4.0 INJECTION WELL CONSTRUCTION PLAN
40 CFR 146.86

BONANZA SEQUESTRATION

Facility Information

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Well name: Doll INJ-1

Well location: FINNEY COUNTY, KANSAS
[redacted] [redacted]

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

This section describes how the injection well (Doll INJ-1) will be constructed for the Bonanza BioEnergy Ethanol Facility at Garden City, Kansas to meet the requirements of 40 CFR 146.86.

Figure 4-1 shows a base map of the project area and the location of the injection well, the Area of Review (AoR) and the deep monitor well.

The injection well has been initially drilled as a Stratigraphic Test Well (STW) and a comprehensive suite of [redacted] were acquired in February 2025. During the construction phase of this project, the STW will be converted to the injection well by final installation of the production casing string and other downhole components detailed in Figure 4-2.

The injection well will be vertical from surface to total depth (TD) and 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 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**. Additional safety systems related to the injection wellhead are noted in Section 6.

Table 4-1 details the depths of the geological formations of interest at the site based on the STW and available regional data (146.86 (b)(1)(i)). 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 design itself. Formation and casing depths for the injection well have been determined using data from the STW.

No completion stimulation beyond an acid-wash to clean up near wellbore drilling mud and cement invasion is planned at this time. The maximum injection volumes and pressures for this project are detailed in Permit Section 1 - Project Narrative and Permit Section 6.0 - Well Operation Plan. No oil or gas zones were encountered at this location.

[redacted]

Table 4-1: Formations of interest and depths derived from data acquired in the STW.

[redacted]

Figure 4-1: Map of Bonanza Carbon Capture project showing injection well (Doll INJ-1), Deep Monitoring (DMW-1) and Above Zone (ACZ-1) monitor wells, conceptual location of seismicity stations and AoR.

[redacted]

Figure 4-2: Doll INJ-1 injection well schematic.

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))

The chemical and physical characteristics of the injectant are detailed in Section 6.

The corrosivity of the injection stream should be limited given the quantities other constituents in the injection stream. As detailed in the Permit Section 5.0 - Pre-Operational Testing Plan, we will confirm this assertion.

Table 4-2 presents the basic properties of the Arbuckle measured in the STW to assess the corrosivity. The pH, conductivity, and total dissolved solids (TDS) data represent analytical results from a commercial laboratory and the temperature value is the temperature measured at the mid-point of the formation through wireline logging at the STW (146.86 (b)(1)(vi)).

[redacted]

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

4.1.2 Casing/Tubing

The well was designed using carbon steel for the casing and tubulars that are not expected to be in contact with a mixture of the injectant and formation waters. That is, the conductor, surface and second surface casing sections are all carbon steel. The cementing of the surface strings have also been circulated back to the surface. The deep casing string will be constructed with corrosion-resistant chrome ([redacted]) from the reservoir through the confining zone and carbon steel from above the confining zone to surface. The lower 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. Since the expected water content of the injectant stream will be greater than [redacted] 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. A summary of the maximum injection and annular pressure is found in Permit Section 6.0 – Well Operations Plan. 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 summarizes the casing program with ratings 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. The design is robust, meeting industry accepted minimum safety factors with significant margin. API minimum safety factors based on [redacted] for collapse, [redacted] for burst and [redacted] for axial loading.

The deepest USDW has been confirmed from analysis with wireline logs calibrated to fluid sampling in the STW. Surface casing is set through all active drinking water depths, and the intermediate and production casings will provide additional layers of protection to the USDW.

[redacted]

Table 4-3: Casing dimensions and ratings details.

4.1.3 Tubular Stress Conditions (146.86 (c))

Surface

The surface casing was the first string of casing installed by the drilling rig during the STW drilling. The surface casing will be isolated behind two casing strings during injection operations, so the only applicable load conditions were during the installation of the surface casing and during drilling of the second surface hole section. The highest evaluated burst load occurs when pressure testing the casing, which results in a [redacted] 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 [redacted] and meets design criteria. The worst-case collapse loading for the surface casing would have been if returns are lost while drilling the second surface hole interval; however, this results in a [redacted] SF and 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 above the packer. The lower portion of the string that will be across the storage formation and confining zone will use a corrosion-resistant alloy ([redacted]) as this string will be providing long-term well integrity after the injection phase is completed and the well is plugged. The long-string casing will be centralized with one centralizer per joint through the confining zone interval and bowspring throughout the remainder of the well.

The burst load when pressure testing the casing results in a [redacted] 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 [redacted]. In the event the tubing develops a leak and maximum injection pressure is applied on a column of annular fluid, the resulting SF is above [redacted] 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 [redacted] The worst-case collapse loading for the long string casing is a full evacuation to air which results in a SF of [redacted] 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.

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 [redacted] SF which meets design criteria. Burst load during injection with an annular pressure loss event results in a SF of [redacted]. The highest collapse load assessed assumes that the tubing is evacuated during a high annular pressure event but still results in a SF of [redacted] 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 are cemented using Type I/II and Class G cement. The injection string will be installed using a CO_2 resistant cement system as the tail mix in the storage formation and confining formation with Type I/II cement back to surface. The long string will utilize cement stage tools to enable proper placement of cement across the confining formation and back to surface. The casing within the storage formation will be uncemented as major losses are an issue and cementing the flow features of the Arbuckle would be counter-productive to the purpose of the well. The first stage of cement is targeted to seal the Simpson and Viola, losses were observed while drilling the Viola. The second stage of cement is targeted to properly seal at the confining formation and bring cement back to surface. **Table 4-4** gives a summary of the cement types, sacks, weight and yield to be used for each casing string. Additives may change slightly based on laboratory testing. Volumes may be adjusted based on expected hole enlargement during drilling operations.

[redacted]

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

Type I/II cements are general purpose Portland cements used when special cement specifications are not required. Class G cements are intended for use up to [redacted] ft of depth. When blended with the proper additives Class G can be used in a variety of depth and temperature situations. All casing strings will be cemented to the surface. Additives may change slightly based on laboratory testing. Volumes may be adjusted based on expected hole enlargement during drilling operations.

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 profile plug can be set and the tubing released from the on-off tool for workover activities.

The [redacted] tubing will be set with a packer inside the long string casing to approximately [redacted] ft. The packer will be set at approximately [redacted] ft, which is about [redacted] ft above the completion interval and roughly [redacted] ft below the top of the confining zone. 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 run to allow setting of backup pressure/temperature(P/T) sensors if the primary P/T sensors fail. 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 [redacted] 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 Arbuckle between approximately [redacted] ft measured depth (MD). The completion interval is uncemented chrome casing.

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 4-3: Doll INJ-1 wellhead design.

4.2 Drilling Contingencies

As noted in the previous section, the setting depths for the surface and second surface casing strings were designed to provide maximum protection for USDWs. The main sources of drinking water in the area are the shallow aquifers above [redacted] ft MD which provide water to the local municipality in the region. The estimated deepest USDW is between [redacted] (MD) and was defined logs and correlated to water samples collected in the STW. No further drilling contingencies are required as the STW (which will be converted to the injection well), has already been drilled.

4.3 Annular Fluid System

This section discusses 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 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:

- Corrosion inhibitor for carbon steel tubulars – 10 gallons (gal) per 100 barrels (bbls) packer fluid
- Corrosion inhibitor for use with [redacted] 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 suppliers will be determined closer to project execution.

4.4 Stimulation Program

No stimulation program is planned in the injection well. If deemed necessary, a minor acid or chemical wash of the formation face will be performed.

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 Permit Section 5.0 - Pre-Operational Testing Plan and Permit Section 7.0 - Testing and Monitoring Plan for additional details on the demonstration of mechanical integrity.