# SUMMARY OF OPERATING CONDITIONS
# 40 CFR 146.82 (a)(7) and (10) and 146.88 (e)

## South Texas Sequestration Project (Kleberg Hub)



## 1.0 Facility Information

Facility name: South Texas Sequestration Project (Kleberg Hub)
Well Name: Becerra_CCS_01_01

Facility contact: [redacted], Project Manager
5 Greenway Plaza, Suite 110, Houston, TX 77046
[redacted]

Well location: Kleberg County, Texas
[redacted] (NAD27)

## 2.0 Injection Well Operating Conditions

Key injection well operating and project reporting requirements are specified in this attachment and summarized below in Table OP-1. Injection rates included in this section may continue to be refined as 1PointFive acquires, processes, evaluates, and interprets additional data from stratigraphic test wells, as described in this application.

**Table OP-1—Injection Well Operating Conditions**

| Parameter/Condition | Limitation or Permitted Value | Units |
|---|---|---|
| Maximum Injection Rate | [redacted] | Metric tonnes per day |
| Operating Injection Rate | | Metric tonnes per day |
| Maximum Surface Wellhead Injection Pressure | | psig |
| Maximum bottom hole pressure @Downhole Gauge (90% of frac gradient [redacted] psi/ft) | | psig |
| Minimum Annulus Pressure | | psig |

| | | |
|---|---|---|
| Minimum Annulus Pressure/Tubing Differential | [redacted] | psig |

The maximum injection pressure, which serves to prevent confining-formation fracturing, is determined using the following methodology:

- **Maximum Bottomhole Injection Pressure:** The maximum injection pressure for the Becerra_CCS_01_01 well will be equal to or less than 90% of the fracture pressure of the injection zone, measured with downhole pressure gauges and obtained by nearby sonic log data. The data are interpreted using the isotropic method for fracture gradient, a conservative estimate, which provides a fracture gradient of [redacted] psi/ft. The downhole gauge for injection pressure monitoring is located at [redacted] ft below the ground surface. The top of perforations is [redacted] ft below the gauge, so the maximum pressure is calculated at the gauge depth due to the small difference. The maximum injection pressure using a downhole pressure gauge is calculated as follows:

  [redacted]

  The packer and gauge settings will be adjusted based on logs and well information after the well is constructed.

- **Maximum Surface Wellhead Injection Pressure:** The maximum surface wellhead injection pressure will be controlled at the booster pump station. The design pressure of the booster pump discharge is planned to be [redacted] psig, consistent with ASME 1500# flange class piping specifications, though the operating conditions will be significantly lower than design. Normal operating pressure at the wellsite are estimated to be between [redacted] psig, with high and high-high wellsite pressure set points of [redacted] psig, respectively, to protect against operational excursions (set points to be confirmed during detailed engineering). Wellbore tubing curves representative of the Becerra_CCS_01_01 were created in [redacted]-inch internally coated tubing. The bottomhole pressure is not expected to be greater than [redacted] psi at the maximum rate and tubing head pressure, which is below the maximum bottom hole pressure limit of [redacted] psig. The wellhead injection pressure will not exceed the maximum bottom hole pressure because the automated high-high pressure shutdown is set at [redacted] psig. Calibration of the tubing curves will be performed after well construction.

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

## 3.0 Reporting Frequencies

1PointFive Sequestration, LLC (1PointFive) will follow the reporting frequencies as summarized below in Table OP-2.

**Table OP-2—Class VI Reporting Frequencies**

| Activity | Minimum Reporting Frequency |
|---|---|
| $CO_2$ stream characterization | [redacted] |
| Pressure, flow, rate, volume, pressure on the annulus, annulus fluid level, and temperature | |
| Corrosion monitoring | |
| Monthly and cumulative volume and mass of the carbon dioxide stream injected | |
| Monthly annulus fluid volume added | |
| Results and reports for the monitoring systems proposed: Plume tracking, above confining zone monitoring, surface monitoring | |
| Description of any event that triggers a shut-off device and the response taken | |
| Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit | |
| Any injectivity test performed in the well | |
| External MIT and internal MIT | |
| Pressure fall-off testing | |
| Planned workover or well stimulation | |
| Monitoring well MITs | |
| Financial responsibility updates pursuant to H.2 and H.3(a) of this permit | |

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

## 4.0 Startup Monitoring and Reporting Procedures

The special procedures related to the startup of operations, monitoring, and reporting during the first several months are specified in this section. The injection rates will be gradually increased to the planned rate over a period of [redacted] days.

These additional procedures, which are detailed below, describe how 1PointFive will initiate injection and conduct startup-specific monitoring of the Becerra_CCS_01_01 well pursuant to 40 CFR 146.90. Actual initial injection and start-up-specific monitoring may differ from the procedures set forth below based on technical, operational, and safety considerations at the time of injection and startup begins.

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

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the Becerra_CCS_01_01 well.

(2) During the startup period, the permittee 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 step rate injection tests will be performed 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 time step. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of [redacted] psig, which is measured at the wellhead.

(4) The planned injection rates are as follows:

**Table OP-3—Planned Injection Rates During Startup**

| Rate (tonnes per day) | Duration (hours) | Percent of Permit Maximum Injection Rate (%) |
|---|---|---|
| [redacted] | | |

(5) The injection rates will be controlled with process control valves.

(6) The injection rates will be measured and recorded using Coriolis flow meters.

(7) Surface and downhole pressures and temperatures will be measured and recorded for the Becerra_CCS_01_01 as well as continuous reading of temperature profile from the fiber optic.

(8) 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.

(9) 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 characterize the anomaly better. 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, and microseismic data will be reviewed for event signatures.

  (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.