CONSTRUCTION DETAILS
40 CFR 146.86(a)

One Earth CCS

Facility Information

Facility name:	One Earth Sequestration, LLC OES #3
Facility contact:	Mark Ditsworth, VP of Technology and Special Projects One Earth Sequestration, LLC, 202 N Jordan Drive, Gibson City (217) 784-5321 ext. 215 mditsworth@oneearthenergy.com
Well location:	McLean County, IL 40.515989°N, -88.479214°W, (NAD 1983)

Injection Well Operating Conditions

Table 1 provides the injection well operating conditions anticipated for the One Earth Sequestration, LLC OES #3 well.

Table 1. *OES #3 Injection well operating conditions.*

Parameter	Value	Notes
Maximum proposed injection rate	4,255 MT/day	Assumes injection of 1.5 Mt/yr
Planned Injection Duration	20 Years	From Class VI narrative
Injection type	Continuous	The operational target is for continuous injection. However, intermittent injection may occur due to operational downtime.
Volume Flow Rate	934 – 1,019 gpm	Average - Maximum
Flow Velocity in Tubing	124 - 135 ft/min	Assuming 5-1/2" tubing ID of 4.892" at surface
Mass of Stream (mol fraction)	CO_2 – .9938 H_2O – 7.3×10^{-7} O_2 – 0.0013 N_2 – 0.004859	Salof Heat & Material Balance, HMB Design CO_2, Rev. 03
CO_2 Stream Characteristics (lb/hr)	CO_2 – 152,993.369 H_2O – 0.046 O_2 – 145.0241 N_2 – 479.3788	Salof Heat & Material Balance, HMB Design CO_2, Rev. 03
CO_2 Stream Density	45.8 - 53.9lb/ft^3	Average to maximum at perfs.
Fracture Gradient	0.71 psi/ft	Regional data (see AoR and CA Plan)
In-Situ Pressure at Top Perforation	2,749 psia	Regional data (see AoR and CA Plan)
Maximum pressure at top perforation	3,782 psig	Determined using the fracture gradient multiplied by 0.9 (see AoR and CA Plan)
Maximum proposed annular pressure	5,175 psig	To maintain 100 psi differential pressure
Maximum pressure at the wellhead	1,710 psig	Prosper model
Minimum annulus pressure	100 psi	To maintain 100 psi differential pressure
Minimum differential pressure (directly above and across packer)	100 psi	For continuous mechanical integrity assurance
Injection Zone Depth	6,262 ft – 6,469 ft	From OEE #1 well formation tops

Dry supercritical CO_2 is not corrosive, and corrosion occurs only when water is present (Russick et al., 1996; Zhang et al., 2011). Supercritical CO_2 is considered "dry" at water concentrations of less than 10 lb/MMscf (211 ppmv). The design basis for the carbon capture and compression facility at One Earth Sequestration establishes a treatment specification of 10 lb/MMscf (211 ppmv) for CO_2 delivered to the wellhead (FEED). Laboratory and modeling studies for the Mt. Simon Sandstone in the Illinois Basin indicate minimal reactivity of the rock with brine and CO_2. These results are discussed in the Narrative Section, Geochemistry [40 CFR 146.82(a)(6), Subsection: Geochemical Reactions and Modeling], and in the Site Suitability Section [40 CFR 146.83, Subsection: Reservoir and Compatibility with the Injectate].

The annular space above the packer—between the 9⅝-inch long-string casing and the 5½-inch injection tubing—will be filled with fluid to maintain a positive pressure differential that stabilizes the injection tubing and inhibits corrosion. Annular fluid pressure at the surface will be continuously monitored and adjusted to maintain a 100-psi positive pressure differential above the tubing pressure. See the "Injection Rate and Pressure Monitoring" subsection of the Testing and Monitoring Plan for a detailed description of the annulus monitoring system.

The annular fluid will be a non-corrosive fluid with additives that may include a corrosion inhibitor, biocide, and oxygen scavenger. The fluid will be filtered to prevent solids from interfering with the packer or other components of the annular pressure management system. Surface annulus pressure will be maintained at a minimum of 100 psi, and the annulus pressure directly above the packer will be kept at least 100 psi above the adjacent tubing pressure during injection. Throughout the interval above the packer, annulus pressure will remain greater than the injection-zone formation pressure at all times. Permanent downhole gauges will monitor pressure and temperature at the packer. These gauges will be installed in a gauge mandrel above the packer and will transmit data to the surface SCADA system via a cable routed through the annulus.

The Testing and Monitoring Plan provides corrosion monitoring of injection-well tubing using the coupon-monitoring method. It measures water content in the injectate to evaluate the potential corrosiveness of the injected CO_2. In addition, fluid samples from the Above Confining Zone (ACZ #1 and #2) monitoring wells and the In-Zone Monitoring (IZM) wells will include field measurements of pH during each sampling event.

Formation Conditions

Table 2 presents the anticipated formation conditions for the OES #3 injection well.

Table 2. *Formation conditions for OES #3 well.*

Parameter	Value	Notes
Bottomhole Temperature	120° F	Temperature at 7033 ft in OEE #1.
Injectate Temperature	98° F	Salof Heat & Material Balance, HMB Design CO_2, Rev. 03
Injection Lithology	Sandstone	Initially perforating the arkosic section (6,262 ft – 6,469 ft) of the Cambrian Mt. Simon Sandstone (4,455 ft – 6,469 ft).
Confining Lithology	Shale	The Eau Claire Formation (3,921 ft – 4,455 ft) is the primary confining unit of the Mt. Simon Storage Complex.
Formation Fluids	TDS – 165,500 ppm Cl – 101,138 ppm Density – 9.2 lb/gal pH – 6.25 Alkalinity – 75 mg/L ORP - -124.1 mV Rw – 0.06 ohm @ 60° F	Based on ISC13 sample collected from a DST in the Mt Simon Sandstone interval from 6,332 ft – 6,390 ft on 01/25/2022.
Lowermost USDW	St. Peter Sandstone (2,215 ft – 2,447 ft)	DST sample in OEE #1 had TDS of 1,779 mg/L.

Open Hole Parameters

The open-hole construction parameters for the OES #3 injection well are presented in Table 3. Mud weight will be designed to maintain an overbalanced drilling condition. Two single-shot surveys will be acquired in the surface section, followed by directional surveys at least every 500 feet below the surface casing set depth to total depth. If wellbore deviation issues arise, additional surveys will be performed as needed, and drilling practices will be adjusted accordingly.

Table 3. *Well construction open hole details for the OES #3 well.*

Name	Depth Interval (feet)	Open Hole Diameter (inches)	Comment	Drilling Mud Type & Weight (lb/gal)[1]	Pressure Gradient (psi/ft)	Maximum Deviation and Dog Leg Severity[2]
Surface	0 – 374	26	To bedrock	Fresh Spud Mud 8.6 – 9.0	0.433	>5° Deviation and <2° per 100 ft
Intermediate	374 – 4,046	17-1/2	To primary seal	Fresh Water Mud 8.8 – 9.0	0.433	>5° Deviation and <2° per 100 ft
Long	4,046 – 7,100	12-1/4	To bedrock	Fresh Water Mud 8.8 – 9.0	0.439	>5° Deviation and <2° per 100 ft

Casing and Completion Tubing Specifications

The proposed casing and tubing specifications are provided in Table 4, and the wellbore schematic is shown in Figure 6. Appendix A contains monitoring well construction details.

Table 4. *Well casing and tubing specifications for the OES #3 well.*

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Nominal Weight (lb/ft)	Material/Alloy	Design Coupling/Joint Yield (klbf)	Thermal Conductivity @ 77 °F (BTU/ft.hr °F)	Tensile Strength (klbf)	Collapse Strength (psi)	Burst Strength (psi)
Surface[1]	0 - 347	20	19.124	94	J55	STC / 783	31	1,480	520	2,110
Intermediate[2]	0 - 4,046	13-3/8	12.515	61	J55	BTC / 1,025	31	962	1,540	3,090
Long[3] (chrome)	0 - 3,900	9-5/8	8.835	40	13Cr (API)	VAM 21 / 916	16	916	3,090	5,750
Long[3] (chrome)	3,900 - 7,100	9-5/8	8.681	47	VM 25S CRA	VAM 21 / 1,086	16	1,086	4,750	6,870
Tubing[4]	0 - 4,500	5-1/2	4.839	17	VM 25S CRA	VAM TOP / 397	16	397	6,290	7,740

Note 1: After drilling a 26-inch hole to approximately 374 feet true vertical depth (TVD), a 20-inch, 94-ppf, J55 short-thread-coupling (STC) casing string will be set and cemented to the surface. The coupling outside diameter is approximately 21 inches. Based on available geologic data, setting the surface casing at approximately 347 feet is expected to place the shoe within bedrock, helping to protect shallow groundwater that may be used for domestic or commercial purposes. Centralizers will be installed on the first three joints and then on every third joint to the surface. Figure 1 shows the casing stress analysis for anticipated operating scenarios, and Table 5 provides the corresponding design data.

Note 2: After a shoe test or formation integrity test (FIT), a 17½-inch hole will be drilled to approximately 4,046 feet true vertical depth (TVD). A 13⅜-inch, 61-ppf, J55 buttress-thread-coupling (BTC) casing string will then be run and cemented to the surface. The coupling outside diameter is approximately 14⅜ inches. Centralizers will be installed on the first three joints and then on every third joint to the surface. Figure 2 shows the casing stress analysis for anticipated operating scenarios, and Table 6 provides the corresponding design data.

Note 3: After a shoe test or formation integrity test (FIT), a 12¼-inch hole will be drilled to approximately 7,100 feet true vertical depth (TVD) through the Mt. Simon Sandstone, where the long-string casing will be run and cemented. The long-string casing includes sections of 13Cr (API) and CRA – Vallourec VM 25S (25Cr-class, proprietary), as shown in the applicable casing table. Hereafter, this material is referred to as "VM 25S CRA." The coupling outside diameter is 10⅝ inches for 13Cr (API) and 10.420 inches for VM 25S CRA. Centralizers will be installed on every joint from total depth to 200 feet above the injection interval and on every third joint thereafter.

Note 4: The maximum allowable suspended weight, based on the specified yield strength of the injection tubing and the weakest tubular or connection, is 318,000 pounds. Figure 4 shows the tubing stress analysis for anticipated operating scenarios, and Table 8 provides the corresponding design data. The final tubing design will include profile nipples and latching devices suitable for downhole shut-in, testing, and well workovers. The packer will be a hydraulic-set mechanical packer with an HNBR sealing element and HNBR/Viton elastomers, with metallurgy of at least VM 25S CRA. Final vendor selection will occur during construction.

The annular completion fluid will be an inhibited $CaCl_2$ brine containing a corrosion inhibitor, scale inhibitor, oxygen scavenger, and biocide, with a density of approximately 8.8 lb/gal. Downhole instrumentation will include high-resolution tubing and annulus pressure gauges. Single-mode and multi-mode fiber-optic cable will be installed externally on the tubing for distributed temperature sensing (DTS) and distributed acoustic sensing (DAS).

A primary design objective of the well is to isolate and protect the Underground Source of Drinking Water (USDW) from the injection stream. Design considerations include sufficient casing diameters for proper cement emplacement, structural strength to maintain integrity throughout the well's lifecycle, and material compatibility with anticipated fluid interactions. Across the injection zone and confining zone, VM 25S CRA will be used where specified in the casing and tubing design. The injection tubing will also be constructed of VM 25S CRA and will be landed in a packer with equivalent or higher material specified to ensure compatibility with any fluids the materials may encounter. CO_2 will be injected through the tubing and into the injection zone via perforations in the long string. The selection of VM 25S CRA is supported by the Association for Materials Protection and Performance (AMPP) 2023 Guidelines.

Casing stress analysis was performed using Blade Energy Partners' StrinGnosis® software to evaluate structural strength and mechanical integrity of the casing strings. Tubular grades were selected to ensure long-term structural integrity based on the worst-case load scenarios in Table 6, 7, 8 and 9 . Table 5 summarize the design factors and load cases. Burst, collapse, and tension capacities were calculated using the defined load scenarios, with respect to the depth, fracture gradients, and required safety factors. Overpull for all strings was simulated with 100,000 lbs. Casing test pressures were set at 70% of the API Maximum Internal Yield Pressure (MIYP). Results demonstrate the compatibility of casing specification with anticipated operational loads.

Table 5. *Minimum Design Factors.*

Load	Casing Design Criteria	Tubing Design Criteria	Connection Design Criteria
Triaxial	1.25	1.25	NA
Burst	1.10	1.20	1.10
Collapse	1.10	1.10	1.10
Tension	1.40	1.40	1.60
Compression	1.40	1.40	1.60

NA = Not Applicable

Table 6. *Load scenarios evaluated for 20-inch Surface Casing.*

Load Case	Pressure Profile		Temperature Profile
	Internal	External	
Running In Hole	8.6 ppg	8.6 ppg	Static
Overpull	8.6 ppg	8.6 ppg	Static
Bump Cement Plug	8.6 ppg + 500 psi	Cement	Static
As Cemented	8.6 ppg	Cement	Static
Pressure Test	8.6 ppg + 1,472 psi	Pore Pressure	Static
Full Evacuation	No Fluid	8.6 ppg	Static
Negative Pressure Test	8.33 ppg	8.6 ppg	Static
FIT / Drilling ahead	9.0 ppg	Pore Pressure	Static

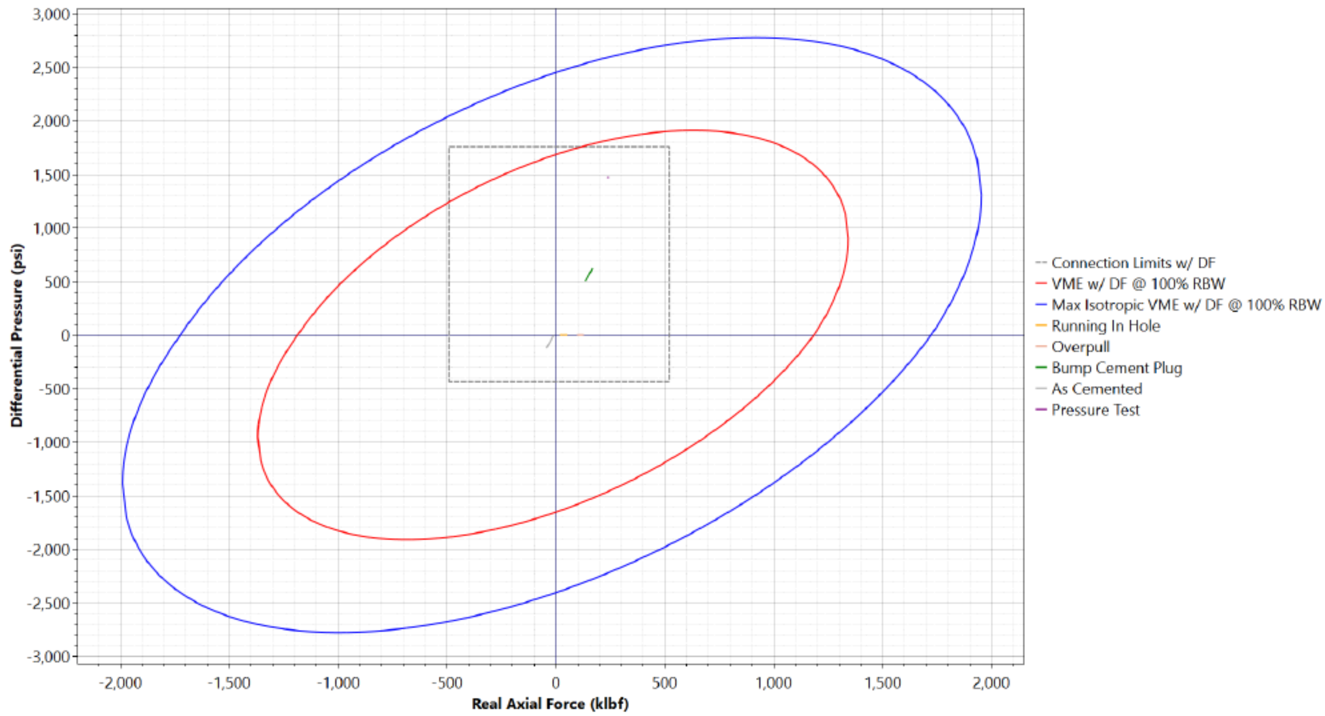

Figure 1. *20-inch Surface Casing axial force design envelope axial force design envelope.*

Table *7. Load scenarios evaluated for 13.375-inch Intermediate Casing.*

Load Case	**Pressure Profile**		**Temperature Profile**
	Internal	**External**	
Running In Hole	8.8 ppg	8.8 ppg	Static
Overpull	8.8 ppg	8.8 ppg	Static
Bump Cement Plug	8.8 ppg + 500 psi	Cement	Static
As Cemented	8.8 ppg	Cement	Static
Pressure Test	8.8 ppg + 2,076 psi	Pore Pressure	Static
Full Evacuation	No Fluid	8.8 ppg	Static
Negative Pressure Test	8.33 ppg	8.8 ppg	Static
FIT / Drilling ahead	9.0 ppg	Pore Pressure	Static

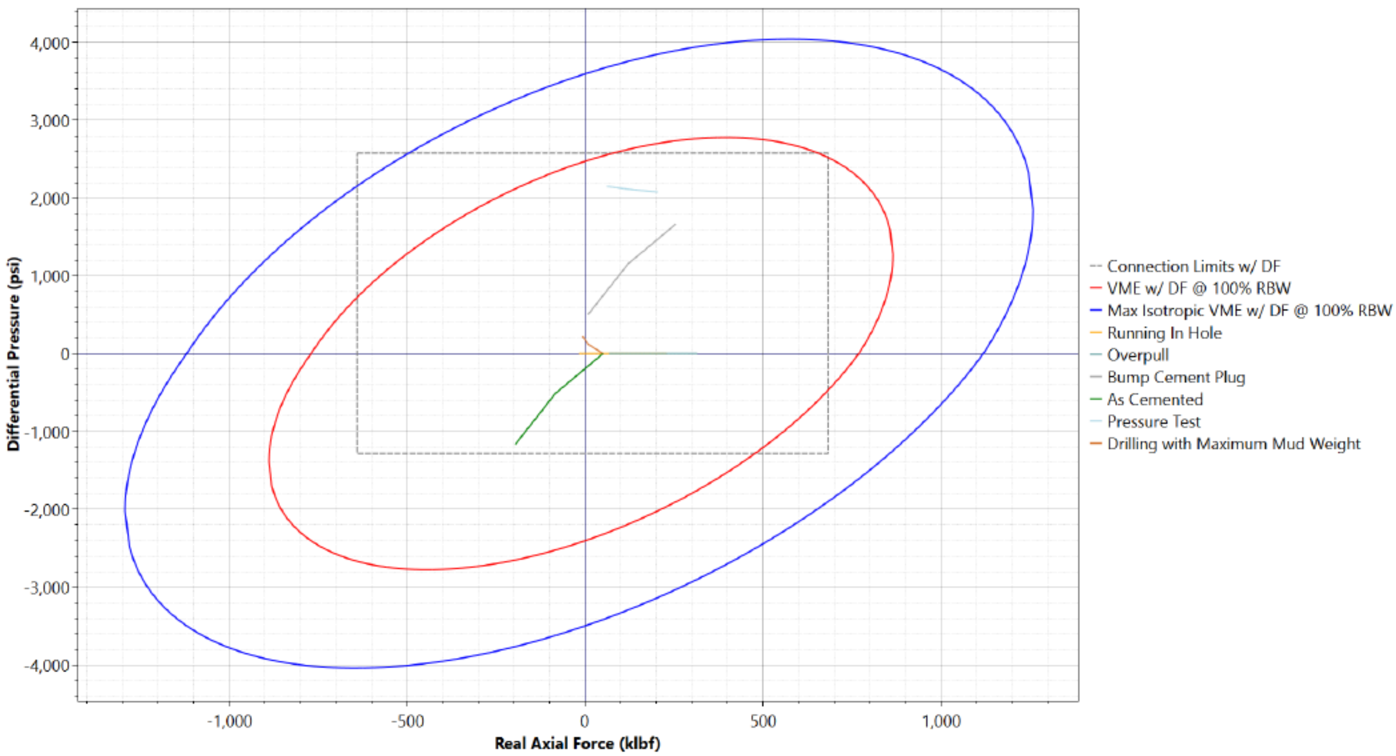

Figure 2. *13.375-inch Intermediate Casing axial force design envelope axial force design envelope.*

Table 8. *Load scenarios evaluated for 9.625-inch Longstring Casing.*

Load Case	Pressure Profile		Temperature Profile
	Internal	External	
Running In Hole	8.8 ppg	8.8 ppg	Static
Overpull	8.8 ppg	8.8 ppg	Static
Bump Cement Plug	8.8 ppg + 500 psi	Cement	Static
As Cemented	8.8 ppg	Cement	Static
Pressure Test	8.8 ppg + 3,914 psi	Pore Pressure	Static
Full Evacuation	No Fluid	8.8 ppg	Static
Negative Pressure Test	8.33 ppg	8.8 ppg	Static
FIT / Drilling ahead	9.0 ppg	Pore Pressure	Static

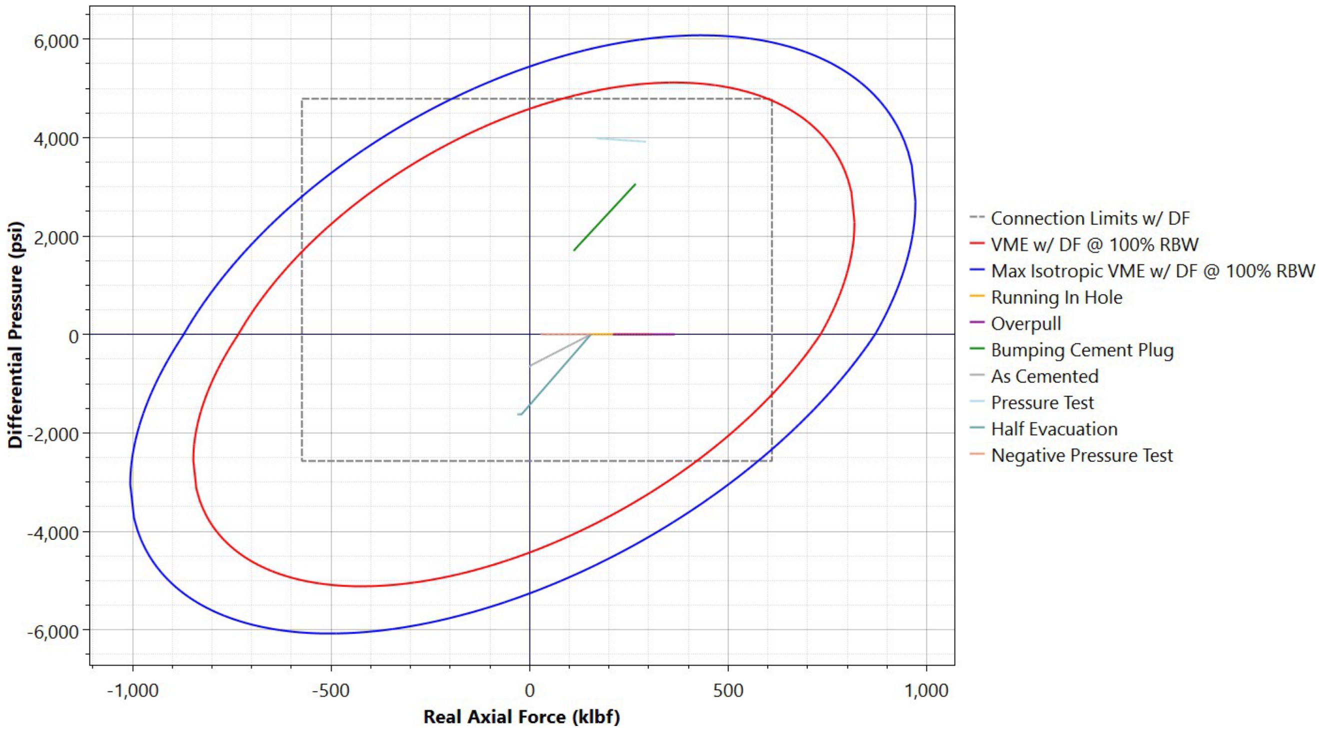

Figure 3. *9.625-inch Longstring Casing (Top section from 0 – 3,900 feet) axial force design envelope.*

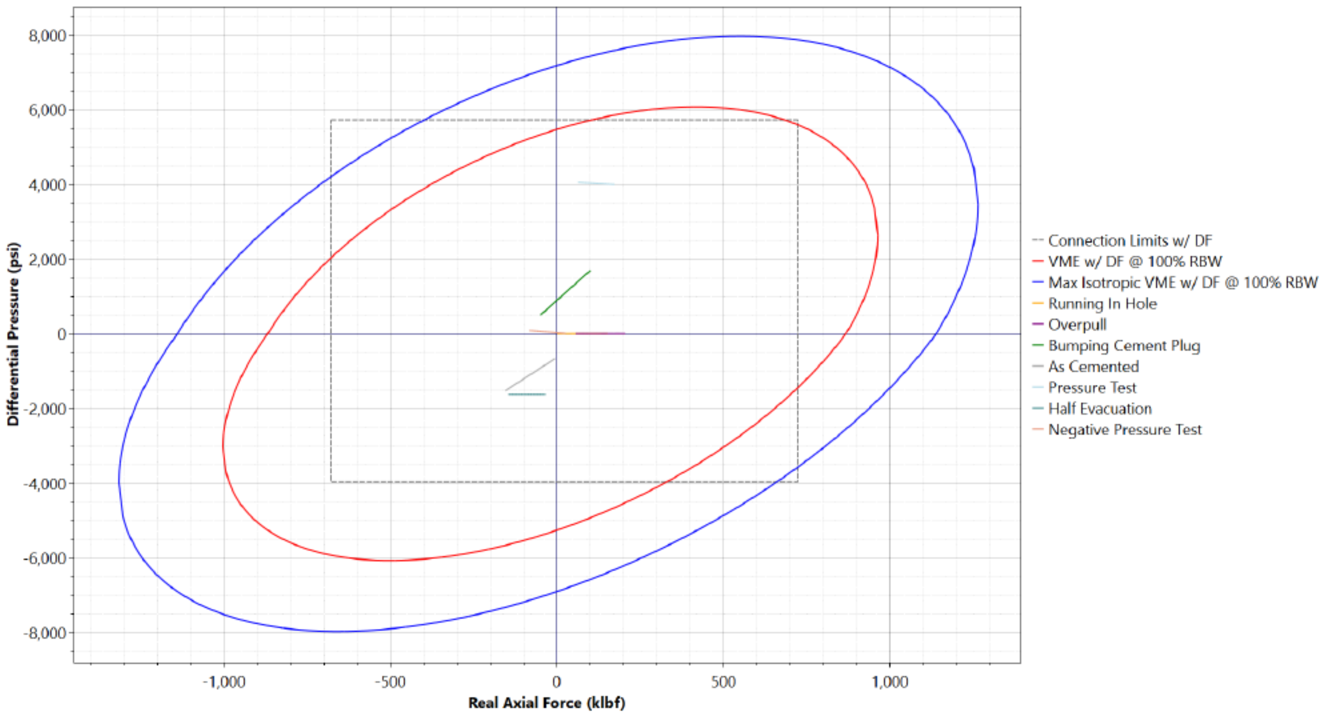

Figure 4. *9.625-inch Longstring Casing (Bottom section from 3,900 – 7,100 feet) axial force design envelope.*

Table 9. *Load scenarios evaluated for 5.5-inch Tubing.*

Load Case	Pressure Profile		Temperature Profile
	Internal	**External**	
Running in Hole	8.8 ppg	8.8 ppg	Static
As Run (Installed Load)	8.8 ppg	8.8 ppg	Static
Tubing Pressure Test	8.8 ppg + 5,302 psi	8.8 ppg	Static
Annular Pressure Test	8.8 ppg	8.8 ppg + 5,032 psi	Static
Full Evacuation	Tubing Evacuated	8.8 ppg	Wellbore Temperature at Maximum Wellhead Pressure and Injection Rate
Maximum CO_2 Injection	6.12 ppg + 1,710 psi	8.8 ppg + 1,500 psi	Wellbore Temperature at Maximum Wellhead Pressure and Injection Rate
Tubing Shut In	SITP	8.8 ppg	Wellbore Temperature at Maximum Wellhead Pressure and Injection Rate

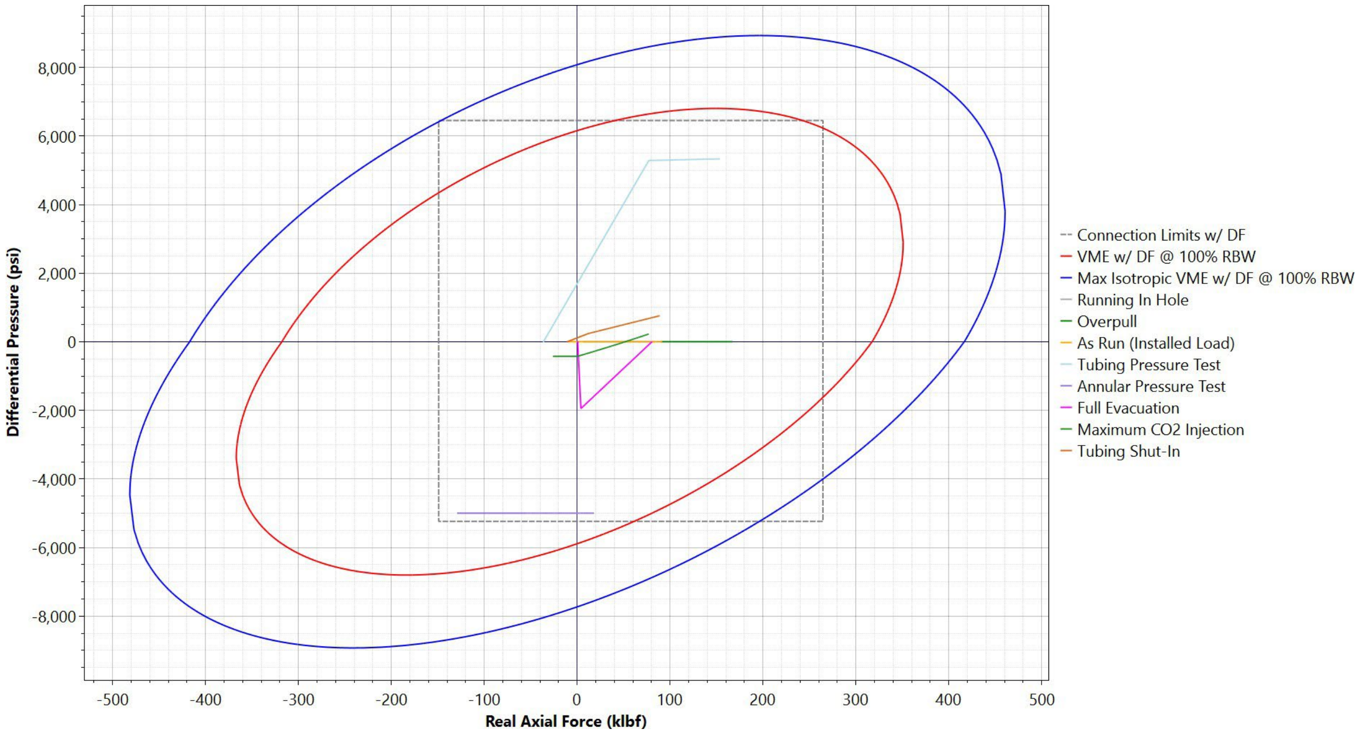

Figure 5. *5-1/2-inch tubing axial force design envelope.*

Minimum Logging Specifications for Well Construction

Table 10 shows the minimum logging that will be conducted during well construction tasks. Additional logs may be run as needed for additional characterization, testing, and monitoring.

Table 10. *Minimum logging planned related to well construction parameters.*

Name	Depth Interval (feet)	Open Hole Logs	Cased Hole Logs
Surface	0 – 374	Resistivity SP Caliper	Radial CBL/VDL or Ultrasonic Temperature
Intermediate	374 – 4,046	Resistivity SP Caliper	Radial CBL/VDL or Ultrasonic Temperature
Long	4,046 – 7,100	Resistivity SP Caliper Porosity Gamma Ray Fracture Finder	Radial CBL/VDL or Ultrasonic Temperature

Cement Specifications

The well will be fully cased, and all casing strings will be cemented back to ground level as detailed in Table 11 and illustrated in Figure 10. The long string will include a CO_2-resistant cement system such as EverCRETE. CO_2-resistant cement will be placed from total depth upward and tied back approximately 200 feet into the 13⅜-inch intermediate casing across the Eau Claire sealing formation. These CO_2-resistant cement systems are stable under highly acidic conditions, resistant to CO_2 and formation fluids, and capable of maintaining long-term integrity over the design life of the injection well.

The surface-casing cement system will provide isolation for shallow groundwater for the remainder of the well, and the intermediate string will serve as an additional barrier to prevent migration of CO_2 or formation fluids out of the injection zone. The final cementing program—including volumes, displacement rates, and placement technique (e.g., single-stage or two-stage)—will be refined using cement-design software with inputs from drilling operations such as caliper logs, fracture logs, and mud-loss data. A mud flush will be pumped ahead of all cement jobs to aid in borehole cleaning. The injection well will include approximately 80 feet of cement above the casing shoe to prevent the injected CO_2 from contacting the Precambrian granite basement.

Table 11. *Well cement specifications for OES #3 well.*

Name	Depth Interval (feet)	Access.	Stage 1 Lead	Stage 1 Tail	Stage 2 Lead	Stage 2 Tail
Surface	0 - 347	Float Shoe Float Collar Wiper Plug Centralizers	953 sacks (200 bbl) of 15.6 lb/gal Class A Cement (2% C-1 +1/8# C-30) yielding 1.18 ft^3/sack	n/a	n/a	n/a
Intermed.	0 - 4,046	Float Shoe Float Collar Wiper Plug Csg Pkr DV Tool Centralizers	212 sacks (64 bbl) of 13.1 lb/gal G/Poz Cement eXtreme blend with dry latex yielding 1.69 ft^3/sack	415 Sacks (87 bbl) of 15.6 lb/gal Class H Cement (0.8% C-17 + 1/8#C-30 + 2#C-42) yielding 1.18 ft^3/sack	1385 sacks (417 bbl) of 13.1 lb/gal 35/65 Poz/H Cement (6% C-20 + 0.8% C-17 + 0.2% C-13 + C-30) yielding 1.69 ft^3/sack	727 Sacks (153 bbl) of 15.6 lb/gal Class H Cement (0.8% C-17 + 1/8#C-30 + 2#C-42) yielding 1.18 ft^3/sack
Long	0 – 7,100	Float Shoe Float Collar Wiper Plug	481 sacks (209 bbl) of 12.7 lb/gal 35/65 Class A (D035, D020, D046, D167, D153, D079, D013) yielding 2.44 ft^3/sack	1022 Sacks (233 bbl) of 814.0 lb/gal EverCRETE CO_2 resistant (D206, D145A, D500, D177, D174) yielding 1.28 ft^3/sack	n/a	n/a

Casing centralizers are designed to keep the casing centered within the wellbore, ensuring a uniform annular space that supports cement sheath integrity, zonal isolation, and effective mud displacement during cementing. Maximum allowable spacing between centralizers was calculated using API Specification 10D-2. An average inclination of 1.5 degrees was assumed for the calculation, as the wellbore is planned to be vertical. To further improve cement emplacement, the casing will be reciprocated and rotated during cementing operations. The centralizer program will be implemented as detailed in Table 12.

Table 12. *Centralizer Placement Program for Surface, Intermediate, and Long-String Casings.*

Hole Section	Centralizer Program
Surface	One BS centralizer for every joint (approximately 40 ft)
Intermediate	One BS centralizer every 3.3 joints (approximately 120 ft)
Long String	One BS centralizer every 2.7 joints from TD to ~6,000 ft One BS centralizer every 3 joints from ~6,000 ft to the surface
Note: Assumed joint length is 40 ft *BS: Bow-spring*	

Wellhead Design Parameters

The proposed wellhead schematic is presented in Figure 5. The wellhead includes a continuous automatic (shutoff) gate valve, along with access ports for downhole gauges and fiber optic monitoring. The continuous automatic shut-off gate valve is installed for emergency shutdown purposes and meets the referenced criteria. The valve is intended to stop the flow of fluid or gas, without manual intervention, when flow conditions vary outside of predetermined operating conditions. The actuator on the valve converts external energy (compressed air, electricity, hydraulic fluid or stored mechanical energy) into a mechanical motion to close the valve by moving the gate wedge across the flow path and shutting off the flow.

A final design of the annulus pressure maintenance systems is not completed at this time. However, the annular pressure maintenance system will consist of the following components:

- Pressure Gauges - The pressure measurement of the annulus will be automated to alert the CO_2 operator of changes in pressure so manual or automated adjustments can be made to maintain the required positive differential pressure on the annulus. The positive differential may not be maintained during start-up, shutdown, and well maintenance periods.
- Brine Tank(s) and Tank Gauge - The annulus tank will contain an adequate amount of premixed packer fluid so that fluid use can be monitored using a tank gauge, and any fluid introduced into the annulus will be the same as already present.
- Pump or Accumulator – A pump or gas charged accumulator will be incorporated to maintain the pressures necessary on the annulus for the positive differential. It is anticipated that temperature, injection rate, and injection pressure fluctuations will require annular pressure changes to assure appropriate annular pressure.

References

E.M. Russick *et al.* Corrosive effects of supercritical carbon dioxide and cosolvents on metals, Journal of Supercritical Fluids (1996)

Trimeric Corporation et al., 2022. One Earth Energy CO_2 Capture Facility FEED Study and Class 4 Cost Estimate Final Report.

Zhang YC, Gao KW, Schmitt G. 2011. Water effect on steel corrosion under supercritical CO_2 conditions. In: Corrosion 2011. Paper No. 11378. Houston, TX, USA: NACE International, 2011a.

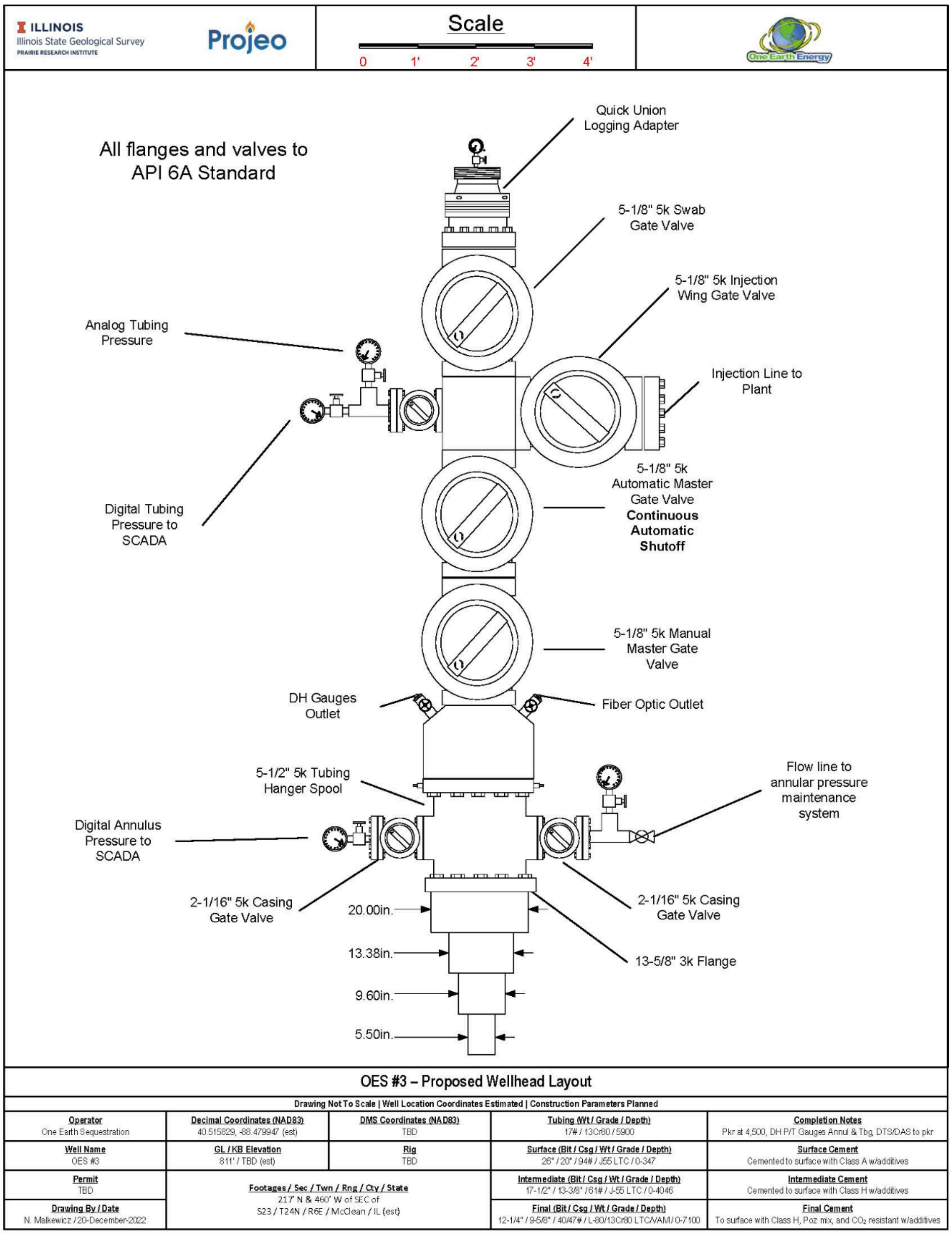

Figure 6*. Proposed OES #3 wellhead schematic.*

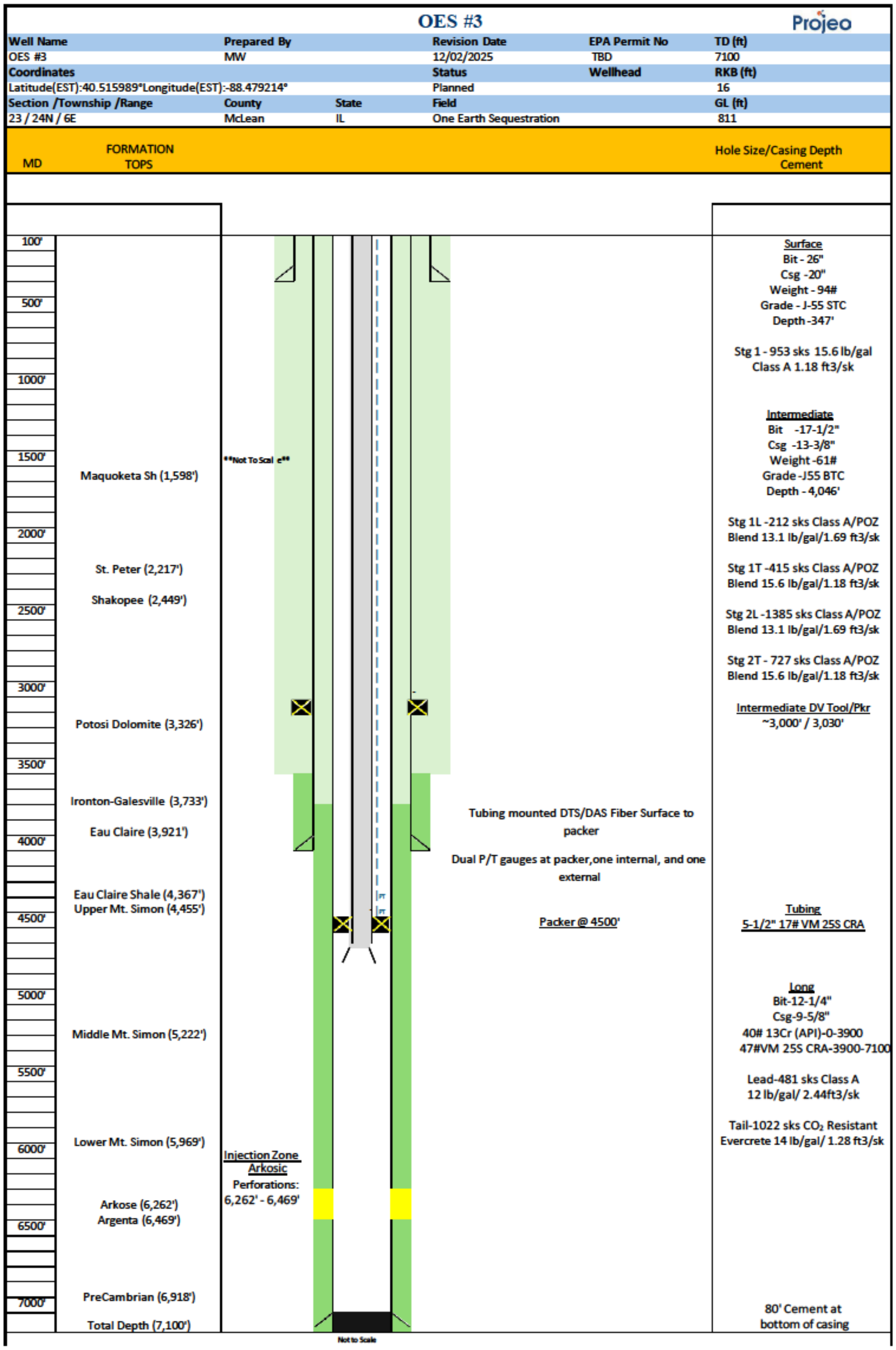

Figure 7. *Wellbore and completions schematic for OES #3 well.*

Appendix A: Construction Details Monitoring Wells

The following section provides construction details for the IZM wells, the ACZ #1 and #2 monitoring wells, and the USDW monitoring well associated with the One Earth Sequestration, LLC OES #3 injection well. Table 13 summarizes all well types for the project, including the injection wells, IZM wells, the ACZ #1 and #2 monitoring wells, the USDW monitoring well, and the planned geophysical monitoring wells.

Table 13. *One Earth CCS well summary.*

Well Type	Well ID	Notes
Injection	OES #1	
	OES #2	
	OES #3	
In-Zone Monitoring (IZM)	IZM #1	Convert stratigraphic test well OEE #1
	IZM #2	Mt Simon Sandstone completion
Above-Confining-Zone Monitoring	OES ACZ #1 OES ACZ#2	Ironton Galesville completion
USDW Monitoring	OES USDW #1	St. Peter Sandstone completion
Geophysical Monitoring Wells	OES #1 OES #2 OES #3 IZM #1 IZM #2 OES ACZ #1 OES ACZ#2 OES USDW #1	Permanent array in project wells

IZM Construction details

The IZM wells will be fully cased, with all casing strings cemented back to ground level as detailed in Table 14 and Table 15 illustrated in Figure 11 and Figure 12. The in-zone monitoring wells will utilize the same materials deemed appropriate for the injection wells and will be compatible with the CO_2 stream. The long string will incorporate a CO_2-resistant cement slurry, such as EverCRETE or equivalent. CO_2-resistant cement will be placed from total depth to approximately 400 feet into the 9-5/8-inch casing, covering the Ironton–Galesville formation.

IZM #1 will be constructed by converting the stratigraphic test well OEE #1 into a monitoring well, which includes covering the 13Cr (API) long string with a VM 25S CRA liner. The final location of IZM #2 will be selected based on site-characterization data. Formation tops and detailed well design parameters will be confirmed during drilling and pre-operational testing. The cementing program for each well—including volumes, displacement rates, and placement technique (e.g., single-stage or two-stage)—will be refined using cement-design software informed by drilling data such as caliper logs, fracture logs, and mud-loss information. A mud flush will be pumped ahead of all cement jobs to assist with mud removal. Cement program can be found in Table 16 and Table 17

Table 14. *Well casing and tubing specifications for the IZM #1 well.*

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Nominal Weight (lb/ft)	Material/Alloy	Design Coupling/Joint Yield (klbf)	Thermal Conductivity @ 77 ° F (BTU/ft.hr. °F)	Tensile Strength (klbf)	Collapse Strength (psi)	Burst Strength (psi)
Surface	0 - 350	13-3/8	12.515	61	J55	STC / 595	31	962	1,540	3,090
Intermediate	0 - 4,000	9-5/8	8.835	40	J55	BTC / *947*	31	630	2,570	3,950
Long (chrome)	0 – 7,100	5-1/2	4.892	17.0	13Cr (API)	VAM 21 /397	16	397	6,290	7,740
Liner (chrome)	3,600 - 7,000	3-1/2	2.922	10.2	VM 25S CRA	VAM 21 / 233	16	233	12,120	11,560
Tubing	0 - 3,500	2-7/8	2.259	8.7	VM 25S CRA	VAM TOP / 397	16	198	15,300	15,430

Table 15. *Well casing and tubing specifications for the IZM #2 well.*

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Nominal Weight (lb/ft)	Material/Alloy	Design Coupling/Joint Yield (klbf)	Thermal Conductivity @ 77° F (BTU/ft.hr. °F)	Tensile Strength (klbf)	Collapse Strength (psi)	Burst Strength (psi)
Surface	0 - 350	13-3/8	12.515	61	J55	STC / 595	31	962	1,540	3,090
Intermediate	0 - 4,000	9-5/8	8.835	40	J55	BTC / 947	31	630	2,570	3,950
Long (chrome)	0 - 3,600	5-1/2	4.892	17.0	13Cr (API)	VAM 21 / 397	16	397	6,290	7,740
Long (chrome)	3,600 - 7,100	5-1/2	4.892	17.0	VM 25S CRA	VAM 21 / 397	16	397	6,290	7,740
Tubing	0 - 3,500	2-7/8	2.259	8.7	VM 25S CRA	VAM TOP / 397	16	198	15,300	15,430

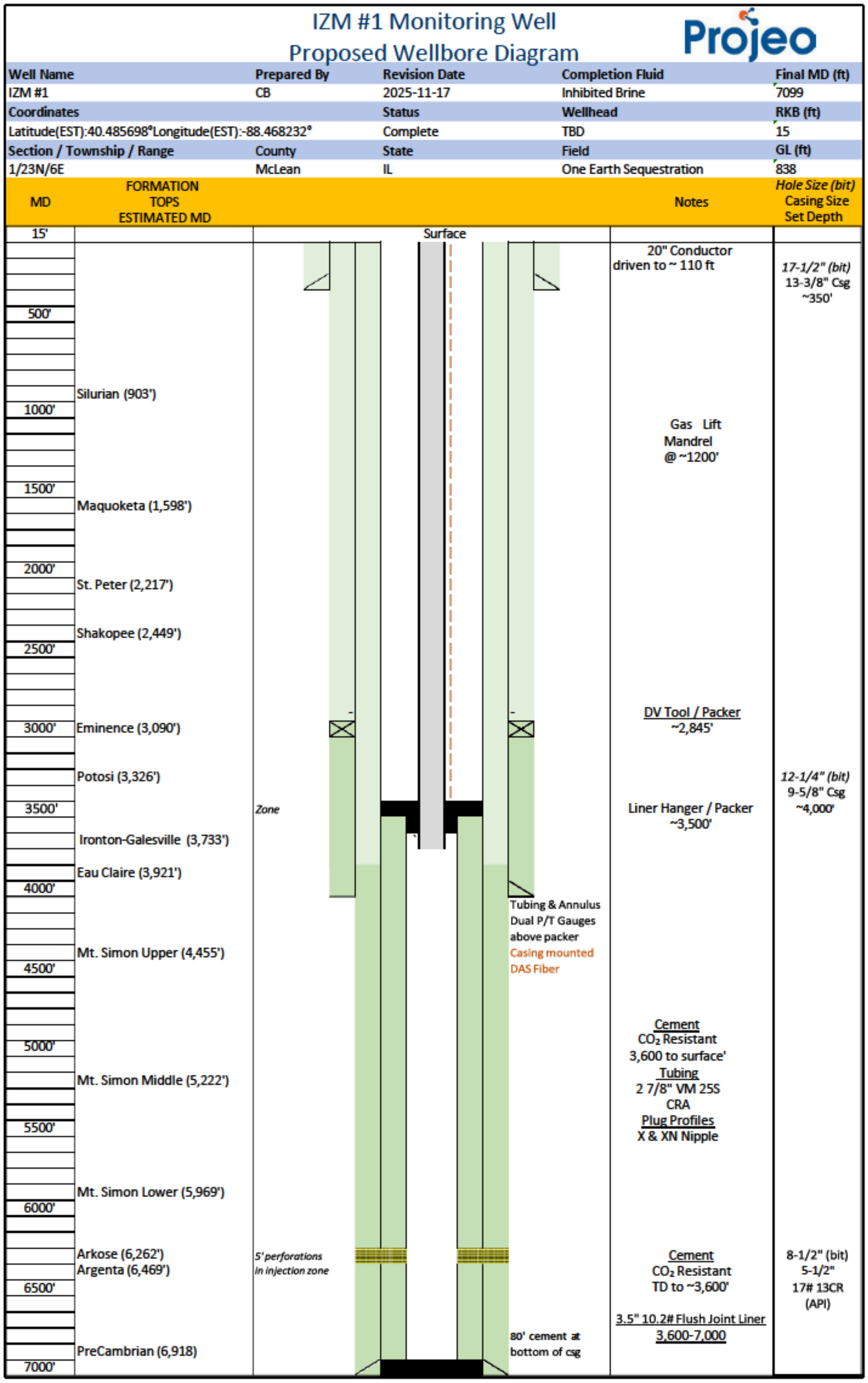

Figure 11. *Wellbore and completions schematic for IZM #1 well.*

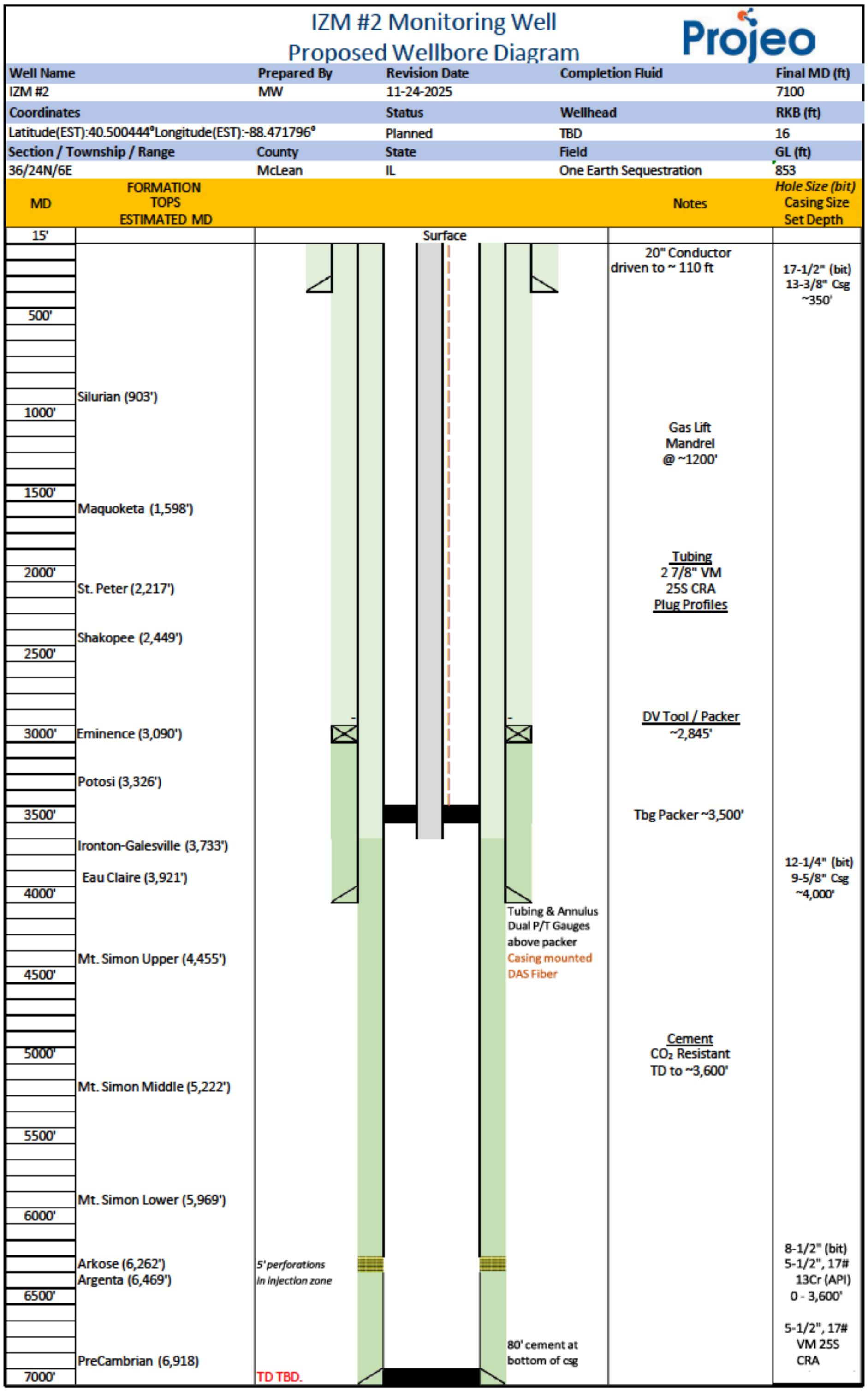

Figure 12. *Wellbore and completions schematic for IZM #2 well.*

IZM Cement Specifications

Table 16. *Well cement specifications for IZM #1 well.*

Name	Depth Interval (feet)	Access.	Stage 1 Lead	Stage 1 Tail	Stage 2 Lead	Stage 2 Tail
Surface	0 - 350	Float Shoe Float Collar Wiper Plug Centralizers	441 sacks (92 bbl) of 15.6 lb/gal Class A Cement 1.18 ft^3/sack	n/a	n/a	n/a
Intermediate.	0 - 4,000	Float Shoe Float Collar Wiper Plug Csg Pkr DV Tool Centralizers	48 sacks (15 bbl) of 13.1 lb/gal 35/65 Poz/H Cement blend with 1.69 ft^3/sack	361 Sacks (76 bbl) of 15.6 lb/gal Class H Cement yielding 1.18 ft^3/sack	569 sacks (172 bbl) of 13.1 lb/gal 35/65 Poz/H Cement yielding 1.69 ft^3/sack	276 sacks (58 bbl) of 15.6 lb/gal Class H Cement yielding 1.18 ft^3/sack
Longstring	0 – 7,100	Float Shoe Float Collar Wiper Plug Centralizers	347 sacks (151 bbl) of 12.0 lb/gal 35/65 Poz/Class A yielding 2.44 ft^3/sack	1129 Sacks (257 bbl) of 14.0 lb/gal EverCRETE CO_2 resistant cement yielding 1.28 ft^3/sack	n/a	n/a
Liner	3,600 - 7,000	Float Shoe Float Collar Wiper Plug Centralizers	176 Sacks (40 bbl) of 14.0 lb/gal EverCRETE CO_2 resistant cement yielding 1.28 ft3/sack	n/a	n/a	n/a

Table 17. Well cement specifications for IZM #2 well.

Name	Depth Interval (feet)	Access.	Stage 1 Lead	Stage 1 Tail	Stage 2 Lead	Stage 2 Tail
Surface	0 - 350	Float Shoe Float Collar Wiper Plug Centralizers	441 sacks (92 bbl) of 15.6 lb/gal Class A Cement 1.18 ft^3/sack	n/a	n/a	n/a
Intermediate.	0 - 4,000	Float Shoe Float Collar Wiper Plug Csg Pkr DV Tool Centralizers	48 sacks (15 bbl) of 13.1 lb/gal 35/65 Poz/H Cement blend with 1.69 ft^3/sack	361 Sacks (76 bbl) of 15.6 lb/gal Class H Cement yielding 1.18 ft^3/sack	569 sacks (172 bbl) of 13.1 lb/gal 35/65 Poz/H Cement yielding 1.69 ft^3/sack	276 sacks (58 bbl) of 15.6 lb/gal Class H Cement yielding 1.18 ft^3/sack
Longstring	0 – 7,100	Float Shoe Float Collar Wiper Plug Centralizers	347 sacks (151 bbl) of 12.0 lb/gal 35/65 Poz/Class A yielding 2.44 ft3/sack	1129 Sacks (257 bbl) of 14.0 lb/gal EverCRETE CO2 resistant cement yielding 1.28 ft3/sack	n/a	n/a

IZM Plugging Plan

The IZM wells will be plugged and abandoned in a manner similar to the injection well, details can be found in the Plugging and Abandonment Plan. A CO_2-resistant cement slurry, such as EverCRETE, will be used for Plugs #1–5 from total depth to within the confining zone. The first plug will be placed as a retainer squeeze to seal the perforations, followed by balanced cement plugs for the remaining stages. An inhibited spacer fluid will then be pumped prior to placing the remaining Class A cement plugs (Plugs #6–10) to the surface. Plugging details are provided in Tables 18 and 19 and illustrated in Figures 13 and 14.

Table 18. *Proposed plugging plan for IZM #1.*

Plug Info.		Plug #1	Plug #2	Plug #3	Plug #4	Plug #5	Plug #6	Plug #7	Plug #8	Plug #9	Plug #10
Plug Diameter (inches)		2.922	2.922	2.922	2.922	2.922	4.892	4.892	4.892	4.892	4.892
Depth to bottom of pipe (feet, ft)		6,200	6,190	5,490	4,990	4,490	2,490	1,990	1,490	990	490
Sx of cement to be used (sacks)		36	30	22	22	22	56	56	55	55	55
Slurry volume	ft3	38	33	23	23	23	65	65	65	65	65
	barrels	6.8	5.8	4.1	4.1	4.1	11.6	11.6	11.6	11.6	11.6
Slurry weight (pounds/gallon)		16	16	16	16	16	15.6	15.6	15.6	15.6	15.6
Cement Yield (cu.ft./sack)		1.08	1.08	1.08	1.08	1.08	1.18	1.18	1.18	1.18	1.18
Top of Plug (ft)		6,200	5,500	5,000	4,500	4,000	2,000	1,500	1,000	500	0
Bottom of Plug (ft)		7,020	6,200	5,500	5,000	4,500	2,500	2,000	1,500	1,000	500
Type of Cement		CO_2 Resistant Cement					Class "A"				
Method of Placement		Retainer	Balance				Balance				

__Table 19.__ Proposed plugging plan for IZM #2.

Plug Info.		Plug #1	Plug #2	Plug #3	Plug #4	Plug #5	Plug #6	Plug #7	Plug #8	Plug #9	Plug #10
Plug Diameter (inches)		4.892	4.892	4.892	4.892	4.892	4.892	4.892	4.892	4.892	4.892
Depth to bottom of pipe (feet, ft)		6,200	6,190	5,490	4,990	4,490	2,490	1,990	1,490	990	490
Sx of cement to be used (sacks)		99	84	60	60	60	56	56	55	55	55
Slurry volume	ft3	107	91	65	65	65	65	65	65	65	65
	barrels	19.1	16.3	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Slurry weight (pounds/gallon)		16	16	16	16	16	15.6	15.6	15.6	15.6	15.6
Cement Yield (cu.ft./sack)		1.08	1.08	1.08	1.08	1.08	1.18	1.18	1.18	1.18	1.18
Top of Plug (ft)		6,200	5,500	5,000	4,500	4,000	2,000	1,500	1,000	500	0
Bottom of Plug (ft)		7,020	6,200	5,500	5,000	4,500	2,500	2,000	1,500	1,000	500
Type of Cement		CO_2 Resistant Cement					Class "A"				
Method of Placement		Retainer	Balance				Balance				

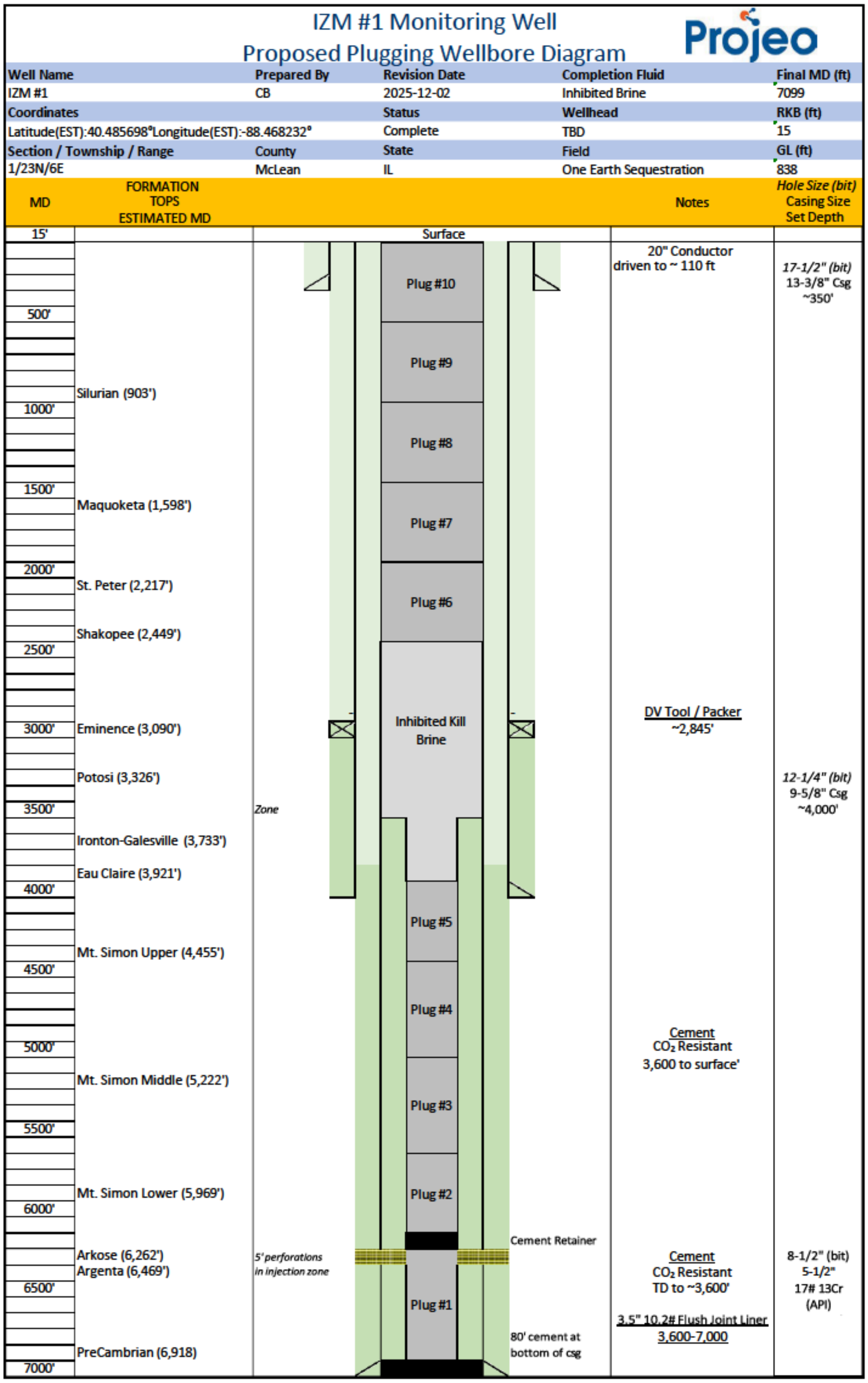

Figure 13. *Planned wellbore plugging schematic for IZM #1 well.*

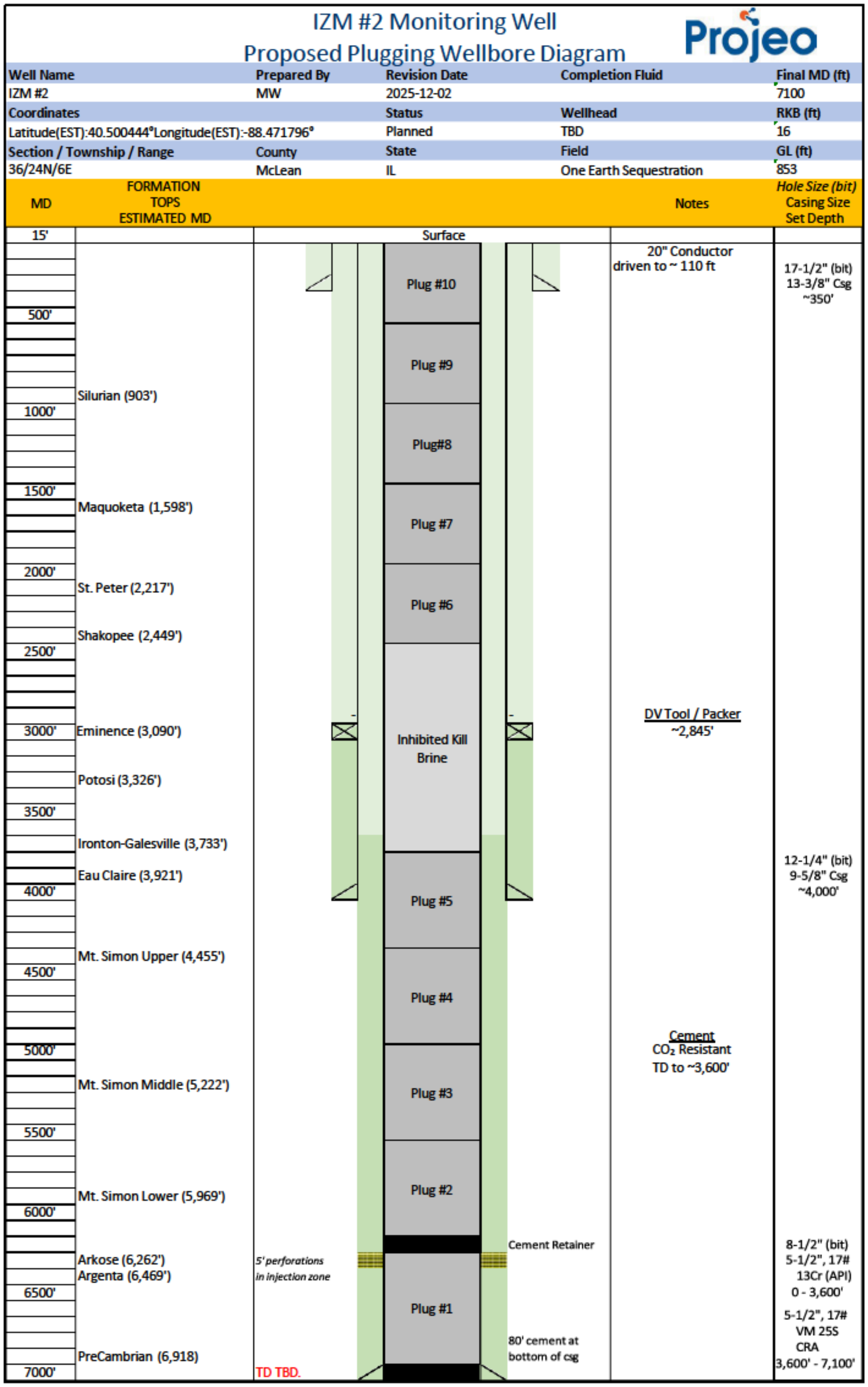

Figure 14. *Planned wellbore plugging schematic for IZM #2 well.*

ACZ #1 and #2 Construction Details

The ACZ #1 and #2 monitoring wells is not anticipated to encounter injected CO_2 or experience significant mechanical stresses. Construction details are provided in Table 20 and illustrated in Figure 15. The well will be constructed with all casing strings cemented to the surface using conventional Portland cement. Cement program is listed in Table 21. Perforations through the long string into the Ironton–Galesville will be monitored using downhole pressure and temperature gauges. The tubing will be installed open-ended and without a packer.

Table 20. *Well casing and tubing specifications for the ACZ#1 and #2 wells.*

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Nominal Weight (lb/ft)	Material/Alloy	Design Coupling/Joint Yield (klbf)	Thermal Conductivity @ 77 ° F (BTU/ft.hr. °F)	Tensile Strength (klbf)	Collapse Strength (psi)	Burst Strength (psi)
Conductor	0 - 110	13-3/8	12.515	61	J55	STC / 595	31	962	1,540	3,090
Surface	0 - 350	9-5/8	8.835	40	J55	LTC / 520	31	630	2,570	3,950
Long	0 - 3,961	5-1/2	4.892	17	J55	STC / 229	31	273	4,910	5,320
Tubing	0 - 3,500	2-7/8	2.441	6.5	J55	8rd EUE / 100	31	100	7,680	7,260

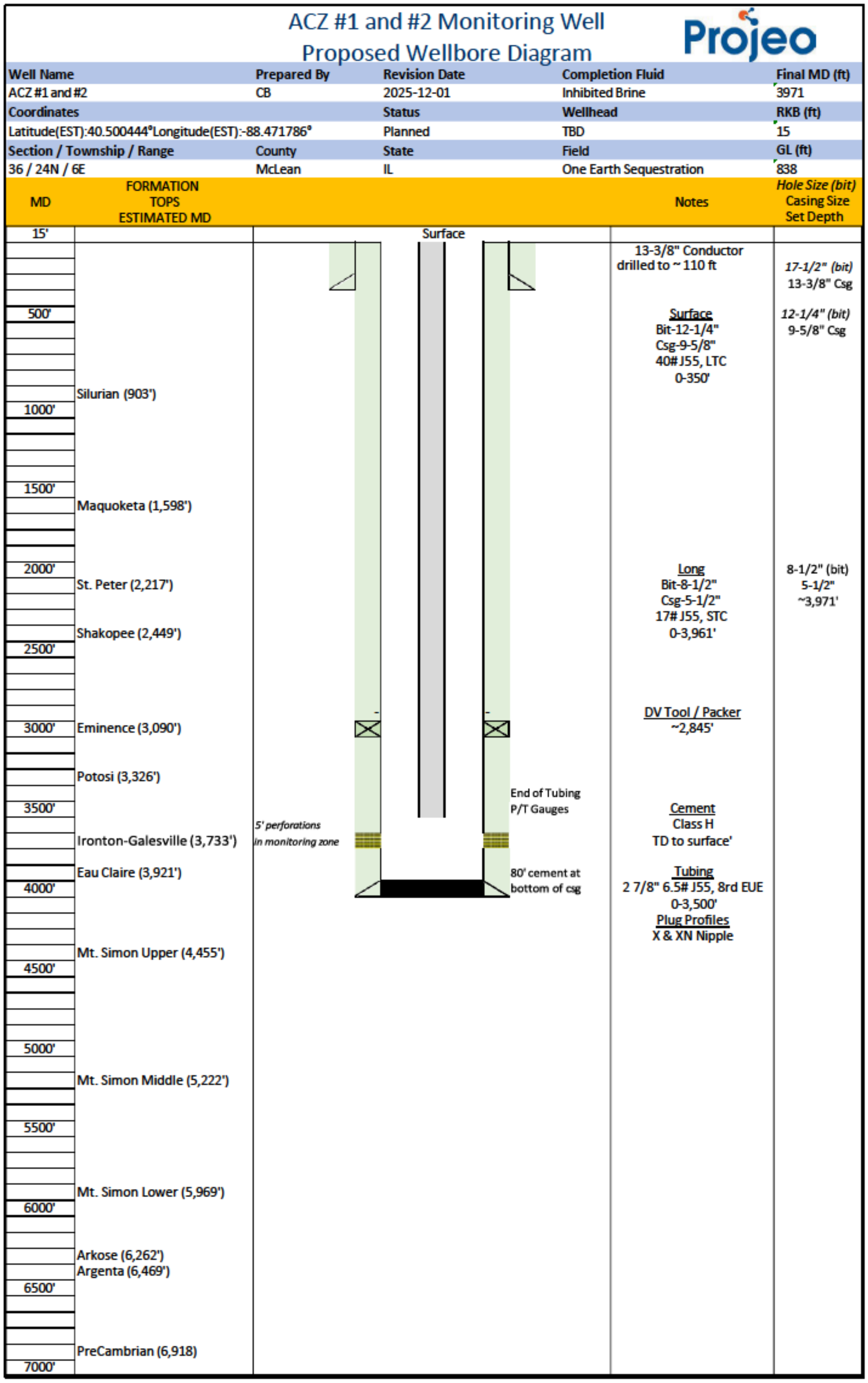

Figure 15. *Wellbore and completions schematic for ACZ #1and #2 wells.*

ACZ #1 and #2 Cement Specifications

Table 21. *Well cement specifications for ACZ #1 and #2 wells.*

Name	Depth Interval (feet)	Access.	Stage 1 Lead	Stage 1 Tail	Stage 2 Lead	Stage 2 Tail
Conductor	0 – 110	Float Shoe Float Collar Wiper Plug Centralizers	146 sacks (31 bbl) of 15.6 lb/gal Class A Cement with 1.18 ft^3/sack	n/a	n/a	n/a
Surface	0 – 350	Float Shoe Float Collar Wiper Plug Centralizers	200 sacks (42 bbl) of 15.6 lb/gal Class A Cement with 1.18 ft^3/sack	n/a	n/a	n/a
Longstring	0 – 3,961	Float Shoe Float Collar Wiper Plug Csg Pkr DV Tool Centralizers	338 sacks (69 bbl) of 15.8 lb/gal Class G cement with 1.15 ft^3/sack		335 sacks (101 bbl) of 13.1 lb/gal 65/35 POZ cement with 1.69 ft3/sack	245 sacks (50 bbl) of 15.8 lb/gal Class G cement with 1.15 ft3/sack

ACZ Plugging Plan

Monitoring well ACZ #1 and #2 will be plugged and abandoned with Class A cement from total depth to the surface. The well is anticipated to be static; however, if necessary, it will be bullheaded with an appropriately weighted kill brine. The required brine weight will be calculated based on bottomhole pressure measured using the gauges in the well.

The tubing and completion accessories will then be pulled, and balanced cement plugs of approximately 500 feet each will be pumped to the surface. See Table 22 for plugging details and illustrated in Figure 16.

Table 22. *Proposed plugging plan for ACZ #1 and #2.*

Plug Info.		Plug #1	Plug #2	Plug #3	Plug #4	Plug #5	Plug #6	Plug #7	Plug #8
Plug Diameter (inches)		4.892	4.892	4.892	4.892	4.892	4.892	4.892	4.892
Depth to the bottom of pipe (feet, ft)		3,881	3,381	2,881	2,381	1,881	1,381	881	381
Sx of cement to be used (sacks)		56	56	56	56	56	56	56	43
Slurry volume	ft3	65	65	65	65	65	65	65	51
	barrels	11.6	11.6	11.6	11.6	11.6	11.6	11.6	9.1
Slurry weight (pounds/gallon)		15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Cement Yield (cu.ft./sack)		1.18	1.18	1.18	1.18	1.18	1.18	1.18	1.18
Top of Plug (ft)		3,391	2,891	2,391	1,891	1,391	891	391	0
Bottom of Plug (ft)		3,891	3,391	2,891	2,391	1,891	1,391	891	391
Type of Cement		Class A							
Method of Placement		Balance							

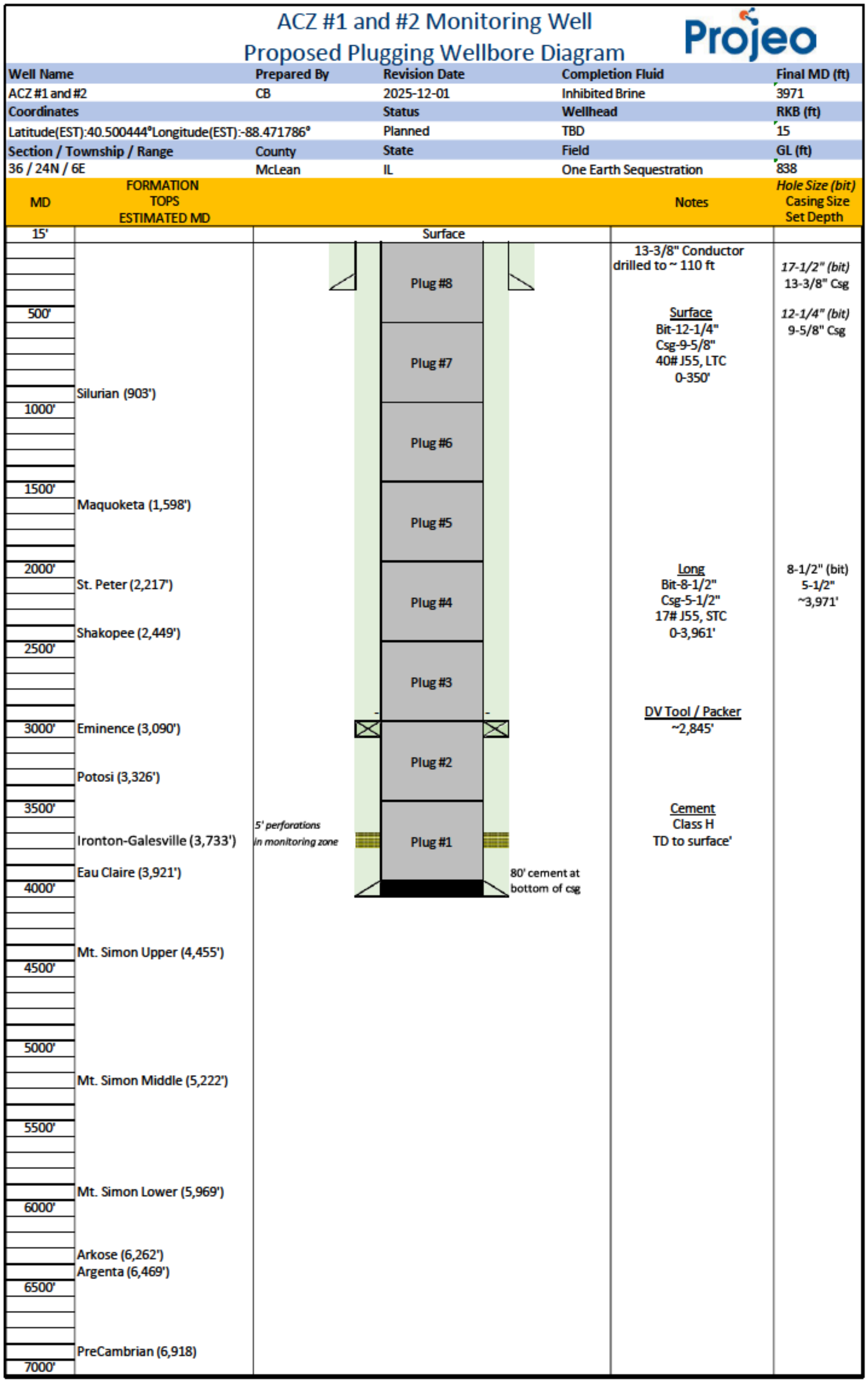

Figure 16. *Planned wellbore plugging schematic for ACZ #1 and #2 wells.*