4.0 INJECTION WELL CONSTRUCTION PLAN
40 CFR 146.82(a)(8), 146.87

MARQUIS BIOCARBON PROJECT

Facility Information

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Well name: MCI CCS 3

Well location: PUTNAM COUNTY, ILLINOIS
S2 T32N R2W
Latitude: 41.27026520 N, Longitude: 89.30939322 W

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4.0 Injection Well Construction Plan ((146.86 (a)(1))

This section describes how a single, newly drilled injection well (MCI CCS 3) will be constructed at the Marquis BioCarbon Project site near Hennepin, Illinois, to meet the requirements of 40 CFR 146.82(a)(9)(11) and 40 CFR 146.86. The well design is discussed in detail in the following sections, including the drilling phase, materials to be used, and the initial expected design. Formation and casing depths for the injection well were determined using data from the MCI MW 1.

No completion stimulation is planned at this time because the expected reservoir quality is sufficient for the planned injection volumes. The maximum injection volume for this project is anticipated to be 1.5 million tonnes (MT)/year. No oil or gas zones are anticipated to be encountered at this location. The only expected zone that may present corrosion issues during the life of the project is the injection zone itself, the Mt. Simon Sandstone, as carbon dioxide (CO_2) is injected over time and mixes with the connate waters to form carbonic acid.

The reservoir modeling section of this application determined that a single, vertical injection well is sufficient to achieve the target CO_2 injection rate. The surveyed location of the well is shown in Figure 4-2. The proposed injection well diagram is shown in Figure 4-1. Table 4-1 details the depths of the geological formations of interest at the site. Refer to the Area of Review (AoR) and Corrective Action Plan (Permit Section 2) for further details on these formations.

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Table 4-1: Formations of Interest measured in *MCI MW 1 well*.

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Figure 4-1: MCI CCS 3 injection well schematic.

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Figure 4-2: Plot showing anticipated injection well location for MCI CCS 3.

4.1 Well Design (146.86 (b))

The proposed well design is shown above in Figure 4-1. The lithology of the injection and confining zones are shown with the injection depth, hole sizes and casing sizes and depths. These are discussed below.

4.1.2 Corrosiveness of the CO_2 stream and formation fluids (146.86 (b)(1)(v)(vi))

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[redacted] process stream, water vapor may be present in the injection stream. The injection system has been designed with corrosive-resistant materials that contact the injection stream to prevent corrosion of the components caused by the presence of water vapor. Hydrogen sulfide (H_2S) is not expected to be present in the injection stream; however, analyses will be performed to identify its presence. A target concentration of H_2S will be <20 ppm to reduce corrosivity of the injection stream.

The corrosivity of the injection stream should be limited given the quantities of the minor concentrations of the trace constituents in the injection stream, and the water content will be maintained below the regulated limit of <30 lb/MMSCF for CO2 transport pipeline standards.

Component	Quantity
CO_2	Sensitive, Confidential, or Privileged Information [redacted]
Oxygen	
Nitrogen	
TEG	
Water Vapor	
Hydrogen sulfide (H_2S)	

Table 4-2: Chemical Composition of CO2 stream.

Table 4-3 presents the analytical results for parameters that may be used to assess the corrosivity of the formation waters in the Mt. Simon Sandstone. These data represent average results for the brine samples collected from the Mt. Simon Sandstone. The pH, conductivity, and 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 were collected, and the temperature value is the temperature measured at the mid-point of the formation through wireline logging.

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Table 4-3: Chemical parameters of Mt. Simon brine used for corrosivity assessment.

A summary of the measured downhole temperatures are shown in Table 4-4. Based on these measurements the temperature gradient between the top Eau Claire and base Mt. Simon is 0.0053 F/ft.

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Table 4-4: Downhole temperatures measured in characterization well, MCI MW 1 .

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Although neither the CO_2 stream or formation waters are expected to be highly corrosive, the injection materials that come in contact with the CO_2 stream and/or reservoir brines will be constructed of corrosion-resistant materials, such as Cr13 steel, or similar. For example, the casing string across the Mt. Simon, the packer, and deep portion of the tubing with be constructed with corrosion-resistant materials.

4.1.1 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 injectate (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 (CR13) across the reservoir and caprock to total depth (TD) and carbon steel from above the caprock 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 life of the

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Specific pressure ratings for the tubulars are provided in Section 4.1.2. However, 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, and exposure to wellbore fluids were also assessed. Table 4-3 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.

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The deepest underground source of drinking water (USDW) was confirmed from the fluid sampling program during the characterization phase and was determined to be the Gunter Sandstone formation. Intermediate casing will be set through the Gunter and into the top of the Eau Claire caprock which will provide an additional layer of protection to the USDW.

Casing String Name	Open Hole Size (in.)	Outside Diameter (in.)	Setting Depth (ft rGL)	Weight (lb/ft)	Wall Thickness (in.)	Grade	Connection
Conductor	Sensitive, Confidential, or Privileged Information [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	X-42	Welded
Surface	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	J/K-55	Buttress or Long Round Thread
Intermediate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	J/K-55	Buttress or Long Round Thread
Long String	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	L-80 (0-2750') L-8013Cr (2750' – TD)	Premium
Injection Tubing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	L-8013Cr	Premium

Table 4-5: Casing details.

Casing String Name	Outside Diameter (in.)	Weight (lb/ft)	Grade	Connection	Burst Rating (psi)	Collapse Rating (psi)	Tensile Yield(klbf)
Surface	Sensitive, Confidential, or Privileged Information [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Intermediate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Long String	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Injection Tubing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 4-6: Tubular performance details.

4.1.2 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 4.0 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 10 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; however, this results in a 3.4 SF and meets design criteria.

Intermediate

The intermediate casing will be the second string of casing installed by the drilling rig. The intermediate casing will not be exposed to injected fluids due to being isolated behind the long string. All applicable load conditions occur during the installation of the intermediate casing and during drilling of the production hole section. The highest evaluated burst load occurs when pressure testing the casing, which results in a 1.6 SF and meets design criteria. Axial loading will be minimal due to relatively shallow setting depth, and all evaluated axial load cases result in SF that exceed 3. The worst-case collapse loading for the intermediate casing occurs during cementing operations and results in a 1.5 SF which meets design criteria.

Long String

The long 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 injection zone and caprock 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 will be plugged. The highest evaluated burst load occurs when pressure testing the casing, which results in a 3 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 6. In the event the tubing develops a leak and maximum injection pressure is applied on a column of annular fluid, the resulting SF is 3.2; however, this will be a short-term event due to safety systems. Axial loading will be minimal due to shallow setting depth and minimal temperature fluctuations. All evaluated axial load cases result in SF that exceed 3. The worst-case collapse loading for the long string casing is a full evacuation to air which results in a SF of 1.4 which meets design criteria. This annulus will be filled with packer fluid (to minimize corrosion) and will be monitored to check for leaks; thus, this evacuated load case is extremely unlikely. A triaxial analysis was also performed based on the data from the MCI MW 1 well, resulting in a minimal SF of 2.4.

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 4.3 SF which meets design criteria. Burst load during normal injection operations (maximum injection pressure, low annular pressure) results in a SF greater than 8. Burst load during injection with an annular pressure loss event results in a SF that exceeds 4. The highest collapse load assessed assumes that the tubing is evacuated during a high annular pressure event, but still results in a SF of 2.8 and meets design criteria. Axial loading will be minimal due to shallow setting depth, low temperatures and all evaluated axial load cases result in SF that exceed 4.

4.1.3 Cement (146.86 (b))

The cemented casing strings (four in total) for the proposed injection well will all be cemented back to surface. The surface strings will be cemented using Class A, H, or G cement while the intermediate string will be cemented using Class H or G cement. The injection string will be installed using Schlumberger's EverCRETE (or equivalent) as the tail mix across the injection reservoir and caprock intervals with Class G or H as the lead above the caprock. Table 4-7 gives a summary of the cement types to be used for each casing string.

Casing String	Appx. Depth Range (MDKB ft)	Cement Type
Surface	Sensitive, Confidential, or Privileged Information [redacted]	
Intermediate		
Deep		

Table 4-7: 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 the 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).

The deep casing string will be cemented with a slurry similar to Schlumberger's EverCRETE system, which has been widely used in other carbon capture and storage (CCS) applications with reliable results. This cement system is useful in the injected CO_2 environment because it is highly resistant to carbonic acid, has very low permeability, and becomes self-healing when exposed to CO_2 (Schlumberger).

All casing strings will be cemented to surface. Table 4-8 describes the type of cement, estimated volumes, and weight of the mixture in pounds-per-gallon (ppg). Additives may change slightly based on laboratory testing. Volumes may be adjusted based on expected hole enlargement.

Casing String	Casing Depth (MDKB ft)	Cement Description
Surface	[redacted]	
Intermediate		
Deep		

Table 4-8: Cement program for the CO_2 injection well.

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

Completion equipment will exceed the ratings of the injection tubing and will be suitable for the downhole conditions. Completion equipment will be designed such that a tubing plug can be set in the tail pipe below the packer allowing for removal of the upper completion string during workover activities. The downhole completion equipment will include:

- CO_2 compatible packer with tail pipe to allow for Pressure / Temperature gauge and a profile for setting a tubing plug.
- Subsurface safety valve (SCSSV) to allow for shut-in of the well

[redacted]

throughout the life of the well. A perforated joint of tubing may be required for the use of the pressure/temperature gauges, 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 (Section 4.7).

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 CR13 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.

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4.1.5 Perforation Strategy

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Because the Mt. Simon is expected to have some level of heterogeneity the final selected perforation intervals will largely depend on interpreted permeability layers within the Mt. Simon. Modeled perforation intervals based on data from MCI MW 1 well.

4.2 Drilling Contingencies

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Illinois Basin to the south and east. However, it is a risk that the project will plan to manage at the project site. The Potosi formation did not present drilling problems during the installation of the MCI MW1 well. However, in the event circulation is nearly or completely lost, the plan is to drill ahead without drilling fluid returns through the remainder of the formation if possible. Then, a thixotropic cement slurry will be pumped, likely several slurries, to seal off the lost circulation zones. Once circulation has been fully restored drilling will proceed as planned.

In the event of severe lost circulation issues, a two-stage cement job may be implemented. The differential valve (DV) tool will be set just above the uppermost encountered lost circulation zone.

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.

Other planned contingencies include standard oilfield practices for preventing excessive borehole deviation and a lost drill string. A stiff bottom-hole assembly (BHA), including stabilizers and/or drill collars, will be used to prevent significant deviation from vertical and to minimize the corkscrew tendency of the drill string. Intermittent deviation checks using single shot surveys will be used to verify that wellbore deviation stays below five degrees from vertical. Directional drillers will be contracted in the event consecutive deviation surveys show to be greater than five degrees from vertical to bring the wellbore back to near zero degrees.

Periodically throughout the drilling process the drill string will be pulled back up through the wellbore to ensure the hole is in good working condition, known as “wiper trips.” These short trips can prevent the buildup of formation cuttings around the outside of the drill string which can cause the string to become stuck in the hole, in the worst cases. They also ensure the formation of an even mud-cake layer along the walls of the wellbore which aids in better data collection with wireline tools in addition to a smoother installation of casing later in the process.

4.3 Annular Fluid System

The 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 [redacted] Sensitive, Confidential, or Privileged Information 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:

- TETRAHib Plus (corrosion inhibitor for carbon steel tubulars) – 10 gallons (gal) per 100 barrels (bbls) packer fluid
- CORSAF™ SF (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
- Spec-cide 50 (biocide) – 1 gal per 100 bbls packer fluid

- Oxban-HB (non-sulfite oxygen scavenger) – 10 gal per 100 bbls packer fluid

These products were recommended by and are provided by Tetra Technologies, Inc., of Houston, TX. Actual comparable products and provider may be used other than those described above.

4.4 Stimulation Program

No stimulation program is being planned as the expected injectivity of the Mt. Simon Sandstone should be adequate for the planned injection volumes. A small volume of acid may be required to “clean the perforations” prior to injection but formation breakdown pressure will not be reached during the activity.

4.5 Demonstration of Mechanical Integrity

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

Please 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.

Schlumberger. EverCRETE system: https://www.slb.com/drilling/drilling-fluids-and-well-cementing/well-cementing/cemcrete-cementing-technology/evercrete-co2-resistant-cement-system.

Appendix - EverCRETE

Transition Technologies

Schlumberger

Aligned with United Nations Sustainable Development Goals: 12—Responsible consumption and production, 13—Climatic action.

EverCRETE CO_2-resistant cement system

Extend cement barrier lifetime in reservoirs containing CO_2

CO_2 Reduction:
Serves as barrier for CO_2 storage wells or high CO_2-producing formations. Lowers CO_2 footprint during well construction due to significantly reduced usage of Portland cement.

Temperature:
up to 284 degF [140 degC]

Applications

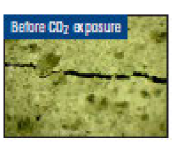
- Carbon capture and storage wells
- Wells in fields that use CO_2 injection for enhanced oil recovery (EOR)
- Primary cementing in CO_2 environments
- Long-term decommissioning objectives for plug and abandonment (P&A) in CO_2 environments

How it improves wells

Because of its intrinsic low permeability, EverCRETE* CO_2-resistant cement system resists cement matrix attack from wet supercritical CO_2 and water saturated with CO_2 conditions. Accelerated reaction kinetics lead to a stabilized matrix within days of exposure to the CO_2 environment, leading to stabilized mechanical properties.

How it works

EverCRETE system blends can be prepared locally using the standard bulk plant. The density can be tailored to well requirements, providing operational flexibility. Unlike other offerings, EverCRETE system is compatible with portland cement. The EverCRETE system can be used as a cement across potential CO_2-producing formations or as the primary barrier in the wellbore for any in situ fluids, with a portland cement-based slurry used as a filler slurry for coverage of remaining casing. It can be prepared and pumped using standard equipment. Additionally, the cement can be engineered with self-healing properties that are reactive to CO_2 exposure.



What it replaces

Portland cement systems are used conventionally for zonal isolation in wells. However, portland cement is thermodynamically unstable in CO_2-rich environments and can degrade rapidly upon exposure to CO_2 in the presence of water. As CO_2-laden water diffuses into the cement matrix, the dissociated acid (H_2CO_3) reacts with the free calcium hydroxide and the calcium silicate hydrate (C-S-H) gel. The reaction products are soluble and migrate out of the cement matrix. Eventually, the compressive strength of the set cement decreases and the permeability and porosity increase, leading to loss of zonal isolation.

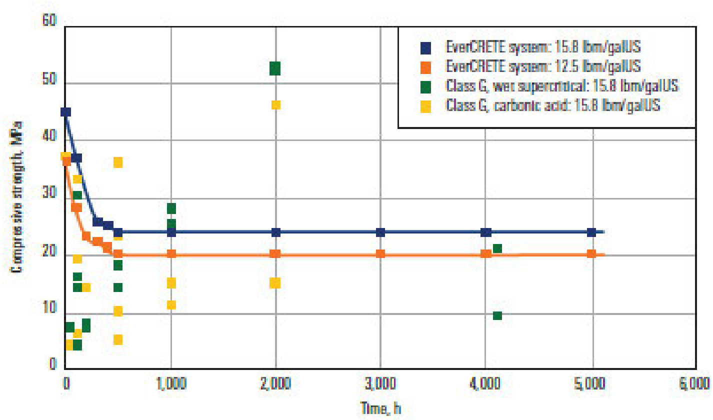
Why it's ideal in any CO_2 environment

Well integrity has been identified as the biggest risk contributing to leakage of CO_2 from underground carbon capture and storage sites. EverCRETE system enables efficient underground storage and keeps greenhouse gases out of the atmosphere.

For wells in fields that use CO_2 injection for EOR or may use it in the future, EverCRETE system reduces the risk of cement sheath degradation and leakage. It can be used to cement new CO_2 injection wells or to plug and abandon injection or production wells at the end of the field life.

In case there is damage to the cement matrix and CO_2 starts to migrate, the self-healing capabilities that can be incorporated in EverCRETE system will repair the crack, reestablishing the integrity of the well and recovering zonal isolation.

EverCRETE system can also be used as a cement across potential CO_2-producing formations or as the primary barrier in the wellbore for in situ fluids after abandonment and permanent decommissioning.



Compressive strength evolution of portland cement and EverCRETE system samples with time in wet supercritical CO_2 fluid and in CO_2 saturated in water at 194 degF [90 degC] under 28 MPa of pressure. After 6 months in CO_2-saturated water, the compressive strength of portland cement is not measurable because most of the samples are highly deteriorated. The stability of the EverCRETE system minimizes the degradation potential of the long-term barrier.

slb.com/EverCRETE