SUMMARY OF OPERATING CONDITIONS: BRP CCS2
40 CFR §146.82 (a)(7) and (10) and §146.88 (e)

Brown Pelican CO_2 Sequestration Project

1.0 Facility Information

Facility name:	Brown Pelican CO_2 Sequestration Project BRP CCS2 Well
Facility contact:	[redacted]
Well location:	Penwell, Texas 31.76994887, -102.73320589

2.0 Injection Well Operating Conditions

UIC Class VI injection well operating and project reporting requirements for the Brown Pelican CO_2 Sequestration Project (BRP Project or Project) are specified in this document and summarized below in Table 1.

Table 1—UIC Class VI Injection Well Operating Conditions

Parameter/ Condition	BRP CCS2: Updated Permit Value	Units
Daily group maximum injection mass	2,547	Metric tons per day
Daily group average injection mass	2,079	Metric tons per day
Daily maximum injection mass	1,196	Metric tons per day
Daily average injection mass	1,040	Metric tons per day
Daily maximum injection rate	23	Million standard cubic feet per day
Daily average injection rate	20	Million standard cubic feet per day
Total mass	4.17	Million metric tons
Group maximum injection mass	929,693	Metric tons per year
Group average injection mass	758,933	Metric tons per year
Maximum injection mass	436,386	Metric tons per year
Average injection mass	379,466	Metric tons per year
Maximum surface wellhead injection pressure	3,027	psig
Maximum bottomhole injection pressure	4,125.30	psig
Average bottomhole injection pressure	3,667.00	psig
Minimum annulus pressure	100	psig
Minimum annulus pressure/ tubing differential	100	psig

Limitations or permitted values for the maximum surface wellhead injection pressure, maximum bottomhole injection pressure, minimum annulus pressure, and minimum annulus pressure/tubing differential limitation are set as follows:

- **Maximum Surface Wellhead Injection Pressure:** CO_2 will be supplied by a dehydration and compression facility located approximately four miles northeast of the CO_2 Injector well location. The pressure at the facility discharge will be between 1,800 psig and 2,500 psig . The CO_2 will then be routed via pipeline to valve stations near the UIC Class VI injection well. Here the pressure will be reduced to below 2,500 psig prior to reaching the wellhead. Pressure at the well will be controlled via control valves with shutdown protocols in place to protect the well in the event of a high-pressure scenario. The minimum and maximum wellbore tubing pressures were determined after well construction.
- **Maximum Bottomhole Injection Pressure:** To meet EPA requirements in 40 CFR §146.88(a), the maximum pressure considered for the CO_2 Injector well is 90% of the fracture opening pressure of the Injection Zone, measured using a downhole pressure gauge.

The fracture pressure of the Injection Zone is determined from a mini-frac test conducted during well construction. Reservoir modeling indicates the pore pressure required to move the effective stress state into tensile failure is near 4,583.7 psi at a depth of 5,093 ft TVD (approximate depth of shallowest perforation). Maximum downhole injection pressure is therefore set to be less than 90% of that 4,583.7 psi threshold, calculated as follows:

$$0.9 \times 4{,}583.7 = 4{,}125.3 \text{ psia} - 14.7 \text{ psi} = 4{,}110.6 \text{ psig} \quad \textit{Equation 1}$$

The maximum bottomhole injection pressure was calculated based on logs and well information from the UIC Class VI Injection well after construction.

- **Minimum Annulus Pressure:** As necessary to prevent "burst" or "collapse" of the tubing, the minimum annulus pressure is calculated as follows:

$$\text{Collapse Pressure} = \text{depth} \times [(\text{pressure gradient of formation}) + (\text{pressure gradient of cement}) - (\text{pressure gradient of water})] \quad \textit{Equation 2}$$

$$\text{Burst Pressure} = \text{depth} \times (\text{pressure gradient of injectant}) + \text{surface pressure} \quad \textit{Equation 3}$$

- **Minimum Annulus Pressure/Tubing Differential:** The annulus pressure/tubing differential is measured directly above and across the injection packer and is set to be a minimum of 100 psi above the surface wellhead injection pressure.

  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

Oxy Low Carbon Ventures, LLC (OLCV) will maintain the reporting frequencies as summarized below in Table 2.

Table 2—Class VI Reporting Frequencies

Activity	Minimum Reporting Frequency
Change to the CO_2 stream characterization	Semi-annually
Monthly injection pressure, flow rate, volume, pressure on the annulus, annulus fluid level, and temperature (Min, Max, and Avg.)	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

Activity	Minimum Reporting Frequency
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 shutoff 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	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT*	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results 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: The reporting frequency for MIT will comply with TAC Title 16 Chapter 5.206(e)(1): "The operator of an anthropogenic CO2 injection well must maintain and comply with the approved monitoring, sampling, and testing plan to verify that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone."

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 procedures related to the startup of operations, as well as monitoring and reporting during startup, are specified in this section. The injection rates will be gradually increased to the planned rate over a period of six (6) days.

The procedures detailed below describe how OLCV will initiate injection and conduct startup-specific monitoring of the CO_2 Injector well, pursuant to 40 CFR §146.90.

The multistage (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 CO_2 Injector 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 successively higher injection rates will be applied, as shown in Table 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 3,027 psig, which is measured at the wellhead.

(4) The planned injection rates are shown in Table 3. OLCV modeled the injection pressure considering a surface injection temperature of 62 °F.

Table 3—Planned Injection Rates During Startup

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Pressure (%)
52	24	71%
130	24	71%
260	24	73%
364	24	74%
520	24	75%
780	24	76%

(5) The injection rates will be controlled with variable actuated choke valves.

(6) The injection rates will be measured and recorded using an orifice flowmeter.

(7) Surface and downhole pressures and temperatures will be measured and recorded.

(8) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented, and the project team will look for any evidence of anomalous pressure behavior.

(9) If during the startup period any anomalous pressure behavior is observed, additional logging and modification of the injection rate program may be conducted 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.

(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.

5.0. Operations after startup

Automatic alarms and automatic shutoff systems will be installed and maintained. Successful function of the alarm system and shutoff system will be demonstrated prior to injection and once annually thereafter.

At all times, pressure will be maintained on the well to prevent the return of the injection fluid to the surface. The wellbore must be filled with a high-specific-gravity fluid during workovers to maintain a positive (downward) gradient and/or a plug shall be installed that can resist the pressure differential. A blowout preventer must be installed and kept in proper operational condition whenever the wellhead is removed to work on the well.

- OLVC shall cease injection should it appear that the well is lacking mechanical integrity or that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW.

Permittee will cease injection according to the guidelines provided below:

- OLCV must shut in the well by gradual reduction of the injection pressure as outlined in the Summary of Operating Conditions document of this permit; or
- OLCV must immediately cease injection and shut in the well as outlined in the Emergency and Remedial Response Plan document of this permit.