4.0 INJECTION WELL CONSTRUCTION PLAN
40 CFR 146.86

CLECO DIAMOND VAULT PROJECT

Facility Information

Facility name:	DIAMOND VAULT
Facility contact:	Sensitive, Confidential, or Privileged Information [redacted]
Well name:	CLDV-IW2
Well location:	RAPIDES PARISH, LOUISIANA Sensitive, Confidential, or Privileged Information [redacted]

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4.0 Injection Well Construction Plan ((146.86 (a)(1,2,3))

This section describes how a single, newly drilled injection well (CLDV-IW2) will be constructed at the Cleco Diamond Vault facility near Boyce, Louisiana, to meet the requirements of 40 CFR 146.86.

This injection well is one of six being proposed at the Diamond Vault facility. Each well has an s-shaped trajectory with land-based surface locations and injection zones located under Lake Rodemacher as shown below in Figure 4-1. The well will be vertical from when it enters the confining later to total depth (TD). 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.

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)) and will be updated based on data collected in the stratigraphic test well (STW). A detailed discussion of the STW can be found in the Project Narrative (Permit Section 1.0). Refer to the Area of Review (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 initial expected design. Formation and casing depths for the injection well have been determined using regional data and will be confirmed and updated based on data collected in the STW.

No completion stimulation 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.

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Table 4-1: Formations of Interest at the CLDV-IW2 well location based on available regional data.

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Figure 4-1: Map of Diamond Vault showing six proposed injection wells and AoR.

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Figure 4-2: Map of proposed injection well CLDV-IW2

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Figure 4-3: CLDV-IW2 injection well schematic.

4.1 Casing and Cementing (146.86 (b))

The proposed well design is shown 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 described below.

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

Prior to injection, the chemical and physical characteristics of the injectant will be confirmed using appropriate analytical methods.

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/million standard cubic feet (MMSCF) (equivalent to 630 ppm), for CO_2 transport pipeline standards.

Table 4-2 presents the analytical parameters that will be measured in the STW to assess the corrosivity of the formation waters in the Wilcox. 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.

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

Table 4-2: Chemical parameters of Wilcox brine to be used for corrosivity assessment.

A summary of the estimated down-hole temperatures is shown in Table 4-3. Temperatures are estimated from a temperature gradient acquired from a United States Geological Survey (USGS) study of a series of wells in Louisiana (Pitman & Rowan, 2012). Sensitive, Confidential, or Privileged Information [redacted]

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Table 4-3: Temperatures data used to estimate temperature gradient (Pitman & Rowan 2012).

The data described above (composition of injection stream, brine composition and downhole temperature) will be used to assess how corrosive the formation waters will be.

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 injectate (CO_2) and water. That is, the conductor and surface casing sections will all be carbon steel. The deep casing string will be constructed with corrosion-resistant chrome (13CR) across the reservoir and caprock to 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 project. Although the expected water content of the injectate stream will be less than 50 parts per million (ppm), the injection tubing string and flow-wetted injection tree components will be composed of corrosion-resistant materials.

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 4-4 summarize the casing program for the injection well. All casing strings will be cemented to 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. API minimum safety factors 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 long string casing will provide an additional layer of protection to the USDW.

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Table 4-4: Casing details.

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Table 4-5: 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 tubular 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 2.7 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 5.2 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 2.5 SF and meets design criteria.

Production String

The production long string is the second and 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 production casing will be centralized with one centralizer per joint with solid body centralizers through the caprock interval and bowspring throughout the remainder of the well.

The burst load when pressure testing the casing results in a 3.5 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 3.39. In the event the tubing develops a leak and maximum injection pressure is applied on a column of annular fluid, the resulting SF is 3.0; 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 2. 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 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 1.7 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 2.4. The highest collapse load assessed assumes that the tubing is evacuated during a high annular pressure event, but still results in a SF of 2.0 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 of 3.8.

4.1.4 Cement (146.86 (b))

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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 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).

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All casing strings will be cemented to surface. Table 4-7 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.

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Table 4-7: Cement program for the CO_2 injection well.

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 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 to accommodate a pressure and temperature gauge.

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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 Perforation Strategy

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4.1.7 Wellhead Design

The injection wellhead design is shown below in Figure 4-4. 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.

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Figure 4-4: CLDV-IW2 wellhead design.

4.2 Drilling Contingencies

As noted in the previous section, the setting depths for the surface and intermediate casing strings are designed to provide maximum protection for both groundwater and USDWs. The main sources of drinking water in the area are the shallow aquifers between approximately 150 ft and 250 ft MD which provide water to several municipalities in the region. The estimated deepest USDW is between 850 ft and 1000 ft (MD). Geochemical testing of downhole water samples collected in the STW will determine the actual depth of the deepest USDW and casing depths will be modified accordingly.

In the event of lost circulation issues, Lost Circulation Material (LCM) additives 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.

The planned well trajectory includes an s-shaped path returning to vertical just above the caprock that overlies the injection zone (Figure 4-2). This well design will provide the maximum surface to TD offset while ensuring that the wellbore remains vertical through the caprock and into the injection zone. 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 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. Final choice of the type 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:

- 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 Wilcox 1 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.

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.

Pitman, J.K., and Rowan, Elisabeth, 2012, Temperature and petroleum generation history of the Wilcox Formation, Louisiana: U.S. Geological Survey Open-File Report 2012–1046, 51 p.

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

Appendix - [redacted]

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