SUMMARY OF REQUIREMENTS
CLASS VI OPERATING AND REPORTING CONDITIONS
40 CFR 146.88

Project Name: Buckeye III CCS

Facility Information

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

Well location: Coshocton County, Ohio

Well Name	Latitude (WGS84)	Longitude (WGS84)
Bellflower 1	40.215516	-81.864158

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^oF	Degree Fahrenheit
Ar	Argon
CBS	Cambrian Basal Sandstone
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
BIC	Basal Sandstone Injection Complex

ft	Feet
lb	Pound
LLC	Limited Liability Company
MASP	Maximum Allowable Surface Pressure
MIT	Mechanical Integrity Testing
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
N_2	Nitrogen
O_2	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

Buckeye III CCS, LLC seeks to safely inject carbon dioxide (CO_2) at a maximum rate of 0.5 MMt/y into injection well Bellflower 1 at Buckeye III CCS in Coshocton County, Ohio (the "project") while maintaining well integrity and remaining below 90% of the fracture pressure in the Basal Sandstone Injection Complex (BIC). The operational details provided in this document satisfy 40 CFR 146.82(a)(7) and (10). The operational design described in this document has been developed to adhere to requirements set forth in 40 CFR 146.88.

2. Operational Procedures [40 CFR 146.82(a)(10)]

2.1. Injection Rates

Bellflower 1 will be constructed as outlined in the Construction Details, drilled for CO_2 injection into the Cambrian Basal Sandstone (CBS) in the BIC. Injection is planned for 30 years. Once the total planned injection is achieved, the tubing and completion will be retrieved, and the Basal Sandstone will be plugged off with CO_2 resistant cement.

Table 1 summarizes the proposed operational parameters for the injection well. 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 pressure values detailed in Table 1 were modeled using Petroleum Experts' PROSPER software, and results can be found in subsection 2.1 of the Construction Details.

Using the maximum CO_2 injection rate as summarized in Table 1, the injection tubing string size was selected to meet the project requirements. Maximum injection (wellhead) pressure was calculated based on the hydraulic fracture gradient and 90% of hydraulic fracture pressure. The maximum injection pressure was modeled at the depth of the shallowest perforation in the Basal Sand Sandstone (7,204ft), assuming a constant injection rate of 0.5 MMt/y, which is considered the maximum allowable surface pressure (MASP) for Bellflower 1.

Based on expected operating ranges, Buckeye III 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 40 CFR 146.88(c). Maximum annulus pressures at the wellhead are also summarized inTable 1. No injection will take place between the long string casing and surface casing to protect the USDW, per 40 CFR 146.88(b).

Final design criteria to operate Bellflower 1 will be developed following data collection from the Pre-Operational Testing Program.

Table 1: Bellflower 1 Operating Conditions.

Parameters/Conditions	Limit or Permitted Value	Units
Injection Pressure		
Maximum Allowable Surface	1,938	psig
Maximum Allowable Delivery	2,220	psig
Maximum / Average Downhole	3,821	psig
Maximum Downhole	4,538	psig
CO_2 Injection Rate		
Max/Average[1, 2]	0.5	MMt/y
Injection Volume		
Maximum Injection Volume and/or Mass (30-year period)	15.0	MMt
Annular Pressure		
Minimum Annulus Pressure at Wellhead	100	psig
Minimum Differential Pressure (directly above and across packer)	100	psig
Maximum Proposed Annulus Pressure at the Wellhead	2,038	psig

[1] Current reservoir modeling is informed by limited site-specific data and provides estimated pressures based on a constant injection rate for the whole duration of the project.
[2] The average will be updated with data from the Pre-Operational testing.

2.2. CO_2 Stream Specifications

In accordance with 40 CFR 146.82(a)(7)(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 sourced from the Three Rivers Energy biorefinery with the potential to add other sources such as industrial facilities and power plants located in the vicinity of the project, which would be transported by pipeline. The stream composition will be constrained through the implementation of a gas tariff on the pipeline operated by Buckeye III CCS, LLC. The tariff will mandate maximum allowable concentrations that sources are committed to meeting under the services agreement. 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, Buckeye III 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 3.0 of the Testing and Monitoring Plan). The CO_2 injection stream coming into the storage site is expected to have at least the specifications presented in Table 2, with a CO_2 concentration of 95% or higher. Buckeye III CCS, LLC will engage with individual customers/sources to enfore a tariff specification that meets or exceeds this composition.

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Table 2: Specifications of the anticipated CO_2 stream composition.

Component	Specification	Unit
Carbon Dioxide (CO_2)	> 95	Mol%, dry
Carbon Monoxide (CO)	< 1000	ppmv
Water (H_2O)	< 20	lb/MMSCF
Total Hydrocarbons	< 2	Mol%, dry
Amine	< 20	ppmv
Ammonia (NH_3)	< 40	ppmv
Total Organic Compounds	< 50	ppmv
Hydrogen Sulfide (H_2S)	< 40	ppmv
SO_x	< 100	ppmv
Total Sulfur	< 100	ppmv
NO_x	< 100	ppmv
Glycol	< 1	ppmv
Hydrogen (H_2)	< 1	mol%
Inert Gasses (Non-Condensable)	< 5	Mol%, dry
Oxygen (O_2)	< 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_2 stream is expected to average around 60 ºF at the wellhead. After injection, the CO_2 stream is anticipated to be supercritical and heat to near formation temperature at or above the native reservoir pressure.

Table 3: Estimated Surface and Downhole Temperature and Densities During Injection modeled under Maximum Injection Rate Conditions.

Parameters/Conditions	Limit or Permitted Value	Units
Temperature		
Surface (CO_2 stream)[1]	80.0 - 120.0	°F
Downhole	155	°F
CO_2 Density		
Surface	44.94	lb/ft^3
Downhole	48.87	lb/ft^3

[1] Injection simulations were performed assuming an injection temperature of 95.0 °F.

2.3. Estimated Maximum Allowable Surface Pressure

Using Petroleum Experts' PROSPER software, the MASP for CO_2 injection was modeled for the well with 3.5-inch tubing. MASP represents 90% of the fracture pressure, per 40 CFR 146.88(a), at the depth of the injection interval using a maximum injection rate of 0.5 MMt/y. The maximum surface injection pressure, as reported in Table 1 is equal to the MASP.

As an example, the MASP calculated for Bellflower 1 based on a downhole pressure of 4,538 psig and maximum injection rate of 0.5 MMt/y is approximately 1,938 psig, as shown in Figure 1. The downhole pressure of 4,538 psig corresponds to 90% of fracture pressure at a depth of 7,204 ft TVD determined using a frac gradient of 0.7 psi/ft as discussed in subsection 1.7 of the Area of Review and Corrective Action Plan.

Figure 1 highlights multiple maximum injection pressure cases for Bellflower 1. At injection pressures below the MASP, the downhole pressure at the top of the BIC stays below 90% of the fracture pressure. At injection pressures higher than the MASP, the downhole pressure at the top perforation 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 40 CFR 146.88(a).

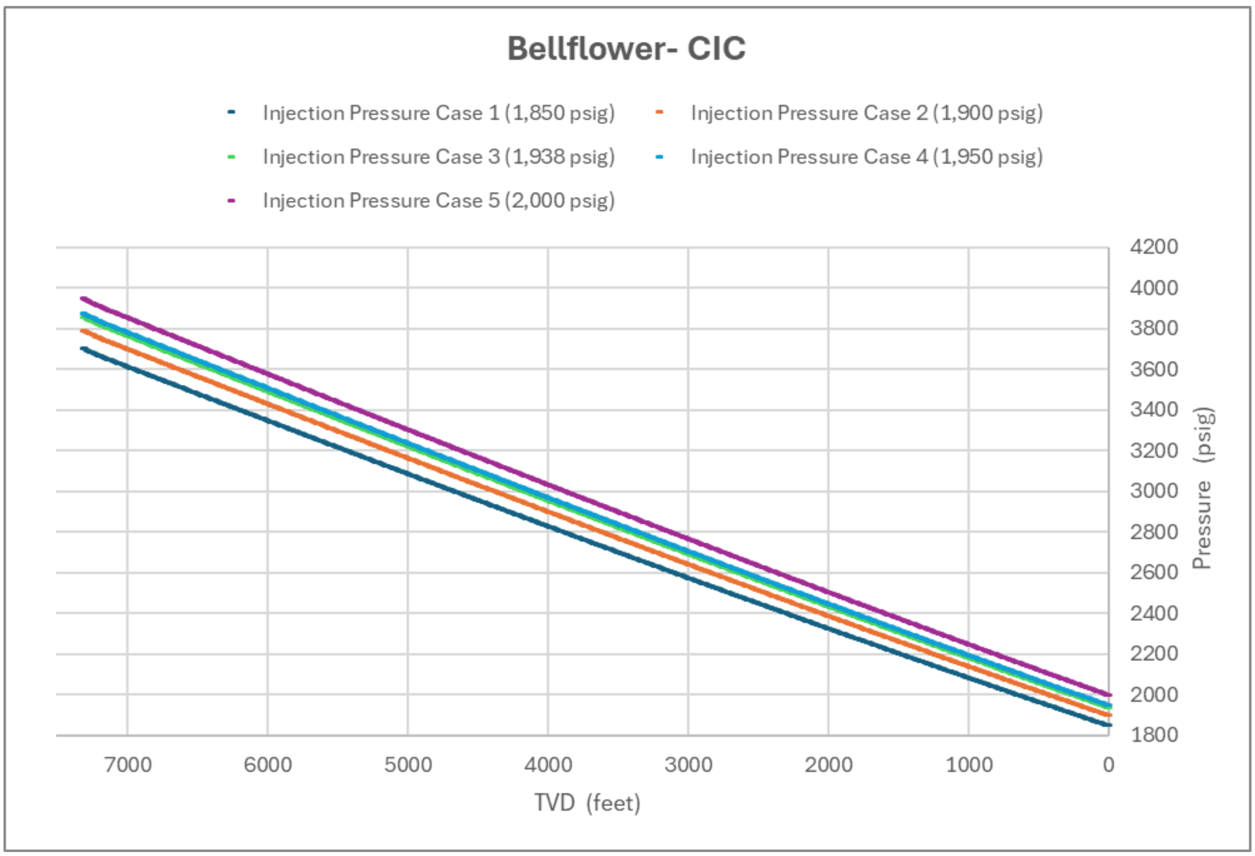

Figure 1: Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Injection Interval (7,204 ft) for Bellflower.

2.4. Injection Well Operational Monitoring

Bellflower 1 will be monitored to ensure safe operations, in compliance with 40 CFR 146.88(e)(2). 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_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, 4.0 and 5.0 of the Testing and Monitoring Plan.

In adherence to 40 CFR 146.88(e), Bellflower 1 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 adherence to 40 CFR 146.88(f), 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, Buckeye 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 Bellflower 1 will be pressurized with brine containing appropriate corrosion inhibiting additives and monitored for changes in pressure and volume as required by 40 CFR 146.88(c). 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 confining zone (Maryville Silt). 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 40 CFR 146.88(d), Buckeye III CCS, LLC will monitor and maintain the mechanical integrity of Bellflower 1 at all times. Well maintenance and workovers will be part of normal operations to keep Bellflower 1 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 40 CFR 146.91(d), Buckeye III 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 (40 CFR 146.91(b)).

4. Routine Shutdown Procedure

For injection shutdowns occurring under routine conditions (e.g., for well workovers), Buckeye III CCS, LLC will reduce CO_2 injection at a rate of up to 60,000 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 include potential downtime periods when annual injection well testing, maintenance, well service, and stimulation occur.

Adhering to proper operations practices, including regular well maintenance and service, will reduce most injection well down-time. In the unlikely event that Bellflower 1 is temporarily unavailable or is 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

Federal reporting requirements for Bellflower are listed below in Table 4 per 40 CFR 146.91(a), and project reporting requirements are listed below in Table 5, per 40 CFR 146.91(b) and (c). All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan of this permit application.

Table 4: Class VI Injection Well Reporting Requirements.

Activity	Reporting Requirements
Changes to physical, chemical, or other characteristics of CO_2 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_2 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 on this permit.

Table 5: Class VI Project Reporting Requirements.

Activity	Reporting Requirements
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 on this permit.