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

Pelican Sequestration Project

1.0 Facility Information

Facility name: Pelican Sequestration Project
Pelican CCS 1 Well

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

Well location: Holden, Livingston Parish, Louisiana
[redacted] (NAD 1927, BLM Zone 15N)

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.

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	[redacted]	Metric tonnes per day
Maximum Surface Wellhead Injection Pressure	[redacted]	psig
Maximum bottom hole pressure @ 90% of frac gradient	[redacted]	psig
Minimum Annulus Pressure	[redacted]	psig

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

- **Maximum Bottomhole Injection Pressure:** Operating requirements from 40 CFR 146.88(a) indicate that injection pressure must not exceed 90% of the injection zone fracture pressure. To meet this requirement, the maximum pressure considered for the Pelican CCS 1 well is 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. [redacted] Therefore, the maximum injection pressure using a downhole pressure gauge is calculated as follows:

  [redacted]

- **Maximum Surface Wellhead Injection Pressure:** The maximum surface wellhead injection pressure is limited by the third-party supply pipeline and the booster pumping system. The design pressure of the pipeline is planned to be [redacted] psig, consistent with ASME [redacted] flange class piping specifications. The design pressure of the booster pumping system is planned to be [redacted] psig, consistent with ASME [redacted] flange class piping specifications, [redacted]. Normal operating pressure at the wellsite will be between [redacted] psig and [redacted] psig, with high and high-high wellsite pressure setpoints of [redacted] and [redacted] psig, respectively, to protect against operational excursions. Wellbore tubing curves representative of the Pelican CCS 1 were created in PROSPER for [redacted]” tubing. The wellhead injection pressure, corresponding to the calculated maximum bottomhole injection pressure of [redacted] psig at [redacted] ft TVD, is modeled to be [redacted] psig. [redacted]. The wellhead injection pressure will not reach this value due to the shutdown pressure at the high-high pressure setpoint of [redacted] psig. Calibration of the tubing curves will be performed after well construction.

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

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

The Pelican Sequestration Hub, LLC will maintain 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	Semi-annually
Pressure, flow, rate, volume, pressure on the annulus, annulus fluid level, and temperature	Semi-annually
Corrosion monitoring	Semi-annually
Monthly and cumulative volume and mass of the carbon dioxide stream injected	Semi-annually
Monthly annulus fluid volume added	Semi-annually
Results and reports for the monitoring systems proposed: Plume tracking, above confining zone monitoring, surface monitoring	Semi-annually
Description of any event that triggers a shut-off device and the response taken	Semi-annually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semi-annually
Any injectivity test performed in the well	Within 30 days of completion of test
External MIT and internal MIT	Within 30 days of completion of test
Pressure fall-off testing	Within 30 days of completion of test
Planned workover or well stimulation	30 days in advance
Monitoring well MITs	Within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

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

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] ([redacted]) days.

These additional procedures, which are detailed below, describe how the permit owner will initiate injection and conduct startup-specific monitoring of the Pelican CCS 1 well pursuant to 40 CFR 146.90.

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 Pelican CCS 1 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 successfully higher injection rates 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]	[redacted]	40
[redacted]	[redacted]	50
[redacted]	[redacted]	66
[redacted]	[redacted]	83
[redacted]	[redacted]	90
[redacted]	[redacted]	95
[redacted]	[redacted]	100

(5) A spinner log will be conducted during each change (step) in rate.

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

(7) The injection rates will be measured and recorded using orifice flow meters.

(8) Surface and downhole pressures and temperatures will be measured and recorded for the Pelican CCS 1 well.

(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 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.

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

Pelican Sequestration Project

1.0 Facility Information

Facility name: Pelican Sequestration Project
Pelican CCS 2 Well

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

Well location: Holden, Livingston Parish, Louisiana
[redacted] (NAD 1927, BLM Zone 15N)

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Maximum Surface Wellhead Injection Pressure	[redacted]	psig
Maximum bottom hole pressure @ 90% of frac gradient	[redacted]	psig
Minimum Annulus Pressure	[redacted]	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:** Operating requirements from 40 CFR 146.88(a) indicate that injection pressure must not exceed 90% of the injection zone fracture pressure. To meet this requirement, the maximum pressure considered for the Pelican CCS 2 well is 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. [redacted] Therefore, the maximum injection pressure using a downhole pressure gauge is calculated as follows:

  [redacted]

- **Maximum Surface Wellhead Injection Pressure:** The maximum surface wellhead injection pressure is limited by the third-party supply pipeline and the booster pumping system. The design pressure of the pipeline is planned to be [redacted] psig, consistent with ASME [redacted] flange class piping specifications. The design pressure of the booster pumping system is planned to be [redacted] psig, consistent with ASME [redacted] flange class piping specifications, thought the operating conditions will be significantly lower than design. Normal operating pressure at the wellsite will be between [redacted] psig and [redacted] psig, with high and high-high wellsite pressure setpoints of [redacted] and [redacted] psig, respectively, to protect against operational excursions. Wellbore tubing curves representative of the Pelican CCS 2 were created in PROSPER for [redacted]" tubing. The wellhead injection pressure, corresponding to the calculated maximum bottomhole injection pressure of [redacted] psig at [redacted] ft TVD, is modeled to be [redacted] psig. [redacted] The wellhead injection pressure will not reach this value due to the shutdown pressure at the high-high pressure setpoint of [redacted] psig. Calibration of the tubing curves will be performed after well construction.

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

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Monthly annulus fluid volume added	Semi-annually
Results and reports for the monitoring systems proposed: Plume tracking, above confining zone monitoring, surface monitoring	Semi-annually
Description of any event that triggers a shut-off device and the response taken	Semi-annually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semi-annually
Any injectivity test performed in the well	Within 30 days of completion of test
External MIT and internal MIT	Within 30 days of completion of test
Pressure fall-off testing	Within 30 days of completion of test
Planned workover or well stimulation	30 days in advance
Monitoring well MITs	Within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

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

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(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the Pelican CCS 2 well.

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[redacted]	[redacted]	95
[redacted]	[redacted]	100

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(7) The injection rates will be measured and recorded using orifice flow meters.

(8) Surface and downhole pressures and temperatures will be measured and recorded for the Pelican CCS 2 well.

(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.

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   (c) The permittee will consult with the agency before initiating any further injection.