INJECTOR WELL CONSTRUCTION DETAILS PLAN
40 CFR 146.82(a)(11) and (12), 146.86, 146.87, and 146.88 (a), (b), (c), and (e)

Bluebonnet Sequestration Hub

1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3,
Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 wells.

Facility contacts: Claimed as PBI [redacted]

Well location: Claimed as PBI [redacted]

	Surface Coordinates		Bottom Hole Coordinates	
Well Name	Latitude (NAD27)	Longitude (NAD27)	Latitude (NAD27)	Longitude (NAD27)
Bluebonnet CCS 1	Claimed as PBI [redacted]	[redacted]	[redacted]	[redacted]
Bluebonnet CCS 2	[redacted]	[redacted]	[redacted]	[redacted]
Bluebonnet CCS 3	[redacted]	[redacted]	[redacted]	[redacted]
Bluebonnet CCS 5	[redacted]	[redacted]	[redacted]	[redacted]
Bluebonnet CCS 6	[redacted]	[redacted]	[redacted]	[redacted]
Bluebonnet CCS 7	[redacted]	[redacted]	[redacted]	[redacted]

Bluebonnet Sequestration Hub, LLC will be building the Bluebonnet Sequestration Hub (Bluebonnet Hub or the project) where it will construct CO_2 injection wells, Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7, according to the procedures below. The matter of construction details is relevant to the requirements of Environmental Protection Agency (EPA) document 40 CFR Subpart H – Criteria and Standards Applicable to Class VI Wells. The main topics covered in this attachment are special construction requirements, open hole diameters and intervals, casing specifications, tubing specifications, and pressure control systems, amongst others.

2.0 Overview

This Construction Plan sets forth the operational parameters and material selection requirements to provide mechanical integrity, minimize potential endangerment of the Underground Sources of Drinking Water (USDW), and optimize operation during the life of the project. While this Construction Details Plan describes the intended procedures for drilling and construction of the project, changes to the plan may be required based on technical, operational, or safety conditions encountered during the development and execution. The project team will notify the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director if substantial deviations from this plan are required.

As mentioned, the Bluebonnet Sequestration Hub, LLC will drill six new CO_2 injection wells, Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS

6, and Bluebonnet CCS 7. These wells will target the [redacted] formations, specifically the [redacted] sands.

Oxy Low Carbon Ventures, LLC, the parent company of Bluebonnet Sequestration Hub, LLC, drilled one stratigraphic well, [redacted] in the Bluebonnet Hub in 2022-2023. This well has been used to obtain site-based information and additional characterization to complement the geological and numerical simulation models. The [redacted] stratigraphic well was designed with the goal of being converted into an in-zone monitoring well to track the CO_2 plume extension and pressure front in the [redacted] formations, as described in the Testing and Monitoring Plan.

Additionally, the project plans to drill two new in-zone monitoring wells in [redacted] injection zone to directly monitor the injection targets (IZM FM), one in-zone monitoring well in the [redacted] injection zone (IZM M), seven USDW/ Above Confining Zone (ACZ) monitoring wells (targeting the shallowest zone above the confining zone that was defined by the project as the deepest USWD), two water production wells in the [redacted] injection zone to manage increases in the reservoir pressure, and one water disposal well.

Since the shallowest above-confining zone has been defined as the base of the USDW, the seven USDW monitoring wells will track the quality of the water and variations in geochemistry in the USDW. These shallow water wells will be produced and sampled based on the requirements described in the Testing and Monitoring Plan presented in this application.

Location, well schematics, and construction details for the in-zone monitoring wells, above confining zone/USDW monitoring wells, water production wells, and water disposal well are included in the Testing and Monitoring Plan of this application.

3.0 Design Considerations for CO_2 Injector Wells

Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 are designed to maximize the rate of injection and reduce the surface pressure and friction alongside the tubing, while maintaining the bottomhole pressure below 90% of the frac gradient. A nodal analysis using PROSPER software performed sensitivities on the tubing size, rate of erosion, stresses, operating pressures, and potential movement of the tubulars. The injection rate will continue to be refined as the project acquires, processes, evaluates, and interprets additional data.

Well materials and equipment were selected based on the maximum operating conditions expected during the life of the well and compatibility with the expected CO_2 stream, to ensure mechanical integrity and reliability of the system during the life of the project.

The selected design provides enough clearance to deploy pressure and temperature gauges on the tubing and continuous surveillance of external mechanical integrity through an external fiber optic cable.

During the design process, the project team integrated years of experience and data collected by Oxy (the parent company of Bluebonnet Sequestration Hub, LLC) as a CO_2 operator in enhanced oil recovery (EOR) fields, with the expertise of worldwide-recognized providers of tubulars, cementing services companies, and downhole and surface equipment manufacturers, amongst others, to complete the final design of the CO_2 injectors.

The operating conditions expected during the life of the CO2 injector wells are shown in Table CON-1.Table CON-2, Table CON-3, Table CON- 4, Table CON- 5, and Table CON- 6. Table CON-7 shows the CO_2 specifications of the Bluebonnet Hub.

Table CON-1: Operating design parameters for Bluebonnet CCS 1.

Claimed as PBI

[redacted]

(1) MD: Measured Depth
(2) TVD: True Vertical Depth

Table CON-2: Operating design parameters for Bluebonnet CCS 2.

Claimed as PBI

[redacted]

Table CON-3: Operating design parameters for Bluebonnet CCS 3.

Claimed as PBI

[redacted]

Table CON- 4: Operating design parameters for Bluebonnet CCS 5.

Claimed as PBI

[redacted]

Table CON- 5: Operating design parameters for Bluebonnet CCS 6.

Claimed as PBI

[redacted]

Table CON- 6: Operating design parameters for Bluebonnet CCS 7.

Claimed as PBI

[redacted]

Table CON-7: CO_2 Specification for Bluebonnet Hub.

Claimed as PBI

[redacted]

4.0 Well Design Bluebonnet CCS 1 - CO_2 Injector Well

The Bluebonnet CCS 1 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-1, Figure CON-2, and Figure CON-3 show the proposed well schematics for Bluebonnet CCS 1 original completion, first recompletion, and second recompletion, respectively.

Claimed as PBI

[redacted]

Figure CON-1: Bluebonnet CCS 1 well schematic – original completion.

Claimed as PBI

[redacted]

Figure CON-2: Bluebonnet CCS 1 well schematic – first recompletion.

Claimed as PBI

[redacted]

Figure CON-3: Bluebonnet CCS 1 well schematic – second recompletion.

4.1 Design Overview Bluebonnet CCS 1

4.1.1 Conductor

The [redacted] wellbore for the conductor casing will be drilled via auger to a depth [redacted] The wellbore will be cased with a [redacted] line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

4.1.2 Surface Section

The [redacted] vertical wellbore will be drilled [redacted] to cover the base of the USDW, [redacted], and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum of every 100 ft while drilling. This section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, [redacted] casing will be run and cemented to surface via circulation with a conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test the BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

4.1.3 Long String Section

[redacted]

A [redacted] directional wellbore will be drilled [redacted] to total depth (MD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string [redacted] casing will be deployed with the distributed temperature sensing (DTS)/distributed acoustical sensing (DAS) fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after it is drilled.

After the cementing is complete, Section B of the wellhead will be installed, and the DTS/DAS cable will be threaded through the slips and pack off. The team will then install the rest of the wellhead to prepare for completion operations.

4.1.4 Completion

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The [redacted] tubing and packer completion will be run [redacted] in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

4.2 Directional Plan Bluebonnet CCS 1

Table CON-8 summarizes the proposed trajectory for Bluebonnet CCS 1.

Table CON-8: Bluebonnet CCS 1 directional trajectory.

[redacted]

Claimed as PBI

[redacted]

Claimed as PBI

[redacted]

Claimed as PBI

[redacted]

4.3 Casing, Tubing and Completion Design Bluebonnet CCS 1

The different casing sections and completion tubing were designed to withstand expected operating loads such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations
- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull
- Corrosion environments

Table CON-9 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-9: Minimum safety factors for tubular design – Bluebonnet CCS 1.

Claimed as PBI [redacted]

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Appendix D of this document. Safety factors for the second recompletion events are similar that the ones presented in Table CON-9.

Figure CON-4 shows the design limits envelope for the 5 ½-in. injection tubing used to validate the selection of the material. The analysis was developed with WELLCAT™ software from Landmark.

Claimed as PBI [redacted]

Figure CON-4: Bluebonnet CCS 1 injection tubing design limits.

A summary of the loads used in the simulation of the tubing with WELLCAT™ is provided in Attachment E of this Injection Well Construction Plan.

The tables listed below provide further details regarding the Bluebonnet CCS 1 well. Table CON-10 contains the open hole diameters and intervals, Table CON-11 lists the casing specifications, Table CON-12 details the conductor material, and Table CON-13 details the casing material properties for Bluebonnet CCS 1.

Table CON-10: Open hole diameters and intervals - Bluebonnet CCS 1.

[redacted]

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated [redacted]

Table CON-11: Casing specifications - Bluebonnet CCS 1.

[redacted]

Table CON-12: Conductor material properties - Bluebonnet CCS 1.

[redacted]

Table CON-13: Casing material properties - Bluebonnet CCS 1.

[redacted]

Notes:

- A stage tool will be located [redacted] in the [redacted] casing to perform the two-stage cementing job.
- The centralization program will aim at minimum 70% standoff and be adjusted using the field data for deviation, caliper, and hole conditions.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-14 and Table CON-15 contain the upper completion specifications for the original completion and first and second recompletions. Table CON-16 shows the specification of the [redacted] tubing.

Table CON-14: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 1.

[redacted]

Table CON-15: Tubing material properties – second recompletion - Bluebonnet CCS 1.

Claimed as PBI

Table CON-16: Tubing material properties - Bluebonnet CCS 1.

Claimed as PBI

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The annular space between the Claimed as PBI tubing and Claimed as PBI casing will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-17 shows the specifications of the injection packer.

Table CON-17: Packer specifications - Bluebonnet CCS 1.

Claimed as PBI

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.
- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and completion elements are included in Appendix A.

4.4 Cementing Program Bluebonnet CCS 1

Table CON-18 shows the cementing program details.

Table CON-18: Cementing program - Bluebonnet CCS 1.

Claimed as PBI [redacted]

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated Claimed as PBI [redacted], but the depth will be adjusted based on final drilling conditions.

Details on cementing operation design, materials, and additives selection are included in Appendix B, with examples of the proposed cementing slurries.

4.5 Mud Program Bluebonnet CCS 1

Table CON-19 shows the mud program details for Bluebonnet CCS 1.

Table CON-19: Mud program - Bluebonnet CCS 1.

Claimed as PBI

[redacted]

4.6 Wellhead Schematic Bluebonnet CCS 1

Figure CON-5 below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet CCS 1 well. Details on the blowout preventors (BOP) and wellhead design are included in Appendix C.

Claimed as PBI

[redacted]

Figure CON-5: Schematic diagram of Bluebonnet CCS 1 well.

4.7 Bluebonnet CCS 1 Procedure

4.7.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger [redacted] hole to a depth [redacted].
- Set a [redacted] conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

4.7.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up [redacted] bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill [redacted] surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.

- Make up shoe track and run [redacted] surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbls of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when 10 bbls before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.
- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the [redacted] 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi, BOPE to 3,000 psi.

4.7.3 Long String Section

- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- [redacted] Ensure that all solid control equipment is installed and operating properly.
- Pick up [redacted] directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out [redacted] surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill [redacted] hole to TD based on the directional plan. Surveys must be taken minimum every 100 ft. Pump sweep pills to improve hole cleaning based on the hydraulic simulations.

If signs of drag or hole-cleaning issues are observed, increase the frequency of pumping the sweep pills.

- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up [redacted] cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.
- Pull out of the hole. Keep a record of the fill volume and level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips and test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

  Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.

- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry as per program, take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer's recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

  Note: This is a standard process for stage tool application; however, it is recommended to evaluate the different methods in the market to include annular packers in combination with circulating ports that could improve the seal, reduce the wait on cement time, and optimize time and cost.

- Rig down cementing equipment.
- Perform nipple down safety meeting and discuss the operational plan and risks.
- Lift the BOPs.
- Install casing slips, threading the fiber optic cable through the port.
- Cut casing and install pack off and fiber optic connectors.
- Wait on cement to reach 500 psi.
- Continue installation of section B and wellhead.
- Rig down drilling equipment.

4.7.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).

- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1,000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.
- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform an injectivity test/step rate test and falloff test.

5.0 Well Design Bluebonnet CCS 2 - CO_2 Injector Well

The Bluebonnet CCS 2 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-6 and Figure CON-7 show the proposed well schematic for Bluebonnet CCS 2 original completion and recompletion, respectively.

Claimed as PBI

[redacted]

Figure CON-6: Bluebonnet CCS 2 well schematic – original completion.

Claimed as PBI

[redacted]

Figure CON-7: Bluebonnet CCS 2 well schematic – recompletion.

5.1 Design Overview Bluebonnet CCS 2

5.1.1 Conductor

The [redacted] wellbore for the conductor casing will be drilled via auger to a depth approximately of [redacted] The wellbore will be cased with a [redacted] line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

5.1.2 Surface Section

The [redacted] vertical wellbore will be drilled [redacted] to cover base of the USDW, [redacted] and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum every 100 ft while drilling. This section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, [redacted] casing will be run and cemented to surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test the BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

5.1.3 Long String Section

[redacted]

A [redacted] wellbore will be drilled [redacted] to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string [redacted] casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

After the cementing is complete, Section B of the wellhead will be installed, and the DTS/DAS cable will be threaded through the slips and pack off. The team will install the rest of the wellhead to prepare for completions operations.

5.1.4 Completion

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The [redacted] tubing and packer completion will be run [redacted] in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

5.2 Directional Plan Bluebonnet CCS 2

Table CON-20 summarizes the proposed trajectory for Bluebonnet CCS 2.

Table CON-20: Bluebonnet CCS 2 directional trajectory.

[redacted]

Claimed as PBI

[redacted]

Claimed as PBI

[redacted]

Claimed as PBI

[redacted]

5.3 Casing, Tubing and Completion Design Bluebonnet CCS 2

The different casing sections and completion tubing were designed to withstand expected operating loads such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations.
- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull
- Corrosion environments

Table CON-21 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-21: Minimum safety factors for tubular design - Bluebonnet CCS 2.

[redacted]

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Appendix D of this document.

The WELLCATTM evaluation performed for Bluebonnet CCS 1 applies to the loads observed for Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 (Appendix E).

The tables listed below provide further details regarding the Bluebonnet CCS 2 well. Table CON-22 contains the open hole diameters and intervals, Table CON-23 lists the casing specifications, Table CON-24 details the conductor material, and Table CON-25 details the casing material properties.

Table CON-22: Open hole diameters and intervals - Bluebonnet CCS 2.

[redacted]

Note:

- The USDW depth will be confirmed with open hole logs. [redacted]

Table CON-23: Casing specifications - Bluebonnet CCS 2.

[redacted]

Table CON-24: Conductor material properties - Bluebonnet CCS 2.

[redacted]

Table CON-25: Casing material properties - Bluebonnet CCS 2.

[redacted]

Notes:

- A stage tool will be located [redacted] in the [redacted] casing to perform the two-stage cementing job.
- The centralization program will aim at minimum 70% standoff and be adjusted using the field data for deviation, caliper, and hole conditions.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-26 contains the upper completion specifications for the original completion. Table CON-27 shows the specification of the [redacted] tubing.

Table CON-26: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 2.

[redacted]

Table CON-27: Tubing material properties - Bluebonnet CCS 2.

[redacted]

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The annular space between the [redacted] tubing and [redacted] casing will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-28 shows the specifications of the injection packer.

Table CON-28: Packer specifications - Bluebonnet CCS 2.

[redacted]

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.
- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and completion elements are included in Appendix A.

5.4 Cementing Program Bluebonnet CCS 2

Table CON-29 shows the cementing program details.

Table CON-29: Cementing program - Bluebonnet CCS 2.

Claimed as PBI [redacted]

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated Claimed as PBI [redacted] but the depth will be adjusted based on final drilling conditions.

Details on cementing operation design, materials, and additives selection are included in Appendix B, with examples of the proposed cementing slurries.

5.5 Mud Program Bluebonnet CCS 2

Table CON-30 shows the mud program details for Bluebonnet CCS 2.

Table CON-30: Mud program - Bluebonnet CCS 2.

Claimed as PBI

[redacted]

5.6 Wellhead Schematic Bluebonnet CCS 2

Figure CON-8 below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet CCS 2 well. Details on blowout preventors (BOP) and wellhead design are included in Appendix C.

Claimed as PBI

[redacted]

Figure [redacted] well.

5.7 Bluebonnet CCS 2 Procedure

5.7.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger [redacted] hole to a depth [redacted]
- Set a [redacted] conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

5.7.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up [redacted] bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill [redacted] surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.

- Make up shoe track and run [redacted] surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbls of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when at 10 bbls before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.
- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the [redacted] 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi.

5.7.3 Long String Section

- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- [redacted] Ensure that all solid control equipment is installed and operating properly.
- Pick up [redacted] directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out [redacted] surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill [redacted] hole to TD based on the directional plan. Surveys must be taken minimum every 100 ft. Pump sweep pills to improve hole cleaning based on the hydraulic simulations.

If signs of drag or hole-cleaning issues are observed, increase the frequency of pumping the sweep pills.

- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up [redacted] cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.
- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips and test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

  Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing per program, coordinating running speed with the fiber optic installation.
- Once on the bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.

- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer's recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

  Note: This is a standard process for stage tool application; however, it is recommended to evaluate the different methods in the market to include annular packers in combination with circulating ports that could improve the seal, reduce the wait on cement time, and optimize time and cost.

- Rig down cementing equipment.
- Perform nipple down safety meeting and discuss the operational plan and risks.
- Lift the BOPs.
- Install casing slips, threading the fiber optic cable through the port.
- Cut casing and install pack off and fiber optic connectors.
- Wait on cement to reach 500 psi.
- Continue installation of section B and wellhead.
- Rig down drilling equipment.

5.7.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).

- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1,000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.
- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform an injectivity test/step rate test and falloff test.

6.0 Well Design Bluebonnet CCS 3 - CO_2 Injector Well

The Bluebonnet CCS 3 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-9, Figure CON-10, and Figure CON-11 show the proposed well schematics for the Bluebonnet CCS 3 original completion and recompletions, respectively.

Claimed as PBI

[redacted]

Figure CON-9: Bluebonnet CCS 3 well schematic – original completion.

Claimed as PBI

[redacted]

Figure CON-10: Bluebonnet CCS 3 well schematic – first recompletion.

Claimed as PBI

[redacted]

Figure CON-11: Bluebonnet CCS 3 well schematic – second recompletion.

6.1 Design Overview Bluebonnet CCS 3

6.1.1 Conductor

The [redacted] wellbore for the conductor casing will be drilled via auger to a depth approximately of [redacted] The wellbore will be cased with [redacted] line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

6.1.2 Surface Section

The [redacted] vertical wellbore will be drilled [redacted] to cover base of the USDW [redacted] and provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum every 100 ft while drilling and this section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, [redacted] casing will be run and cemented to surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

6.1.3 Long String Section

[redacted]

A [redacted] directional wellbore will be drilled [redacted] to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of [redacted] casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

After the cementing is complete, Section B of the wellhead will be installed, and the DTS/DAS cable will be threaded through the slips and packoff. The team will install the rest of the wellhead to prepare for completions operations.

6.1.4 Completion

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The [redacted] tubing and packer completion will be run [redacted] in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

6.2 Directional Plan Bluebonnet CCS 3

Table CON-31 summarizes the proposed trajectory for Bluebonnet CCS 3.

Table CON-31: Bluebonnet CCS 3 directional trajectory.

[redacted]

Claimed as PBI

[redacted]

Claimed as PBI

[redacted]

Claimed as PBI

[redacted]

6.3 Casing, Tubing and Completion Design Bluebonnet CCS 3

The different casing sections and completion tubing were designed to withstand expected operating loads such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations.
- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull

- Corrosion environments

Table CON-32 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-32: Minimum safety factors for tubular design - Bluebonnet CCS 3.

Claimed as PBI [redacted]

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Appendix D of this document.

The WELLCATTM evaluation performed for Bluebonnet CCS 1 applies to the loads observed for Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 (Appendix E).

The tables listed below provide further details regarding the Bluebonnet CCS 3 well. Table CON-33 contains the open hole diameters and intervals, Table CON-34 lists the casing specifications, Table CON-35 details the conductor material, and Table CON-36 details the casing material properties.

Table CON-33: Open hole diameters and intervals - Bluebonnet CCS 3.

Claimed as PBI [redacted]

Note:

- The USDW depth will be confirmed with open hole logs. Claimed as PBI [redacted]

Table CON-34: Casing specifications - Bluebonnet CCS 3.

[redacted]

Table CON-35: Conductor material properties - Bluebonnet CCS 3.

[redacted]

Table CON-36: Casing material properties - Bluebonnet CCS 3.

[redacted]

Notes:

- A stage tool will be located [redacted] in the [redacted] casing to perform the two-stage cementing job.
- The centralization program will aim at minimum 70% standoff and be adjusted using the field data for deviation, caliper, and hole conditions.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-37 contains the upper completion specifications for the original completion and recompletions. Table CON-38 shows the specification of the [redacted] tubing.

Table CON-37: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 3.

[redacted]

Table CON-38: Tubing material properties - Bluebonnet CCS 3.

[redacted]

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and to the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The annular space between the [redacted] tubing and [redacted] casing will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-39 shows the specifications of the injection packer.

Table CON-39: Packer specifications - Bluebonnet CCS 3.

[redacted]

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.

- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and completion elements are included in Appendix A.

6.4 Cementing Program Bluebonnet CCS 3

Table CON-40 shows the cementing program details.

Table CON-40: Cementing program - Bluebonnet CCS 3.

[redacted]

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated [redacted], but the depth will be adjusted based on final drilling conditions.

Details on the cementing operation design, materials, and additives selection are included in Appendix B, with examples of the proposed cementing slurries.

6.5 Mud Program Bluebonnet CCS 3

Table CON-41 shows the mud program details for Bluebonnet CCS 3.

Table CON-41: Mud program - Bluebonnet CCS 3.

Claimed as PBI

[redacted]

6.6 Wellhead Schematic Bluebonnet CCS 3

Figure CON-12 below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet CCS 3 well. Details on blowout preventors (BOPs) and wellhead design are included in Appendix C.

Claimed as PBI

[redacted]

Figure CON-12: Schematic diagram of Bluebonnet CCS 3 well.

6.7 Bluebonnet CCS 3 Procedure

6.7.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger [redacted] hole to a depth [redacted].
- Set a [redacted] conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

6.7.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up [redacted] bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill [redacted] surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.

- Make up shoe track and run [redacted] surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbls of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when at 10 bbls before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.
- While waiting on cement, perform pre-wellhead and nipple up safety meeting, and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the [redacted] 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi.

6.7.3 Long String Section

- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- [redacted] Ensure that all solid control equipment is installed and operating properly.
- Pick up [redacted] directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out [redacted] surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill [redacted] hole to TD based on the directional plan. Surveys must be taken minimum every 100 ft. Pump sweep pills to improve hole cleaning based on the hydraulic simulations.

If signs of drag or hole-cleaning issues are observed, increase the frequency of pumping the sweep pills.

- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up [redacted] cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.
- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips and test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

  Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.

- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer's recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

  Note: This is a standard process for stage tool application; however, it is recommended to evaluate the different methods in the market to include annular packers in combination with circulating ports that could improve the seal, reduce the wait on cement time, and optimize time and cost.

- Rig down cementing equipment.
- Perform nipple down safety meeting and discuss the operational plan and risks.
- Lift the BOPs.
- Install casing slips, threading the fiber optic cable through the port.
- Cut casing and install pack off and fiber optic connectors.
- Wait on cement to reach 500 psi.
- Continue installation of section B and wellhead.
- Rig down drilling equipment.

6.7.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).

- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1,000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.
- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform an injectivity test/step rate test and falloff test.

7.0 Well Design Bluebonnet CCS 5 - CO_2 Injector Well

The Bluebonnet CCS 5 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-13 shows the proposed well schematic for the Bluebonnet CCS 5 original completion.

Claimed as PBI

[redacted]

Figure CON-13: Bluebonnet CCS 5 well schematic.

7.1 Design Overview Bluebonnet CCS 5

7.1.1 Conductor

The [redacted] wellbore for the conductor casing will be drilled via auger to a depth approximately [redacted] The wellbore will be cased with a [redacted] line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

7.1.2 Surface Section

The [redacted] vertical wellbore will be drilled [redacted] to cover base of the USDW, [redacted], and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum every 100 ft while drilling and this section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, [redacted] casing will be run and cemented to surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

7.1.3 Long String Section

A [redacted] vertical wellbore will be drilled [redacted] to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string [redacted] casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

After the cementing is complete, Section B of the wellhead will be installed, and the DTS/DAS cable will be threaded through the slips and packoff. The team will install the rest of the wellhead to prepare for completions operations.

7.1.4 Completion

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The [redacted] tubing and packer completion will be run to [redacted] in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

7.2 Casing, Tubing and Completion Design Bluebonnet CCS 5

The different casing sections and completion tubing were designed to withstand expected operating loads such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations.
- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull
- Corrosion environments

Table CON-42 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-42: Minimum safety factors for tubular design - Bluebonnet CCS 5.

Claimed as PBI [redacted]

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Appendix D of this document.

The WELLCAT™ evaluation performed for Bluebonnet CCS 1 applies to the loads observed for Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 (Appendix E).

The tables listed below provide further details regarding the Bluebonnet CCS 5 well. Table CON-43 contains the open hole diameters and intervals, Table CON-44 lists the casing specifications, Table CON-45 details the conductor material, and Table CON-46 details the casing material properties.

Table CON-43: Open hole diameters and intervals - Bluebonnet CCS 5.

Claimed as PBI [redacted]

Note:

- The USDW depth will be confirmed with open hole logs. Claimed as PBI [redacted]

Table CON-44: Casing specifications - Bluebonnet CCS 5.

Claimed as PBI [redacted]

Table CON-45: Conductor material properties - Bluebonnet CCS 5.

[redacted]

Table CON-46: Casing material properties - Bluebonnet CCS 5.

[redacted]

Notes:

- A stage tool will be located [redacted] in the [redacted] casing to perform the two-stage cementing job.
- The centralization program will aim at minimum 70% standoff and be adjusted using the field data for deviation, caliper, and hole conditions.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-47 contains the upper completion specifications for the original completion and recompletions. Table CON-38 shows the specification of the [redacted] tubing.

Table CON-47: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 5.

[redacted]

Table CON-48: Tubing material properties - Bluebonnet CCS 5.

Claimed as PBI [redacted]

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and to the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The annular space between the Claimed as PBI [redacted] tubing and Claimed as PBI [redacted] casing will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-49 shows the specifications of the injection packer.

Table CON-49: Packer specifications - Bluebonnet CCS 5.

Claimed as PBI [redacted]

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.
- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and completion elements are included in Appendix A.

7.3 Cementing Program Bluebonnet CCS 5

Table CON-50 shows the cementing program details.

Table CON-50: Cementing program - Bluebonnet CCS 5.

[redacted]

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated [redacted] but the depth will be adjusted based on final drilling conditions.

Details on the cementing operation design, materials, and additives selection are included in Appendix B, with examples of the proposed cementing slurries.

7.4 Mud Program Bluebonnet CCS 5

Table CON-51 shows the mud program details for Bluebonnet CCS 5.

Table CON-51: Mud program - Bluebonnet CCS 5.

Claimed as PBI

[redacted]

7.5 Wellhead Schematic Bluebonnet CCS 5

Figure CON-14 below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet CCS 5 well. Details on blowout preventors (BOPs) and wellhead design are included in Appendix C.

Claimed as PBI

[redacted]

Figure CON-14: Schematic diagram of Bluebonnet CCS 5 well.

7.6 Bluebonnet CCS 5 Procedure

<u>8.0 Well Design Bluebonnet CCS 6 - CO_2 Injector Well</u>

The Bluebonnet CCS 6 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-15 shows the proposed well schematic for the Bluebonnet CCS 6 original completion.

Claimed as PBI

[redacted]

Figure CON-15: Bluebonnet CCS 6 well schematic.

8.1 Design Overview Bluebonnet CCS 6

8.1.1 Conductor

The [redacted] wellbore for the conductor casing will be drilled via auger to a depth approximately [redacted] The wellbore will be cased with a [redacted] line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

8.1.2 Surface Section

The [redacted] vertical wellbore will be drilled [redacted] to cover base of the USDW, [redacted] and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum every 100 ft while drilling and this section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, [redacted] casing will be run and cemented to surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

8.1.3 Long String Section

A [redacted] vertical wellbore will be drilled [redacted] to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string [redacted] casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

After the cementing is complete, Section B of the wellhead will be installed, and the DTS/DAS cable will be threaded through the slips and packoff. The team will install the rest of the wellhead to prepare for completions operations.

8.1.4 Completion

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The [redacted] tubing and packer completion will be run to [redacted] in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

8.2 Casing, Tubing and Completion Design Bluebonnet CCS 6

The different casing sections and completion tubing were designed to withstand expected operating loads such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations.
- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull
- Corrosion environments

Table CON-52 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-52: Minimum safety factors for tubular design - Bluebonnet CCS 6.

Claimed as PBI [redacted]

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Appendix D of this document.

The WELLCATTM evaluation performed for Bluebonnet CCS 1 applies to the loads observed for Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 (Appendix E).

The tables listed below provide further details regarding the Bluebonnet CCS 6 well. Table CON-53 contains the open hole diameters and intervals, Table CON-54 lists the casing specifications, Table CON-55 details the conductor material, and Table CON-56 details the casing material properties.

Table CON-53: Open hole diameters and intervals - Bluebonnet CCS 6.

Claimed as PBI [redacted]

Note:

- The USDW depth will be confirmed with open hole logs. Claimed as PBI [redacted]

Table CON-54: Casing specifications - Bluebonnet CCS 6.

Claimed as PBI [redacted]

Table CON-55: Conductor material properties - Bluebonnet CCS 6.

[redacted]

Table CON-56: Casing material properties - Bluebonnet CCS 6.

[redacted]

Notes:

- A stage tool will be located [redacted] in the [redacted] casing to perform the two-stage cementing job.
- The centralization program will aim at minimum 70% standoff and be adjusted using the field data for deviation, caliper, and hole conditions.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-57 contains the upper completion specifications for the original completion and recompletions. Table CON-58 shows the specification of the [redacted] tubing.

Table CON-57: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 6.

[redacted]

Table CON-58: Tubing material properties - Bluebonnet CCS 6.

[redacted]

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and to the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The annular space between the [redacted] tubing and [redacted] casing will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-59 shows the specifications of the injection packer.

Table CON-59: Packer specifications - Bluebonnet CCS 6.

[redacted]

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.
- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and completion elements are included in Appendix A.

8.3 Cementing Program Bluebonnet CCS 6

Table CON-60 shows the cementing program details.

Table CON-60: Cementing program - Bluebonnet CCS 6.

Claimed as PBI [redacted]

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated Claimed as PBI [redacted] but the depth will be adjusted based on final drilling conditions.

Details on the cementing operation design, materials, and additives selection are included in Appendix B, with examples of the proposed cementing slurries.

8.4 Mud Program Bluebonnet CCS 6

Table CON-61 shows the mud program details for Bluebonnet CCS 6.

Table CON-61: Mud program - Bluebonnet CCS 6.

Claimed as PBI

[redacted]

8.5 Wellhead Schematic Bluebonnet CCS 6

Figure CON-16 below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet CCS 6 well. Details on blowout preventors (BOPs) and wellhead design are included in Appendix C.

Claimed as PBI

[redacted]

Figure CON-16: Schematic diagram of Bluebonnet CCS 6 well.

8.6 Bluebonnet CCS 6 Procedure

8.6.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger [redacted] hole to a depth [redacted]
- Set a [redacted] conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

8.6.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up [redacted] bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill [redacted] surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.

- Make up shoe track and run [redacted] surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbls of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when at 10 bbls before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.
- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the [redacted] 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi.

8.6.3 Long String Section

- Perform pre-section meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- [redacted] Ensure that all solid control equipment is installed and operating properly.
- Pick up [redacted] directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out [redacted] surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill [redacted] hole to TD based on the directional plan. Surveys must be taken minimum every 100 ft. Pump sweep pills to improve hole cleaning based on the hydraulic simulations.

If signs of drag or hole-cleaning issues are observed, increase the frequency of pumping the sweep pills.

- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up [redacted] cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.
- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips and test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

  Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.

- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer’s recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

  Note: This is a standard process for stage tool application; however, it is recommended to evaluate the different methods in the market to include annular packers in combination with circulating ports that could improve the seal, reduce the wait on cement time, and optimize time and cost.

- Rig down cementing equipment.
- Perform nipple down safety meeting and discuss the operational plan and risks.
- Lift the BOPs.
- Install casing slips, threading the fiber optic cable through the port.
- Cut casing and install pack off and fiber optic connectors.
- Wait on cement to reach 500 psi.
- Continue installation of section B and wellhead.
- Rig down drilling equipment.

8.6.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.

- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1,000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.
- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform and injectivity test/step rate test and falloff test.

9.0 Well Design Bluebonnet CCS 7 - CO_2 Injector Well

The Bluebonnet CCS 7 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-17 shows the proposed well schematic for the Bluebonnet CCS 7 the original completion.

Claimed as PBI

[redacted]

Figure CON-17: Bluebonnet CCS 7 well schematic.

9.1 Design Overview Bluebonnet CCS 7

9.1.1 Conductor

The [redacted] wellbore for the conductor casing will be drilled via auger to a depth [redacted] The wellbore will be cased with a [redacted] line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

9.1.2 Surface Section

The [redacted] vertical wellbore will be drilled [redacted] to cover base of the USDW, [redacted] and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum every 100 ft while drilling and this section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, [redacted] casing will be run and cemented to surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

9.1.3 Long String Section

A [redacted] vertical wellbore will be drilled [redacted] to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string [redacted] casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

After the cementing is complete, Section B of the wellhead will be installed, and the DTS/DAS cable will be threaded through the slips and packoff. The team will install the rest of the wellhead to prepare for completions operations.

9.1.4 Completion

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The [redacted] tubing and packer completion will be run [redacted] in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

9.2 Casing, Tubing and Completion Design Bluebonnet CCS 7

The different casing sections and completion tubing were designed to withstand expected operating loads such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations.
- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull
- Corrosion environments

Table CON-62 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-62: Minimum safety factors for tubular design - Bluebonnet CCS 7.

Claimed as PBI [redacted]

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Appendix D of this document.

The WELLCATTM evaluation performed for Bluebonnet CCS 1 applies to the loads observed for Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 (Appendix E).

The tables listed below provide further details regarding the Bluebonnet CCS 7 well. Table CON-63 contains the open hole diameters and intervals, Table CON-64 lists the casing specifications, Table CON-65 details the conductor material, and Table CON-46 details the casing material properties.

Table CON-63: Open hole diameters and intervals - Bluebonnet CCS 7.

Claimed as PBI [redacted]

Note:

- The USDW depth will be confirmed with open hole logs. Claimed as PBI [redacted]

Table CON-64: Casing specifications - Bluebonnet CCS 7.

Claimed as PBI [redacted]

Table CON-65: Conductor material properties - Bluebonnet CCS 7.

[redacted]

Table CON-66: Casing material properties - Bluebonnet CCS 7.

[redacted]

Notes:

- A stage tool will be located [redacted] in the [redacted] casing to perform the two-stage cementing job.
- The centralization program will aim at minimum 70% standoff and be adjusted using the field data for deviation, caliper, and hole conditions.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-67 contains the upper completion specifications for the original completion and recompletions. Table CON-68 shows the specification of the [redacted] tubing.

Table CON-67: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 7.

[redacted]

Table CON-68: Tubing material properties - Bluebonnet CCS 7.

[redacted]

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and to the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The annular space between the [redacted] tubing and [redacted] casing will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-69 shows the specifications of the injection packer.

Table CON-69: Packer specifications - Bluebonnet CCS 7.

[redacted]

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.
- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and completion elements are included in Appendix A.

9.3 Cementing Program Bluebonnet CCS 7

Table CON-70 shows the cementing program details.

Table CON-70: Cementing program - Bluebonnet CCS 7.

[redacted]

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated [redacted] but the depth will be adjusted based on final drilling conditions.

Details on the cementing operation design, materials, and additives selection are included in Appendix B, with examples of the proposed cementing slurries.

9.4 Mud Program Bluebonnet CCS 7

Table CON-71 shows the mud program details for Bluebonnet CCS 7.

Table CON-71: Mud program - Bluebonnet CCS 7.

[redacted]

9.5 Wellhead Schematic Bluebonnet CCS 7

Figure CON-18 below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet CCS 7 well. Details on blowout preventors (BOPs) and wellhead design are included in Appendix C.

[redacted]

Figure CON-18: Schematic diagram of Bluebonnet CCS 7 well.

9.6 Bluebonnet CCS 7 Procedure

9.6.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger [redacted] hole to a depth [redacted]
- Set [redacted] conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

9.6.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.

- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up [redacted] bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill [redacted] surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.
- Make up shoe track and run [redacted] surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbls of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when at 10 bbls before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.

- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the [redacted] 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi.

9.6.3 Long String Section

- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- [redacted] Ensure that all solid control equipment is installed and operating properly.
- Pick up [redacted] directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out [redacted] surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill [redacted] hole to TD based on the directional plan. Surveys must be taken minimum every 100 ft. Pump sweep pills to improve hole cleaning based on the hydraulic simulations. If signs of drag or hole-cleaning issues are observed, increase the frequency of pumping the sweep pills.
- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up [redacted] cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.

- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and the casing slips and test the correct function of the tools.
- Rig up the spooler and the equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

  Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing per program, coordinating running speed with the fiber optic installation.
- Once on bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer’s recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

Note: This is a standard process for stage tool application; however, it is recommended to evaluate the different methods in the market to include annular packers in combination with circulating ports that could improve the seal, reduce the wait on cement time, and optimize time and cost.

- Rig down cementing equipment.
- Perform nipple down safety meeting and discuss the operational plan and risks.
- Lift the BOPs.
- Install casing slips, threading the fiber optic cable through the port.
- Cut casing and install pack off and fiber optic connectors.
- Wait on cement to reach 500 psi.
- Continue installation of section B and wellhead.
- Rig down drilling equipment.

9.6.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1,000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.

- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform an injectivity test/step rate test and falloff test.

Claimed as PBI

[redacted]