

SUMMARY OF REQUIREMENTS

CLASS VI OPERATING AND REPORTING CONDITIONS

Bluebonnet Sequestration Hub

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1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 1

Facility contacts:

Claimed as PBI

Well location:

Claimed as PBI

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

Claimed as PBI

- (1) MD: measured depth.
- (2) TVD: true vertical depth.
- (3) Maximum rate is limited by tubing size, not by reservoir.

Notes:

- Claimed as PBI tubing select as injection string.
- Assumed 90°F as injection temperature for the CO₂ 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 1 well is 90% of the fracture propagation pressure of the Claimed as PBI injection zone, measured with downhole pressure gauges during the testing of the stratigraphic well Claimed as PBI, performed in 2023. Analysis of the well test in the stratigraphic well in the Claimed as PBI formation shows a fracture gradient of 0.76 psi/ft. The Claimed as PBI Injection Zone was also tested in 2023 in the stratigraphic well. The test reached the maximum injection rate proposed of Claimed as PBI 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:

Claimed as PBI

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

Claimed as PBI

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, CO₂ supply pipeline, and booster pumping system. The main pipeline design pressure 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 1 were created in PROSPER for tubing. Normal operating pressure at the Bluebonnet CCS 1 wellhead will be between psig for the proposed operating rate. The surface pressure will be between psig at the maximum injection rate proposed, with wellhead pressure setpoints of psig, 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 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 was estimated as follows:

$$DP \text{ (psi)} = \text{max bottom hole pressure during injection} - \text{hydrostatic pressure in annulus} + 100 \text{ psi}$$

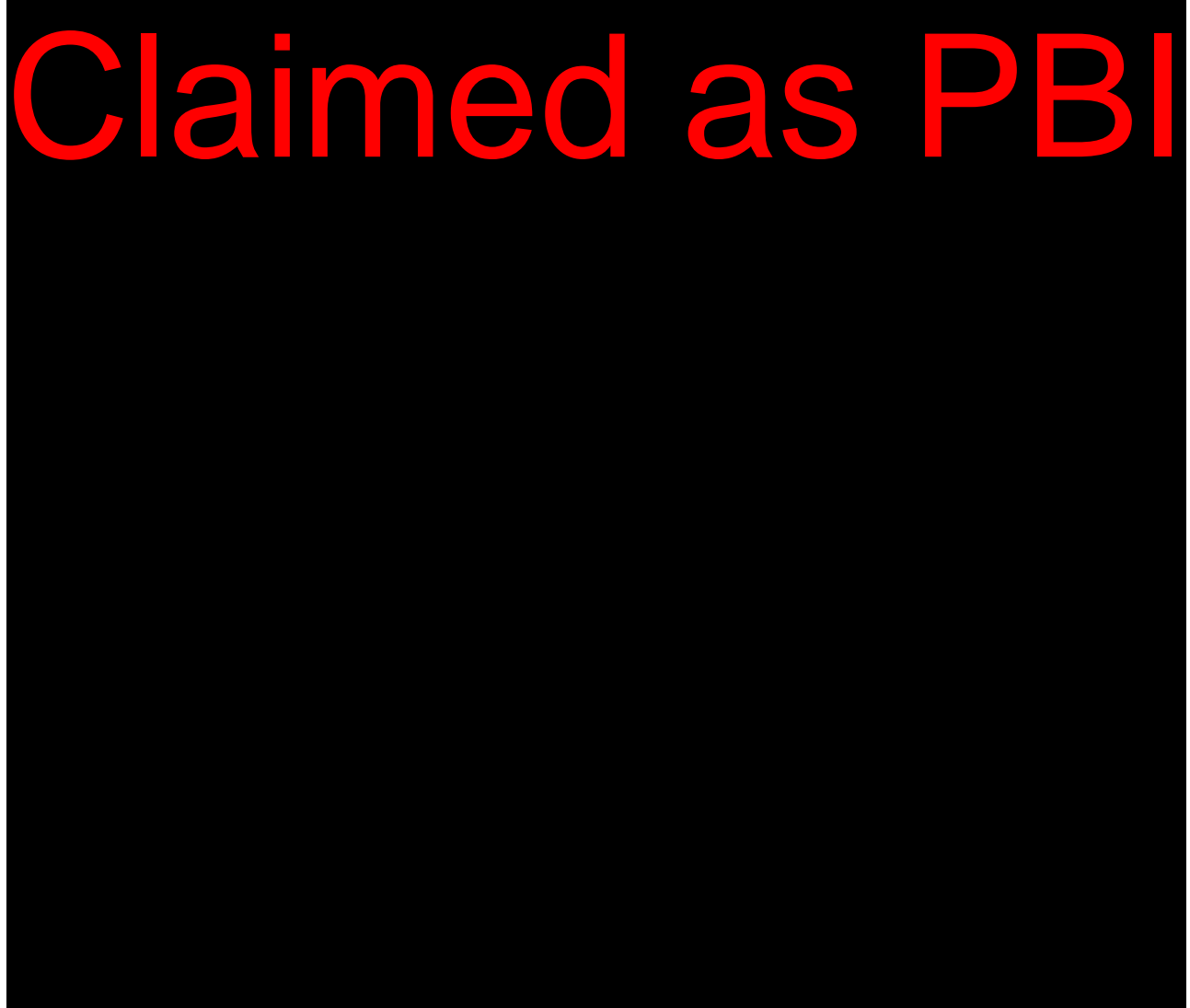
Plan revision number: 2
Plan revision date: 11/01/2024

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.



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 CO₂ 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 CO₂ 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 CO₂ injector well.
- (2) During the startup period, the Bluebonnet Hub 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 2,500 psig, measured at the wellhead.
- (4) The planned injection rates are shown in Table OP-3.

Table OP-3: Planned injection rates during startup.



- (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 the 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.