CONSTRUCTION DETAILS FOR TR2-4
47 CSR 13-13.3

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

Well Name	Latitude (WGS84)	Longitude (WGS84)
TR2-4	39.95642300	-80.63531600

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List of Acronyms

°F	Degree Fahrenheit
22Cr-110	22% Chromium Duplex Stainless Steel with 110,000 Pounds per Square Inch Minimum Yield Strength
AMPP	Association for Materials Protection and Performance
API	American Petroleum Institute
BTU	British Thermal Unit
Ca^{2+}	Calcium
CarbonSAFE	Carbon Storage Assurance Facility Enterprise
CCS	Carbon Capture and Storage
Cl^-	Chloride

CO_2	Carbon Dioxide
DF	Design Factor
DTS	Distributed Temperature Sensing
Ft	Feet
Gal	Gallon
gpm	Gallons Per Minute
H40	H40 Carbon Steel
HCO^{3-}	Bicarbonate
ID	Internal Diameter
In	Inch
J55	J55 Carbon Steel
K^+	Potassium
LIC	Lockport Injection Complex
KLBF	Kilo Pound-Force
L80	L80 Grade Steel
lb	Pound
MASP	Maximum Allowable Surface Pressure
mg/L	Milligrams Per Liter
Mg^{2+}	Magnesium
MIC	Medina Injection Complex
MIYP	Maximum Internal Yield Pressure
MMSCF	Million Metric Standard Cubic Feet
MMt	Million Metric Tons
MMt/y	Million Metric Tons per Year
Mol%	Molecular Percentage of Total Moles in a Mixture made up by One Constituent
Na^+	Sodium
NA	Not Applicable
O_2	Oxygen
OD	Outer Diameter
PH	Potential of Hydrogen
PPG	Pounds Per Gallon
ppmv	Parts Per Million, Volume
ppmw	Parts Per Million, Weight
psi	Pounds Per Square Inch
psig	Pounds Per Square Inch Gauge
RBW	Remaining Body Wall
sec	Second
SITP	Shut-In Tubing Pressure

SO_4^{2-}	Sulphate Ion
STC	Short Thread Coupling
TDS	Total Dissolved Solids
TEC	Tubing Encapsulated Cables
TVD	True Vertical Depth
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USGS	United States Geological Survey
VME	Von Mises Equivalent Stress
WVDEP	West Virginia Department of Environmental Protection

1. Introduction

The construction details for the TR2-4 injection well at Tri-State CCS Redbud 2 in Marshall County, West Virginia (the "project") are described in this document. The injection well has been designed to accommodate the anticipated mass of carbon dioxide (CO_2) and the subsurface characteristics of the CO_2 injection intervals that affect the well design. The following reviews the analysis performed to comply with Class VI West Virginia Department of Environmental Protection (WVDEP) Underground Injection Control (UIC) well standards at 47 CSR 13-13.3 regarding the design of the casing, cement, and wellhead.

Additionally, construction of TR2-4 will include drilling through the geographic limits of the Ohio County Mine, an underground coal mine that is currently being used to extract coal from the Pittsburg Coal seam (see Appendix A of this document for mine details). Tri-State CCS, LLC will work with WVDEP to determine which state requirements will apply to drilling and casing Class VI wells through an active underground mining operation. In absence of regulations protecting the coal resource under 47 CSR 13-13.3, Tri-State CCS, LLC will construct TR2-4 in adherence to West Virginia Code § 22-6-17, 18 and 20 to protect health, safety, and the coal resource.

2. TR2-4 Construction Details

2.1. Wellhead Injection Pressure

Petroleum Experts' PROSPER software was used to perform nodal analysis on multiple tubing diameters for injection of supercritical CO_2 into the subsurface. The injection is planned into the Lockport Dolomite Group of the Lockport Injection Complex (LIC) and into the Medina Group of the Medina Injection Complex (MIC), as defined in subsection 2.4 of the Geologic Narrative. For the LIC, nodal analysis was performed with a long-string of 7-inch 26 lb/ft casing set to a depth of 9,694 ft TVD. The long-string casing was designed with L80 grade steel (L80) from surface to 8,458 ft TVD, and 22Cr-110 grade duplex stainless steel (22Cr-110) in the injection complexes from 8,458 ft to 9,694 ft TVD. The well as planned will be perforated, as discussed in subsection 2.8.3 of this plan, in the LIC from the depth of 8,690 ft to 8,997 ft TVD and in the MIC from 9,411 ft to 9,593 ft TVD. The exact perforation depths will depend on additional characterization data from the pre-injection testing activities. Feasibility of CO_2 injection was determined with a 3.5-inch outer diameter (OD) 9.2 lb/ft 22Cr-110 tubing set at 9,098 ft TVD.

For injection into the LIC, the maximum allowable surface pressure (MASP) is identified based on 90% of the fracture gradient at the depth of the shallowest LIC injection interval, assuming an anticipated maximum injection rate of 0.5 MMt/y (see subsection 2.3 of the Summary of Requirements – Class VI Operating and Reporting Conditions). Since both the injection zones have planned injection over the life of the project, the MASP will be the same for MIC injection interval. The average injection rates predicted by reservoir modeling are lower than 0.5 MMt/y, as current reservoir models are informed by limited site-specific data. Once site-specific reservoir characterization data becomes available from the planned Carbon Storage Assurance Facility Enterprise (CarbonSAFE) stratigraphic test wells and the Pre-Operational Testing Program associated with the injection wells, the average and the maximum injection rates will be finalized. Tubing design was carried out using a higher injection rate to ensure the design remains valid for rates exceeding the predicted average injection rates.

The design approach is aimed at minimizing the injection pressure while maintaining safe injection conditions at maximum injection rate. For injection into the LIC, several tubing sizes from 2.875-inch through 4.0-inch OD were compared for CO_2 injection at the maximum rate and maximum downhole pressure (5,475 psig) as shown in Figure 1. Nodal analysis at maximum injection rate of 0.5 MMt/y, and downhole pressure limit of 5,475 psig showed all tubing sizes larger than 2.875-inch OD allow for safe CO_2 injection. The 2.875-inch case shows the highest injection pressure of 3,750 psig. For tubing sizes larger than 3.5-inch OD, there is minimal reduction in the modeled injection pressure. As a result, 3.5-inch OD was selected, and a modeled injection pressure limit of 2,545 psig is identified as the MASP for the LIC. Since injection into both the LIC and MIC are planned to be contemporaneous, the MASP for injection into MIC will also be the same. Since both 4.0-inch and 4.5-inch OD cases show surface pressures which are only slightly lower than the surface pressure observed with the 3.5-inch OD tubing, the latter design is selected for this well.

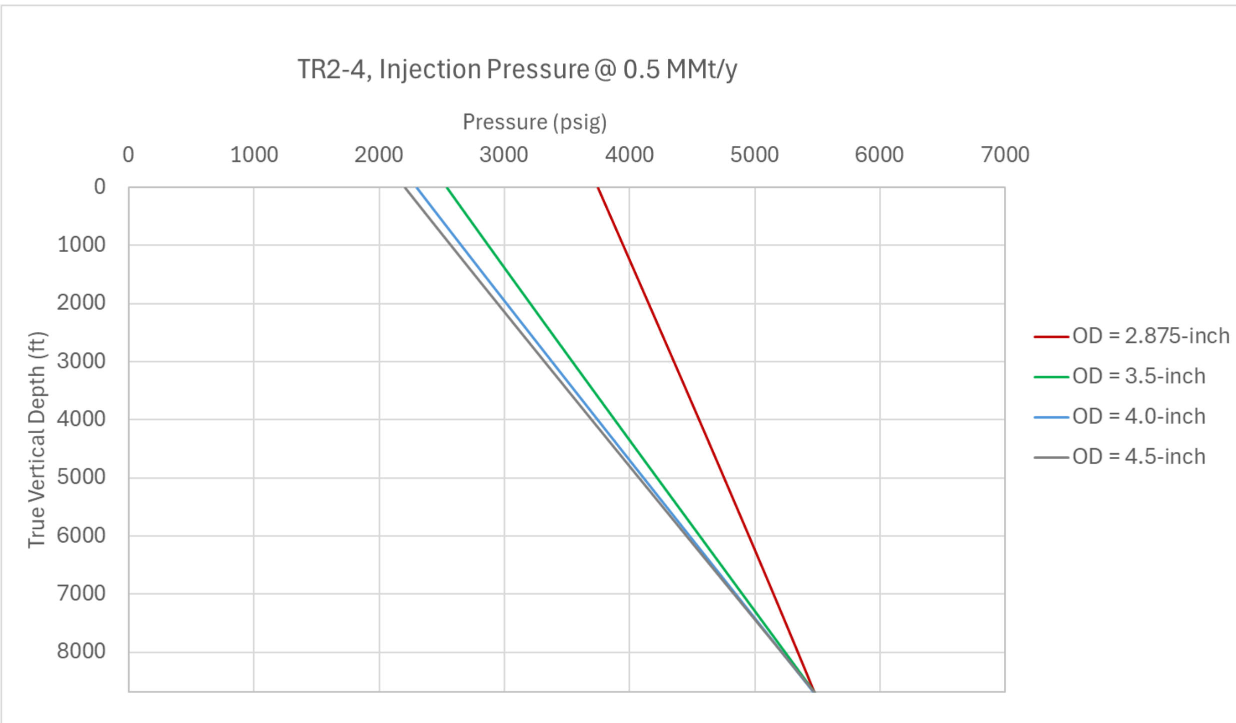

Figure 1: TR2-4 injection pressure at maximum injection rate of 0.5 MMt/y using different tubing sizes for CO_2 injection into the LIC. The downhole pressure is limited by 90% of fracture gradient at the depth of the shallowest LIC injection interval (5,475 psig).

2.2. Injection Well Operating Conditions

Table 1 provides the injection well operating conditions anticipated for TR2-4 that form the basis of design and material selection, in accordance with 47 CSR 13-13.3.2.a.1-2, 5, and 9 and 13.3.3.c.2-5.

Table 1: TR2-4 Operating Conditions.

<table>
<tr><th>Parameter</th><th>Value</th><th>Notes</th></tr>
<tr><td>Maximum proposed injection rate</td><td>LIC: 0.5 MMt/y
MIC: 0.5 MMt/y</td><td>Well designed for a higher maximum injection rate as discussed in subsection 2.3 of the Summary of Requirements – Class VI Operating and Reporting Conditions.</td></tr>
<tr><td>Average proposed injection rate</td><td>LIC: 0.10 MMt/y
MIC: 0.12 MMt/y</td><td>Proposed injection rate from reservoir modelling at 90% of the fracture pressure at the depth of the shallowest perforated interval in the LIC.</td></tr>
<tr><td>Planned Injection Duration</td><td>30 years</td><td></td></tr>
<tr><td>Injection type</td><td>Continuous</td><td>Operational target is for continuous injection. However, some intermittent injection will be likely due to operational downtime.</td></tr>
<tr><td>Volume Flow Rate</td><td>282.28 gpm</td><td>Average volumetric flow rate inside tubing with max injection rate.</td></tr>
<tr><td>Flow Velocity in Tubing</td><td>12.87 ft/sec</td><td>Average flow velocity assuming: 3.5-inch OD tubing w/ 2.992-inch ID from surface to 9,098 ft TVD for injection into both the LIC and MIC.</td></tr>
<tr><td>CO_2 Stream Characteristics</td><td>
<table>
<tr><th>Component</th><th>Specification</th><th>Unit</th></tr>
<tr><td>Carbon Dioxide (CO_2)</td><td>> 95</td><td>Mol%, dry</td></tr>
<tr><td>Carbon Monoxide (CO)</td><td>< 1,000</td><td>ppmv</td></tr>
<tr><td>Water (H_2O)</td><td>< 20</td><td>lb/MMSCF</td></tr>
<tr><td>Total Hydrocarbons</td><td>< 2</td><td>Mol%, dry</td></tr>
<tr><td>Amine</td><td>< 20</td><td>ppmv</td></tr>
<tr><td>Ammonia (NH_3)</td><td>< 40</td><td>ppmv</td></tr>
<tr><td>Total Organic Compounds</td><td>< 50</td><td>ppmv</td></tr>
<tr><td>Hydrogen Sulfide (H_2S)</td><td>< 40</td><td>ppmv</td></tr>
<tr><td>SOx</td><td>< 100</td><td>ppmv</td></tr>
<tr><td>Total Sulfur</td><td>< 100</td><td>ppmv</td></tr>
<tr><td>NOx</td><td>< 100</td><td>ppmv</td></tr>
<tr><td>Glycol</td><td>< 1</td><td>ppmv</td></tr>
<tr><td>Hydrogen (H_2)</td><td>< 1</td><td>mol%</td></tr>
<tr><td>Inert Gasses (Non-Condensable)</td><td>< 5</td><td>Mol%, dry</td></tr>
<tr><td>Oxygen (O_2)</td><td>< 100</td><td>ppmv</td></tr>
<tr><td>Particulate Matter</td><td>< 1</td><td>ppmw</td></tr>
</table>
</td><td>Anticipated CO_2 stream characteristics.</td></tr>
<tr><td>**CO_2 Stream Corrosiveness**</td><td>Non-corrosive</td><td></td></tr>
</table>

Parameter	Value	Notes
Formation Brine Corrosiveness	Mildly corrosive	Data to be collected from CarbonSAFE stratigraphic test wells
Mixture (CO_2 Stream with Formation Brine) Corrosiveness	Corrosive	
CO_2 Stream Density	7.60 lb/gal	At maximum pressure and 60 ºF on the wellhead.
Fracture Gradient	0.70 psi/ft	To be confirmed by step rate test at later date.
In-Situ Pressure at top of injection intervals	LIC: 4,041 psig MIC: 4,376 psig	Determined using the pore pressure gradient of 0.465 psi/ft.
Maximum pressure at top of injection intervals	LIC: 5,475 psig MIC: 5,719 psig	Determined using 90% of the fracture gradient 0.70 psi/ft for LIC and PROSPER software modeling results for MIC.
Maximum proposed annular pressure at wellhead	LIC: 2,645 psig MIC: 2,645 psig	
Maximum proposed injection (wellhead) pressure	LIC: 2,545 psig MIC: 2,545 psig	
Minimum annulus pressure at wellhead	100 psig	To maintain 100 psig differential pressure.
Minimum differential pressure (directly above and across top tubing packer)	100 psig	For continuous mechanical integrity assurance.
Injection Zones True Vertical Depth	LIC: 8,608 ft – 8,997 ft TVD MIC: 9,410 ft – 9,593 ft TVD	
Injection Intervals True Vertical Depth	LIC: 8,690 ft – 8,997 ft TVD MIC: 9,411 ft – 9,593 ft TVD	

2.3. Formation Conditions

Table 2 presents the anticipated formation conditions for TR2-4, as required by 47 CSR 13-13.3.2.a.6-7 and 9. Formation fluid characteristics will be updated following data collection programs associated with the CarbonSAFE stratigraphic test wells planned in the region and as described in the Pre-Operational Testing Program. Information regarding the formations summarized in Table 2 was obtained from the injection and confining zone details in subsection 2.4 and baseline fluid chemistry in subsection 2.8.1 of the Application Narrative.

Table 2: Summary of formation conditions for TR2-4.

Parameter	Value	Notes
Bottomhole Temperature	186 °F	0.013 °F/ft geothermal gradient + 60 °F surface temperature
Injectate Temperature	60 °F	Anticipated CO_2 stream sources discussed in subsection 2.2 of the Summary of Requirements – Class VI Operating and Reporting Conditions.
Injection Lithology	Dolomite (LIC) Sandstone (MIC)	Perforating the Dolomite in the LIC and Sandstone in the MIC.
Confining Lithology	Salt (Evaporite) and Shale – Upper Confining Unit Shale and Limestone – Lower Confining Unit	LIC: Upper Confining Unit – Salina Group Lower Confining Unit – Rochester Shale MIC: Upper Confining Unit – Rochester Shale Lower Confining Unit – Queenston Shale
Formation Fluid Chemistry – Salina Group Confining Zone	TDS : 256,156 mg/L pH : 6.1 Ba^{2+} : 700 HCO_3^- : 211.3 mg/L Ca^{2+} : 17,296.5 mg/L Cl^- : 158,758.5 mg/L K^+ : 3438.1 mg/L Mg^{2+} : 3,012.2 mg/L Na^+ : 76,927.0 mg/L SO_4^{2-} : 1,971.8 mg/L	Based on USGS (National Produced Waters Geochemical Database, Blondes et al., 2019); data to be collected from CarbonSAFE stratigraphic test wells
Formation Fluid Chemistry – Lockport Dolomite Group Injection Interval	TDS : 264,717 mg/L pH : 6.56 HCO_3^- : 98.9 mg/L Ca^{2+} : 25,202.5 mg/L Cl^- : 143,949.4 mg/L K^+ : 2,930.7 mg/L Mg^{2+} : 4,907.0 mg/L Na^+ : 71,421.2 mg/L SO_4^{2-} : 647.6 mg/L	Based on USGS (National Produced Waters Geochemical Database, Blondes et al., 2019); data to be collected from CarbonSAFE stratigraphic test wells
Formation Fluid Chemistry – Rochester Shale Confining Zone	No data available in the USGS database and publicly available literature. Data to be collected from CarbonSAFE stratigraphic test wells	
Formation Fluid Chemistry – Medina Group Injection Interval	TDS : 266,865 mg/L pH : 5.53 Ba^{2+} : 22.2 mg/L HCO_3^- : 91.3 mg/L Ca^{2+} : 33,238.1 mg/L Cl^- : 164,034.6 mg/L K^+ : 1,637.8 mg/L Mg^{2+} : 4,055.8 mg/L Na^+ : 59,121.6 mg/L SO_4^{2-} : 409.4 mg/L	Based on USGS (National Produced Waters Geochemical Database, Blondes et al., 2019); data to be collected from CarbonSAFE stratigraphic test wells
Coal Seam Depth	Top: ~681 ft TVD Base: ~686 ft TVD (Pittsburgh Coal)	Pittsburgh Coal, Monongahela Group, 2025
Lowermost Underground Source of Drinking Water (USDW)	~291 ft TVD (Mauch Chunk Group)	As discussed in subsection 2.8 of the Application Narrative.

2.4. Demonstration of Well Material Compatibility

Lithology of the storage reservoir's injection and confining zones is discussed in subsection 2.4 of the Application Narrative. Reservoir fluid characteristics are shown in Table 2 above and discussed in subsection 2.8.1 of the Application Narrative. The anticipated composition of the CO_2 stream is shown in Table 1 above, and the anticipated temperature of the CO_2 stream is shown in Table 2 above. Anticipated CO_2 stream composition and temperature are consistent with that of the U.S. CO_2 enhanced oil recovery industry, where mild steel is used. Constructing the wells with 22Cr or better components or coatings should exceed the protection requirements and be consistent with Guoqing Xiao's data (2020). Alloy selection will be verified by testing of representative samples in an equivalent operating environment based on results of sequestration zone fluid samples obtained during the CarbonSAFE stratigraphic well testing.

CO_2 resistant cement slurries utilized will be selected based on the most current formulations with sufficient testing to validate suitability for the project's life. This may include self-healing properties to seal cracks induced by operational cycles and cement placement dynamics (Engelke et al, 2017). A minimum of two products suitable for this application are currently available in the marketplace (Brandl et al, 2011; Engelke et al, 2017). One alternative, EverCRETE, has provided wellbore isolation in numerous CO_2 sequestration projects, including but not limited to CO2CRC in Australia, the Japan Carbon Capture Storage Co. Ltd. Demonstration project in Tomakomai, Hakkaido, and the Archer Daniels Midland Illinois Basin Decatur Project injection wells. Laboratory study results were reposted in the following paper: "Well Technologies for CO_2 Geological Storage: CO_2-Resistant Cement" concluding that "This material remains comparably inert in both wet supercritical CO_2 and CO_2-saturated water phases. Weight, density, compressive strength, microstructural characterizations, and Hg-porosity measurements confirm the good stability of the CO_2-resistant cement" (Barlet-Gouedard et al, 2007).

In areas where the risk of CO_2 corrosion is not a concern, H-40, J-55, or L-80 mild steel will be utilized.

22Cr or better material is planned for wetted sections that are exposed to CO_2, where the mixing of CO_2 and formation brine pose a higher corrosion risk. The 22Cr alloy specification will be manufactured to ASTM/ASME standard A240 UNS S32205/S31803 and is suitable for the injectate stream and anticipated high chloride formation brine composition. Samples of this alloy tested in aqueous and condensed phases of water in excess of 268,000 mg/L chloride content experienced a maximum of 0.0012 mm/year thickness loss and no indication of pitting or crevice corrosion in either the immersed or vapor phases (Neel, 2024).

Interior coatings for injection pipe and/or tubing, such as Tuboscope TK-99 (or equivalent) are designed for CO_2 and related injection fluids and present an alternative to the use of high-grade chromium alloys. The TK-99 coating has been laboratory and field tested and has shown viable corrosion resistance in CO_2, water, and hydrocarbon environments (Tuboscope TK-99 Specification Sheet, 2019). Actual installation of 22Cr or coated injection tubing will depend on availability.

2.5. Casing Program

Access to both the Lockport Dolomite Group and Medina Group injection intervals will utilize a 7-inch long-string casing to accommodate a 3.5-inch OD tubing. TR2-4 has been designed to accommodate concentric casing sizes required to isolate the injection reservoir from the USDWs, in accordance with 47 CSR 13-13.3.1.a. Material for the casing was selected to be appropriate for the fluids and stresses expected to be encountered within the well 47 CSR 13-13.3.2.a.

The entire injection tubing string will be comprised of 3.5-inch 22Cr-110 or lined carbon steel tubing with gas tight premium connections. In the case of lined tubing, corrosion rings will be utilized in all connections. Similarly, the 7-inch OD long-string casing will be constructed of 22Cr-110 or higher alloy across both the injection zones of the well, as discussed in subsection 2.6.4 below. In brine wetted, non-CO_2 exposed portions of the wellbore, L80 will be utilized. Lithology of the storage reservoir's injection and confining zones is discussed in subsection 2.4 of the Application Narrative, and reservoir fluid characteristics are discussed in subsection 2.8 of the Application Narrative.

Casing stresses and loadings were modeled using Blade Energy Partners' StrinGnosis® software. To ensure sufficient structural strength and mechanical integrity throughout the life of the project, stresses were analyzed based on worst-case scenarios, and tubular specifications were selected accordingly. Minimum design factors and casing load scenarios are summarized below in Table 3, Table 4, Table 5, Table 6, and Table 7, in accordance with 47 CSR 13-13.3.2.a.2. The burst, collapse, and tensile loads were calculated according to the scenarios defined below and were dependent on fracture gradients, depths, and minimum safety factors. Casing test pressures were defined to satisfy 70% of API Maximum Internal Yield Pressure (MIYP). The casing and tubing materials proposed were selected to be compatible with the fluids encountered and the stresses induced throughout the sequestration project. If the recommended casing is not available for well construction, alternate tubulars will meet or exceed suitability criteria presented herein.

Table 3: Minimum Design Factors.

Load	Casing Design Criteria	Tubing Design Criteria	Connection Design Criteria
Triaxial	1.25	1.25	NA
Burst	1.25	1.25	1.25
Collapse	1.1	1.1	1.1
Tension	1.6	1.2	1.6
Compression	1.2	1.2	1.6

NA = Not Applicable

Table 4: Load scenarios evaluated for 20-inch Conductor Casing.

Load Case	Pressure Profile		Temperature Profile
	Internal	External	
Running In Hole	8.4 ppg	8.4 ppg	Static
As Cemented	8.4 ppg	Cement	Static

Table 5: Load scenarios evaluated for 13.375-inch Surface Casing.

Load Case	Pressure Profile		Temperature Profile
	Internal	External	
Running In Hole	8.4 ppg	8.4 ppg	Static
Overpull	8.4 ppg	8.4 ppg	Static
Bump Cement Plug	8.4 ppg + 500 psi	Cement	Static
As Cemented	8.4 ppg	Cement	Static
Pressure Test	8.4 ppg + 1,914 psi	Pore Pressure	Static
Full Evacuation	No Fluid	8.4 ppg	Static
Negative Pressure Test	8.33 ppg	8.4 ppg	Static
Drilling with Maximum Mud Weight	12.5 ppg	Pore Pressure	Static

Table 6: Load scenarios evaluated for 9.625-inch Intermediate Casing.

Load Case	Pressure Profile		Temperature Profile
	Internal	External	
Running In Hole	8.4 ppg	8.4 ppg	Static
Overpull	8.4 ppg	8.4 ppg	Static
Bump Cement Plug	8.4 ppg + 500 psi	Cement	Static
As Cemented	8.4 ppg	Cement	Static
Pressure Test	8.4 ppg + 2,464 psi	Pore Pressure	Static
Full Evacuation	No Fluid	8.4 ppg	Static
Negative Pressure Test	8.33 ppg	8.4 ppg	Static
Drilling with Maximum Mud Weight	12.5 ppg	Pore Pressure	Static

Table 7: Load scenarios evaluated for 7-inch Long-String Casing.

Load Case	Pressure Profile		Temperature Profile
	Internal	External	
Running In Hole	12.5 ppg	12.5 ppg	Static
Overpull	12.5 ppg	12.5 ppg	Static
Bump Cement Plug	12.5 ppg + 500 psi	Cement	Static
As Cemented	12.5 ppg	Cement	Static
Pressure Test	12.5 ppg + 3,242 psi	Pore Pressure	Static

Load Case	Pressure Profile		Temperature Profile
	Internal	External	
Half Evacuation	No Fluid + 12.5 ppg	12.5 ppg	Static
Negative Pressure Test	8.33 ppg	12.5 ppg	Static

2.6. Casing Summary

The injection well design for TR2-4 will include the following casing strings: a 20-inch diameter conductor casing string set at a depth of approximately 120 ft TVD inside a 26-inch borehole; a 13.375-inch diameter surface casing string set at a depth of approximately 736 ft TVD inside a 17.5-inch borehole; a 9.625-inch diameter intermediate casing string set at a depth of approximately 2,106 ft TVD inside a 12.25-inch borehole; a 7-inch diameter long casing string set at approximately 9,694 ft TVD inside a 8.5-inch borehole; and a 3.5-inch diameter injection tubing string set at approximately 9,098 ft TVD for injection into the LIC and MIC. The well as planned will be perforated in the Lockport Dolomite Group and the Medina Group injection intervals, as discussed in subsection 2.8.3 below.

All casing strings will be cemented to the surface. The drilled borehole diameters will allow clearance between the outside of the casing and the borehole wall. Proposed casing and tubing internal and drift diameters are compatible with standard testing devices and workover tools, in accordance with 47 CSR 13-13.3.1.b. While specific alloy compositions, weights, grades, and connections may change due to availability, construction of the wells will utilize corrosion resistant alloys such as 22Cr-110 for CO_2 + H_2O wetted sections and adhere to mechanical specifications consistent with design inputs presented herein. Final alloy selection at procurement will be based on the most current applicable materials testing results from API, AMPP, or other standard bodies focused on CCS or alternative project specific testing and modeling.

Due to the proximity of the injection well to existing and proposed oil and gas wells producing from the Marcellus and Utica Shale formations, Tri-State CCS, LLC will conduct deviation measurements during well construction and develop a well collision avoidance management plan before commencing drilling operations. The proposed surface location of the injection well may be adjusted to prevent accidental collisions with existing oil and gas wells during drilling.

The high salinity of the injection formation fluids indicates a possibility of precipitation of evaporite minerals in and near the well bore during CO_2 injection into the Lockport Dolomite Group and Medina Group injection intervals. This salt precipitation may reduce well injectivity and lead to pressure buildup by blocking pore space near the wellbore. Tri-State CCS, LLC proposes using a capillary string outside the tubing from surface to the top of injection interval for evaporite mitigation treatment. Specific capillary size, frequency of treatment, and fluid composition will be determined after gathering additional characterization data from the CarbonSAFE stratigraphic test wells planned in the region and conducting laboratory tests as discussed in subsection 5.2 of the Stimulation Program.

Table 8 summarizes the proposed casing program for TR2-4, in accordance with 47 CSR 13-13.3.2.a.3 and 13.3.3.c.6. Table 9 summarizes the properties of each casing material, in accordance with 47 CSR 13-13.3.2.a.4 and 13.3.3.c.7. Each section of the well is discussed in a separate section below.

Table 8: Summary of borehole and casing program for TR2-4.

Casing String	Casing Depth (TVD; ft)	Borehole Diameter (in.)	Casing Outside Diameter (in.)	Casing Material (Weight, grade, connection)	Coupling Outside Diameter (in.)
Conductor[1]	0 – 120	26.0	20.0	94 lb/ft, H40, STC	NA
Surface	0 – 736	17.5	13.375	54.5 lb/ft, J55, STC	14.375
Intermediate	0 – 2,106	12.25	9.625	36 lb/ft, J55, STC	10.625
Long-String	0 – 8,458	8.5	7.0	26 lb/ft, L80, Premium Connection	7.656
	8,458 – 9,694			26 lb/ft, 22Cr-110, Premium Connection	
Tubing	0 – 9,098	NA	3.5	9.2 lb/ft, 22Cr-110, Premium Connection	4.5

NA = Not Applicable
[1] Depending on wellsite conditions, conductor may be drilled and cemented or driven directly. Borehole diameter is provided in the event the conductor casing is drilled.

Table 9: Properties of well-casing materials for TR2-4.

Casing String	Casing Diameter (inches) Outside / Inside / Drift / Thickness	Burst Rating (psi)	Collapse Rating (psi)	Tension Rating (klbf)	Compression Rating (klbf)	Thermal Conductivity (BTU / hr-ft °F)
Conductor	20.0 / 19.124 / 18.936 / 0.438	1,530	520	1,077	1,077	26.2 @ 77°F
Surface	13.375 / 12.615 / 12.459 / 0.380	2,730	1,130	853	853	
Intermediate	9.625 / 8.921 / 8.765 / 0.352	3,520	2,020	564	564	
Long-String	7 / 6.276 / 6.151 / 0.362	7,240	5,410	604	604	
		10,240	6,230	830	664	8.4 @ 77°F
Tubing	3.5 / 2.992 2.867 / 0.254	14,370	13,530	285	228	

2.6.1. Conductor Casing

The conductor casing is 20-inch diameter 94 lb/ft H-40 pipe with short thread couplings (STCs). Conductor casing extends from surface to 120 ft TVD and provides a stable base required for drilling activities in unconsolidated sediment.

Depending on wellsite conditions, this can be drilled and installed or driven directly. If drilled and installed, this section of the casing will be cemented in place.

Figure 2 and Figure 3 show the conductor casing stress analysis for anticipated operating scenarios.

2.6.2. Surface Casing

The surface casing is 13.375-inch diameter 54.5 lb/ft J55 pipe with STC connections. Surface casing extends from surface to 736 ft TVD, approximately 50 ft below the base of the Pittsburgh coal seam (workable coal bed) at 686 ft, in accordance with West Virginia Code § 22-6-18(a). See Appendix A of this document for mine details.

If gas is found beneath the workable coal bed, a packer shall be placed below the coal bed, and above the gas horizon, and the gas by this means will be diverted to the inside of the adjacent string of casing through perforations made in such casing, and through it passed to the surface without contact with the coal bed. If gas is found between two workable beds of coal, in a hole, of the same diameter from bed to bed, two packers shall be placed, with perforations in the casing between them, permitting the gas to pass to the surface inside the adjacent casing. In either of the cases, the strings of casing shall extend from their seats to the top of the well in adherence to West Virginia Code § 22-6-18(b).

The well is planned to be drilled within a pillar left unmined for structural support. No voids are anticipated; however, if an unanticipated void, or an anticipated void at an unanticipated depth is encountered, Tri-State CCS, LLC will notify the inspector within 24 hours. Modifications to the casing program may be necessary to comply with West Virginia Code § 22-6-18. Under no circumstances will Tri-State CCS, LLC drill more than one hundred feet below the bottom of the void or install less than twenty feet of casing below the bottom of the void.

After installation, surface casing will be cemented in place and circulated from casing shoe to surface as described in subsection 2.8 below. This will isolate all the USDWs and workable coal beds through which the string extends. Following the cementing, a bond log will be run to ensure a sufficient seal to prevent the migration of fluid into USDWs and coal beds. Before drilling out the casing shoe, surface casing will be hydrostatically tested to verify casing integrity. Test pressure will never exceed the rated burst or collapse pressure as summarized in Table 9.

Figure 4 shows the surface casing stress analysis for anticipated operating scenarios.

2.6.3. Intermediate Casing

The intermediate casing is 9.625-inch diameter 36-lb/ft J55 pipe with STCs. Intermediate casing extends from surface to 2,106 ft TVD, approximately 250 ft below the Big Injun Sandstone, to isolate the shallow oil and gas production unit. After installation, intermediate casing will be cemented in place and circulated from casing shoe to surface as described in subsection 2.8.

Following the cement setting, a bond log will be run to ensure a sufficient seal to prevent the migration of fluid into shallow oil and gas reservoirs. Before drilling out the casing shoe, intermediate casing will be hydrostatically tested to verify casing integrity. Test pressure will never exceed the rated burst or collapse pressure as summarized in Table 9.

Figure 5 shows the intermediate casing stress analysis for anticipated operating scenarios.

2.6.4. Long-String Casing

The long-string casing is 7-inch diameter pipe composed of two sections. The first, section from surface to 8,458 ft TVD will be L80, and the second section from 8,458 ft TVD to 9,694 ft TVD, through the injection zone, will be 22Cr-110 or higher alloy, both with gas tight premium connections (47 CSR 13-13.3.2.c). The transition will be targeted at approximately 8,458 ft TVD or 150 ft above the top of the Lockport Dolomite Group, within the Salina Group confining zone.

After installation, casing will be cemented in place and circulated from casing shoe to surface as described in subsection 2.8 below. A DTS fiber optic cable will be run outside the casing from surface to casing shoe and cemented in place with the casing. Following the cement setting, a bond log will be run, and casing will be hydrostatically tested to verify casing integrity. Test pressure will never exceed the rated burst or collapse pressure as summarized in Table 9.

Figure 6 and Figure 7 show the casing stress analysis for anticipated operating scenarios.

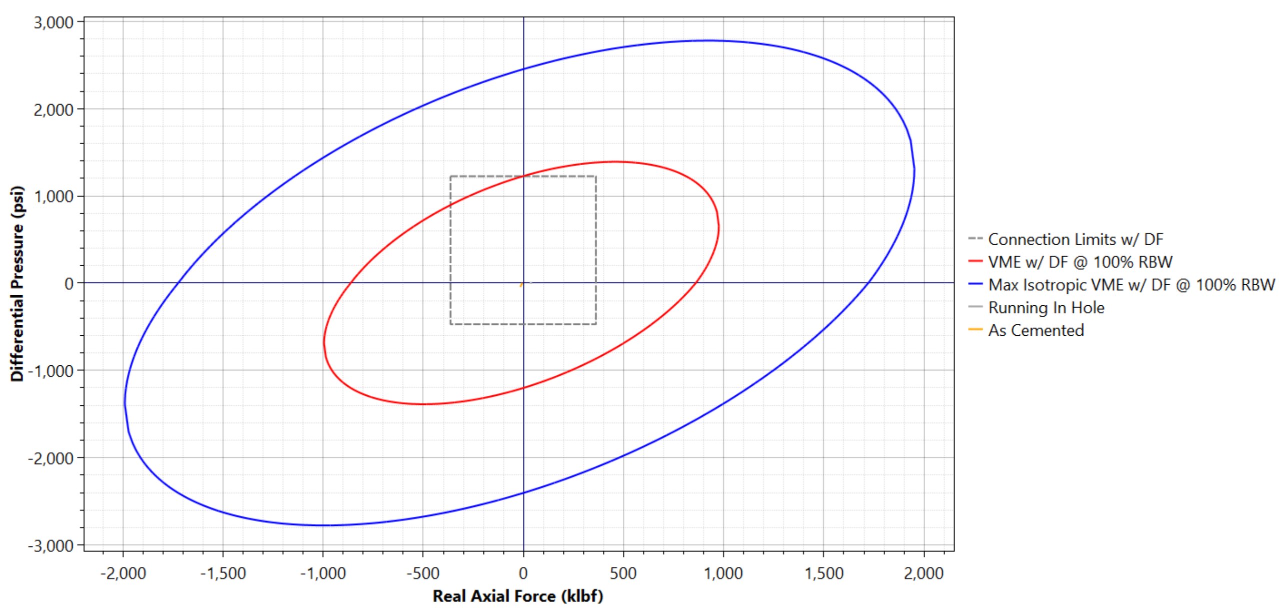

Figure 2: 20-inch conductor casing (H40) axial force design envelope. Results appear small due to the short length of the conductor casing, see Figure 3 for inset.

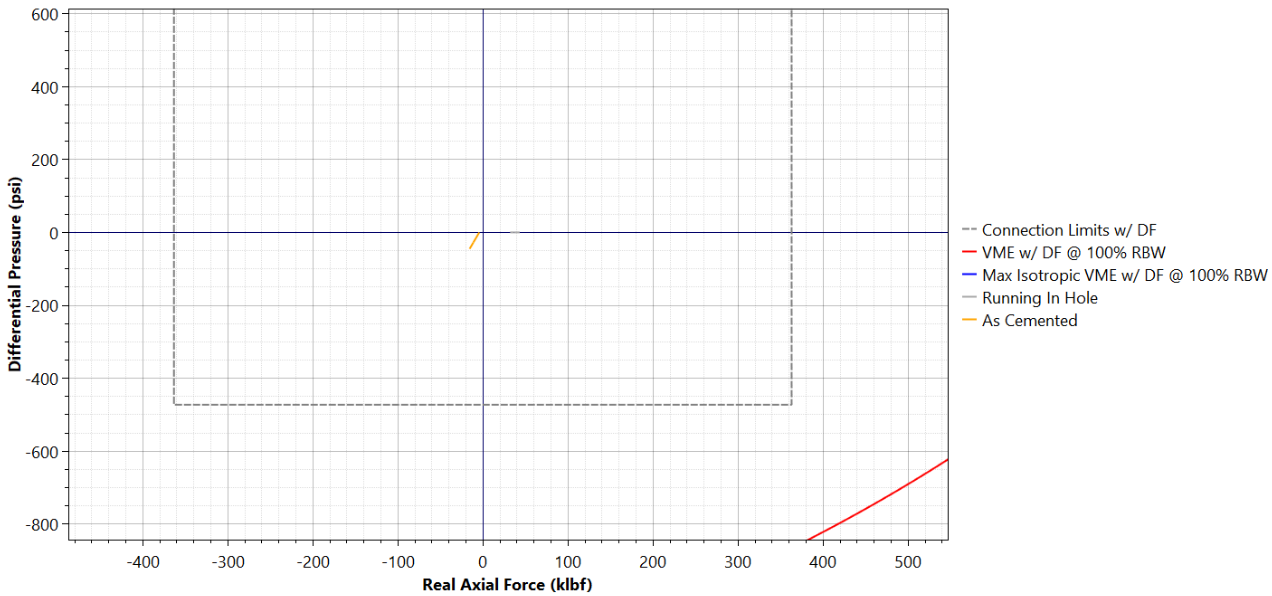

Figure 3: Inset from Figure 2 of 20-inch conductor casing (H40) axial force design envelope.

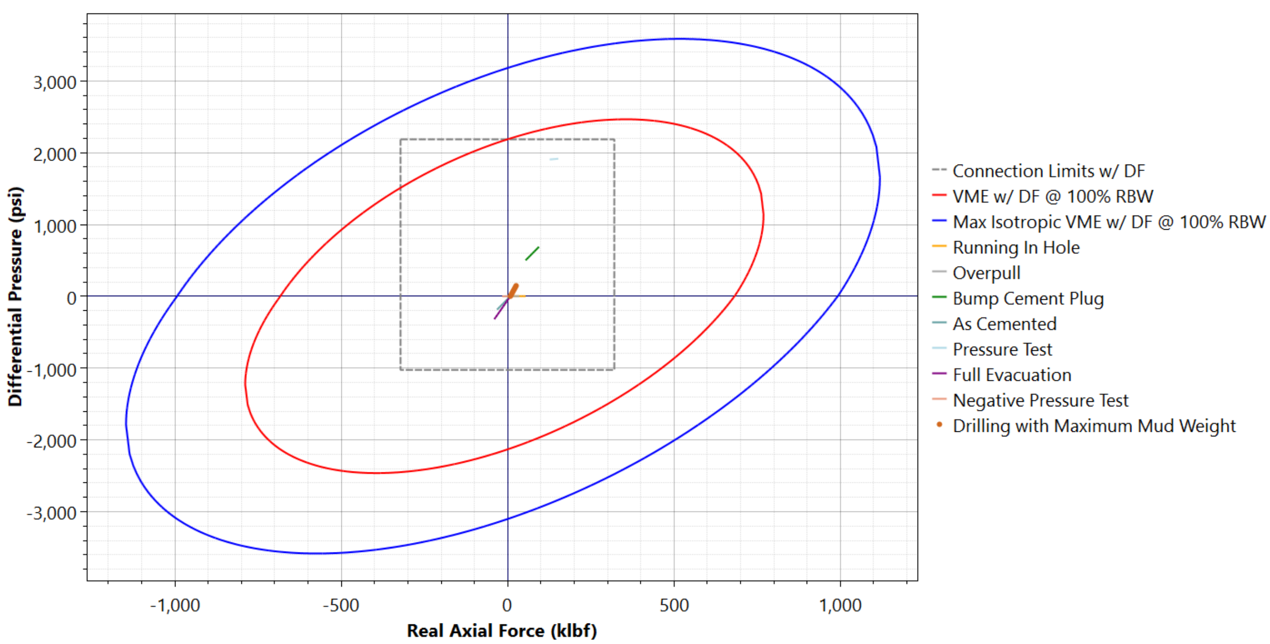

Figure 4: 13.375-inch surface casing (J55) axial force design envelope.

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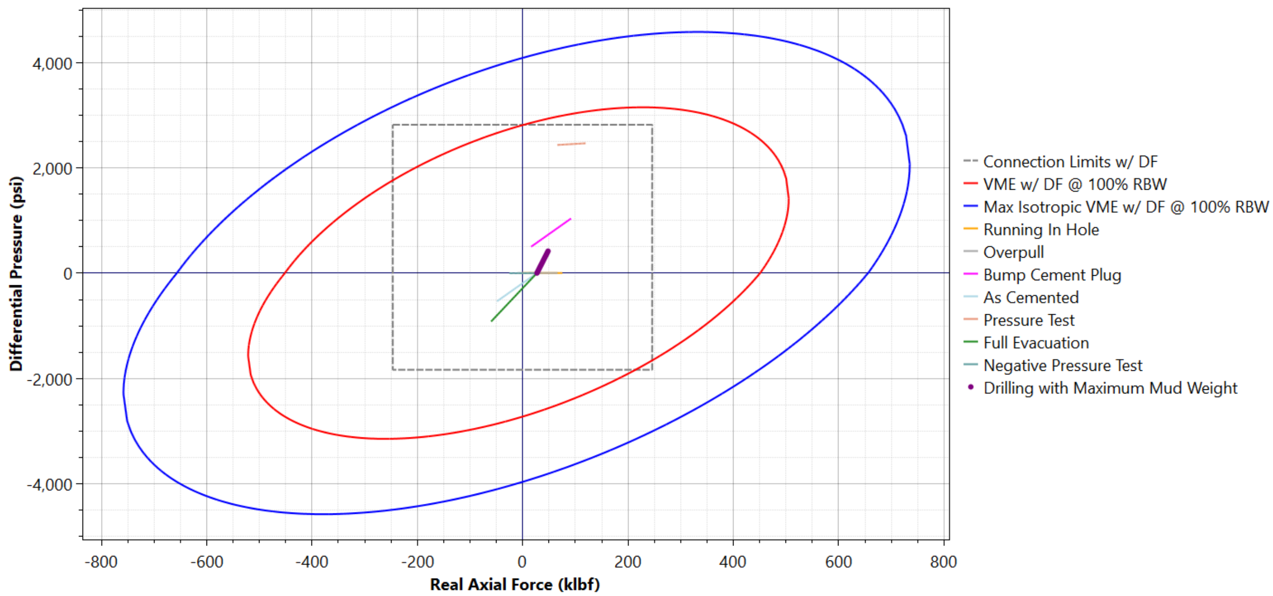

Figure 5: 9.625-inch intermediate casing (J55) axial force design envelope.

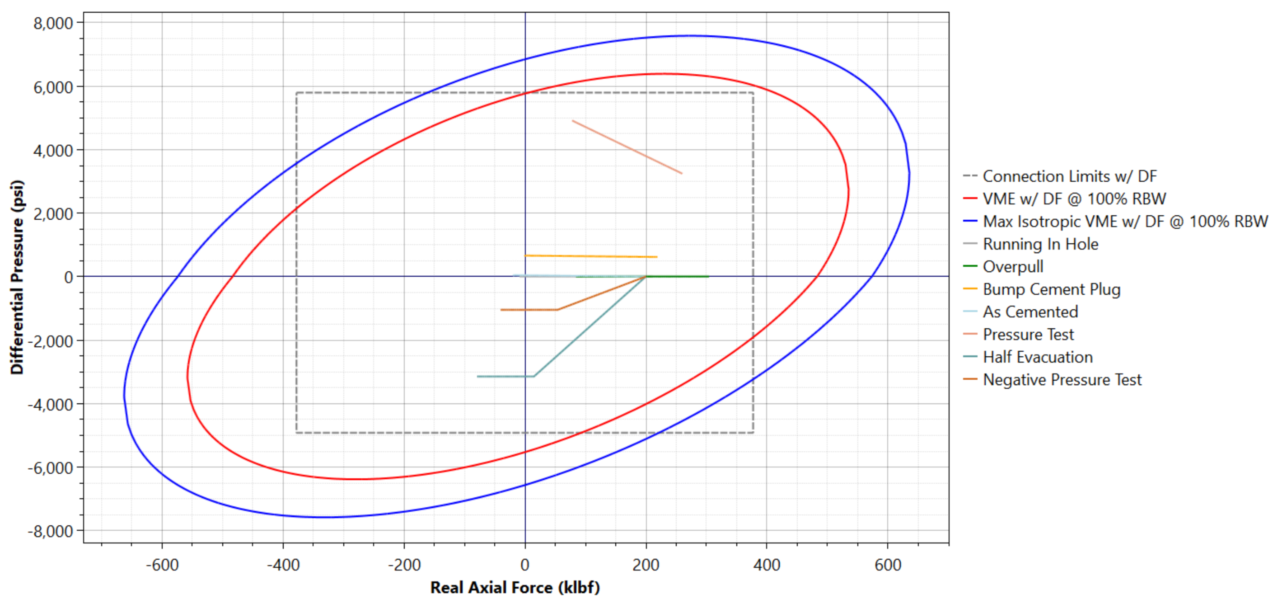

Figure 6:7-inch long-string casing (L80) axial force design envelope from surface to 8,458 ft TVD.

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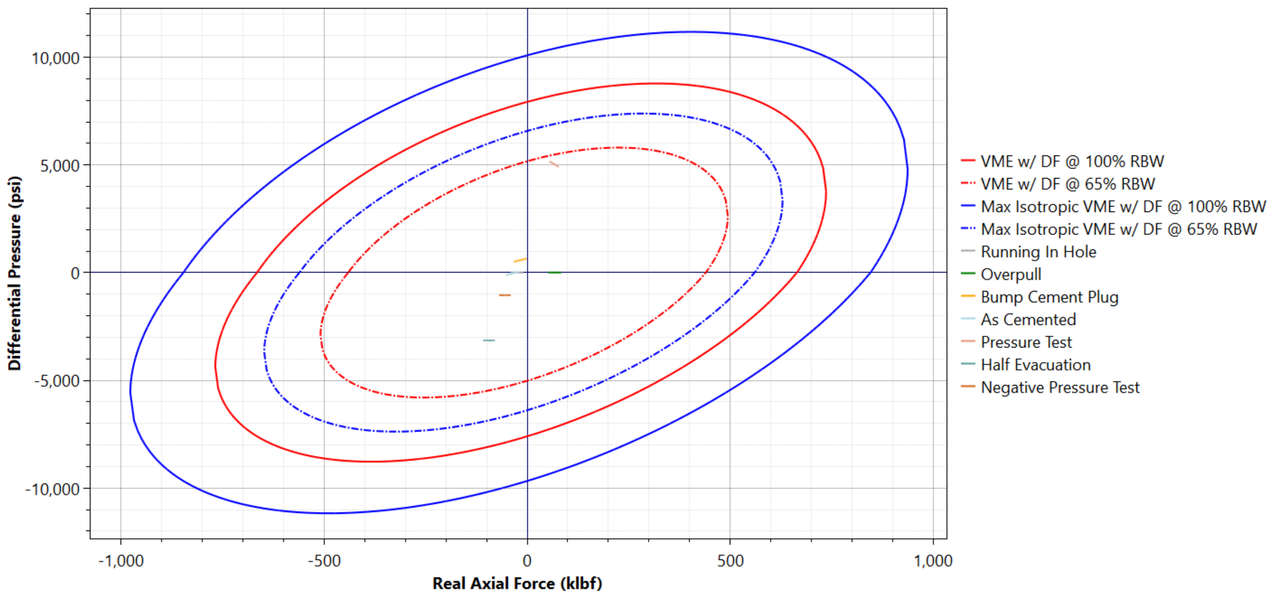

Figure 7: 7-inch long-string casing (22Cr-110) axial force design envelope with 100% and 65% remaining body wall from 8,458 ft to 9,694 ft TVD.

2.6.5. Tubing

The tubing connects the Lockport Dolomite Group and Medina Group injection intervals to the wellhead and provides a pathway for storing CO_2 into the injection zones. This design utilizes 3.5-inch 9.2 lb/ft 22Cr-110 tubing to approximately 9,098 ft TVD. At a depth of approximately 8,625 ft TVD, the first retrievable packer will be set to isolate the LIC injection zone from the tubing-casing annulus. A second retrievable packer will be set at approximately 9,057 ft TVD to isolate the LIC injection zone from the MIC injection zone.

A sliding sleeve will be utilized at the top injection zone at 8,690 ft TVD to open or close the zone to accommodate fluctuations in injection rates due to CO_2 availability. At the end of the tubing string, a no-go profile nipple and wireline entry guide will be installed. This will allow flow control equipment to be installed for flow regulation or pressure isolation.

Downhole gauges will include high resolution tubing and annulus pressure gauge. Considering the anticipated formation pressure, temperature, and stress, the grade of tubing was selected to preserve the integrity of the injected fluid, the injection intervals, and USDWs. Modeled load scenarios for the LIC and MIC are summarized in Table 10. Figure 8 shows the casing stress analysis for anticipated operating scenarios. The tubing may be replaced as necessary during the planned injection period. The annulus between the tubing and long-string casing will be filled with non-corrosive fluid in accordance with 47 CSR 13-13.6.1.b.1.

Potential CO_2 sources and specifications are discussed in subsection 2.2 of the Summary of Requirements – Class VI Operating and Reporting Conditions. The injection tubing string in the well will use corrosion resistant duplex alloy (i.e., 22Cr-110 with premium connections or higher alloy for CO_2 + H_2O wetted sections) or an appropriately lined (i.e., glass reinforced epoxy) carbon steel string. Alloy selection at procurement will be finalized based on the most current applicable materials testing results from American Petroleum Institute (API), Association for Materials

Protection and Performance (AMPP), or other standard bodies currently focused on carbon capture and sequestration (CCS). Tri-State CCS, LLC may also elect to conduct materials testing and corrosion modeling to validate construction materials once data on formation fluids is collected from the CarbonSAFE stratigraphic test wells.

Table 10: Load scenarios evaluated for 3.5-inch tubing for injection into the LIC & MIC.

Load Case	Pressure Profile		Temperature Profile
	Internal	External	
Running in Hole	9.0 ppg	9.0 ppg	Static
As Run (Installed Load)	9.0 ppg	9.0 ppg	Static
Tubing Pressure Test	9.0 ppg + 2,383 psi	9.0 ppg	Static
Annular Pressure Test	9.0 ppg	9.0 ppg + 2,483 psi	Static
Full Evacuation	Tubing Evacuated	9.0 ppg	Wellbore Temperature at Maximum Wellhead Pressure and Injection Rate
Maximum CO_2 Injection	7.60 ppg + 2,545 psi	9.0 ppg + 2,645 psi	Wellbore Temperature at Maximum Wellhead Pressure and Injection Rate
Tubing Shut In	SITP	9.0 ppg	Wellbore Temperature at Maximum Wellhead Pressure and Injection Rate
Shut In Tubing Leak	7.60 ppg	9.0 ppg + SITP	Wellbore Temperature at Maximum Wellhead Pressure and Injection Rate

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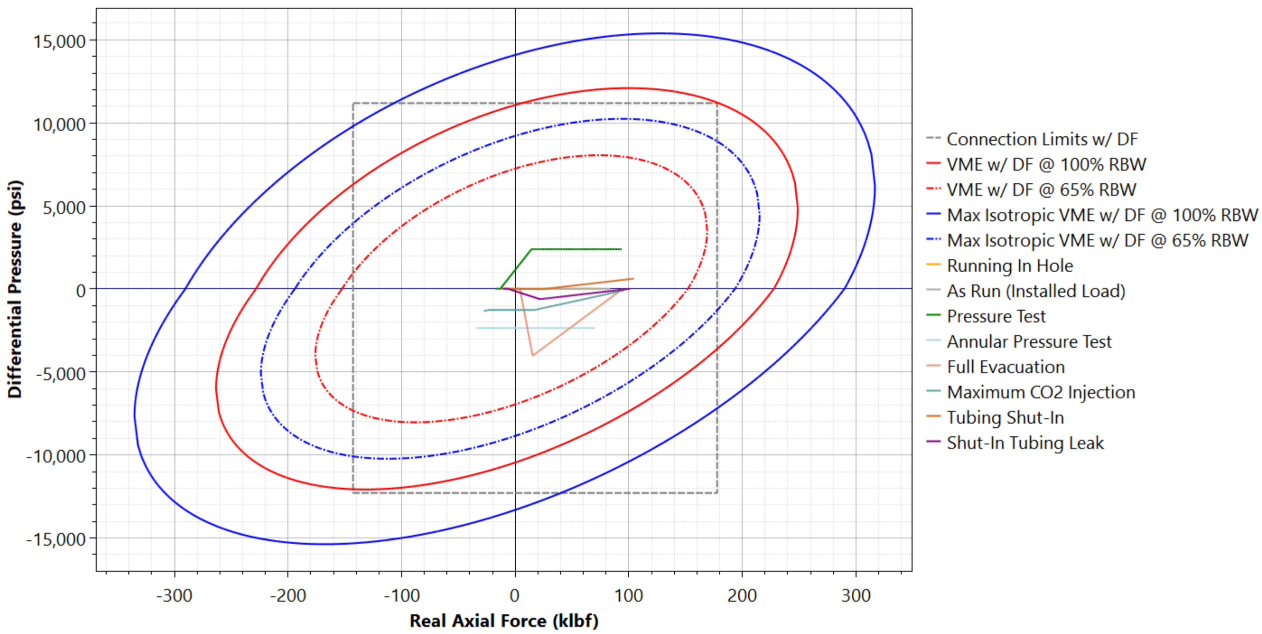

Figure 8: 3.5-inch tubing (22Cr-110) axial force design envelope with 100% and 65% remaining body wall.

2.7. Packer Details

TR2-4 is anticipated to utilize retrievable cased-hole packers during CO_2 injection into both the Lockport Dolomite Group and Medina Group injection intervals to isolate the tubing annulus and the injection zones. The cased-hole tubing packer will be a Baker Hughes Premier Packer or equivalent. Refer to Table 11 for proposed packer specifications and setting depth, as required by 47 CSR 13-13.3.3.c.1. The final packer design and vendor selection will be made after gathering additional characterization data from the CarbonSAFE stratigraphic test wells planned in the region to meet or exceed compatibility standards for the operating environment as required by 47 CSR 13-13.3.3.a.

Table 11: Cased-Hole Packer specifications for TR2-4.

Packer Type and Material	Setting Depth (TVD; ft)	Length (ft)	Nominal Casing Weight (lb/ft)	Packer Main Body OD (in.)	Packer ID (in.)	Tensile Rasing (klbf)	Burst Rating (psi)
Baker Hughes Premier Packer 22Cr-110 or Higher Alloy	LIC: 8,625 MIC: 9,057	6.91	26	5.983	2.875	150	7,500

Collapse Rating (psi)	Maximum Casing ID (in.)	Minimum Casing ID (in.)
7,500	6.396	6.184

2.8. Cementing Program

The conductor, surface, intermediate, and long-string casings will be cemented to the surface in accordance with requirements at 47 CSR 13-13.3.2.b. and c. The proposed cement types and quantities for each casing string are summarized in Table 12, as required by 47 CSR 13-13.3.2.a.8. Casing centralizers will be used to provide standoff from the borehole and allow cement placement outside the full outer diameter of the casing along the entire length of pipe. Logging and fluid data collected from the CarbonSAFE stratigraphic test wells will be incorporated into the cementing model to optimize centralizer placement. Except for the conductor casing, a guide or float shoe will be run on the bottom of the casing string, and a float collar will be run a minimum of one joint above the shoe. In accordance with 47 CSR 13-13.3.2.d., a stage tool will be utilized if needed for multistage cementing operations and will be either nickel plated or of compatible metallurgy with casing.

The 7-inch long-string casing will be cemented using CO_2 resistant tail cement approximately 250 ft into the Salina Group confining zone. As discussed in subsection 2.4, cement and cement additives will be compatible with CO_2 stream and formation fluids, and of sufficient quality and quantity to maintain integrity over the design life of the project, in accordance with 47 CSR 13-13.3.2.e. Following the cement setting, a bond log will be run and analyzed for all cemented casing strings to protect USDWs from fluid migration outside the wellbore. This will also ensure packer setting depth is opposite a cemented interval at a location approved by the UIC Director as required by 47 CSR 13-13.3.3.b.

The actual job design including cement volume, displacement rates, additives and technique (i.e., single vs two-stage) will be refined using data from drilling operations (i.e., caliper logs, fracture logs, mud losses, etc.). The base slurry and additives listed are preliminary and may be adjusted to ensure effective zonal isolation and compatibility with formation conditions. Additives are used to modify properties such as thickening time, density, and fluid loss, and may be refined based on actual well conditions. A spacer will be pumped ahead of all cement jobs to assist in mud removal.

Table 12: Cementing program for TR2-4.

Casing String	Casing Depth (TVD; ft)	Borehole Diameter (in.)	Casing O.D. (in.)	Cement Interval (TVD; ft)	Cement
Conductor [1]	0 – 120	26	20	0 – 120 (cemented to surface)	Type: Class A with 2% Calcium Chloride Weight: 15.6 lb/gal Yield: 1.18 ft^3/sack Quantity: 197 sacks
Surface	0 – 736	17.5	13.375	0 – 736 (cemented to surface)	Type: Class A with 1% Calcium Chloride Weight: 15.6 lb/gal Yield: 1.18 ft^3/sack Quantity: 589 sacks

Casing String	Casing Depth (TVD; ft)	Borehole Diameter (in.)	Casing O.D. (in.)	Cement Interval (TVD; ft)	Cement
Intermediate	0 – 2,106	12.25	9.625	0 – 2,106 (cemented to surface)	Type: Class A 50:50 Poz with 2% Bentonite Weight: 13.3 lb/gal Yield: 1.48 ft^3/sack Quantity: 592 sacks
Long-String	0 – 9,694	8.5	7.0	0 – 8,358 8,358 – 9,694 (cemented to surface)	Lead – Type: Class G 50:50 Poz with 8% Bentonite Weight: 12.4 lb/gal Yield: 1.91 ft^3/sack Quantity: 721 sacks Tail – Type: CO_2 resistant (EverCRETE™ or similar) Weight: 14.8 lb/gal Yield: 1.12 ft^3/sack Quantity: 205 sacks

[1] Depending on wellsite conditions, conductor may be drilled and cemented or driven directly. Information is provided in the event the conductor is drilled and cemented.

2.8.1. Annular Fluid

The annular space above the packer between the 7-inch long-string casing and the 3.5-inch injection tubing will be filled with fluid to provide a positive pressure differential to stabilize the injection tubing and inhibit corrosion. Annular fluid pressure at the surface will be continuously monitored and adjusted to maintain a 100-psi positive pressure differential in excess of tubing pressure, consistent with 47 CSR 13-13.3.1.c (see subsection 4.3 of the Testing and Monitoring Plan for a full description of the injection well annulus monitoring system).

The annular fluid will be non-corrosive fluid with additives potentially including corrosion inhibitor, biocide (to prevent growth of harmful bacteria), and an oxygen scavenger. The fluid will also be filtered so solids do not interfere with the packer or other components of the annular pressure management system. The final fluid composition will be based on anticipated injection pressures derived from data gathered during drilling and pressure transient testing of injection wells, CarbonSAFE stratigraphic wells, or other nearby observation wells.

2.8.2. Wellhead

The wellhead will consist of the following components, from top to bottom:

- 3.125-inch, 5000 psi Tree Cap
- 3.125-inch, 5000 psi Gate Valve (Crown Valve)
- 3.125-inch, 5000 psi Flow Cross
- 3.125-inch, 5000 psi Gate Valve x 2 (Wing Valves)

- 3.125-inch, 5000 psi Actuated Gate Valve (Wing Valve) (Automatic Shutoff Valve)
- 3.125-inch, 5000 psi Actuated Gate Valve (Automatic Shutoff Valve)
- 3.125-inch, 5000 psi Gate Valve (Master Valve)
- 7.0-inch x 3.5-inch, 5000 psi Tubing Hanger
- 2.0625-inch, 5000 psi Gate Valve x 2 (Wing Valves)
- 9.625-inch x 7-inch, 5000 psi Long-String Casing Hanger
- 2.0625-inch, 5000 psi Gate Valve (Wing Valve)
- 13.375-inch x 9.625-inch, 5000 psi Intermediate Casing Hanger
- 20-inch x 13.375-inch, 3000 psi Surface Casing Hanger

The wellhead and Christmas tree will be composed of materials that are designed to be compatible with the injection fluid. A preliminary material specification for wellhead and Christmas tree assembly is described in Table 13 using material classes as defined in API Specification 6A (Specification for Wellhead and Christmas Tree Equipment). The final wellhead and Christmas tree material specification may vary slightly from the information given and will meet or exceed what is outlined below.

The proposed wellhead schematic is presented in Figure 9. The flow line leading to the wellhead and Christmas tree will be equipped with an automatic surface shutoff valve as required in 47 CSR 13-13.6.1.d. Each annulus will have a pressure monitoring system installed on the wellhead. Continuous recording of operational parameters is discussed in Section 4 of the Testing and Monitoring Plan. The final wellhead design will have the required number of ports for fiber optic and Tubing Encapsulated Cables (TEC) lines and is subject to change based on additional data collected from the CarbonSAFE stratigraphic wells.

Table 13: Material specification of wellhead and Christmas tree for TR2-4.

<table>
<tr><th colspan="2">Component</th><th>Material Class</th></tr>
<tr><td colspan="2">Casing Head Housing</td><td>DD</td></tr>
<tr><td colspan="2">Casing Spool Assembly</td><td>FF</td></tr>
<tr><td colspan="2">Tubing Hanger</td><td>FF</td></tr>
<tr><td colspan="2">Tubing Spool Assembly</td><td>FF</td></tr>
<tr><td rowspan="4">Christmas Tree</td><td>Tree Cap</td><td>FF</td></tr>
<tr><td>Manual Gate Valves</td><td>FF, DD</td></tr>
<tr><td>Flow Cross</td><td>FF</td></tr>
<tr><td>Actuated Gate Valve</td><td>FF</td></tr>
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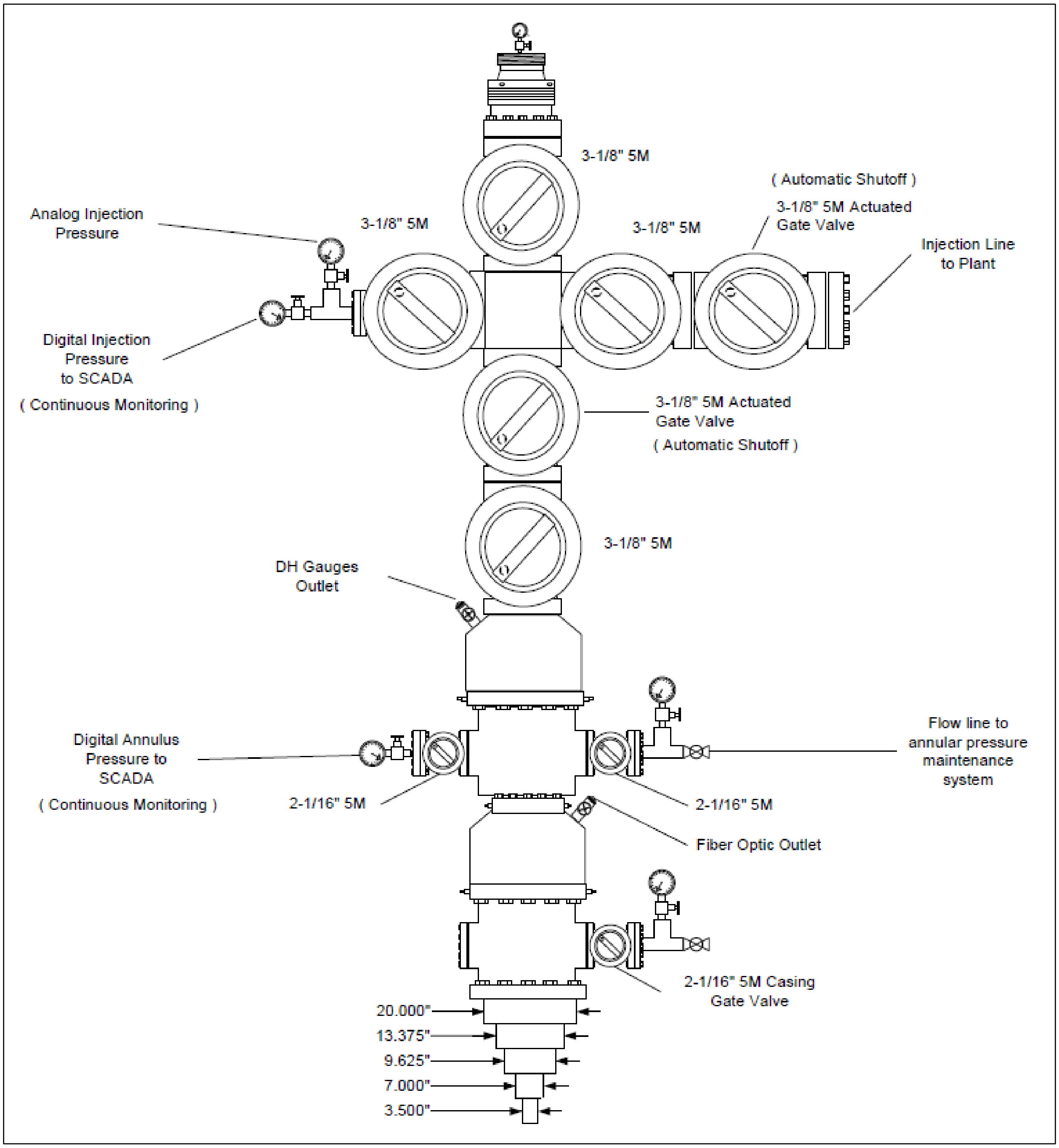

Figure 9: Proposed wellhead and Christmas tree schematic for TR2-4.

2.8.3. Perforations

The long-string casing will be perforated across the Lockport Dolomite Group injection interval and the Medina Group injection interval with deep-penetrating shaped charges from 8,690 ft to 8,997 ft TVD and from 9,411 ft TVD to 9,593 ft TVD respectively. Due to the installation of fiber optics, oriented perforations will be used to avoid damaging the fiber optic cable.

The exact injection intervals will be determined after the well is drilled and characterized with geophysical logging, core analyses, and hydrogeologic testing. The proposed injection interval depths for TR2-4 are found below in Table 14, subject to change based on data collected from the CarbonSAFE stratigraphic test wells planned in the region, Pre-Operational Testing Program associated with these wells, and injection well characterization data.

Table 14: Planned perforated injection intervals for TR2-4.

Perforated Intervals	Top (TVD; ft)	Bottom (TVD; ft)	Mid-Point (TVD; ft)
Lockport Dolomite Group	8,690	8,997	8,843
Medina Group	9,411	9,593	9,502

2.9. Injection Well Construction Diagrams

The proposed well schematics are shown in Figure 10 and Figure 11.

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TR2-4 Proposed Well Schematic

Well Name	Prepared By	Prepared Date	Completion Fluid	Final TVD (ft)
TR2-4	Eliana Botero	3/28/2025	Brine	9694
Coordinates (WSG 84)	**Wellhead**		**RKB (ft)**	
39.956423, -80.635316	TBD		TBD	
County	**State**		**GL (ft)**	
Marshall County	West Virginia		TBD	

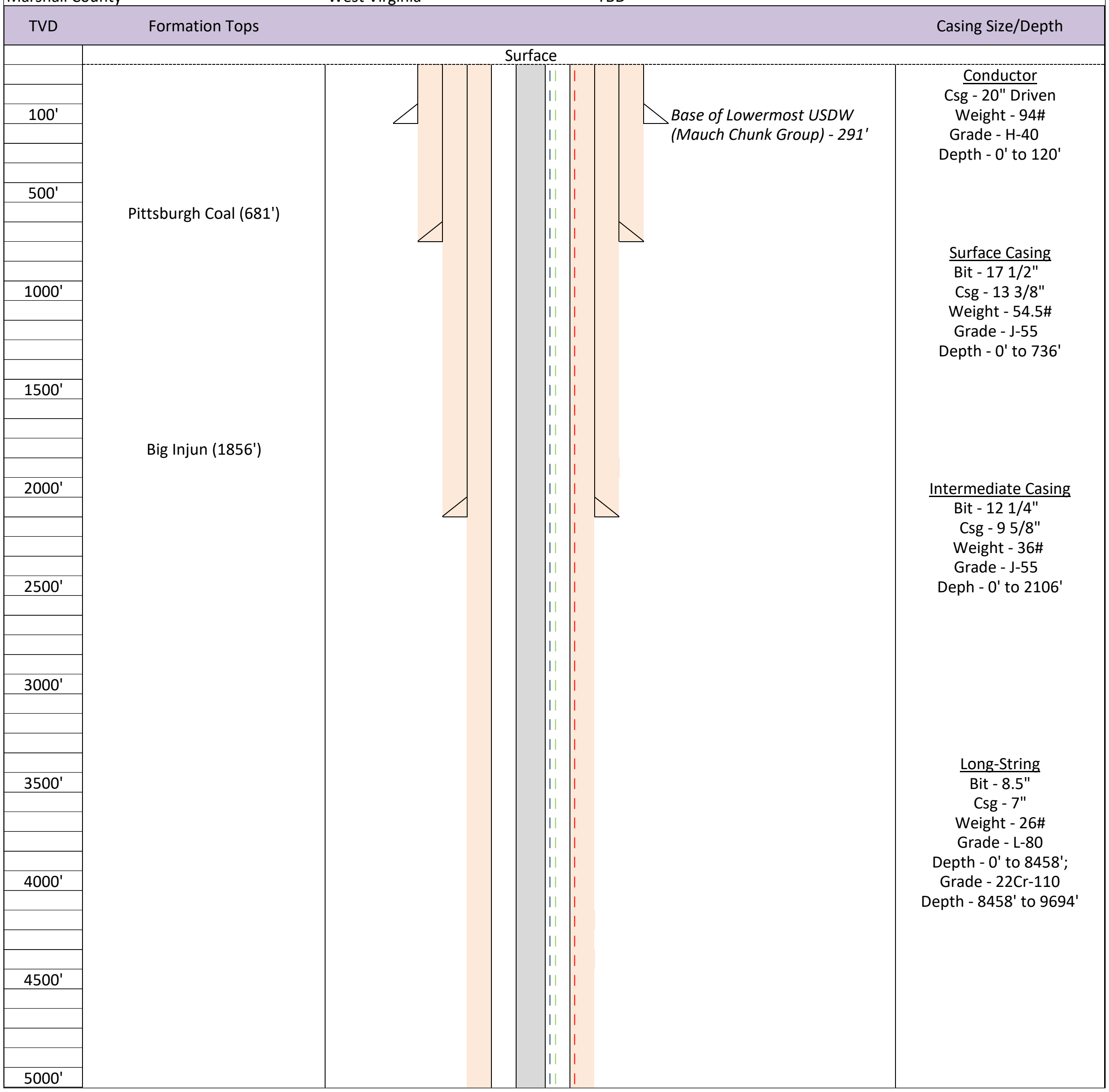

Figure 10: Proposed well schematic for TR2-4. Well schematic split in two for illustration purposes, 1/2: Surface to 5,000 ft TVD.

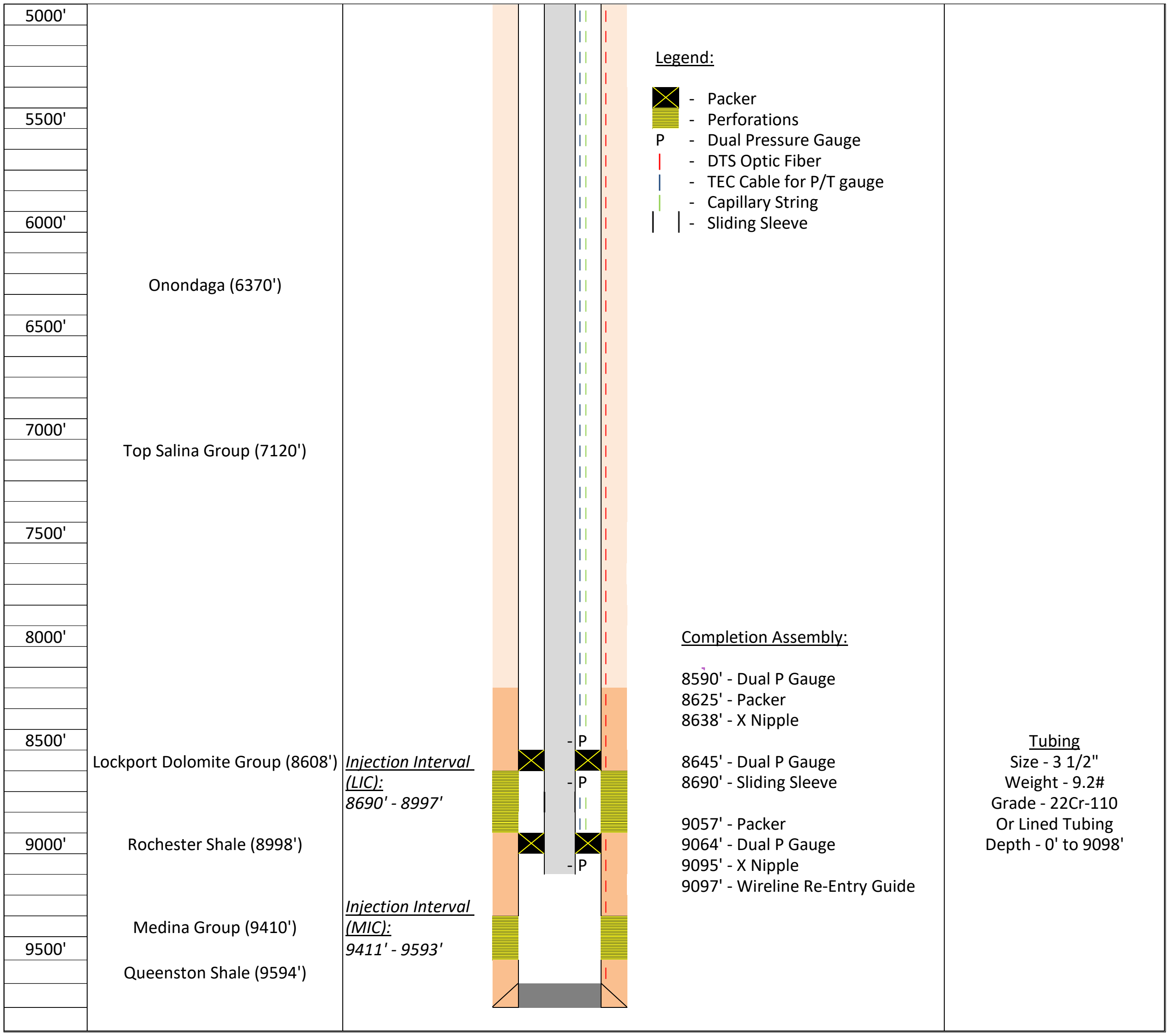

Figure 11: Proposed well schematic for TR2-4. Well schematic split in two for illustration purposes, 2/2: 5,000 ft to 9,694 ft TVD.

Note: All depths are preliminary and will be adjusted based on additional characterization data obtained from stratigraphic test wells planned in the region, Pre-Operational Testing Program associated with the injection wells, and injection well characterization. At minimum, the surface casing, intermediate casing, and long-string casing will be cemented to surface.

3. References

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Appendix A: Detailed Information on Ohio County Mine, Marshall County, W. Va.

TR2-4 is located above the geographic limits of the Ohio County Mine, formerly known as the Shoemaker Mine (state permit #D-4791, federal permit/mine ID #4601436), an active underground coal mine that is currently being used to extract coal from the Pittsburgh Coal seam using longwall and continuous mining method. WVDEP recently renewed this permit on September 17, 2020. Figure A - 1 illustrates the mine boundaries for Ohio County Mine and the adjacent Valley Camp No. 3 and Bailey Mine, along with oil and gas wells drilled within the Ohio County Mine boundary. Figure A - 2 overlays the mine map of the Ohio County Mine (Mine Map 913270, 2021) with the mine boundary and proposed injection well locations.

Tri-State CCS, LLC proposes installing a surface casing to a depth of 736 ft TVD, approximately 50 ft below the base of the workable coal bed i.e., the Pittsburgh Coal at approximately 686 ft, as identified using the West Virgina Mine Information Database System, (Mine Maps 913270, 2021 and 908474, 2016); Pittsburgh Coal, Monongahela Group, 2025. However, the final surface casing depth will depend on where the actual Pittsburgh coal seam is encountered during drilling.

At this time, no voids are anticipated, and the well will be drilled within a pillar left unmined for structural support, if drilling within the mined area. The proposed surface location was identified using Mine Maps 913270, 2021 and 908474, 2016 and may be adjusted to ensure drilling within a pillar and to avoid encountering any underground mine voids. TR2-4 is positioned on a pillar, as shown in Figure A - 3. Tri-State CCS, LLC will work with WVDEP and Ohio County Mine operator to finalize the drilling location in accordance with West Virginia Code § 22-6-17, and during field operations, to determine the final depth of the surface casing in adherence to West Virginia Code § 22-6-18 and -20.

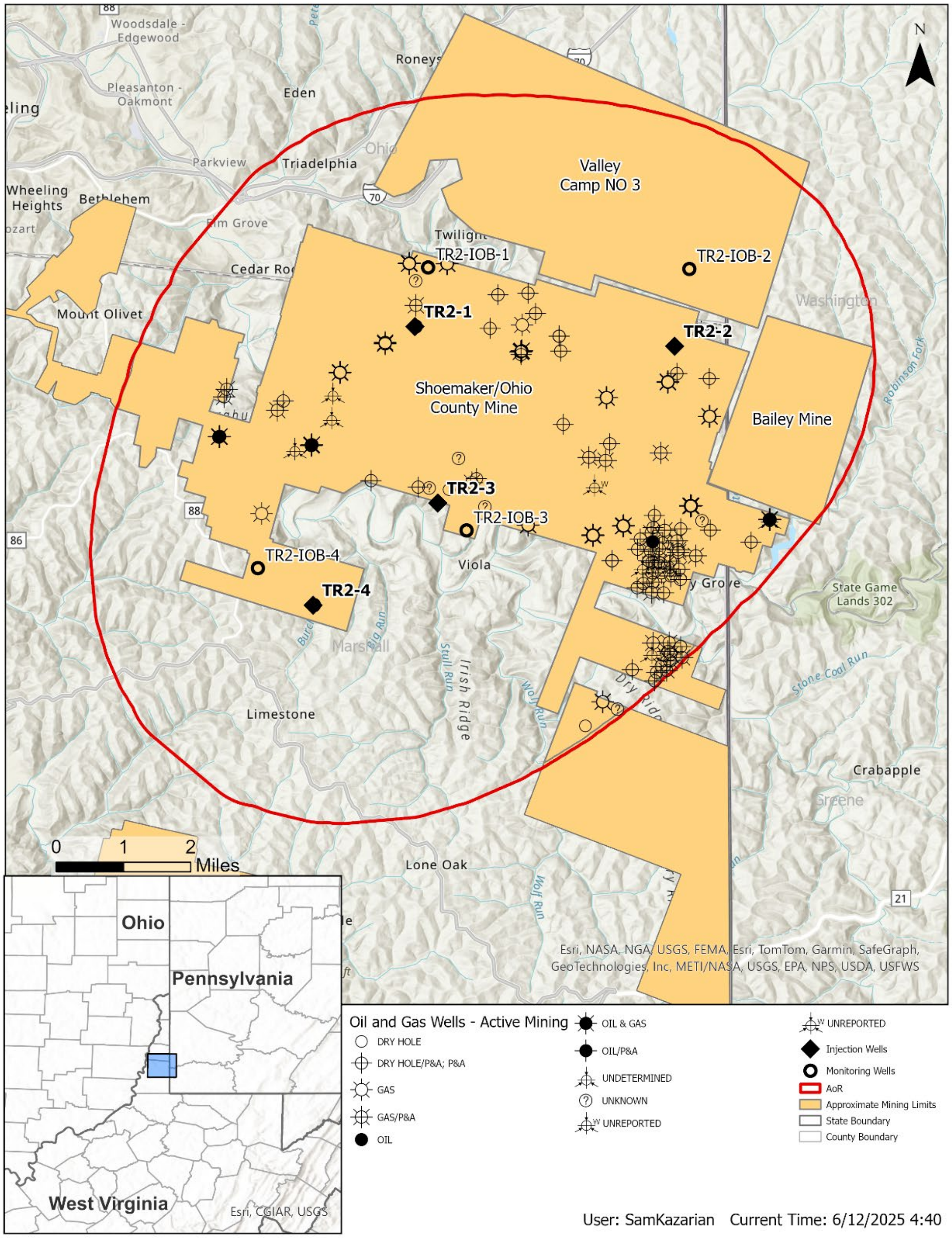

Figure A - 1: Proposed location of the TR2-4 injection well, showing the Ohio County Mine and adjacent mines boundary along with offset wells drilled through the currently active mine.

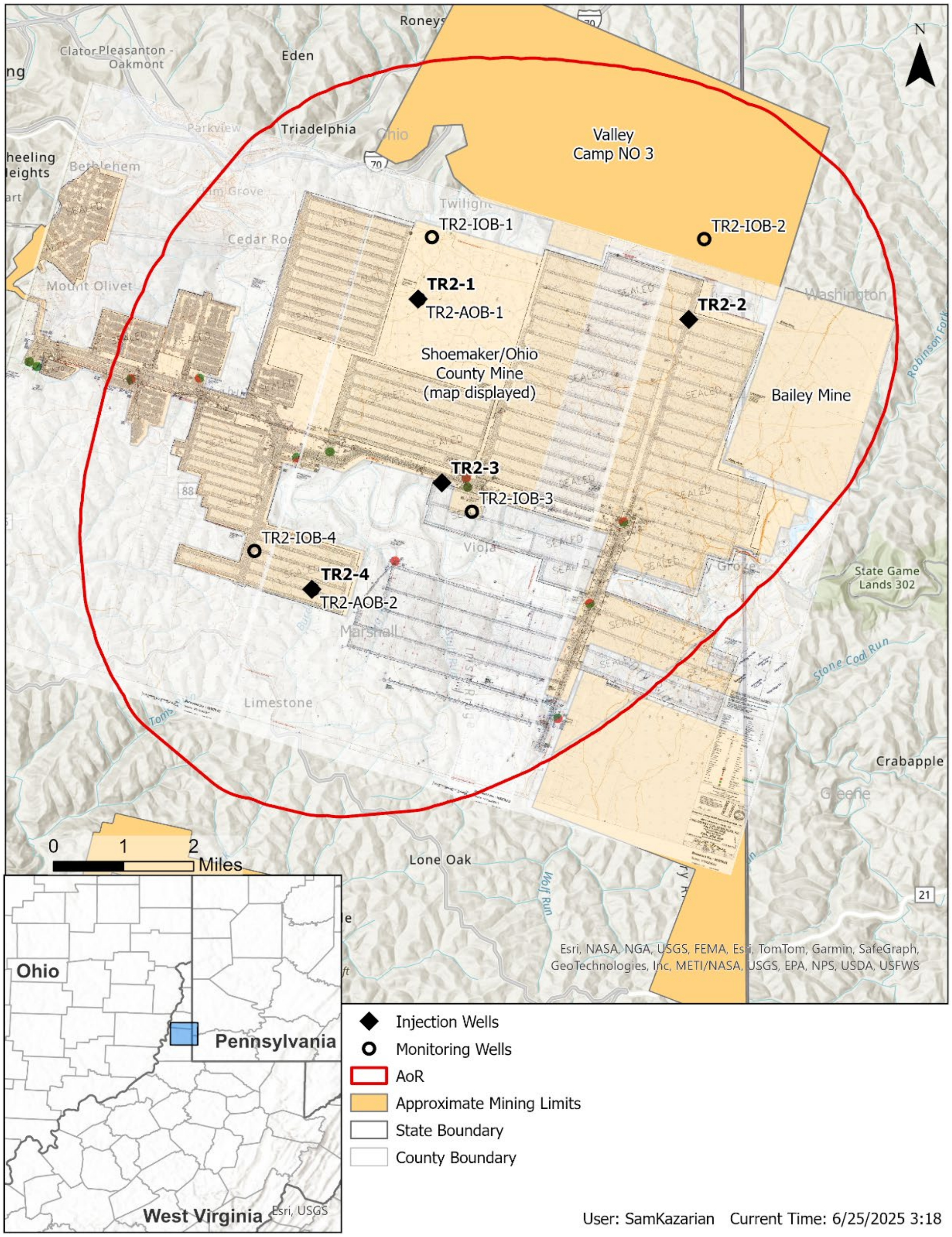

Figure A - 2: Proposed location of the TR2-4 injection well with map overlay of the Ohio County Mine (Mine Map 913270, 2021).

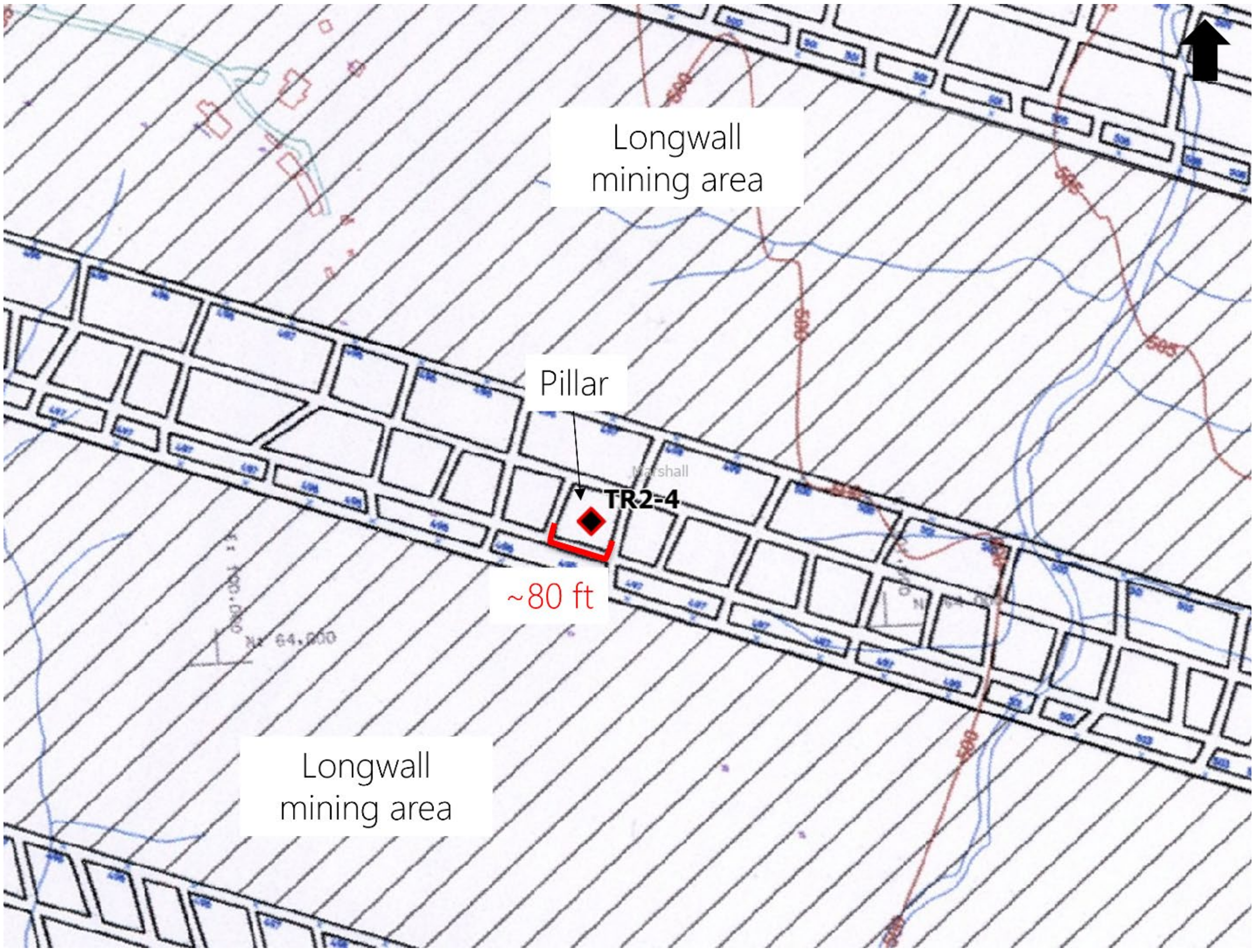

Figure A - 3: Proposed location of the TR2-4 injection well and targeted pillar within a zoomed in section of the Ohio County Mine Map (Mine Map 908474, 2016).