SUMMARY OF REQUIREMENTS

CLASS VI OPERATING AND REPORTING CONDITIONS
LAC 43: XVII.3621

Project Name: Live Oak CCS Hub

Facility Information

Facility Contact: Live Oak CCS, LLC
14302 FNB Parkway
Omaha, Nebraska 68154
402-691-9500

OOC Code: L1135

Well locations:

Well Name	Latitude (WGS84)	Longitude (WGS84)	Parish	State
LO-01 M[1]	Claimed as PBI [redacted]	[redacted]	West Baton Rouge	Louisiana
LO-01 F[1]	Claimed as PBI [redacted]	[redacted]	West Baton Rouge	Louisiana
LO-02 M	Claimed as PBI [redacted]	[redacted]	West Baton Rouge	Louisiana
LO-03 M	Claimed as PBI [redacted]	[redacted]	Iberville	Louisiana
LO-04 F-M	Claimed as PBI [redacted]	[redacted]	Iberville	Louisiana
LO-05 M	Claimed as PBI [redacted]	[redacted]	Iberville	Louisiana
LO-06 M[1]	Claimed as PBI [redacted]	[redacted]	Iberville	Louisiana
LO-06 F[1]	Claimed as PBI [redacted]	[redacted]	Iberville	Louisiana

[1] For shared well pads, surface hole location spacing is set at a minimum of 15 feet.

Table of Contents

List of Figures

List of Tables

List of Acronyms

Ar	Argon
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
^oF	Degree Fahrenheit
EPA	Environmental Protection Agency
ft	Feet
LLC	Limited Liability Company
LAC	Louisiana Administrative Code
OC	Louisiana Department of Energy and Natural Resources' Office of Conservation
LMIC	Lower Miocene Injection Complex
MASP	Maximum Allowable Surface Pressure
MIT	Mechanical Integrity Testing
MMSCF	Million Metric Standard Cubic Feet
MMt	Million Metric Tonnes
MMt/y	Million Metric Tonnes per Year
Mol%	Molecular Percentage of Total Moles in a Mixture made up by One Constituent
NIST	National Institute of Standards and Technology
N_2	Nitrogen
OFIC	Oligocene Frio Injection Complex
O_2	Oxygen
ppmv	Parts per Million, Volume
lb	Pound
psi	Pounds per Square Inch
psig	Pounds per Square Inch, Gauge

1. Introduction

Live Oak CCS, LLC seeks to safely inject carbon dioxide (CO_2) at average rates ranging from 0.4 MMt/y to 3.1 MMt/y in injection wells LO-01 M, LO-01 F, LO-02 M, LO-03 M, LO-04 F-M, LO-05 M, LO-06 M, and LO-06 F, located at Live Oak CCS Hub in West Baton Rouge and Iberville parishes, Louisiana (the "project") while maintaining well integrity and remaining below 90% of the fracture pressure at the depth of the shallowest perforated interval. The average injection rates across various wells and both the injection complexes, Lower Miocene Injection Complex (LMIC) and Oligocene Frio Injection Complex (OFIC), are summarized in Table 1. The operational details provided in this document satisfy LAC 43:XVII.3607(C)(2)(f) and (i). The operational design described in this document has been developed to adhere to requirements set forth in LAC 43:XVII.3621.

2. Operational Procedures

2.1. Injection Rates

In accordance with LAC 43:XVII.3607(C)(2)(f)(i) and (ii), this subsection provides information on the anticipated injection rates and pressure during the injection period.

The injection wells will be constructed as shown in the Construction Details for LO-01 M, LO-01 F, LO-02 M, LO-03 M, LO-04 F-M, LO-05 M, LO-06 M, and LO-06 F. A total of eight injection wells will be drilled: five in Miocene formation, denoted as M; three in Frio formation, denoted as F; and one well perforated into both the Miocene and Frio formations, denoted as F-M. Table 1 summarizes the proposed operational parameters for all the injection wells. These parameters are expected to remain constant throughout the injection period. However, some variability in operational parameters may stem from variations in volume from the CO_2 sources, which may impact injection volumes during limited periods of time. The injection rate values detailed in Table 1 were modeled using Petroleum Experts' PROSPER software, and the nodal analysis results can be found in subsection 2.1 of the Construction Details for all the injection wells.

Using average annual and maximum instantaneous CO_2 injection rates as summarized in Table 1, injection tubing string sizes were selected for injection wells to meet the project requirements. Expected wellhead pressures during injection operations were calculated using the average reservoir pressure during a 30-year injection period, as derived from the reservoir model. Maximum wellhead pressures for injection wells were calculated based on the hydraulic fracture gradient and 90% of hydraulic fracture pressure at the top depth in the LMIC. However, pipeline specifications for CO_2 transport limit the maximum wellhead pressure to 2,220 psig, which is lower than the calculated fracture pressures.

Based on expected operating ranges, Live Oak CCS, LLC proposes to maintain a 100-psi positive pressure differential in the annular space directly above the packer compared to the adjacent tubing during injection. Maximum annulus pressures at the wellhead are also summarized in Table 1. No injection will take place between the long string casing and surface casing to protect the USDW, per LAC 43:XVII.3621(A)(2). Final design criteria to operate the injection wells will be developed following data collection from the Pre-Operational Testing Program.

Table 1: Injection Well Operating Conditions.

Parameters/Conditions	Limit or Permitted Value								Units
	LO-01 M	LO-01 F	LO-02 M	LO-03 M	LO-04 F-M	LO-05 M	LO-06 M	LO-06 F	
Maximum Injection Pressure									
Surface[1]	2,220	2,220	2,220	2,220	2,220	2,220	2,220	2,220	psig
Downhole	4,641	7,919	4,513	4,443	4,528	4,410	4,275	7,059	psig
Average Injection Pressure									
Surface – LMIC	1,220	NA	1,220	1,480	1,790	1,695	1,185	NA	psig
Surface – OFIC	NA	1,360	NA	NA	1,370	NA	NA	1,340	psig
Downhole – LMIC	3,821	NA	3,963	4,249	4,128	4,009	3,777	NA	psig
Downhole – OFIC	NA	5,098	NA	NA	5,152	NA	NA	4,651	psig
Injection Rate									
Maximum Injection Rate – LMIC	3.5	NA	3.5	3.5	3.5	3.5	3.5	NA	MMt/y
Maximum Injection Rate – OFIC	NA	1.5	NA	NA	1.5	NA	NA	1.5	MMt/y
Average Injection Rate – LMIC	1.3	NA	0.85	2.1	2.9	3.1	1.0	NA	MMt/y
Average Injection Rate – OFIC	NA	0.5	NA	NA	0.5	NA	NA	0.4	MMt/y
Injection Volume									
Maximum Injection Volume and/or Mass (30-year period) – LMIC	105	NA	105	105	105	105	105	NA	MMt
Maximum Injection Volume and/or Mass (30-year period) – OFIC	NA	45	NA	NA	45	NA	NA	45	MMt
Average Injection Volume and/or Mass (30-year period) – LMIC	39	NA	25.5	63	87	93	30	NA	MMt
Average Injection Volume and/or Mass (30-year period) – OFIC	NA	15	NA	NA	15	NA	NA	12	MMt
Annular Pressure									
Minimum Annulus Pressure at Wellhead	100	100	100	100	100	100	100	100	psig
Minimum Differential Pressure (directly above and across packer)	100	100	100	100	100	100	100	100	psi
Maximum Proposed Annulus Pressure at the Wellhead	2,320	2,320	2,320	2,320	2,320	2,320	2,320	2,320	psig

NA = Not applicable
[1] Maximum surface injection pressure based on CO_2 transport pipeline specifications.

2.2. CO_2 Stream Specifications

In accordance with LAC 43:XVII.3607(C)(2)(f)(iii) and (iv), this subsection provides information on the sources and chemical and physical characteristics of the CO_2 stream. The CO_2 will be captured from industrial facilities and power plants located in the industrial corridor surrounding the Mississippi River south of Baton Rouge and transported by pipeline to the Live Oak CCS Hub. The CO_2 will be in the liquid phase as it enters the wellhead and will transition to a supercritical phase in the wellbore. The injectate stream composition coming into the storage field will vary throughout the injection phase of the project. To account for this, Live Oak CCS, LLC plans to continuously monitor the CO_2 stream chemical composition to ensure it meets minimum composition specifications that will be refined when sources are finalized, and capture equipment is operational (see section 2.0 and 3.0 of the Testing and Monitoring Plan). The CO_2 injection stream coming into the storage site is anticipated to have the specifications presented in Table 2, with a CO_2 concentration of 95% or higher.

Table 2. Specifications of the Anticipated CO_2 Stream Composition.

Component	Specification	Unit
Minimum CO_2	> 95	Mol%, dry
Water Content	< 20	lb/MMSCF
Impurities (Dry Basis)		
Total Hydrocarbons	< 2	Mol%, dry
Inert Gases (N_2, Ar, O_2)	< 4	Mol%, dry
Hydrogen	< 1	mol%
Alcohols, Aldehydes, Esters	<500	ppmv
Hydrogen Sulfide	< 50	ppmv
Total Sulfur	< 100	ppmv
Oxygen	< 20	ppmv
Carbon Monoxide	< 1000	ppmv
Glycol	< 1	ppmv

Table 3 provides the estimated density under normal operating conditions both at the surface as well as downhole at reservoir conditions during planned injection operations. The CO_2 stream is expected to average around 67 ºF at the wellhead. After injection into the LMIC or OFIC, the CO_2 stream is anticipated to be supercritical and heat to near formation temperature at or above the native reservoir pressures.

Table 3: Estimated Surface and Downhole Temperature and Densities During Injection.

Parameters/Conditions	Limit or Permitted Value								Units
	LO-01 M	LO-01 F	LO-02 M	LO-03 M	LO-04 F-M	LO-05 M	LO-06 M	LO-06 F	
Temperature									
Surface (CO_2 stream)	67.0	67.0	67.0	67.0	67.0	67.0	67.0	67.0	°F
Downhole	99.7	135.2	102.7	110.6	136.6	106.0	98.6	120.5	°F
CO_2 Density									
Surface – LMIC	46.8	NA	46.8	49.5	50.7	51.0	46.4	NA	lb/ft^3
Downhole - LMIC	51.3	NA	51.1	53.1	53.4	53.4	50.9	NA	lb/ft^3
Surface – OFIC	NA	48.3	NA	NA	48.4	NA	NA	48.1	lb/ft^3
Downhole - OFIC	NA	51.1	NA	NA	51.4	NA	NA	50.3	lb/ft^3

NA = Not applicable

Due to the anticipated low water content within the CO_2 stream, CO_2-induced corrosion affecting well components is not likely - as noted by EPA well construction guidance (EPA, 2012). Live Oak CCS, LLC will monitor for potential corrosion induced by the injectate as outlined in Section 4.0 of the Testing and Monitoring Plan.

2.3. Estimated Maximum Allowable Surface Pressure

Using Petroleum Experts' PROSPER software, the maximum injection (wellhead) pressure observed during simulation of injection was modeled for all the wells. This was done based on the bottomhole pressure at either LMIC or OFIC, depending on which injection zone the well targets. For LO-04 F-M injecting in both LMIC and OFIC, the maximum injection pressure was modeled at the upper injection zone, LMIC. This injection pressure limit represents 90% of fracture gradient, per LAC 43:XVII.3621(A)(1), at the depth of the shallowest perforated interval using maximum instantaneous injection rate as reported in Table 1. The maximum allowable surface pressure (MASP) for all the injection wells will be limited to the pipeline specification of 2,220 psig, well below the modeled maximum injection pressure.

As an example, the maximum injection pressure calculated for LO-01 M based on bottomhole pressure of 4,641 psig and maximum instantaneous rate of 3.5 MMt/y was approximately 2,595 psig, as shown in Figure 1. The bottomhole pressure of 4,641 psig corresponds to 90% of fracture pressure at a depth of 6,289 ft determined using a frac gradient of 0.82 psi/ft as discussed in subsection 1.9 of the Area of Review and Corrective Action Plan. The MASP for LO-01 M will be 2,220 psig, well below the modeled maximum injection pressure. Table 4 summarizes the calculated maximum injection pressure for all the injection wells.

Figure 2 through Figure 8 highlight multiple maximum injection pressure cases for all the injection wells. At injection pressures below the calculated maximum values (Table 4), the bottomhole pressure at the top of LMIC or OFIC, depending on the injection zone, stays below 90% of the fracture pressure. At higher injection pressures, the bottomhole pressure at the top perforation exceeds the 90% fracture pressure limit. This indicates that at or below the calculated maximum injection pressures (Table 1), the injection operations will not fracture the rock as per LAC 43:XVII.3621(A)(1).

Table 4: Calculated Maximum Injection Pressure Based on 90% of Fracture Gradient at the Depth of the Shallowest Perforated Interval.

Parameters/Conditions	Limit or Permitted Value								Units
	LO-01 M	LO-01 F	LO-02 M	LO-03 M	LO-04 F-M	LO-05 M	LO-06 M	LO-06 F	
Calculated Maximum Injection Pressure	2,595	3,700	2,535	2,505	2,535	2,490	2,425	3,325	psig

Modeling to calculate the maximum injection pressure assumed that the reservoir is not pressure limited. If pre-operational testing indicates the reservoir is pressure limited, the maximum injection pressure may have to be recalculated accordingly.

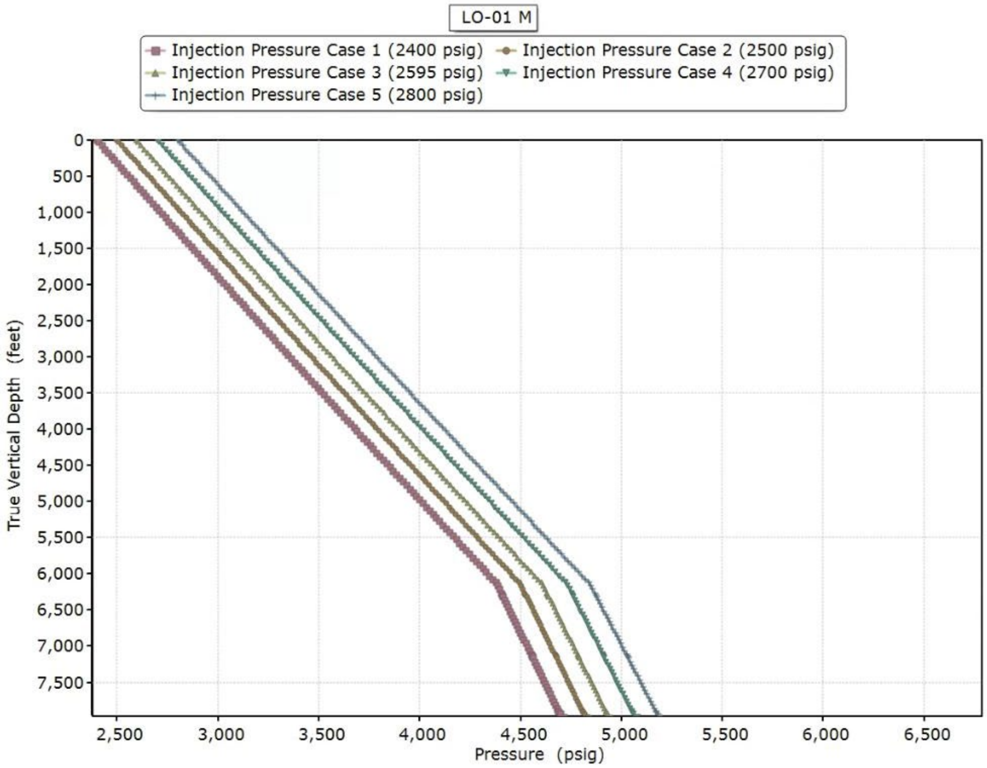
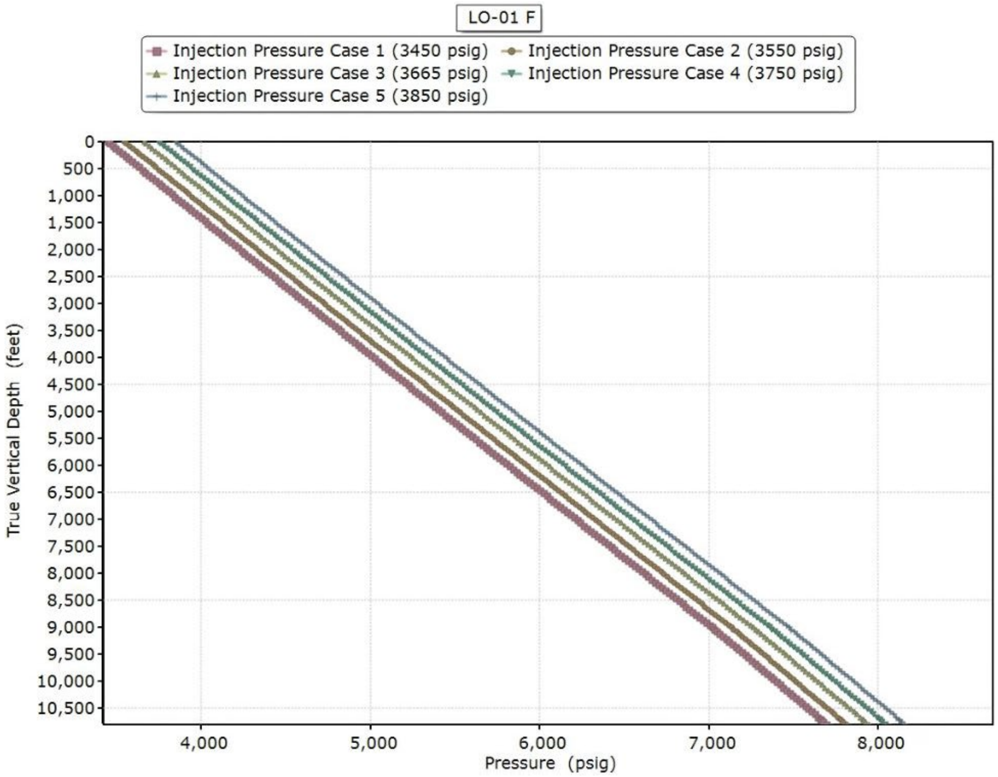


Figure 1: Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of Miocene Formation (6,289 ft) for LO-01 M.



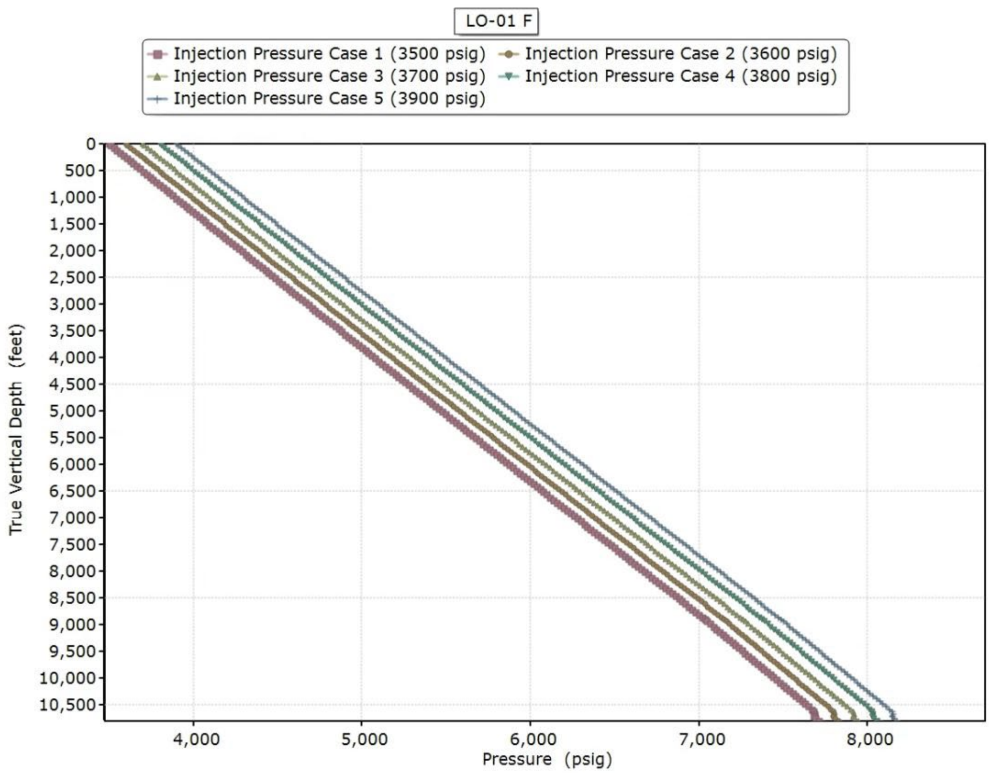


Figure 2: Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of Frio Formation (10,730 ft) for LO-01 F.

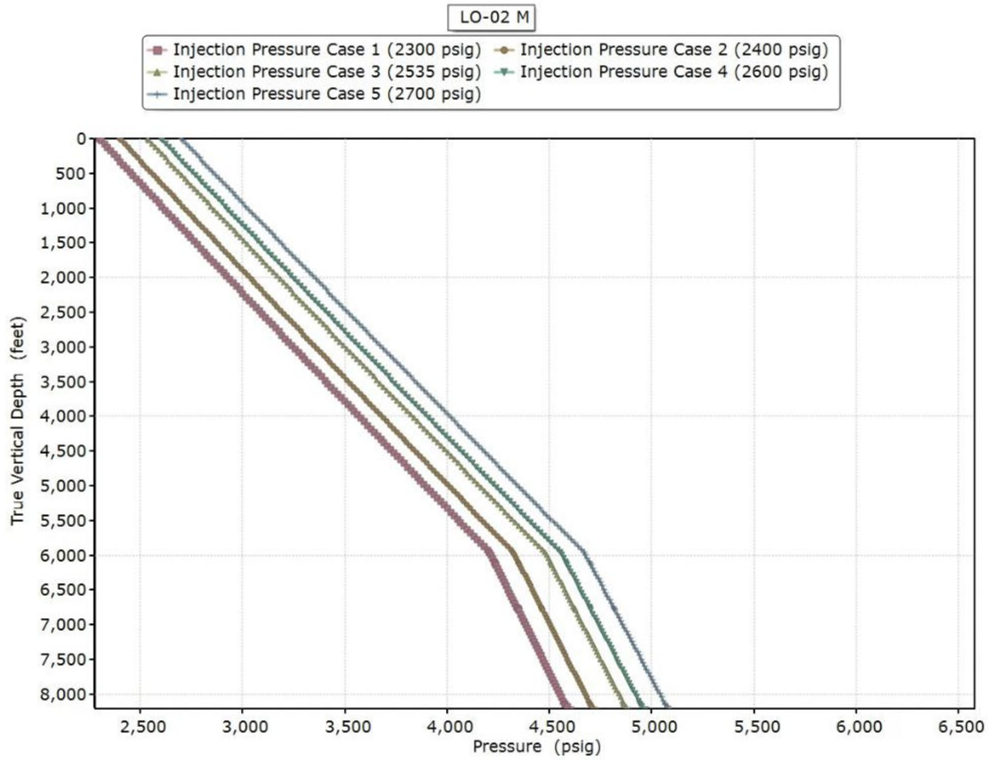


Figure 3: Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of Miocene Formation (6,115 ft) for LO-02 M.

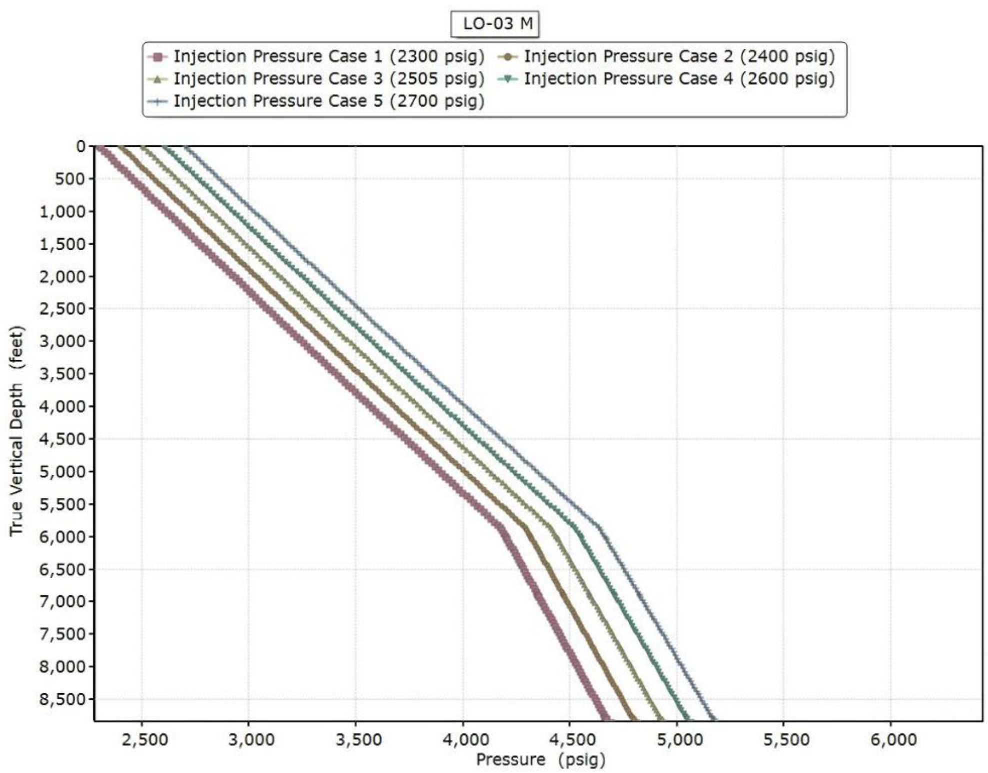
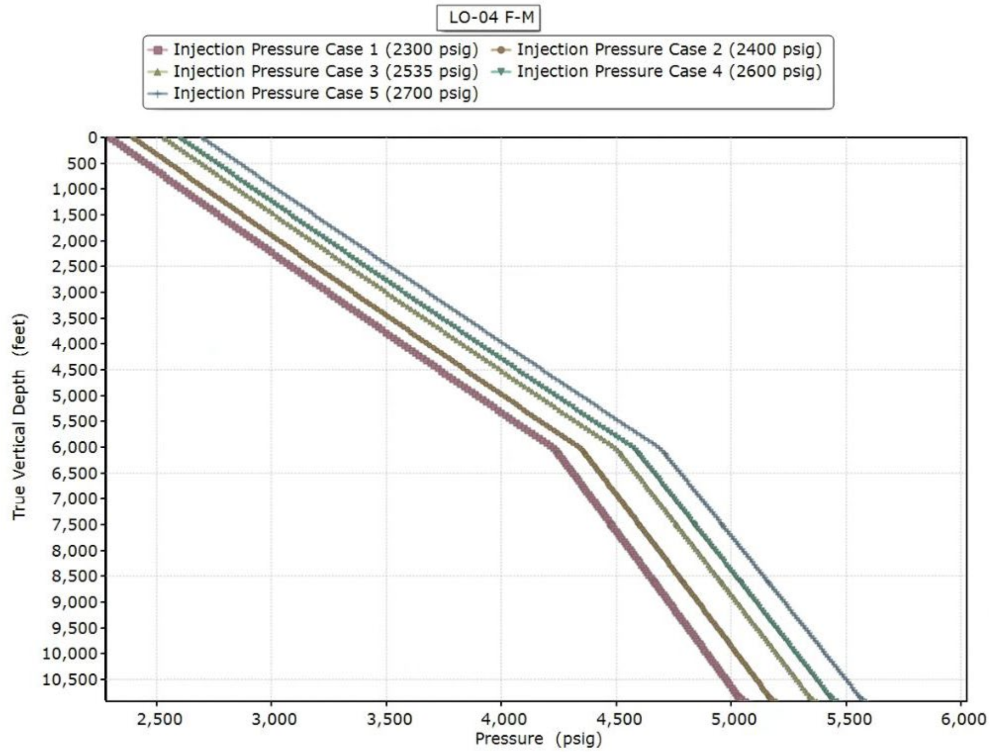


Figure 4: Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of Miocene Formation (6,020 ft) for LO-03 M.



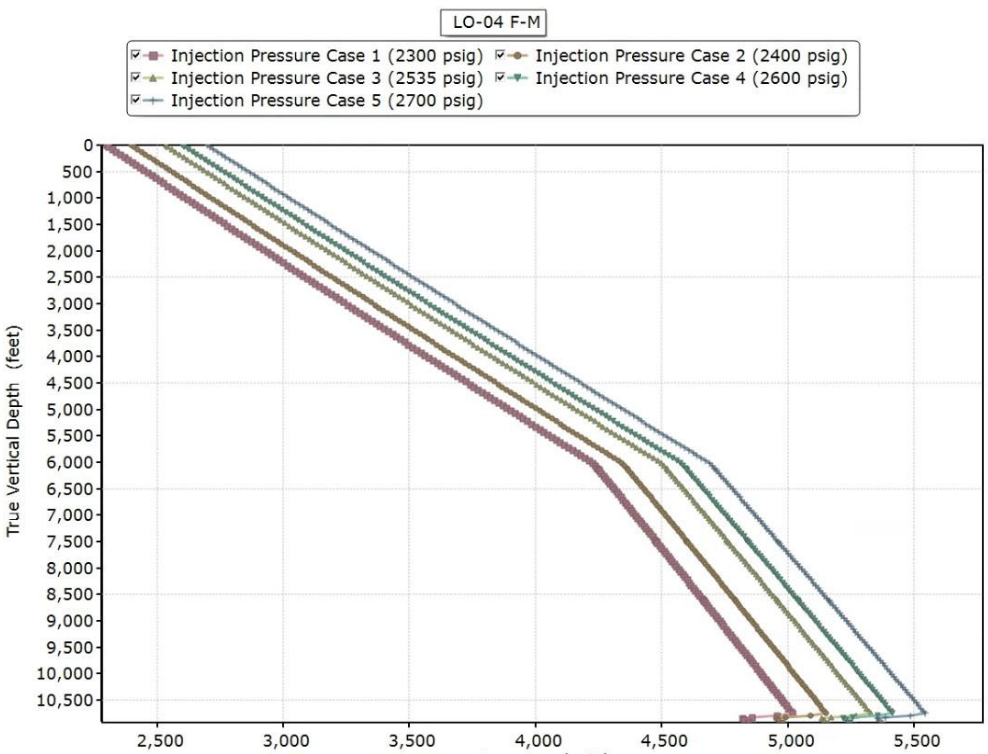


Figure 5: Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of Miocene Formation (6,135 ft) for LO-04 F-M.

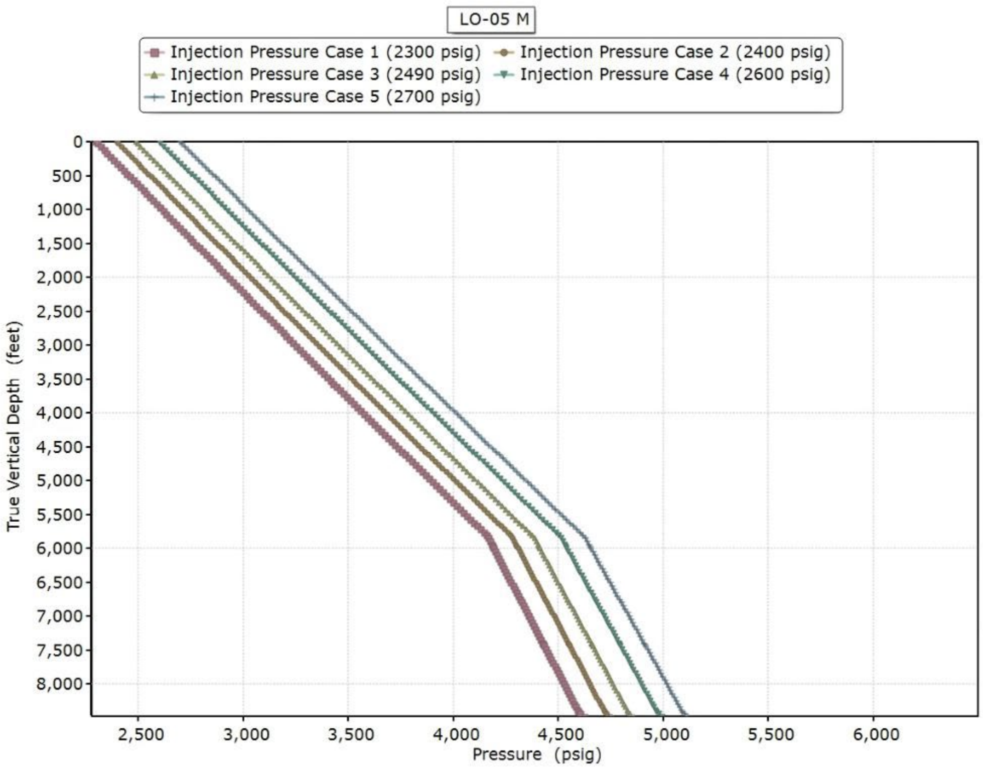


Figure 6: Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of Miocene Formation (5,976 ft) for LO-05 M.

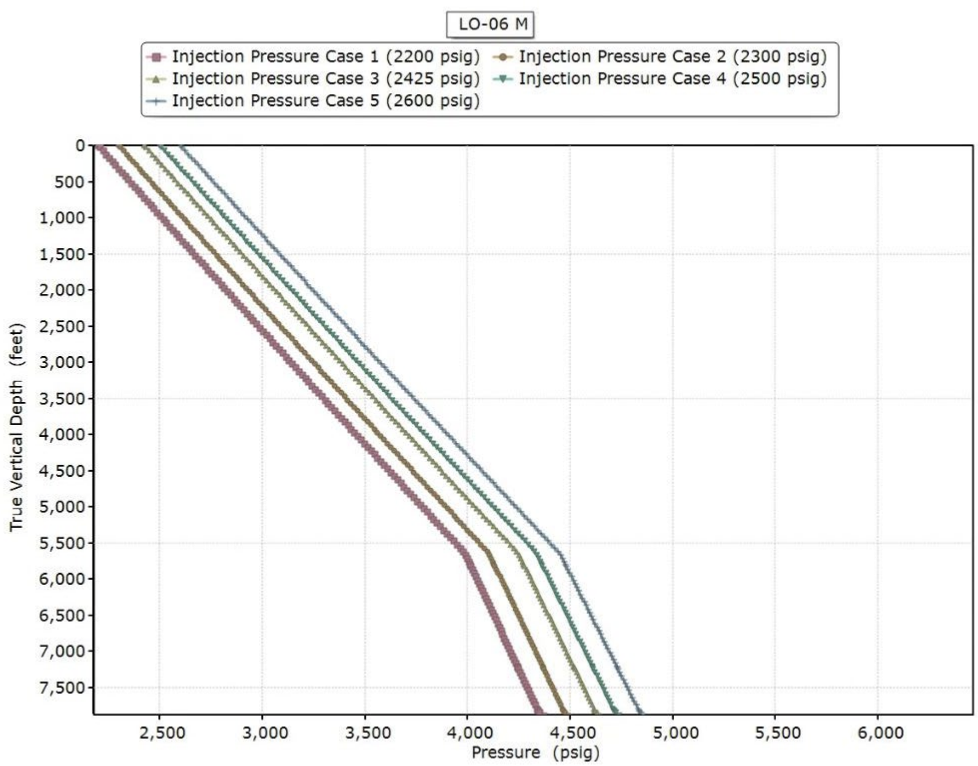
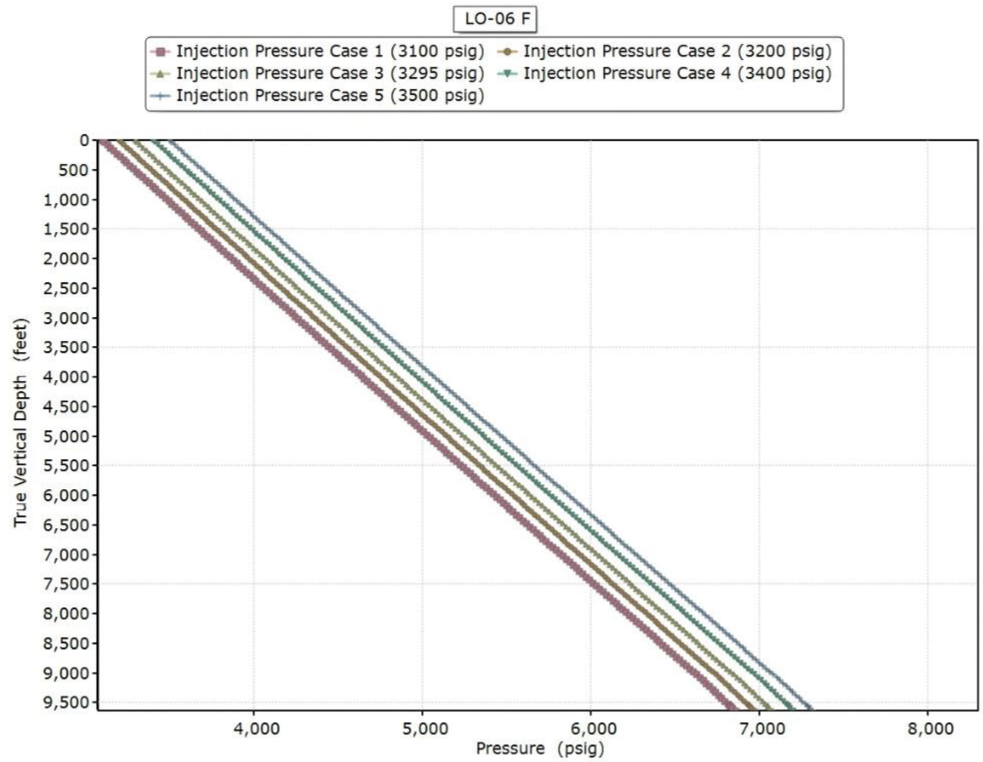


Figure 7: Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of Miocene Formation (5,793 ft) for LO-06 M.



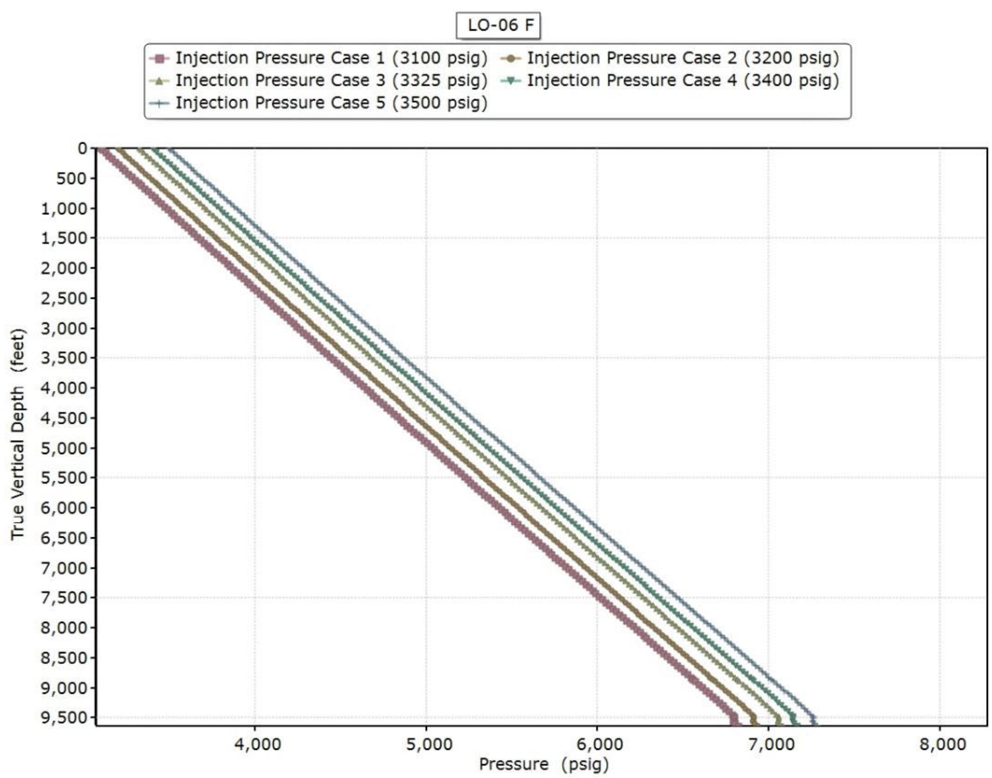


Figure 8: Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of Frio Formation (9,565 ft) for LO-06 F.

2.4. Injection Well Operational Monitoring

Each injection well will be monitored to ensure safe operations, in compliance with LAC 43:XVII.3621(A)(6)(a). Operational safety monitoring includes continuous monitoring of the injection pressure at the wellhead and bottomhole, continuous monitoring of flow rate, volume and/or mass, and temperature of CO_2 stream, continuous monitoring of the pressurized annulus, continuous fiber optic temperature monitoring along the well, and corrosion coupon monitoring to identify and monitor corrosion of materials used in construction of compression equipment, pipeline, and wells which encounter CO_2. Each of these monitoring systems is fully described in Sections 3.0 and 4.0 of the Testing and Monitoring Plan. In compliance with LAC 43:XVII.3621(A)(6)(b), all the continuous monitoring data will be digitally recorded, and instruments will be weatherproof or housed in weatherproof enclosures when located in areas exposed to climatic conditions.

In adherence to LAC 43:XVII.3621(A)(7)(a), each injection well will have a wellhead pressure gauge (tubing and annular pressure) and flow computer, both tied into the injection control system and set to trigger an alarm at the project control room and shut down injection in the well if: (1) the MASP is reached; (2) the CO_2 injection rate exceeds maximum permitted rate; or (3) the annulus fluid pressure drops below the injection pressure at the packer. Injection parameters, including pressure, rate, volume and/or mass flowrate, and temperature of the CO_2 stream, will be continuously measured and recorded. The pressure and fluid volume changes of the annulus between the tubing and casing will also be continuously recorded. In compliance with LAC 43:XVII.3621(A)(10), both the wellhead pressure gauges will read values in increments of 10 psig and will be calibrated in compliance with LAC 43:XVII.3621(A)(7)(c) to maintain them in good working order.

In adherence to LAC 43:XVII.3621(A)(7)(c), all emergency shutdown systems will be fail-safe. All critical systems of control and safety will be function tested at least once every six months, with records of the test date and results maintained. Testing will include alarms, test tripping of emergency shutdown valves, and ensuring the integrity of all electrical, pneumatic, and hydraulic circuits.

In adherence to LAC 43:XVII.3621(A)(7)(b), all automatic shutdowns will be investigated prior to bringing injection back online to ensure that no integrity issues were the cause of the shutdown. If an un-remedied shutdown is triggered or a loss of mechanical integrity is discovered, Live Oak CCS, LLC will immediately investigate and identify, as expeditiously as possible, the cause of the shutdown. Please refer to Appendix A of the Emergency and Remedial Response Plan for response actions if mechanical integrity is lost.

In adherence to LAC 43:XVII.3621(A)(3) and (A)(4), the annular space between the tubing and long string casing of each injection well will be pressurized to exceed the operating injection pressure using brine with corrosion inhibiting additives and monitored for changes in pressure and volume (see additional discussion of the annular fluid in subsection 2.7.1 of the Construction Details for each injection well). The fiber optic cable cemented onto the outside of the long-string casing will be used to continuously monitor temperature along the length of the casing. Rapid temperature changes or other deviations from a normal operating temperature profile will be investigated to ensure that there has been no breach of wellbore integrity.

In adherence to LAC 43:XVII.3621(A)(8), a protective barrier will be installed and maintained around the wellhead, pipeline, and other surface equipment that may be vulnerable to physical or accidental damage by mobile equipment or trespassers An identifying sign will be placed at the wellhead or at the fence around the wellhead of the injection well and will include operator's name, well name and number, well serial number, and section-township-range. The sign will be of durable construction with all lettering kept in a legible condition. Please refer to Appendix A of the Emergency and Remedial Response Plan for response actions if any damage occurs to the wellhead and pipeline due to external impact during injection and post injection site care periods.

3. Workover and Maintenance

In adherence to LAC 43:XVII.3621(A)(5), Live Oak CCS, LLC will monitor and maintain mechanical integrity of each injection well at all times. Well maintenance and workovers will be part of normal operations to keep each injection well in a safe operating condition. Procedures for well maintenance will vary depending on the nature of the procedure. All maintenance and workover operations will be monitored to ensure there is not a loss of mechanical integrity. In adherence to LAC 43:XVII.3621(A)(9), prior written authorization from the Louisiana Department of Energy and Natural Resources' Office of Conservation (OC) is required before conducting remedial work, well maintenance or repair, well or injection formation simulation, well plug and abandonment or temporary abandonment, any other test of the injection well, or well work of any kind. Notification and reporting of well work is described in Section 6 below and in subsection 1.5 of the Testing and Monitoring Plan,

4. Routine Shutdown Procedure

For injection shutdowns occurring under routine conditions (e.g., for well workovers), Live Oak CCS, LLC will reduce CO_2 injection at a rate of up to 200,000 metric tons per day over a maximum of 2 days to ensure protection of health, safety, and the environment. See the Emergency and Remedial Response Plan for procedures on immediately shutting in an injection well.

5. Operational Contingency Plans

Contingency plans will be in place to identify situations where potential plant and/or process upset conditions may occur and take appropriate measures which are protective to the local area and the environment by shutting in the wells and monitoring their pressure fall-off. Operational contingency plans for all the Live Oak CCS, LLC injection wells include potential downtime periods when maintenance, well service, and stimulation occur.

The availability of multiple wells and adhering to proper operations practices, including regular well maintenance and service, will reduce most injection well down-time and should eliminate the unlikely occurrence of one or more wells being simultaneously unavailable for use. In the unlikely event that all wells are temporarily unavailable or are out of commission, CO_2 may be vented to the atmosphere for that limited period until operations and injectivity are re-established. Additional detailed monitoring and other contingency planning for potential events that may occur during well injection operations are provided in the Testing and Monitoring Plan and in the Emergency and Remedial Response Plan.

6. Reporting Requirements

Reporting requirements for the injection wells are listed below in Table 5, and project reporting requirements are listed below in Table 6 (LAC 43:XVII.3629(A)(1)). All reports and notifications shall be submitted to OC and EPA (LAC 43:XVII.3629(A)(1) and (3)). All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan.

Table 5: Class VI Injection Well Reporting Requirements.

Activity	Reporting Requirements
Changes to physical, chemical, or other characteristics of CO_2 stream	Quarterly
Monthly average, maximum, and minimum injection pressure, injection rate, injection volume, and pressure on the annulus	Quarterly
Monthly and cumulative CO_2 injected over life of project	Quarterly
Automatic shut-off events	Quarterly
Operating parameter exceedance events	Quarterly
Monthly annulus fluid volume changes	Quarterly
Raw operating data from continuous recording devices	Quarterly
Results of monitoring in Testing and Monitoring Plan (i.e., corrosion monitoring, pressure fall-off testing, etc.)	Quarterly
External MITs, well workover, other required tests	Provide a 30-day notice on Form UIC-17 and report within 30 days of completion of test (work shall not commence until authorization is received from OC)

Table 6: Class VI Project Reporting Requirements.

Activity	Reporting Requirements
Groundwater quality monitoring	Quarterly
Plume and pressure front tracking	In the next quarterly report
Monitoring well MITs	Within 30 days of completion of test
Financial responsibility updates	See section 4 of the Financial Assurance Demonstration
Evidence of USDW endangerment, release of CO_2 into the atmosphere or biosphere, non-compliance with permit conditions, triggering of shut-off system, or failure to maintain mechanical integrity	Within 24 hours