Plan revision number: 1
Plan revision date: 11/01//24

SUMMARY OF REQUIREMENTS

CLASS VI OPERATING AND REPORTING CONDITIONS

Bluebonnet Sequestration Hub

1.0 Facility Information

Facility name:	Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project) Bluebonnet CCS 7
Facility contacts:	Claimed as PBI [redacted]
Well location:	Claimed as PBI [redacted]

2.0 Injection Well Operating Conditions

Key injection well operating and project reporting requirements are specified in this attachment and are summarized below in Table OP-1

Table OP-1—Injection well operating conditions.

[redacted]

(1) MD: measured depth.
(2) Maximum rate is limited by tubing size, not by reservoir.

Notes:

- [redacted] tubing select as injection string.
- Assumed 90°F as injection temperature for the CO_2 on surface for maximum pressure calculations for estimations.

2.1 Maximum Bottomhole Injection Pressure

The maximum injection pressure limitation serves to prevent fracturing the confining formation. Operating requirements from 40 CFR 146.88(a) specify that injection pressure must not exceed 90% of the injection zone fracture pressure. To meet this requirement, the maximum pressure considered for the Bluebonnet CCS 7 well is 90% of the fracture propagation pressure of the [redacted] injection zone, measured with downhole pressure gauges during the testing of the stratigraphic well [redacted] performed in 2023. Analysis of the well test in the stratigraphic well in the [redacted] formation shows a fracture gradient of 0.76 psi/ft. The [redacted] injection zones were also tested in 2023 in the stratigraphic well. The test reached the maximum injection rate proposed of [redacted] without creating a fracture in the formation. A conservative fracture gradient value of 0.76 psi/ft was used based on the Frio fracture gradient.

The maximum bottomhole pressures at the top of perforations are calculated as follows:

[redacted]

The downhole gauge for injection pressure monitoring will be located at approximately [redacted] during Completion 1, Completion 2, Completion 3, and Completion 4. Therefore, the maximum injection pressures using a downhole pressure gauge are calculated as:

[redacted]

The packer and gauge settings will be adjusted based on logs and well information after the well is constructed, and pressures will be calibrated during the well testing and startup of the operation.

2.2 Wellhead Surface Injection Pressure Ranges

The surface wellhead injection pressure is limited by the selected tubing size, CO_2 supply pipeline, and booster pumping system. The design pressure of the main pipeline is planned to be 2,200 psig, consistent with ASME 900# flange class piping specifications. The design pressure of the booster pumping system is planned to be 3,700 psig, consistent with ASME 1500# flange class piping specifications, though the operating conditions will be significantly lower than design.

Wellbore tubing curves representative of the Bluebonnet CCS 7 were created in PROSPER for [redacted] tubing. Normal operating pressure at the Bluebonnet CCS 7 wellhead will be between [redacted] for the proposed operating rate. The surface pressure will be between [redacted] at the maximum injection rate, with wellhead pressure setpoints of [redacted] respectively, to protect against operational excursions.

If the downhole pressure gauge fails to function properly, the maximum injection pressure shall be limited by the maximum surface wellhead injection pressure until it can be repaired or replaced.

2.3 Wellhead Minimum Differential Annulus/Tubing Pressure

The well is designed to inject through tubing and packer. The annulus space will be filled with inhibited completion fluid with a minimum density of 9.8 ppg. The project team will maintain at least 100 psi differential pressure between the annulus and bottom of the injection string as proposed in Table OP-1. The calculated pressure required in the annulus space between the long string casing and tubing will be estimated as follows:

DP (psi) = max bottomhole pressure during injection – hydrostatic pressure in annulus +100 psi Calculated at packer depth.

3.0 Reporting Frequencies

Bluebonnet Sequestration Hub, LLC, will maintain the reporting frequencies as summarized below in Table OP-2.

Table OP-2—Class VI reporting frequencies.

Claimed as PBI

[redacted]

Note: All testing and monitoring frequencies as well as methodologies are included in the Testing and Monitoring Plan document on this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the 40 CFR 146.91 reporting requirements.

4.0 Startup Monitoring and Reporting Procedures

This section specifies the procedures related to the startup of operations and monitoring and reporting during startup. The injection rates will gradually increase to the planned rate over seven to ten days as the CO_2 volumes become available at the site, during the commissioning period.

The multi-stage (step rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the operative injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

The procedures detailed below describe how Bluebonnet Sequestration Hub, LLC will initiate injection and conduct startup-specific monitoring of the CO_2 injector well pursuant to 40 CFR 146.90.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 injector well.
(2) During the startup period, the project will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, the permittee may be required to schedule a daily conference call to discuss this information.
(3) A series of successively higher injection rates will be applied, as shown in Table OP-3 below in Step 4. The elapsed time and pressure values will be read and recorded for each rate and timestep. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 2,100 psig, measured at the wellhead.
(4) The planned injection rates are as follows:

Table OP-3—Planned injection rates during startup.

Claimed as PBI [redacted]

(5) The injection rates will be controlled with variable frequency drive pumps.
(6) The injection rates will be measured and recorded using Coriolis meters.
(7) Surface and downhole pressures and temperatures will be measured and recorded.

(8) The temperature profile will be continuously read from the fiber optic installed alongside the casing.
(9) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented. During this period, the project team will also look for any evidence of anomalous pressure behavior.
(10) If, during the startup period, any anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate program to better characterize the anomaly. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the injection to cease and line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:
    (a) The instantaneous shut-in pressure (ISIP) will be measured.
    (b) The permittee will notify the agency within 24 hours of the determination.
    (c) The permittee will consult with the agency before initiating any further injection.