CONSTRUCTION DETAILS
40 CFR 146.86

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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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
BIC	Basal Sandstone Injection Complex
CCS	Carbon Capture and Storage
CFR	Code of Federal Regulations
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
KLBF	Kilo Pound-Force
L80	L80 Grade Steel
lb	Pound
MASP	Maximum Allowable Surface Pressure
mg/L	Milligrams Per Liter
Mg^{2+}	Magnesium
MIYP	Maximum Internal Yield Pressure
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
Na^+	Sodium
NA	Not Applicable
O_2	Oxygen
OD	Outer Diameter
ODNR	Ohio Department of Natural Resources
ORC	Ohio Revised Code
PBTD	Plug Back Total Depth
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

1. Introduction

This plan describes the construction details for the Bellflower 1 injection well and the well schematics and cementing program for the observation wells (B3-IOB-1, B3-AOB-1, B3-UOB-1) at Buckeye III CCS in Coshocton County, Ohio (the "project").

2. Construction Details for Bellflower 1

Bellflower 1 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 Underground Injection Control (UIC) well standards at 40 CFR 146.86(a) regarding the design of the casing, cement, and wellhead. Additionally, Tri-State CCS, LLC is working with the Ohio Department of Natural Resources (ODNR) to determine what state requirements will apply to constructing Bellflower 1.

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. Injection is planned into the Basal Sandstone Injection Complex (BIC). For the BIC, nodal analysis was performed with a long- string of 7-inch 26 lb/ft casing set to a depth of 7,309 ft TVD. The long-string casing was designed in two sections: the first one is L80 grade steel (L80) from surface to 7,000 ft TVD; the second section (covering the injection complex) is 22Cr-110 grade duplex stainless steel (22Cr-110) from 7,000 ft TVD to 7,309 ft TVD. The well is planned to be perforated, as discussed in subsection 2.7.3 of this plan, in the Basal Sand Formation injection interval from the depth of 7,204 ft to 7,307 ft TVD. Feasibility of CO_2 injection was determined with a 3.5-inch outer diameter (OD) 9.2 lb/ft, 22Cr-110 tubing set at 7,204 ft TVD, at the top of the BIC.

For injection into the BIC, the maximum allowable surface pressure (MASP), 1,938 psig, is identified based on 90% of the fracture gradient at the depth of the shallowest perforation (7,204 ft), assuming a constant injection rate of 0.5 MMt/y (see subsection 2.3 of the Summary of Requirements – Class VI Operating and Reporting Conditions). Maximum surface injection pressures were derived from the reservoir model indicating the maximum downhole pressure limit of 3,821 psig in the BIC (Figure 1).

Initial reservoir modeling indicated that the Area of Review (AoR) was determined by the CO_2 plume rather than the pressure differential. Consequently, a series of reservoir simulations was conducted to ensure that the CO_2 plume remained within the preferred AoR, allowing for the determination of an optimal injection rate. In the well construction design, only this preferred rate of 0.5 MMt/y was applied. For this design, several tubing sizes from 2.875-inch through 4.5-inch OD were compared for CO_2 injection at the constant injection rate and maximum downhole pressure (3,821 psig) as shown in Figure 1. Nodal analysis at constant injection rate of 0.5 MMt/y, and maximum downhole pressure limit of 3,821 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 2,915 psig at the wellhead which is well above the maximum allowable delivery pressure (2,220 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 1,938 psig identified as the MASP for the BIC.

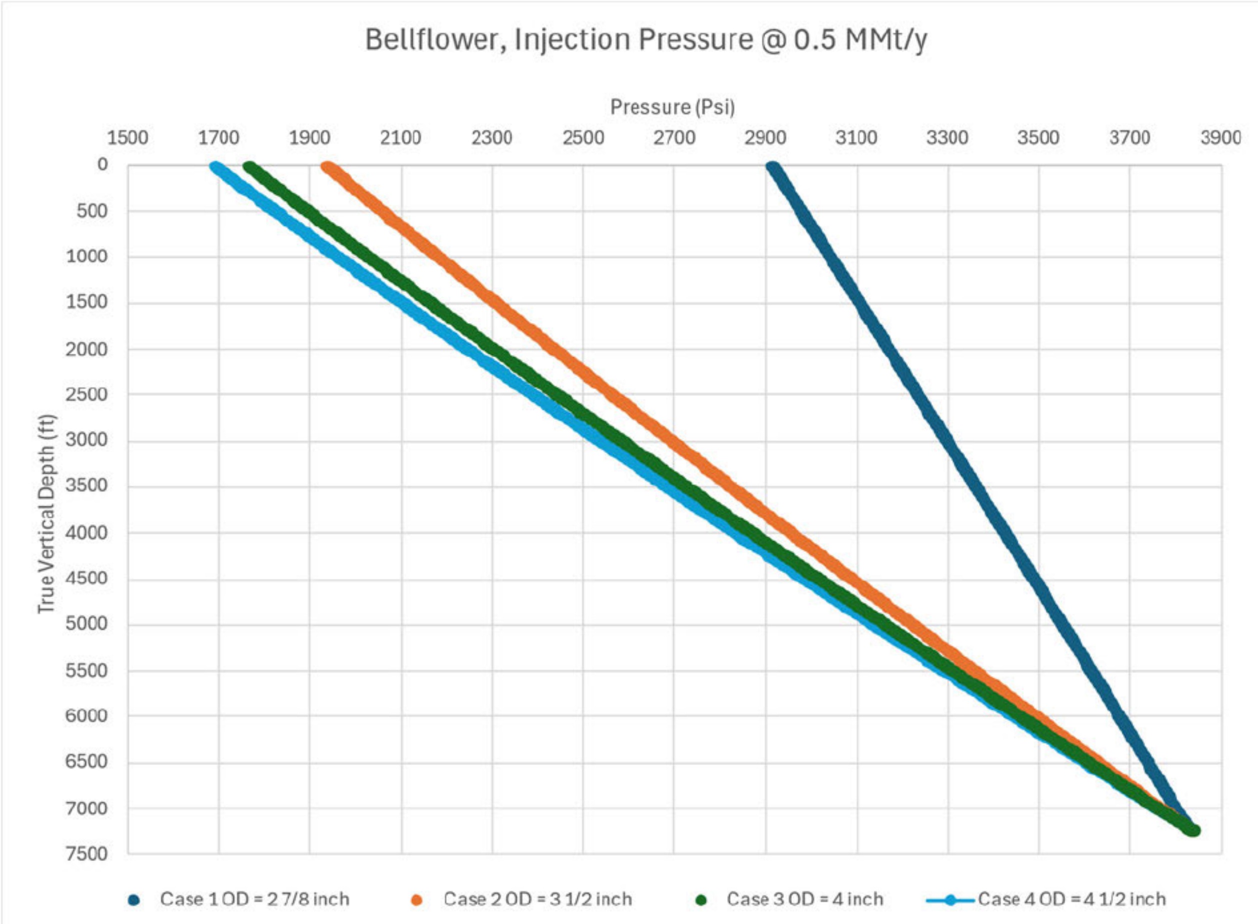

Figure 1: Injection pressure at a constant injection rate of 0.5 MMt/y using different tubing sizes for CO_2 injection into the BIC. The downhole pressure is limited by 90% of fracture gradient at the depth of the shallowest perforation (7,204') in the injection interval (3,821 psig).

2.2. Injection Well Operating Conditions

Table 1 provides the injection well operating conditions anticipated for Bellflower 1 that form the basis of design and material selection.

Table 1: Operating Conditions.

Parameter	Value	Notes
Proposed injection rate	0.5 MMt/y	Proposed injection rate is AoR limited, not equipment or reservoir limited
Planned Injection Duration	30 years	Planned total 15 MMt CO_2 injection in 30 years.

Parameter	Value	Notes
Injection type	Continuous	Operational target is for continuous injection. However, intermittent injection will be likely due to operational downtime.
Volume Flow Rate	275.28 gpm	Maximum flow rate at surface.
Flow Velocity in Tubing	15.5 ft/sec	Average flow velocity assuming 3-1/2-inch OD tubing w/ 2.992-inch ID at surface.
CO_2 Stream Characteristics	**Component** / **Specification** / **Unit** Carbon Dioxide (CO_2) / > 95 / Mol%, dry Carbon Monoxide (CO) / < 1,000 / 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 SOx / < 100 / ppmv Total Sulfur / < 100 / ppmv NOx / < 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	Anticipated CO_2 stream characteristics.
CO_2 Stream Corrosiveness	Non-corrosive	To be confirmed during pre- operational testing
CO_2 Stream Density	6.31 lb/gal	At maximum pressure and 60 ºF on the wellhead.
Fracture Gradient	0.7 psi/ft	To be confirmed by step rate test during pre-operational testing
In-Situ downhole pressure at top perforation	3,451 psig	Determined using the pore pressure gradient of 0.479 psig/ft.
Maximum downhole pressure at top perforation	3,821 psig	Determined using 90% of the fracture gradient 0.7 psi/ft.
Maximum annular pressure at wellhead	2,038 psig	

Parameter	Value	Notes
Maximum allowable surface pressure	1,938 psig	From PROSPER ® analysis as discussed in subsection for Bellflower 1 Bellflower 1 has been designed to accommodate the anticipated mass of carbon dioxide (CO2) and the subsurface characteristics of the CO2 injection intervals that affect the well design. The following reviews the analysis performed to comply with Class VI Underground Injection Control (UIC) well standards at 40 CFR 146.86(a) regarding the design of the casing, cement, and wellhead. Additionally, Tri-State CCS, LLC is working with the Ohio Department of Natural Resources (ODNR) to determine what state requirements will apply to constructing Bellflower 1. Wellhead Injection Pressure.
Minimum annulus pressure at well head	100 psig	To maintain 100 psi differential pressure.
Minimum differential pressure (directly above and across packer)	100 psig	For continuous mechanical integrity assurance.
Injection Zone Measured Depth	7,194 ft – 7,309 ft (BIC)	

2.3. Formation Conditions

Table 2 presents the anticipated formation conditions for Bellflower 1. Formation fluid characteristics will be updated following data collection from the Pre-Operational Testing Program.

Table 2: Formation conditions for Bellflower 1.

Parameter	Value	Notes
Bottomhole Temperature	153.5 °F	1.3 °F/100 ft geothermal gradient + 60 °F Surface Temp
Injectate Temperature	80 – 120 °F (avg 95 °F)	Estimated from Three Rivers Energy biorefinery
Injection Lithology	Sandstone (BIC)	Perforating the Sandstone formation of the BIC.
Confining Lithology	Silty Dolomite	The Maryville Silt is the confining unit of the BIC.
Formation Fluid Chemistry – Cambrian Basal Sandstone (CBS)	TDS: 266,000 mg/L* pH: 6.07 Ba^{2+}: - Ca^{2+}: 28,925 mg/L Cl^{-}: 102,500 mg/L K^{+}: - Mg^{2+}: 3,060 mg/L Na^{+}: 54,500 mg/L SO_4^{2-}: 793 mg/L	Based on USGS (National Produced Waters Geochemical Database, 2023) *Buckeye Brine (2023)
Lowermost USDW Measured Depth	351 ft TVD (Black Hand Sandstone)	Based on Majchszak, 1984

2.4. Casing Program

Access to the BIC injection interval will utilize a 7-inch long-string casing to accommodate a 3.5-inch OD tubing. Bellflower 1 has been designed to accommodate concentric casing sizes required to isolate the injection reservoir from the USDWs. Material for the casing was selected to be appropriate for the fluids and stresses expected to be encountered within the well (40 CFR 146.86(b)(1)).

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 better across the injection zone of the well, as discussed in subsection 2.7.3 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.

2.5. 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 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).

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 (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.

2.6. Analysis of Casing Stress & Loading

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, and Table 6. 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.

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Table 3: Minimum Design Factors.

Load	Casing Design Criteria	Tubing Design Criteria	Connection Design Criteria
Triaxial	1.25	1.25	NA
Burst	1.10	1.20	1.1
Collapse	1.0	1.1	1.0
Tension	1.4	1.4	1.6
Compression	1.4	1.4	1.6

NA = Not Applicable

Table 4: Load scenarios evaluated for 16-inch Conductor Casing.

Load Case	Pressure Profile		Temperature Profile
	Internal	External	
Running In Hole	8.33 ppg	8.33 ppg	Static
As Cemented (Green Cement)	8.33 ppg	Cement	Static

Table 5: Load scenarios evaluated for 9 5/8-inch Surface Casing.

Load Case	Pressure Profile		Temperature Profile
	Internal	External	
Running In Hole	9.3 ppg	9.3 ppg	Static
Overpull (Shoe Depth)	9.3 ppg	9.3 ppg	Static
Bumping Cement Plug	9.3 ppg + 500 psi	Cement	Static
As Cemented (Green Cement)	9.3 ppg	Cement	Static
Pressure Test	9.3 ppg + 1,000 psi	Pore Pressure	Static
Negative Pressure Test	8.33 ppg	9.3 ppg	Static
FIT (Drilling Scenario)	9.4	Pore Pressure	Static
Casing Full Evacuation	No Fluid	9.3 ppg	Static

Table 6: Load scenarios evaluated for 7-inch Long-String Casing.

Load Case	Pressure Profile		Temperature Profile
	Internal	External	
Running In Hole	9.4 ppg	9.4 ppg	Static
Overpull (Shoe Depth)	9.4 ppg	9.4 ppg	Static
Bumping Cement Plug	9.4 ppg + 500 psi	Cement	Static
As Cemented (Green Cement)	9.4 ppg	Cement	Static
Pressure Test	9.4 ppg + 3,500 psi	Pore Pressure	Static
Negative Pressure Test	8.33 ppg	9.4 ppg	Static
FIT (Drilling Scenario)	9.7	Pore Pressure	Static
Casing Full Evacuation	No Fluid	9.4 ppg	Static

2.7. Casing Summary

The injection well design for Bellflower will include the following casing strings: a 16-inch diameter conductor casing string set at a depth of approximately 150 ft TVD; a 9.625-inch diameter surface casing string set at a depth of approximately 1,200 ft TVD inside a 12.25-inch borehole; a 7-inch diameter long casing string set approximately 96 ft below the top of Basal Sand Formation (~ 7,213 ft TVD) inside a 8.75-inch borehole; and a 3.5-inch diameter deep (injection) tubing string set at approximately 7,204 ft TVD,

All casing strings will be cemented to the surface. The borehole diameters are considered conventional for the sizes of casing that will be used and should allow ample clearance between the outside of the casing and the borehole wall to ensure that a continuous cement seal can be emplaced along the entire length of the casing string. While specific alloy compositions or specific weights, grades, and connections may change due to availability, construction of the wells will utilize corrosion resistant alloys such as 22Cr-110 or better for wetted sections and adhere to mechanical specifications consistent with design inputs presented herein. Final alloy selection or coatings at procurement will be based on the most current applicable materials testing results from API, AMPP, or other standard bodies currently focused on carbon sequestration or alternative project specific testing and modeling.

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 Cambrian Basal Sandstone injection interval. This salt precipitation may reduce well injectivity and lead to pressure buildup by blocking pore space near the wellbore. Buckeye III CCS, LLC may use a capillary string outside the tubing from surface to the top of injection interval for evaporite mitigation treatment based on an evaluation of the formation fluid chemistry during the Pre-Operational Testing program. Specific capillary size, frequency of treatment, and fluid composition will be determined after gathering additional characterization data from the wells planned in the region and conducting laboratory tests as discussed in subsection 5.2 of the Stimulation Program.

Table 7 and Table 8 summarize the proposed casing program for Bellflower 1 and the properties of each casing material. Each section of the well is discussed in a separate section below.

Table 7: Summary of borehole and casing program for Bellflower 1.

Casing String	Casing Depth (TVD; Ft)	Borehole Diameter (in.)	Casing Outside Diameter (in.)	Casing Material (Weight/grade/ connection)	Coupling Outside Diameter (in.)
Conductor	150	NA	16.0	65 lb/ft, H-40, STC	NA
Surface	1,200	12.25	9.625	36 lb/ft, J-55, STC	10.625
Long String	0 – 7,000	8.75	7.0	26 lb/ft, L-80, VAM® 21	7.593
	7,000 – 7,309		7.0	26 lb/ft, 22Cr-110 or better,VAM® 21	7.593
Tubing	0 – 7,204	NA	3.5	9.2 lb/ft, 22Cr-110 or better, VAM® 21	3.930

NA = Not Applicable

Table 8: Properties of well-casing materials for Bellflower 1.

Casing String	Casing Material (Weight/grade/ connection)	Casing Outside/Inside/Drift Diameter (in.)	Burst Rating (psi)	Collapse Rating (psi)	Tension Rating (klbf)	Thermal Conductivity (Btu-in/h·ft2·°F) at 77°F
Conductor	65 lb/ft, H-40, STC	16.0 / 15.25 / 15.06	1,640	630	736	
Surface	36 lb/ft, J-55, STC	9.625 / 8.921 / 8.765	3,520	2,020	564	
Long String	26 lb/ft, L-80, VAM® 21	7.0 / 6.276 / 6.151	7,240	5,410	604	26.4
	26 lb/ft, 22Cr-110 or better, VAM® 21	7.0 / 6.276 / 6.151	10,240	6,230	664	8.4
Tubing	9.2 lb/ft, 22Cr-110 or better, VAM® 21	3.5 / 2.992 / 2.867	14,370	13,530	285	8.4

2.7.1. Conductor Casing

The conductor casing is 16-inch diameter 65-lb/ft H-40 carbon steel pipe with short thread couplings (STCs). Conductor casing 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 shows the conductor casing stress analysis for anticipated operating scenarios.

2.7.2. Surface Casing

The surface casing is 9.625-inch diameter 36-lb/ft J-55 carbon steel (J-55) pipe with STCs. Surface casing will be cemented to surface, extending from surface to 1,200 ft TVD below the base of the lowermost USDW, isolating the USDWs through which the string extends. Following the cement setting, a bond log will be run to ensure a sufficient seal to prevent the migration of fluid into USDWs. Figure 3 shows the surface casing stress analysis for anticipated operating scenarios.

2.7.3. Long-String Casing

The long-string casing will be 7-inch diameter pipe composed of two sections. The long-string casing is required to extend from surface to injection zone (40 CFR 146.86(b)(3)). The uppermost section will be L-80 grade steel (L-80), and the lower section will be 22Cr-110 or better, both with gas tight premium connections. The transition will be targeted at approximately 7,000 ft TVD (Maryville Silt Formation). A DTS fiber optic cable will be run outside the casing from surface into the confining unit (Maryville Silt Formation) 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 8.

Figure 4 and Figure 5 show the long-string casing stress analysis for anticipated operating scenarios.

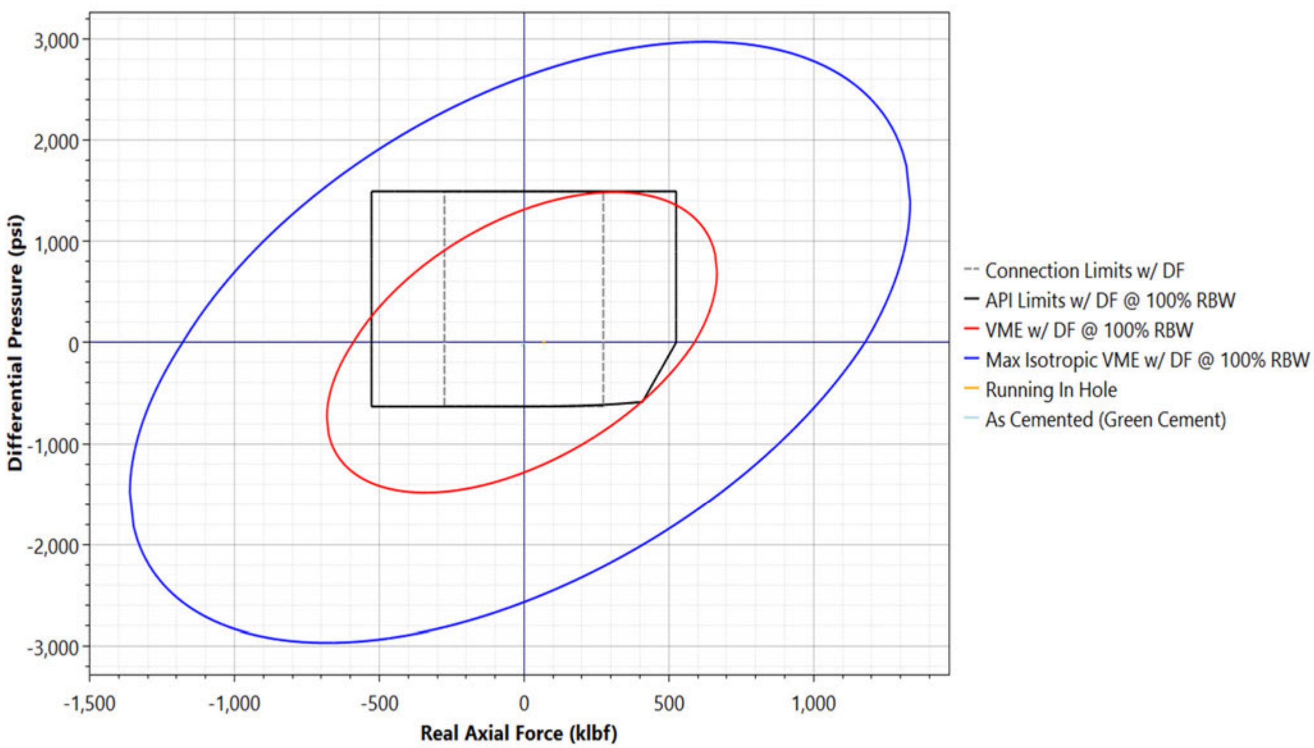

Figure 2: 16-inch Conductor casing (H-40) axial force design envelope.

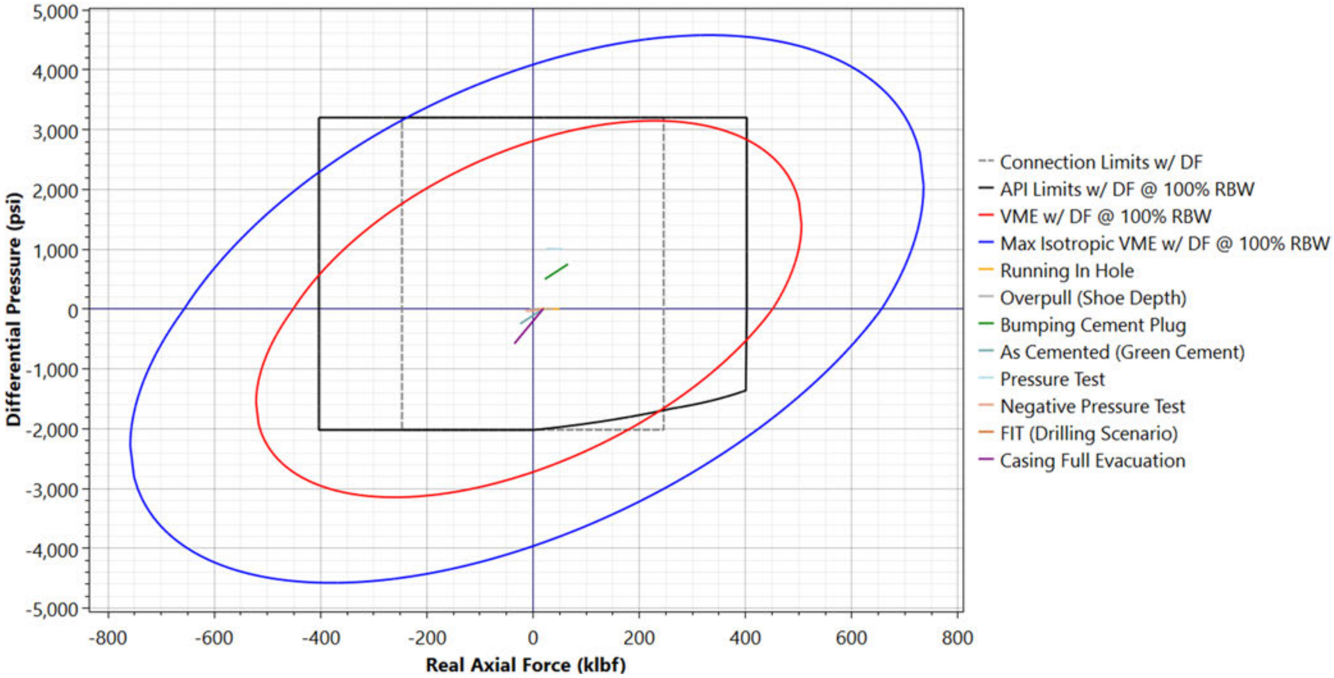

Figure 3: 9.625-inch surface casing (J-55) axial force design envelope.

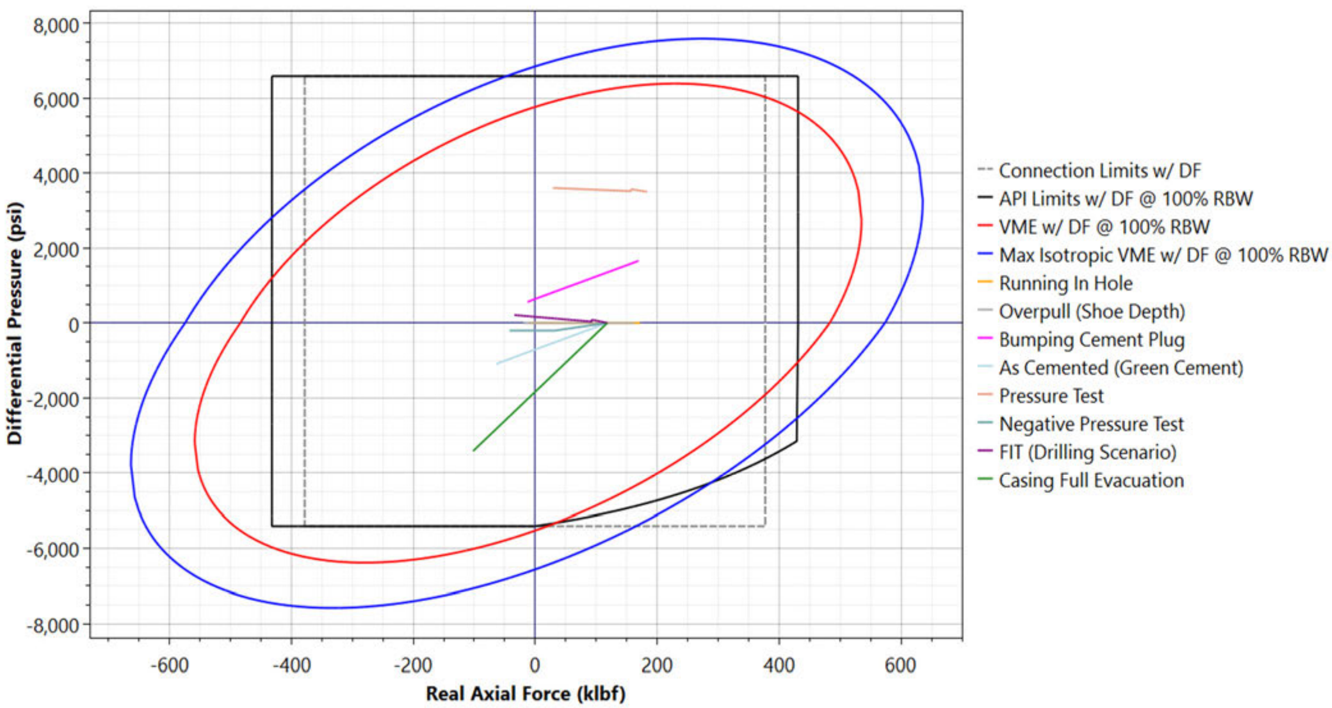

Figure 4: 7-inch long-string casing (L-80) axial force design envelope.

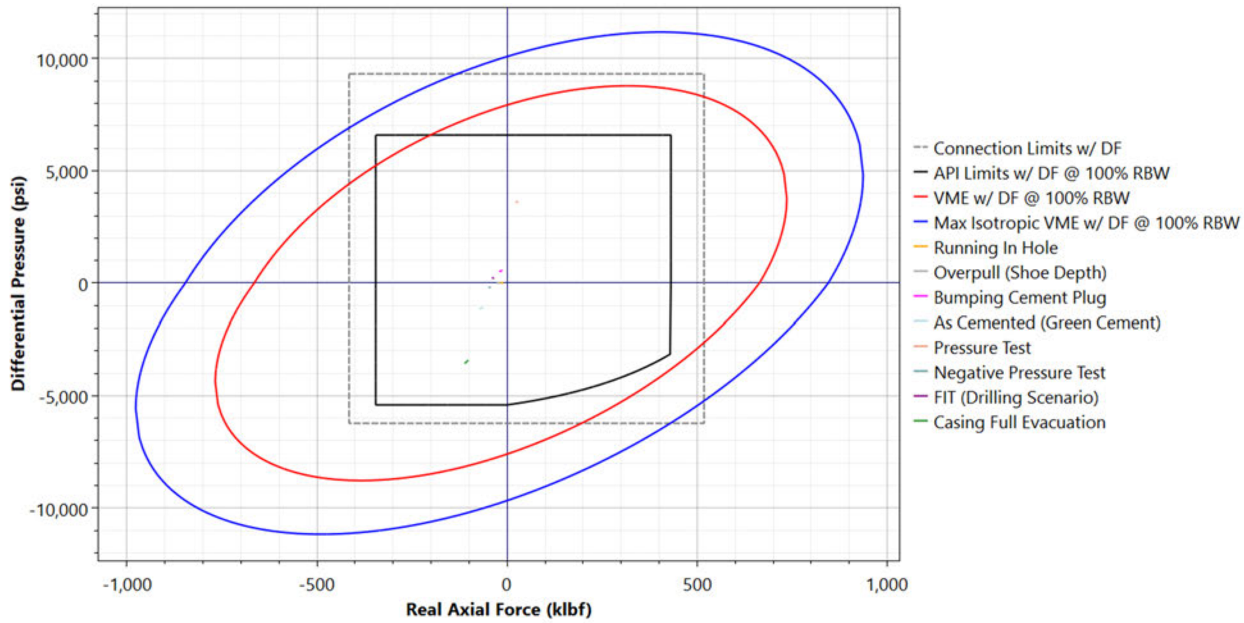

Figure 5: 7-inch long-string casing (22Cr-110) axial force design envelope.

2.7.4. Tubing

The tubing connects the Basal Sand injection interval to the wellhead and provides a pathway for storing CO_2 into the injection zone. This design utilizes 3.5-inch 9.2 lb/ft 22Cr-110 or better tubing, or lined carbon steel tubing, to approximately 7,204 ft TVD. At a depth of approximately 7,000 ft, a packer will be set within the Marysville Silt confining zone to isolate the BIC injection zone from the tubing-casing annulus. At the end of the tubing string, a no-go profile nipple and wireline re-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 gauges. Considering the anticipated formation pressure, temperature, and stress, the grade of tubing was selected to preserve the integrity of the injected fluid, the injection zone, and USDWs. Modeled load scenarios are summarized in Table 9. Figure 6 shows the tubing stress analysis for anticipated operating scenarios. The annulus between the tubing and long-string casing will be filled with noncorrosive fluid in accordance with 40 CFR 146.88(c) (see subsection 2.7.1 below).

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 or better 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 API, AMPP, or other standard bodies currently focused on carbon sequestration.

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Table 9: Load scenarios evaluated for 3-1/2-inch tubing.

Load Case	Pressure Profile		Temperature Profile
	Internal	External	
Running In Hole	8.6 ppg	8.6 ppg	Static
Overpull (Shoe Depth)	8.6 ppg	8.6 ppg	Static
Tubing Pressure Test	8.6 ppg + 5,000 psi	8.6 ppg	Static
Shut- In Tubing Leak	SITP	8.6 ppg	Wellbore Temperature at Maximum Wellhead Pressure and Injection Rate
Tubing Evacuation	Tubing Evacuated	8.6 ppg	Wellbore Temperature at Maximum Wellhead Pressure and Injection Rate
Annular Pressure Test	8.6 ppg	8.6 ppg + 1,500 psi	Static
Operations Load CO2 Production	6.31 ppg	8.6 ppg + 3,451 psi	Wellbore Temperature at Maximum Wellhead Pressure and Injection Rate
Tubing Shut- In	6.31 ppg	8.6 ppg + SITP	Wellbore Temperature at Maximum Wellhead Pressure and Injection Rate

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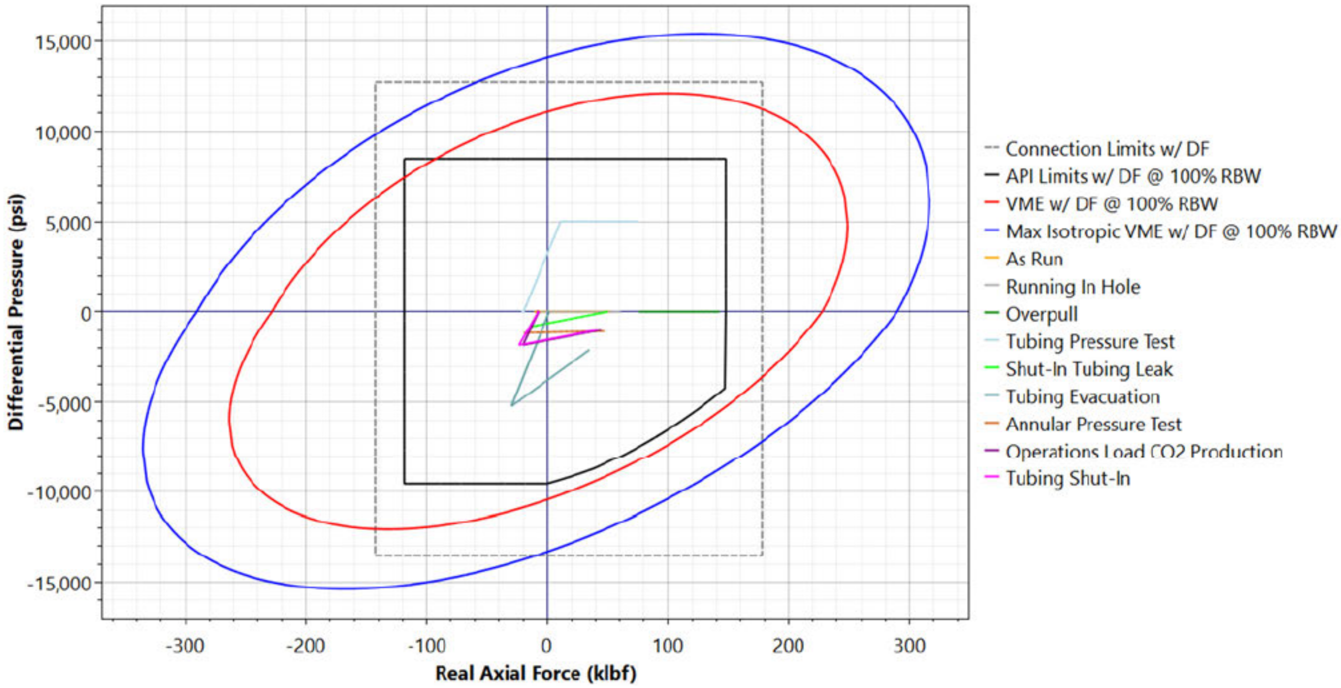

Figure 6: 3.5-inch tubing (22Cr-110) axial force design envelope. Analysis of the design envelope shows 22Cr-110 tubing passes the load scenario and hence will be able to withstand the planned injection duration. The tubing body wall loss will be monitored during the injection period to ensure mechanical integrity. The tubing may be replaced as necessary during the planned injection period.

2.8. Packer Details

Bellflower 1 will utilize one packer. This packer will be used to isolate the tubing annulus and to isolate the injection interval. The packer system will be nickel-plated hydraulic set packer using Hydrogenated Nitrile Butadiene Rubber sealing elements with Viton elastomers with compatible metallurgy. The final vendor selection will be made at the time of construction. Please refer to Table 10 for specifications of the packer.

Table 10: Cased-hole packer specifications for Bellflower 1.

Packer Type and Material	Setting Depth (Approximate)	Length	Packer Main Body Outer Diameter (inch)	Packer Inner Diameter (inch)	Tensile Rating (klbf)
Nickel-plated hydraulic set packer	7,000 ft	3 ft to 10 ft	5.820 – 5.983	2.870	285

Burst Rating (psi)	Collapse Rating (psi)	Nominal Casing Weight (lb/ft)	Maximum Casing Inner Diameter (inch)	Minimum Casing Inner Diameter (inch)
13,970	13,530	26 - 29	6.381	6.184

2.9. Cementing Program

Conductor casing will be driven if geotechnical conditions permit. If conductor hole is drilled or cementing is required, the conductor pipe will be cemented to surface. The surface and long-string casings will be cemented to the surface in accordance with requirements at 40 CFR 146.86(b)(3). The proposed cement types and quantities for each casing string are summarized in Table 11. 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 well 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. 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 set 100 ft below the bottom of the BIC, within the Precambrian Basement, will be cemented using CO_2 resistant tail cement until the top of the Marysville Silt confining zone. 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. 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.

The actual job design including cement volume, displacement rates, 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.). A spacer will be pumped ahead of all cement jobs to assist in mud removal.

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Table 11: Cementing program for Bellflower 1.

Casing String	Casing Depth (TVD; ft)	Borehole Diameter (in.)	Casing O.D. (in.)	Cement Interval (TVD; ft)	Cement
Conductor	0 to ≈150	17.5	16	0-150 (cemented to surface)	Type: Class A with 2% $CaCl_2$ (calcium chloride) and 0.25 lb/sack cell flake (or similar)[1] Weight: 13.3 lb/gal Yield: 1.48 ft^3/sack Quantity: 75 sacks
Surface	0 – 1,200	12.250	9.625	0 – 1,200 (cemented to surface)	Type: Class A with 2% $CaCl_2$ (calcium chloride) and 0.25 lb/sack cell flake (or similar)[1] Weight: 13.3 lb/gal Yield: 1.48 ft^3/sack Quantity: 343 sacks
Long-String	0 – 7,309	8.750	7	0 – 7,309 (cemented to surface)	Lead – Type: 65/35 Pozmix with 2% gel (or similar)[1] Weight: 12.4 lb/gal Yield: 1.91 ft^3/sack Quantity: 706 sacks Tail – Type: EverCRETE CO_2 resistant cement (or similar)[1] Weight: 13 lb/gal Yield: 1.55 ft^3/sack Quantity: 58 sacks

1: Buckeye III CCS, LLC will request prior approval for any changes to the additives

2.9.1. 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 (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 or other nearby observation wells.

2.9.2. Wellhead

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 12 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 7 and Figure 8. The flow line leading to the wellhead and Christmas tree will be equipped with an automatic shutoff valve as required in 40 CFR 146.88(e). Each annulus will have a pressure monitoring system installed on the wellhead. 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 pre-operational testing.

Table 12: Material specification of wellhead and Christmas tree for Bellflower 1.

Component		Material Class
Casing Head Housing		DD
Casing Spool Assembly		FF
Tubing Hanger		FF
Tubing Spool Assembly		FF
Christmas Tree	Tree Cap	FF
	Manual Gate Valves	FF, DD
	Flow Cross	FF
	Actuated Gate Valve	FF

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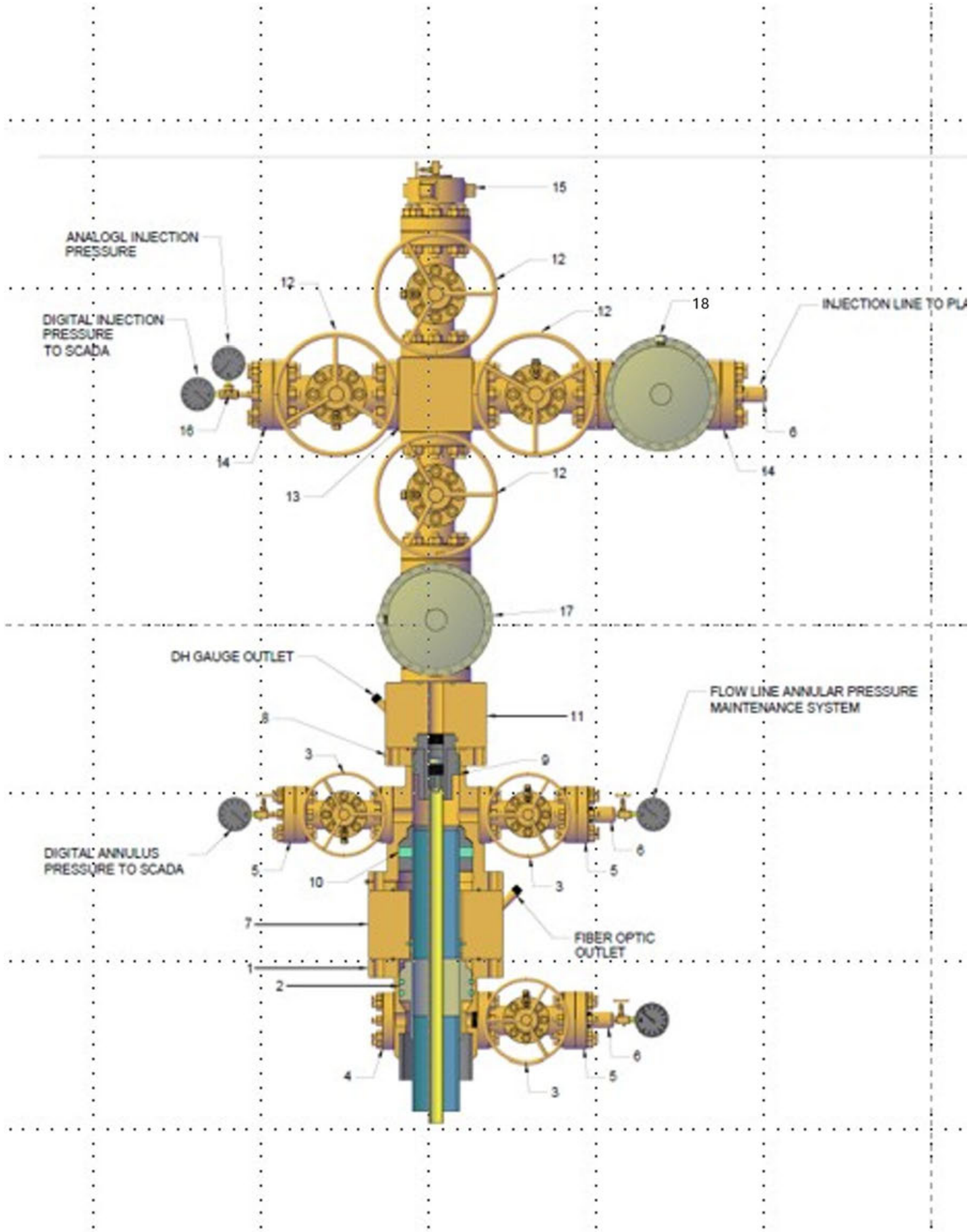

Figure 7: Proposed wellhead and Christmas tree schematic for Bellflower 1. Numbered components are listed in Figure 8.

ITEM	QTY	DESCRIPTION
1	1	CASING HEAD (C-22, 9-5/8", SOW x, 11" 3K, 2" 3K/5K SSO
2	1	CASING HANGER-MANDREL (NON-FLUTED, C-22, 11" OD x, 7")
3	3	GATE VALVE (EXPANDING GATE, 2-1/16" 3K/5K)
4	1	FLANGE-RTJ (2-1/16" 3K/5K x, SOLID)
5	3	FLANGE-RTJ (2-1/16" 3K/5K x, 2" LP)
6	3	BULL PLUG (2" LP, 1/2" NPT, ROUND, SS, XXH)
7	1	DOUBLE STUDDED PACKOFF, 11" 5K x 11" 5K
8	1	TUBING HEAD TCM (11" 3K x 7-1/16" 5K, W/ 2-1/16" 3K/5K)
9	1	TUBING HANGER (TC1A, -EN 5K, 7" OD x, 3-1/2", W/2 DHCL PORTS
10		SECONDARY SEAL, PE, 9" OD x 7"
11	1	DOUBLE STUDDED PACKOFF, 7-1/16" 5K x 3-1/8" 5K
12	5	GATE VALVE (EXPANDING GATE, 3-1/8" 5K)
13	1	CROSS, (3-1/8" 5K BTM X, 3-1/8" 5K TOP X, 3-1/8" 5K LEFT X, 3-1/8" 5K RIGHT)
14	2	FLANGE-RTJ (3-1/8" 5K x, 2" LP)
15	1	TREE CAP (3-1/8" 5K, 3-1/2" 8RD HAMMER CAP)
16	1	COUPLING TEE, ½" F x F
17	1	MASTER VALVE (AUTOMATIC SHUTOFF DEVICE)
18	1	PNEUMATIC FAIL-SAFE AIR ACTIVATED VALVE (AUTOMATIC SHUTOFF DEVICE)

Figure 8: Proposed wellhead and Christmas tree schematic for Bellflower 1.

2.9.3. Perforations

The long-string casing will be perforated across the Basal Sandstone Injection interval (BIC) with deep-penetrating shaped charges from 7,213.5 ft to 7,298.39 ft TVD. Due to the installation of fiber optics, oriented perforations will be used to avoid damaging the fiber optic cable. Once the total planned injection into the BIC is achieved, the injection zone will be plugged off with CO_2 resistant cement as discussed in subsection 5.2 of the Injection Well Plugging Plan.

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 Bellflower 1 are found below in Table 13, though are subject to change based on data collected from the Pre-Operational Testing Program associated with the injection well.

Table 13: Planned perforated injection interval for Bellflower 1.

Perforated Interval	Top (TVD; ft)	Bottom (TVD; ft)	Mid-Point (TVD; ft)
Basal Sandstone Injection Complex	7,204	7,307	7,255.5

2.10. Injection Well Construction Diagram

The proposed well schematic for injection into the Basal Sandstone Injection interval in the BIC is shown in Figure 9.

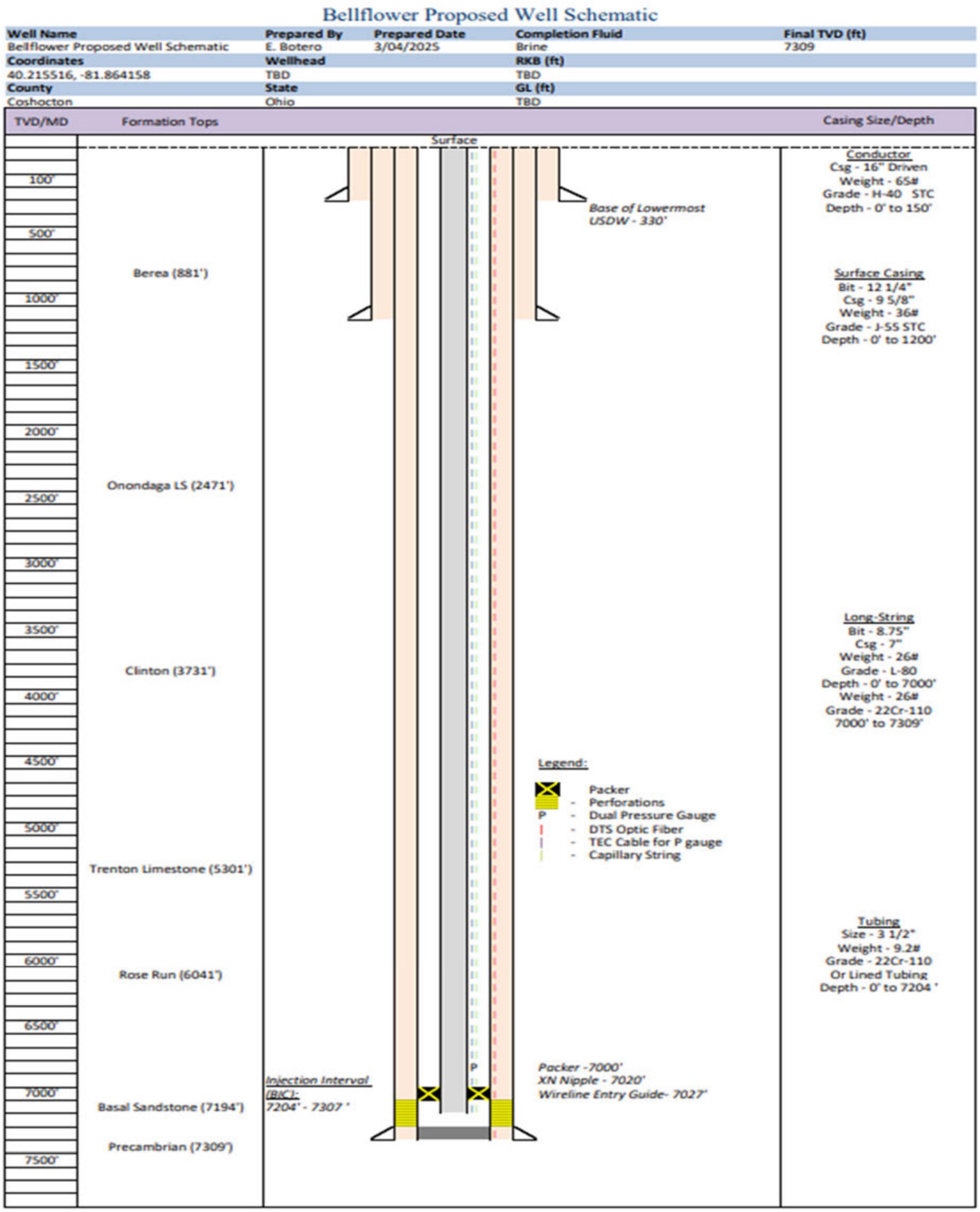

Figure 9: Proposed well schematic for Bellflower 1 for injection into the BIC.

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

3. Construction Information for Observation Wells

Proposed well schematics and the cementing program for the in-zone observation well (B3-IOB-1), above-zone observation well (B3-AOB-1), and lowermost USDW observation well (B3-UOB-1) are provided in Appendix A to this plan. These wells along with an existing shallow groundwater well are proposed to monitor the project prior to, during, and post injection. Buckeye III CCS, LLC plans to obtain a permit to drill from the ODNR for each observation well and, subsequently, will construct these observation wells in compliance with state requirements at ORC 1509 and OAC 1501:9.

4. References

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Blondes, M.S., Knierim, K.J., Croke, M.R., Freeman, P.A., Doolan, C., Herzberg, A.S., and Shelton, J.L., 2023, U.S. Geological Survey National Produced Waters Geochemical Database (ver. 3.0, December 2023): U.S. Geological Survey data release, https://doi.org/10.5066/P9DSRCZJ.

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Appendix A: Observation Well Schematics and Cementing Program

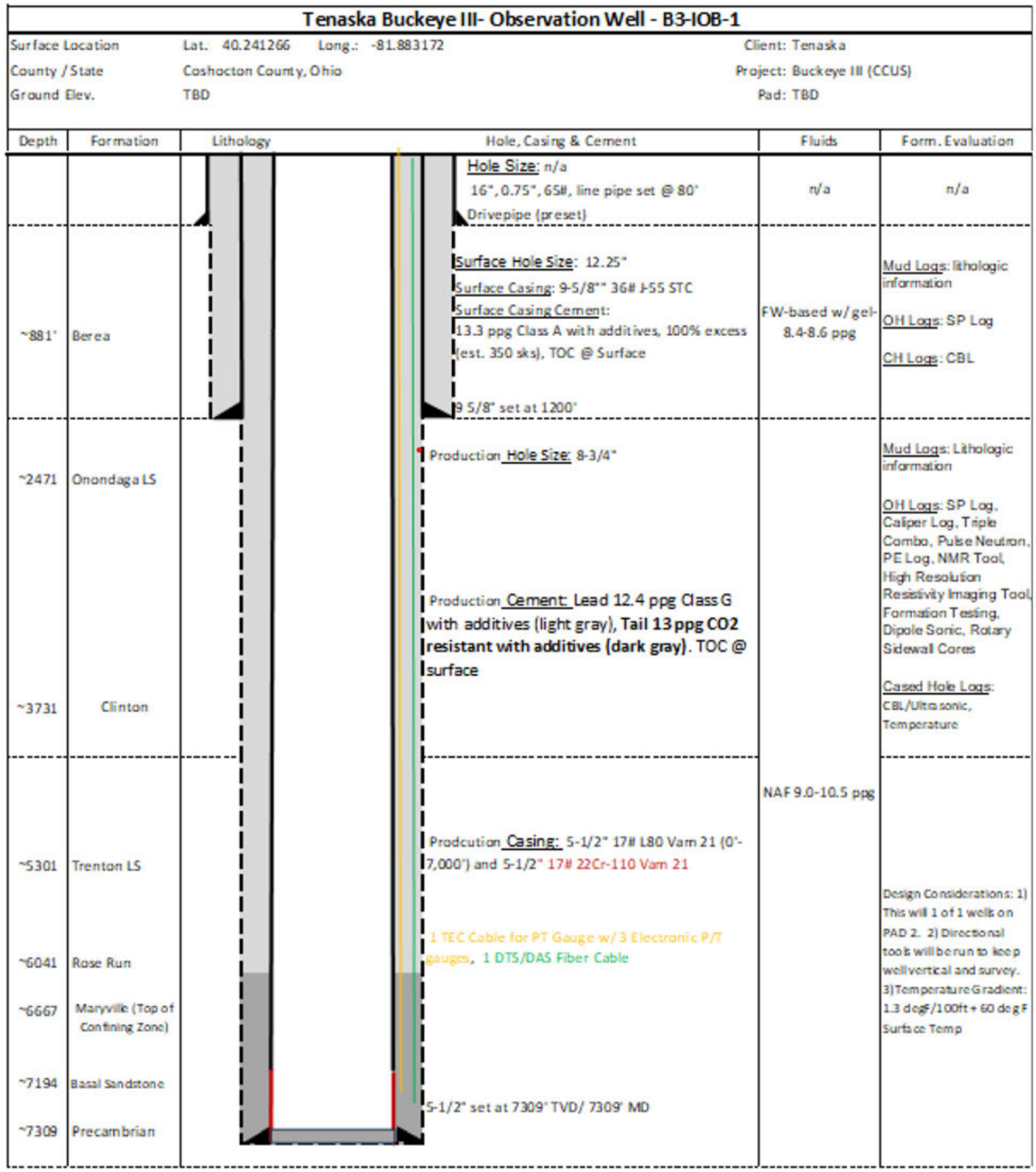


Figure A-1: Proposed well schematic for in-zone observation well B3-IOB-1.

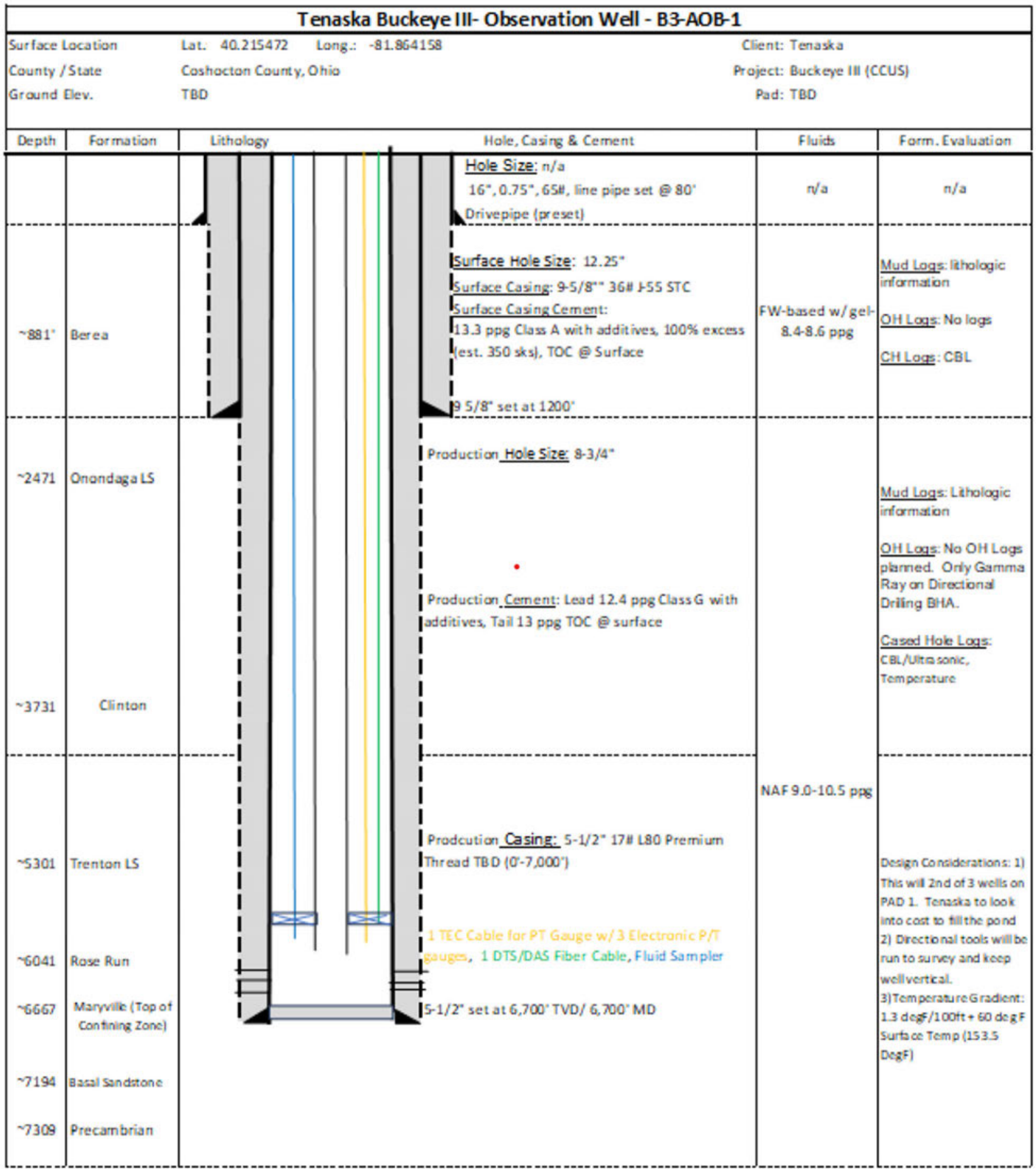
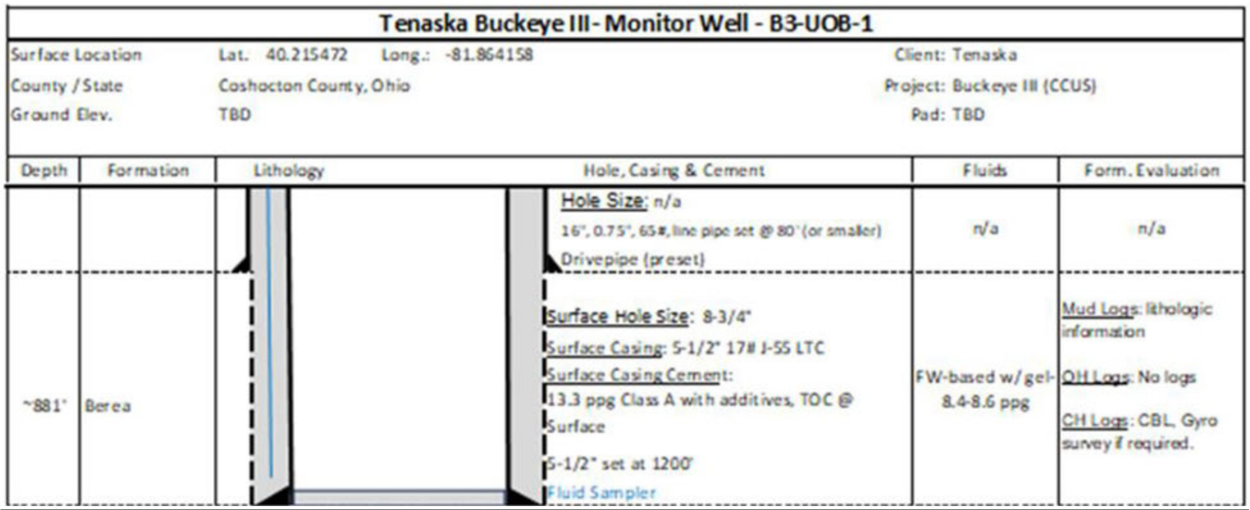


Figure A-2: Proposed well schematic for above-zone observation well B3-AOB-1.



Tenaska Buckeye III- Monitor Well - B3-UOB-1

Surface Location	Lat. 40.215472 Long.: -81.864158		Client: Tenaska
County / State	Coshocton County, Ohio		Project: Buckeye III (CCUS)
Ground Elev.	TBD		Pad: TBD

Depth	Formation	Lithology	Hole, Casing & Cement	Fluids	Form. Evaluation
			Hole Size: n/a 16", 0.75", 65#, line pipe set @ 80' (or smaller) Drivepipe (preset)	n/a	n/a
~881'	Berea		Surface Hole Size: 8-3/4" Surface Casing: 5-1/2" 17# J-55 LTC Surface Casing Cement: 13.3 ppg Class A with additives, TOC @ Surface 5-1/2" set at 1200' Fluid Sampler	FW-based w/ gel- 8.4-8.6 ppg	Mud Logs: lithologic information OH Logs: No logs CH Logs: CBL, Gyro survey if required.

Figure A-3: Proposed well schematic for the lowermost USDW observation well B3-UOB-1.

Table A-1: Cementing Program[1] for the in-zone observation well B3-IOB-1.

Casing String	Casing Depth	Borehole Diameter	Casing OD (in)	Cement Interval (TVD; ft)	Cement
Surface	0 - 1,200	12.250	9.625	0 -1,200 (cemented to surface)	Type: Class A with additives Weight: 13.3 lb/gal Yield: 1.48 ft^3/sack Quantity: 343 sacks
Long - String	0-7,309	8.75	5.5	0 - 7,309 (cemented to surface)	Lead - Type: Class G with additives Weight: 12.4 lb/gal Yield: 1.91 ft^3/sack Quantity: 898 sacks Tail - Type: CO_2 resistant with additives Weight: 13 lb/gal Yield: 1.55 ft^3/sack Quantity: 98 sacks

Table A-2: Cementing Program[1] for the above-zone observation well B3-AOB-1.

Casing String	Casing Depth	Borehole Diameter	Casing OD (in)	Cement Interval (TVD; ft)	Cement
Surface	0 - 1,200	12.250	9.625	0 -1,200 (cemented to surface)	Type: Class A with additives Weight: 13.3 lb/gal Yield: 1.48 ft^3/sack Quantity: 343 sacks
Long - String	0-6,700	8.75	5.5	0 - 6,700 (cemented to surface)	Type: Class G with additives Weight: 12.4 lb/gal Yield: 1.91 ft^3/sack Quantity: 897 sacks

Table A-3: Cementing Program[1] for the lowermost USDW observation well B3-UOB-1.

Casing String	Casing Depth	Borehole Diameter	Casing OD (in)	Cement Interval (TVD; ft)	Cement
Surface	0 - 1,200	8.750	5.500	0 -1,200 (cemented to surface)	Type: Class A with additives Weight: 13.3 lb/gal Yield: 1.48 ft^3/sack Quantity: 205 sacks

1: Specific additives will be determined based on formation conditions and CO_2 compatibility for cement that may be exposed to CO_2. Additives may include 2% $CaCl_2$, 0.25 lb/sack cell flake (or similar), and/or 2% gel. Buckeye III CCS, LLC will request prior approval for any changes to the additives.