (Permit Section 7) for additional details on the demonstration of mechanical integrity.

4.6 References

Guner, D., Ozturk, H., 2015. Comparison of Mechanical Behavior of G Class Cements for Different Curing Time. Presented at 24th International Mining Congress and Exhibition of Turkey, 2015.

Kozar, Mark D., and David Phillip Brown. Location and site characteristics of the ambient ground-water-quality-monitoring network in West Virginia. No. 95-130. US Geological Survey; Earth Science Information Center, Open-File Reports Section (distributor), 1995.