

**SUMMARY OF REQUIREMENTS  
CLASS VI OPERATING AND REPORTING CONDITIONS  
47 CSR 13-13.6.1**

**Project Name: Tri-State CCS Redbud 2**

**Facility Information**

Facility contact: Tri-State CCS, LLC  
14302 FNB Parkway  
Omaha, Nebraska 68154  
402-691-9500

Well location: Marshall County, West Virginia

<b>Well Name</b>	<b>Latitude (WGS84)</b>	<b>Longitude (WGS84)</b>
TR2-1	40.01637500°	-80.60641900°
TR2-2	40.01188400°	-80.53358900°
TR2-3	39.97833300°	-80.60023400°
TR2-4	39.95642300°	-80.63531600°

## Table of Contents

List of Figures .....	2
List of Tables .....	2
List of Acronyms .....	3
1. Introduction.....	4
2. Operational Procedures [47 CSR 13-13.8.1.j] .....	4
2.1. Injection Rates .....	4
2.2. CO <sub>2</sub> Stream Specifications.....	6
2.3. Estimated Maximum Allowable Surface Pressure .....	7
2.4. Injection Well Operational Monitoring .....	10
3. Workover and Maintenance .....	10
4. Routine Shutdown Procedure .....	11
5. Operational Contingency Plans.....	11
6. Reporting Requirements .....	11

## List of Figures

Figure 1: TR2-1 Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of LIC Injection Interval (8,621 ft) for CO <sub>2</sub> Injection. ....	8
Figure 2: TR2-2 Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of LIC Injection Interval (8,858 ft) for CO <sub>2</sub> Injection.....	8
Figure 3: TR2-3 Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of LIC Injection Interval (8,861 ft) for CO <sub>2</sub> Injection. ....	9
Figure 4: TR2-4 Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of LIC Injection Interval (8,690 ft) for CO <sub>2</sub> Injection. ....	9

## List of Tables

Table 1: Injection Well Operating Conditions for the LIC.....	5
Table 2: Specifications of the Anticipated CO <sub>2</sub> Stream Composition.....	6
Table 3: Estimated Surface and Downhole Temperature and Densities During Injection into the LIC Modeled under Maximum Injection Rate Conditions. ....	7
Table 6: Class VI Injection Well Reporting Requirements. ....	12
Table 7: Class VI Project Reporting Requirements.....	12

## List of Acronyms

°F	Degree Fahrenheit
CarbonSAFE	Carbon Storage Assurance Facility Enterprise
CCS	Carbon Capture and Storage
CO <sub>2</sub>	Carbon Dioxide
EPA	Environmental Protection Agency
ft	Feet
lb	Pound
LIC	Lockport Injection Complex
LLC	Limited Liability Company
MASP	Maximum Allowable Surface Pressure
MIC	Medina Injection Complex
MMSCF	Million Metric Standard Cubic Feet
Mol%	Molecular Percentage of Total Moles in a Mixture made up by One Constituent
MMt	Million Metric Tonnes
MMt/y	Million Metric Tonnes per Year
O <sub>2</sub>	Oxygen
ppmv	Parts per Million, Volume
ppmw	Parts per Million, Weight
psi	Pounds per Square Inch
psig	Pounds per Square Inch, Gauge
UIC	Underground Injection Control

## **1. Introduction**

Tri-State CCS, LLC seeks to safely inject carbon dioxide (CO<sub>2</sub>) at a maximum rate of 0.5 MMt/y into injection wells TR2-1, TR2-2, TR2-3, and TR2-4, located at Tri-State CCS Redbud 2 in Marshall County, West Virginia (the “project”) while maintaining well integrity and remaining below 90% of the fracture pressure at the depth of the shallowest perforated interval in the Lockport Injection Complex (LIC). The operational details provided in this document satisfy 47 CSR 13-13.8.1.g and j. The operational design described in this document has been developed to adhere to requirements set forth in 47 CSR 13-13.6.1.

## **2. Operational Procedures [47 CSR 13-13.8.1.i]**

### **2.1. Injection Rates**

The injection wells will be constructed as outlined in the Construction Details for TR2-1, TR2-2, TR2-3, and TR2-4. A total of four wells will be drilled for CO<sub>2</sub> injection into the Lockport Dolomite Group in the LIC and Medina Group in the Medina Injection Complex (MIC).

Table 1 and Table 2 summarize the proposed operational parameters for all of 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<sub>2</sub> sources, which may impact injection volumes and rates during limited periods of time. The injection pressure values detailed in Table 1 and Table 2 were modeled using Petroleum Experts’ PROSPER software, and the results can be found in subsection 2.1 of the Construction Details for each injection well.

Using the maximum CO<sub>2</sub> injection rates as summarized in Table 1 and Table 2, the injection tubing string sizes were selected for the four injection wells to meet the project requirements. These maximum injection rates are theoretical maximums for well design, considering the uncertainties associated with the reservoir properties. Based on these theoretical maximum injection rates, the maximum injection (wellhead) pressures were calculated using the hydraulic fracture gradient and 90% of hydraulic fracture pressure at the depth of the shallowest perforated interval in the LIC. These pressure limits are considered the maximum allowable surface pressure (MASP) for the four injection wells for injection into both the LIC and MIC.

Modeling to calculate the average injection pressure assumed that the LIC is pressure limited and the downhole pressure is equal to 90% of the hydraulic fracture pressure at the top perforation in the LIC. If data from the CarbonSAFE site characterization and pre-operational testing program indicate the LIC is not pressure limited, the average injection pressure may have to be recalculated accordingly.

Based on expected operating ranges, Tri-State 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, per 47 CSR 13-13.6.1.b.1. Maximum annulus pressures at the wellhead are also summarized in Table 1 and Table 2. No injection will take place between the long string casing and surface casing to protect the USDW, per 47 CSR 13-13.6.1.b.

**Table 1: Injection Well Operating Conditions for the LIC.**

Parameters/Conditions	Limit or Permitted Value				Units
	TR2-1	TR2-2	TR2-3	TR2-4	
<b>Maximum Injection Pressure</b>					
Surface	2,525	2,585	2,585	2,545	psig
Downhole - LIC	5,431	5,581	5,582	5,475	psig
Downhole - MIC	5,674	5,833	5,830	5,719	psig
<b>Average Injection Pressure</b>					
Surface - LIC	2,175	2,225	2,225	2,190	psig
Surface - MIC	2,165	2,215	2,220	2,180	psig
<b>CO<sub>2</sub> Injection Rate</b>					
Maximum <sup>1</sup>	0.5	0.5	0.5	0.5	MMt/y
Average - LIC <sup>1</sup>	0.10	0.11	0.11	0.10	MMt/y
Average - MIC <sup>1</sup>	0.12	0.15	0.13	0.12	MMt/y
<b>Injection Volume</b>					
Maximum Injection Volume and/or Mass (30-year period) - LIC	15.0	15.0	15.0	15.0	MMt
Maximum Injection Volume and/or Mass (30-year period) - MIC	15.0	15.0	15.0	15.0	MMt
Average Injection Volume and/or Mass (30-year period) - LIC	2.9	3.2	3.2	3.1	MMt
Average Injection Volume and/or Mass (30-year period) - MIC	3.6	4.4	3.8	3.6	MMt
<b>Annular Pressure</b>					
Minimum Annulus Pressure at Wellhead	100	100	100	100	psig
Minimum Differential Pressure (directly above and across packer)	100	100	100	100	psi
Maximum Proposed Annulus Pressure at the Wellhead	2,625	2,685	2,685	2,645	psig

<sup>1</sup> Current reservoir modeling is informed by limited site-specific data and provides lower estimates of average injection rates. Once reservoir characterization data has been collected from the CarbonSAFE stratigraphic test wells planned in the region and Pre-Operational Testing Program associated with the injection wells, the average and the maximum injection rates will be finalized. Accordingly, the injection pressures will also change depending on the identified maximum injection rates and 90% of the fracture pressure at the top perforation in the LIC or MIC as applicable.

The remainder of this page intentionally left blank.

## 2.2. CO<sub>2</sub> Stream Specifications

In accordance with 47 CSR 13-13.8.1.g.3 and 4, this subsection provides information on the sources and chemical and physical characteristics of the CO<sub>2</sub> stream. The CO<sub>2</sub> will be sourced from industrial facilities and power plants located in the Tri-State area and transported by pipeline to the Tri-State CCS Hub. The sources of CO<sub>2</sub> for the project have not yet been placed under contract, although the stream composition will be constrained through the implementation of a gas tariff on the pipeline operated by Tri-State CCS, LLC. The tariff will mandate maximum allowable concentrations that sources are committed to meeting under the services agreement. The CO<sub>2</sub> 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, Tri-State CCS, LLC plans to continuously monitor the CO<sub>2</sub> 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 3.0 of the Testing and Monitoring Plan). The CO<sub>2</sub> injection stream coming into the storage site is expected to have at least the specifications presented in Table 2, with a CO<sub>2</sub> concentration of 95% or higher. Tri-State CCS, LLC will engage with individual customers/sources to enforce a tariff specification that meets or exceeds this composition.

**Table 2: Specifications of the Anticipated CO<sub>2</sub> Stream Composition.**

Component	Specification	Unit
Carbon Dioxide (CO <sub>2</sub> )	> 95	Mol%, dry
Carbon Monoxide (CO)	< 1,000	ppmv
Water (H <sub>2</sub> O)	< 20	lb/MMSCF
Total Hydrocarbons	< 2	Mol%, dry
Amine	< 20	ppmv
Ammonia (NH <sub>3</sub> )	< 40	ppmv
Total Organic Compounds	< 50	ppmv
Hydrogen Sulfide (H <sub>2</sub> S)	< 40	ppmv
SO <sub>x</sub>	< 100	ppmv
Total Sulfur	< 100	ppmv
NO <sub>x</sub>	< 100	ppmv
Glycol	< 1	ppmv
Hydrogen (H <sub>2</sub> )	< 1	mol%
Inert Gasses (Non-Condensable)	< 5	Mol%, dry
Oxygen (O <sub>2</sub> )	< 100	ppmv
Particulate Matter	< 1	ppmw

Table 3 provides the estimated density under normal operating conditions both at the surface and downhole at reservoir conditions during planned injection operations. The CO<sub>2</sub> stream is expected to average around 60 °F at the wellhead. After injection into the LIC or MIC, the CO<sub>2</sub> 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 into the LIC Modeled under Maximum Injection Rate Conditions.**

Parameters/Conditions	Limit or Permitted Value				Units
	TR2-1	TR2-2	TR2-3	TR2-4	
<i>Temperature</i>					
Surface (CO <sub>2</sub> stream)	60.0	60.0	60.0	60.0	°F
Downhole - LIC	102.60	103.93	103.95	102.98	°F
Downhole - MIC	107.2	108.67	108.62	107.53	°F
<i>CO<sub>2</sub> Density</i>					
Surface - LIC	55.96	56.15	56.15	56.02	lb/ft <sup>3</sup>
Surface - MIC	55.96	56.15	56.15	56.02	lb/ft <sup>3</sup>
Downhole - LIC	57.05	57.20	57.20	57.11	lb/ft <sup>3</sup>
Downhole - MIC	57.00	57.14	57.14	57.05	lb/ft <sup>3</sup>

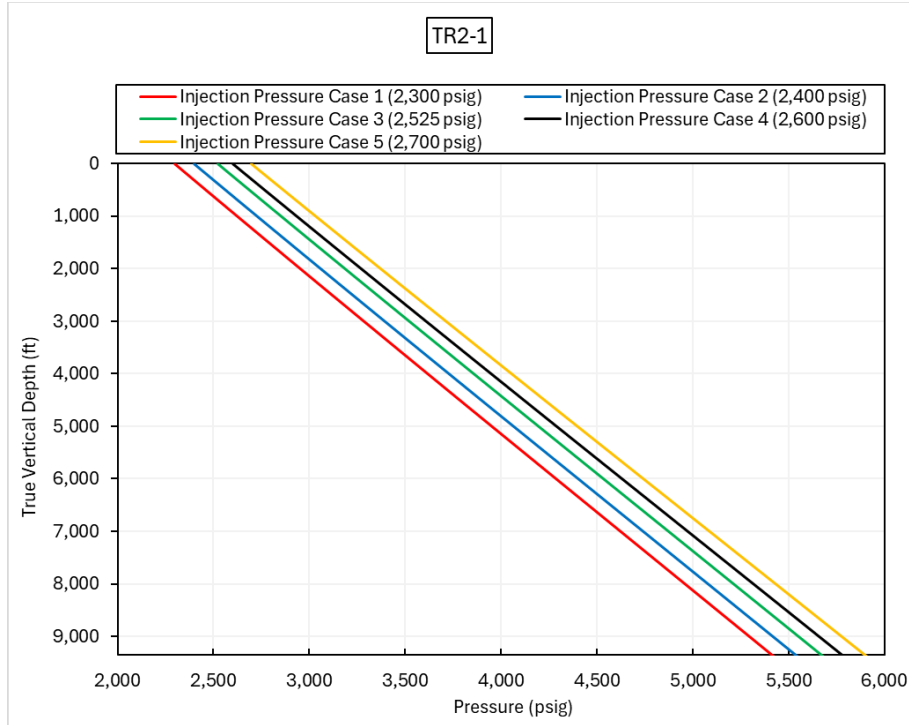
### 2.3. Estimated Maximum Allowable Surface Pressure

Using Petroleum Experts’ PROSPER software, MASP for CO<sub>2</sub> injection was modeled for all of the wells with 3.5-inch tubing. This was based on the downhole pressure at the top perforation depth in the LIC, regardless of which injection interval is being targeted. MASP represents 90% of the fracture pressure, per 47 CSR 13-13.6.1.a, at the depth of the shallowest injection interval using a maximum injection rate of 0.5 MMT/y. For each of the four wells, the maximum surface injection pressure, as reported in Table 1, is equal to the MASP.

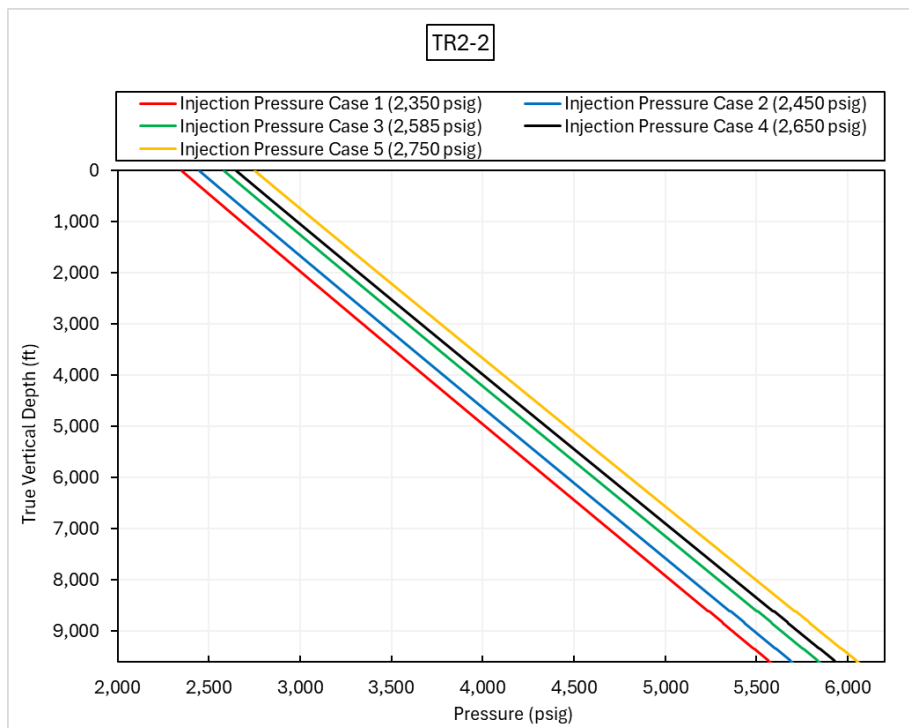
As an example, the MASP calculated for TR2-1 in the LIC based on downhole pressure of 5,431 psig and maximum injection rate of 0.5 MMT/y is approximately 2,525 psig, as shown in Figure 1. The downhole pressure of 5,431 psig corresponds to 90% of fracture pressure at a depth of 8,621 ft determined using a frac gradient of 0.7 psi/ft as discussed in subsection 1.9 of the Area of Review and Corrective Action Plan.

Figure 1 through Figure 4 highlight multiple maximum injection pressure cases for all the injection wells. At injection pressures below the MASP, the downhole pressure at the top of the LIC stays below 90% of the fracture pressure. At injection pressures higher than the MASP, the downhole pressure at the top perforation at LIC exceeds the 90% fracture pressure limit. This indicates that at or below the MASP, the injection operations will not fracture the rock, as required by 47 CSR 13-13.6.1.a.

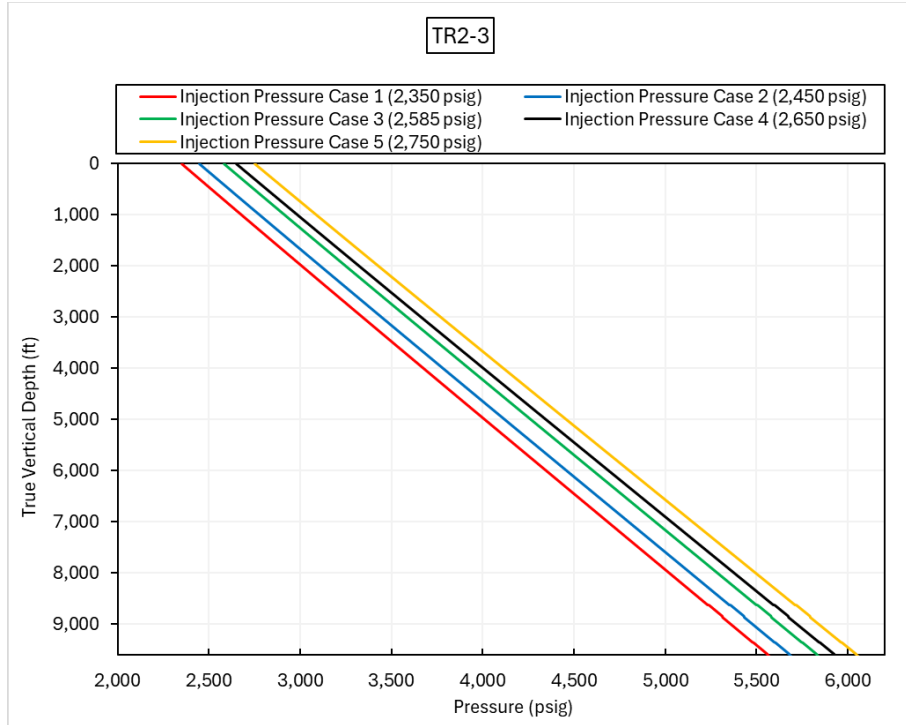
The remainder of this page intentionally left blank.



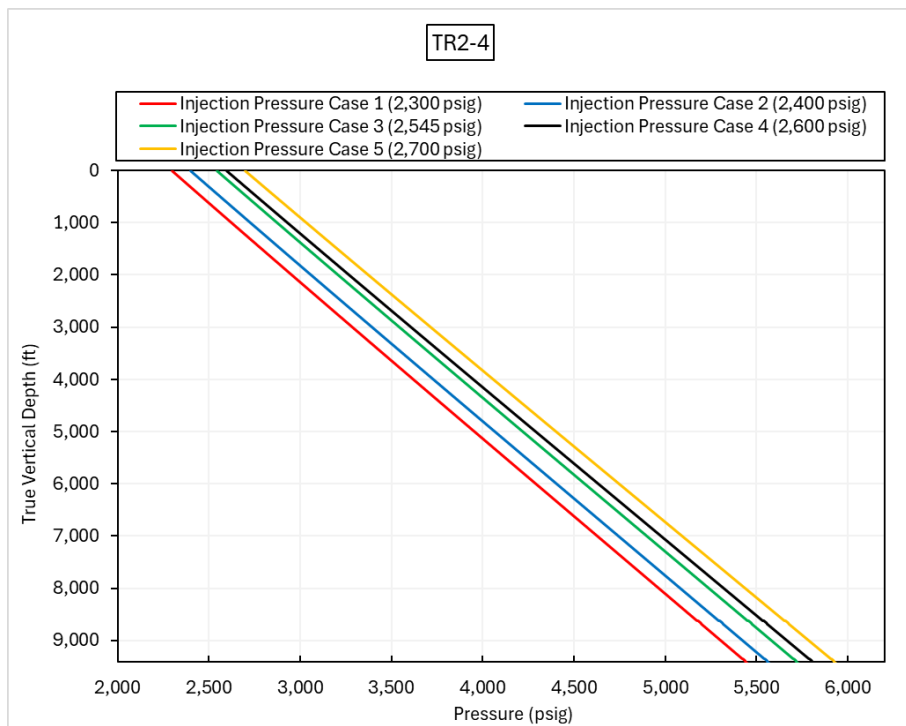
**Figure 1: TR2-1 Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of LIC Injection Interval (8,621 ft) for CO<sub>2</sub> Injection into both the LIC and MIC.**



**Figure 2: TR2-2 Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of LIC Injection Interval (8,858 ft) for CO<sub>2</sub> Injection into both the LIC and MIC.**



**Figure 3: TR2-3 Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of LIC Injection Interval (8,861 ft) for CO<sub>2</sub> Injection into both the LIC and MIC.**



**Figure 4: TR2-4 Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of LIC Injection Interval (8,690 ft) for CO<sub>2</sub> Injection into both the LIC and MIC.**

## **2.4. Injection Well Operational Monitoring**

Each injection well will be monitored to ensure safe operations, in compliance with 47 CSR 13-13.6.1.d. Operational safety monitoring includes continuous monitoring of the injection pressure at the wellhead and downhole, continuous monitoring of flow rate, volume and/or mass, and temperature of CO<sub>2</sub> 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<sub>2</sub>. Each of these monitoring systems is fully described in Sections 3.0, 4.0 and 5.0 of the Testing and Monitoring Plan.

In adherence to 47 CSR 13-13.6.1.d, 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<sub>2</sub> 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<sub>2</sub> 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 adherence to 47 CSR 13-13.6.1.e, 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 unremedied shutdown is triggered or a loss of mechanical integrity is discovered, Tri-State CCS, LLC will immediately investigate and identify, as expeditiously as possible, the cause of the shutdown. Response actions to be taken in the event that mechanical integrity is lost are outlined in Appendix A of the Emergency and Remedial Response Plan.

The annular space between the tubing and long string casing of each injection well will be pressurized with brine containing appropriate corrosion inhibiting additives and monitored for changes in pressure and volume as required by 47 CSR 13-13.6.1.b.1. 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 through the primary confining units. For the injection wells, the confining unit is the Rochester Shale Formation for MIC, and the confining unit is the Salina Group for LIC. 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.

## **3. Workover and Maintenance**

In adherence to 47 CSR 13-13.6.1.c, Tri-State 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. As outlined in subsection 2.5 of the Testing and Monitoring Plan, and in adherence to 47 CSR 13-13.6.3.a.4, Tri-State CCS, LLC will notify the UIC Program Director of any planned workover or injection well test at least 30 days in advance, and the results of any mechanical integrity test, workover, or

injection well test will be provided within 30 days after the test or maintenance is completed (47 CSR 13-13.6.3.a.2).

#### **4. Routine Shutdown Procedure**

For injection shutdowns occurring under routine conditions (e.g., for well workovers), Tri-State CCS, LLC will reduce CO<sub>2</sub> injection at a rate of up to 160,000 tonnes 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 project injection wells include potential downtime periods when annual injection well testing, 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<sub>2</sub> 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**

Class VI well reporting requirements for TR2-1, TR2-2, TR2-3, and TR2-4 are listed below in Table 6, and project reporting requirements are listed below in Table 7. All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan of this permit application. In addition to submittal to the UIC Program Director, per 47 CSR 13-13.6.3.a.5, Tri-State CCS, LLC will submit all required reports, submittals, etc. to EPA in an approved electronic format.

The remainder of this page intentionally left blank

**Table 4: Class VI Injection Well Reporting Requirements.**

<b>Activity</b>	<b>Reporting Requirements</b>
Changes to physical, chemical, or other characteristics of CO <sub>2</sub> stream	Semi-annually
Monthly average, maximum, and minimum injection pressure, injection rate, injection volume, and pressure on the annulus, monthly annulus fluid volume changes	Semi-annually
Monthly and cumulative CO <sub>2</sub> injected over life of project	Semi-annually
Automatic shut-off events (description and response)	Semi-annually
Operating parameter exceedance events	Semi-annually
Results of monitoring in Testing and Monitoring Plan (i.e., corrosion monitoring, etc.)	Semi-annually
External MITs, well workover, other required tests	Within 30 days of completion of test
Pressure fall-off testing	In the next semi-annual report

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

**Table 5: Class VI Project Reporting Requirements.**

<b>Activity</b>	<b>Reporting Requirements</b>
Groundwater quality monitoring	Semi-annually
Plume and pressure front tracking	In the next semi-annual report
Monitoring well MITs	Within 30 days of completion of test
Financial responsibility updates pursuant to the Financial Assurance Demonstration of this permit	Within 60 days of update

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