Denbury Carbon Solutions, LLC

Well Construction Details

Orion Storage Facility, Baldwin County, Alabama

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ACRONYMS/ABBREVIATIONS

Acronyms/Abbreviations	Definition
µm	micron
bgs	Below Ground Surface
BTC	Buttress Thread Coupling
ft	Feet
gal	Gallon
ID	Inner Diameter
in	Inch
lb	Pound
LT&C	Long Thread & Coupling
MMscf	Million Standard Cubic Feet
NPT	National Pipe Thread
OD	Outer Diameter
PDHG	Permanent Downhole Gauge
Perf	Perforation
POZ	Pozzolan
ppf	Pounds per Foot
ppg	Pounds per Gallon
psi	Pound per Square Inch
SOW	Slip On Wellhead
ST&C	Short Thread & Coupling
sx	Sacks
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water

1.0 FACILITY INFORMATION

Facility Name: Orion Storage Facility

Facility Location: 30.786402, -87.684030 (NAD27)

Mailing Address: 5851 Legacy Circle, Suite 1200
Plano, Texas 75024

Well Location(s) Baldwin County, Alabama

Orion #1:	30.786402, -87.684030 (NAD27)
Orion #2:	30.800269, -87.683269 (NAD27)
Orion #3:	30.800072, -87.660169 (NAD27)
Chastang #1:	30.763484, -87.685995 (NAD27)

The construction details for the Project Orion injection wells are described in this attachment.

2.0 WELL DESIGN

This document defines the design basis, assumptions, and construction details for Project Orion. Denbury Carbon Solutions, LLC plans to construct three CO_2 injection wells in Baldwin County, Alabama. The wells are to be constructed in compliance with Class VI UIC injection well construction requirements. All three wells, Orion #1, Orion #2, and Orion #3 will target the Paluxy Formation as the primary injection zone target. The Paluxy formation is a heterolithic sandstone that spans across the southern states including Alabama. Multiple confining zones have been identified, including the Ferry Lake Anhydrite, the Mooringsport formation, the shale interval (flooding surface) of the Paluxy, the shale interval (flooding surface) at the base of the Lower Tuscaloosa formation, and the Tuscaloosa Marine Shale. These formations are mainly mudstones, creating multiple confining zones. Denbury will also drill a stratigraphic well (the Chastang #1) that will be converted to a monitoring well. The three injection wells all have a total depth of 11,600 feet. Each well will inject 666,667 tonnes of CO_2 per year over a 20-year period, equating to a total of 40 million metric tonnes of CO_2 injected. Denbury plans to perforate and inject into three (3) separate intervals within the Paluxy Formation at different times during the project. As Denbury operates the Orion #1, #2, and #3 wells, Denbury will isolate the previous injection interval and perforate the next, shallower zone. The assumed bottom-hole temperature is 210°F. The injection wells will be designed to accommodate a stream that is ≥97% CO_2. Further carbon dioxide stream details concerning the constituents, corrosiveness, and temperature will be provided when they become available.

The following sections describe the injection well design, including information about wellhead injection pressure, casing and tubing, cementing, packer, annular fluid, the wellhead, perforations, and schematics.

2.1 AVERAGE AND MAXIMUM WELLHEAD INJECTION PRESSURE

Parameter	Average	Maximum		
Flow rate (MMscf/day)	35.2	92		
Surface Injection Pressure (psi)	1,850	2,200		
Estimated Bottom-hole injection pressure (psi)	**Orion #1 - 4,950** **Orion #2 - 4,760** **Orion #3 - 4,850**	Orion #1	Perf Interval 1	5,531
			Perf Interval 2	5,339
			Perf Interval 3	5,230
		Orion #2	Perf Interval 1	5,352
			Perf Interval 2	5,207
		Orion #3	Perf Interval 1	5,618
			Perf Interval 2	5,412
			Perf Interval 3	5,315

Table 1: Flow Rates and Limiting Pressures for Hydraulic Calculations

3.0 CASING AND TUBING PROGRAM

The safety design factors are as follows:

- Burst rating with design safety factor of 1.1
- Collapse rating with design safety factor of 1.125
- Tensile load with design safety factor of 1.8

Design factors of the casing strings and tubing must exceed these safety design factors. They are described in the following sections.

3.1 INJECTION WELL CONDUCTOR CASING

The 20" diameter conductor casing, 94 lb/ft H-40 with a welded connection will be set using a drive pipe. It will be driven to a depth of 100 feet. The conductor casing will be cemented to the surface.

3.2 INJECTION WELL SURFACE CASING

The 13-3/8" diameter surface casing, 54.5 lb/ft J-55 with BTC (buttress thread coupling) meets the design criteria in Table 2. Burst, collapse, and tension scenarios and assumptions are displayed below. The surface casing will be cemented to the surface and set at 1,475 feet in order to protect the lowermost USDW. The lowermost USDW is at a depth of 1,300 feet. The borehole diameter is 17-1/2 inches.

Burst Scenario and Assumptions

$$P_{shoe} = (FG + SF) \times 0.052 \times D_{csg} - MW \times 0.052 \times D_{csg}$$

and

$$P_{surf} = P_{\text{int}} - (G_g \times D_{csg})$$

where,

P_{shoe} = Maximum anticipated shoe pressure, psi
P_{surf} = Maximum anticipated surface pressure, psi
P_{int} = Internal shoe pressure, psi
FG = Estimated fracture pressure at shoe, lb/gal
SF = Burst loading safety factor
D_{csg} = Casing setting depth, feet
MW = Mud Weight of drilling fluid, lb/gal
0.052 = Conversion factor, psi-gal/ft-lb
G_g = Gas gradient, (0.115 psi/ft)

Collapse Scenario and Assumptions

$$P_{shoe} = (MW_{lead} \times 0.052 \times D_{lead}) + MW_{tail} \times 0.052 \times H_{tail}$$

and

$$P_{tt} = MW_{lead} \times 0.052 \times D_{lead}$$

where,

P_{shoe} = Maximum anticipated external shoe pressure, psi
P_{tt} = Maximum anticipated external pressure at top of tail cement, psi
MW_{lead} = Mud Weight of lead cement, lb/gal
D_{lead} = Depth of Lead Cement, feet
H_{tail} = Height of tail slurry, feet
0.052 = Conversion factor, psi-gal/ft-lb

Tension Scenario and Assumptions

$$W_{\max} = W_{csg} \times D_{csg} - MW \times A_{csg} \times 0.052 \times D_{csg}$$

where,

W_{max} = Maximum tensile weight at worst case, lbs
W_{csg} = Unit casing weight, lb/ft
D_{csg} = Casing setting depth, feet
MW = Mud Weight of drilling fluid, lb/gal
A_{csg} = Cross-sectional area of casing (15.51 sq. in.)

0.052 = Conversion factor, psi-gal/ft-lb

Load Scenario	Calculated Safety Factor	Depth (ft)
Burst	3.15	1,475
Collapse	4.20	1,475
Tension (Axial Loading)	10.61	1,475

Table 2: Minimum Design Factors and Corresponding Scenarios for Surface Casing String

3.3 INJECTION WELL INTERMEDIATE CASING

The 9-5/8" diameter intermediate casing, 47 lb/ft L-80 LT&C meets the design criteria in Table 3. Burst, collapse, and tension scenarios and assumptions are displayed below. The intermediate casing will be cemented to the surface and the borehole diameter is 12-1/4" inches.

Burst Scenario and Assumptions

$$P_{shoe} = MW_{lead} \times 0.052 \times H_{lead} + MW_{tail} \times 0.052 \times H_{tail} - MW \times 0.052 \times (D_{csg}) + MASP_{cmt}$$

where,

P_{shoe} = Maximum anticipated shoe pressure, psi
MW_{lead} = Mud Weight of Lead Cement, lb/gal
H_{lead} = Height of lead cement in pipe, feet
MW_{tail} = Mud Weight of Tail Cement, lb/gal
H_{tail} = Height of tail cement in pipe, feet
MW = Mud Weight of drilling fluid, lb/gal
D_{csg} = Casing setting depth, feet
0.052 = Conversion factor, psi-gal/ft-lb
$MASP_{cmt}$ = Maximum allowable surface pressure during cementing, psig

Collapse Scenario and Assumptions

$$P_{shoe} = (MW_{lead} \times 0.052 \times D_{lead}) + MW_{tail} \times 0.052 \times L_{tail} - MW \times 0.052 \times D_{csg}$$

where,

P_{shoe} = Maximum anticipated shoe pressure, psi
MW_{lead} = Mud Weight of lead cement, lb/gal
D_{lead} = Depth of Lead Cement, feet
MW_{tail} = Mud Weight of tail cement lb/gal
L_{tail} = Height of tail slurry, feet
MW = Mud Weight of drilling fluid, lb/gal
D_{csg} = Casing setting depth, feet
0.052 = Conversion factor, psi-gal/ft-lb

Tension Scenario and Assumptions

$$W_{max} = W_{csg} \times D_{csg} - MW \times A_{csg} \times 0.052 \times D_{csg}$$

where,

W_{max} = Maximum tensile weight at worst case, lbs
W_{csg1} = Unit weight of casing 1, lb/ft
L_{csg1} = Casing 1 length, feet
W_{csg2} = Unit weight of casing 2, lb/ft
L_{csg2} = Casing 2 length, feet
MW = Mud Weight of drilling fluid, lb/gal
A_{csg} = Cross-sectional area of casing 1 (13.57 sq. in.)
D_{csg} = Casing setting depth, feet
0.052 = Conversion factor, psi-gal/ft-lb

Load Scenario	Calculated Safety Factor	Depth (ft)
Burst	1.70	0-6,500
Collapse	3.57	0-6,500
Tension (Axial Loading)	1.93	0-6,500

Table 3: Minimum Design Factors and Corresponding Scenarios for Intermediate Casing String

3.4 INJECTION WELL PROTECTIVE LINER

The 7" diameter protective Liner, 29 lb/ft SM25Cr125 Vam Top meets the design criteria in Table 4. Burst, collapse, and tension scenarios and assumptions are displayed below. The protective liner will be cemented to the liner hanger top depth of 6,200 feet; and the borehole diameter is 8-1/2" inches.

Burst Scenario and Assumptions

$$P_{shoe} = MW_{lead} \times 0.052 \times H_{lead} + MW_{tail} \times 0.052 \times H_{tail} - MW \times 0.052 \times (D_{csg}) + MASP_{cmt}$$

where,

P_{shoe} = Maximum anticipated shoe pressure, psi
MW_{lead} = Mud Weight of Lead Cement, lb/gal
H_{lead} = Height of lead cement in pipe, feet
MW_{tail} = Mud Weight of Tail Cement, lb/gal
H_{tail} = Height of tail cement in pipe, feet
MW = Mud Weight of drilling fluid, lb/gal
D_{csg} = Casing setting depth, feet
0.052 = Conversion factor, psi-gal/ft-lb
$MASP_{cmt}$ = Maximum allowable surface pressure during cementing, psig

Collapse Scenario and Assumptions

$$P_{shoe} = (MW_{lead} \times 0.052 \times D_{lead}) + MW_{tail} \times 0.052 \times L_{tail} - MW \times 0.052 \times D_{csg}$$

where,

P_{shoe} = Maximum anticipated shoe pressure, psi
MW_{lead} = Mud Weight of lead cement, lb/gal
D_{lead} = Depth of Lead Cement, feet
MW_{tail} = Mud Weight of tail cement lb/gal
L_{tail} = Height of tail slurry, feet
MW = Mud Weight of drilling fluid, lb/gal
D_{csg} = Casing setting depth, feet
0.052 = Conversion factor, psi-gal/ft-lb

Tension Scenario and Assumptions

$$W_{\max} = W_{csg} \times D_{csg} - MW \times A_{csg} \times 0.052 \times D_{csg}$$

where,

W_{max} = Maximum tensile weight at worst case, lbs
W_{csg1} = Unit weight of casing 1, lb/ft
L_{csg1} = Casing 1 length, feet
W_{csg2} = Unit weight of casing 2, lb/ft
L_{csg2} = Casing 2 length, feet
MW = Mud Weight of drilling fluid, lb/gal
A_{csg} = Cross-sectional area of casing 1 (8.45 sq. in.)
D_{csg} = Casing setting depth, feet
0.052 = Conversion factor, psi-gal/ft-lb

Load Scenario	Calculated Safety Factor	Depth (ft)
Burst	1.82	6,200-11,600
Collapse	6.37	6,200-11,600
Tension (Axial Loading)	5.87	6,200-11,600

Table 4: Minimum Design Factors and Corresponding Scenarios for Protective Liner String

3.5 INJECTION WELL TUBING

The injection tubing will be a tapered string of 5-½" diameter, 17 lb/ft L-80 and 4-½", 12.6 L-80 (flush joints), internally coated with premium connections. The tubing meets the design criteria in Table 5. Burst, collapse, and tension scenarios and assumptions are displayed below.

Burst Scenario and Assumptions

$$P_{\max} = P_{\max inj} + (0.433 \times SG_{injfl} \times D) - (0.433 \times SG_{afl} \times D)$$

where,

P_{max} = Maximum internal pressure, psi
$P_{max\,inj}$ = Maximum injection pressure, psi
SG_{injfl} = Maximum specific gravity of injection fluid
D = Depth of tubing, feet
0.433 = Pressure gradient, psi/ft
SG_{afl} = Specific gravity of annular fluid
P_{max} = 2,000+ (0.433 x 0.673 x 10,200) – (0.433 x1.01 x 10,200)
P_{max} = 511 psig.

The burst pressure rating of the 5-1/2" O.D., 17lb/ft, L-80 premium connection tubing is 7,740 psig, which results in a design safety factor of 15.15 (7,740/511) and 4-1/2" O.D., 12.6 lb/ft, L-80 premium connection tubing is 8,430 psig, resulting a safety design factor of 16.50 (8,430/511) respectively.

Collapse Scenario and Assumptions

$$P_{max} = P_{maxan} + (0.433 \times SG_{afl} \times D) - (0.433 \times SG_{injfl} \times D)$$

where,

P_{max} = Maximum external pressure, psi
P_{maxan} = Maximum annular pressure, psi
SG_{injfl} = Minimum specific gravity of injection fluid
D = Depth of tubing, feet
0.433 = Pressure gradient, psi/ft
SG_{afl} = Specific gravity of annular fluid
P_{max} = 2,000 + (0.433 x 1.01 x 10,200) – (0.433 x 0.673 x 10,200)
P_{max} = 3,489 psig

The collapse pressure rating of the 5-1/2" O.D., 17lb/ft, L-80 premium connection tubing is 6,390 psig, which results in a design safety factor of 1.83 (6,390/3,489) and 4-1/2" O.D., 12.6 lb/ft, L-80 premium connection tubing is 7500 psig, resulting a safety design factor of 2.15 (7,500/3,489) respectively

Tension Scenario and Assumptions

$$W_{max} = W_{ta} \times D$$

where,

W_{max} = Maximum tensile weight at worst case, lbs
W_{ta} = Unit weight of injection tubing, lb/ft
D = Depth of tubing, feet
W_{max} = (17 x 6,000) + (12.6 x 4,200)
W_{max} = 154,920 lbs

The tensile strength rating of the 5-1/2" O.D., 17lb/ft, L-80 premium connection tubing is 356,000 lbs, which results in a design safety factor of 2.30 (356,000/154,920) and 4-1/2" O.D., 12.6 lb/ft, L-80 premium connection tubing is 288,000 lbs, which results in a design safety factor of 1.90 (288,000/154,920) respectively

Load Scenario	Calculated Safety Factor	Depth (ft)
Burst	15.15 for 5-1/2" 16.50 for 4-1/2"	See Table 8
Collapse	1.83 for 5-1/2" 2.15 for 4-1/2"	See Table 8
Tension (Axial Loading)	2.30 for 5-1/2" 1.90 for 4-1/2"	See Table 8

Table 5: Minimum Design Factors and Corresponding Scenarios for Tubing String

3.6 INJECTION WELL INTERNAL COATING

The internal coating to be used is Tuboscope TK-15XT. TK-15XT has a greater level of abrasion resistance than previous Tuboscope models, but still maintains the same level of temperature and chemical resistance. Specifications for the TK-15XT interior coating are described in Table 6.

TK-15XT Specifications	
Type	Modified Novolac (Powder)
Color	Dark Green
Temperature	300°F (149°C)
Pressure	To yield strength of pipe
Applied Thickness	254-457 µm
Primary Applications	Production tubing, water and CO_2 injection, disposal wells and flow lines.
Primary Service	Oil, natural gas, fresh and salt water, sweet corrosion (CO_2), mild H_2S and alkaline service to pH 12.
Limited Service	Maximum operating temperature and H_2S level will be dependent on total operating environment.

Table 6: TK-15XT Internal Coating Specifications

3.7 CASING AND TUBING SUMMARY FOR INJECTION WELLS

Casing String	Casing Depth, (ft bgs)	Borehole Diameter	Casing Outside Diameter	Casing Material
Conductor	0-100	N/A	20"	94 lb/ft, H-40 Welded
Surface	0-1,475	17-1/2"	13-3/8"	54.5 lb/ft, J-55 BTC
Intermediate	0-6,500	12-1/4"	9-5/8"	47 lb/ft L-80 LT&C
Protective Liner	6,200-11,600	8-1/2"	7"	29 lb/ft SM25Cr125 Vam Top
Tubing	See Table 8	N/A	5-1/2"	17 lb/ft, L-80 (Internally Coated) Premium Connection
	See Table 8	N/A	4-1/2"	12.6 lb/ft, L-80 (Internally Coated) Premium Connection

Table 7: Borehole and Casing Program for the Injection Wells

Depth to End of Tubing (ft)			
	Orion #1	**Orion #2**	**Orion #3**
Perforated Interval 1	10,200	9,860	10,350
Perforated Interval 2	9,840	9,600	9,970
Perforated Interval 3	9,640	-	9,800

Table 8: Tubing Depths for the CO_2 Injection Wells

Casing String	Casing Material	Casing OD/ID/Drift	Thickness	Pipe Body Yield Strength (lbs)	Connection Yield (lbs)	Joint Tensile Strength (lbs)	Burst (psi)	Collapse (psi)
Conductor	94 lb/ft, H-40 Welded	Outside: 20” Inside: 19.124” Drift: 18.937”	0.438”	1,077,000	N/A	N/A	N/A	N/A
Surface	54.5 lb/ft, J-55 BTC	Outside: 13-3/8” Inside: 12.615” Drift: 12.459”	0.380”	853,000	909,000	909,000	2,730	1,130
Intermediate	47 lb/ft L-80 LT&C	Outside: 9-5/8” Inside: 8.681” Drift: 8.525”	0.472”	1,086,000	893,000	893,000	6,870	4,760
Protective Liner	29 lb/ft SM25Cr-125 Vam Top	Outside: 7” Inside: 6.184” Drift: 6.059”	0.408”	1,056,000	1,056,000	1,056,000	13,110	9,110
Tubing	17 lb/ft, L-80 (Internally Coated) Premium Connection	Outside: 5-1/2” Inside: 4.892” Drift: 4.767”	0.304”	397,000	356,000	356,000	7,740	6,390
Tubing	12.6 lb/ft, L-80 (Internally Coated) Premium Connection	Outside: 4-1/2” Inside: 3.958” Drift: 3.833”	0.271”	288,040	288,040	288,040	7,740	7,500

Table 9: Properties of Injection Well Casing and Tubing Materials

3.8 CASING AND TUBING SUMMARY FOR STRATIGRAPHIC WELL

Casing String	Casing Depth, (ft bgs)	Borehole Diameter	Casing Outside Diameter	Casing Material
Conductor	0-100	N/A	20”	94 lb/ft, H-40 Welded
Surface	0-1,475	17-1/2”	13-3/8”	54.5 lb/ft, J-55 BTC
Intermediate	0-7,000	12-1/4”	9-5/8”	47 lb/ft, L-80 LT&C
Protective	0-6,500	-	5-1/2”	23 lb/ft, L-80 LT&C
	6,500-12,000	8-1/2”	5-1/2”	23 lb/ft, 22Cr125 VAM TOP
Tubing	0-9,600	N/A	2-3/8”	4.7 lb/ft, L-80 Premium Connection

Table 10: Borehole and Casing and Tubing Program for the Stratigraphic Well

Casing String	Casing Material	Casing OD/ID/Drift	Thickness	Pipe Body Yield Strength (lbs)	Connection Yield (lbs)	Joint Tensile Strength (lbs)	Burst (psi)	Collapse (psi)
Conductor	94 lb/ft, H-40 Welded	Outside: 20” Inside: 19.124” Drift: 18.937”	0.438”	1,077,000	N/A	N/A	N/A	N/A
Surface	54.5lb/ft, J-55 BTC	Outside: 13-3/8” Inside: 12.615” Drift: 12.459”	0.380”	853,000	909,000	909,000	2,730	1,130
Intermediate	47 lb/ft L-80 LT&C	Outside: 9-5/8” Inside: 8.681” Drift: 8.525”	0.472”	1,086,000	893,000	893,000	6,870	4,760

Casing String	Casing Material	Casing OD/ID/Drift	Thickness	Pipe Body Yield Strength (lbs)	Connection Yield (lbs)	Joint Tensile Strength (lbs)	Burst (psi)	Collapse (psi)
Protective	23 lb/ft, L-80 LT&C	Outside: 5-1/2" Inside: 4.670" Drift: 4.545"	0.415"	530,000	489,000	489,000	9,880	11,160
	23 lb/ft, 22Cr125, VAM TOP	Outside: 5-1/2" Inside: 4.670" Drift: 4.545"	0.415"	800,000	829,000	829,000	16,980	16,070
Tubing	4.7 lb/ft L-80 Premium Connection	Outside: 2-3/8" Inside: 1.995" Drift: 1.901"	0.190"	104,300	104,300	104,300	11,200	11,780

Table 11: Properties of Well Casing for the Stratigraphic Well

4.0 CEMENTING PROGRAM

4.1 INJECTION WELLS

Tables 12, 13 & 14 summarize the cementing details for the injection wells.

Cement	Coverage (feet)	Weight (ppg)	Yield (feet^3/sx)	Water (gal/sx)	Volume (sx)	Notes
Lead Cement	1,175	12.0	2.56	15.10	623	ASTM TYPE 1 Cement + Liquid Defoamer + Extender + Retarder
Tail Cement	300	14.5	1.39	6.80	428	ASTM TYPE 1 Cement+ Liquid Defoamer + Extender + Retarder

Table 12: Cement Information for Injection Well Surface Casing

Cement	Coverage (feet)	Weight (ppg)	Yield (feet³/sx)	Water (gal/sx)	Volume (sx)	Notes
Lead Cement	5,660	13.0	1.76	9.20	1273	Class H Cement, HSR + Extender + Liquid Defoamer +Viscosifier +Retarder
Tail Cement	840	16.4	1.07	4.30	356	Class H Cement, HSR +Liquid Defoamer +Viscosifier, Fluid Loss +Retarder.

Table 13: Cement Information for Injection Well Intermediate Casing

Cement	Coverage (feet)	Weight (ppg)	Yield (feet³/sx)	Water (gal/sx)	Volume (sx)	Notes
Tail Cement	6,200	16.0	1.23	3.50	670	CO_2 Resistant Cement

Table 14: Cement Information for Injection Well Protective Liner

4.2 STRATIGRAPHIC WELL

Tables 15, 16, & 17 summarize the cementing details for the stratigraphic wells.

Cement	Coverage (feet)	Weight (ppg)	Yield (feet³/sx)	Water (gal/sx)	Volume (sx)	Notes
Lead Cement	1,175	12.0	2.56	15.10	623	ASTM TYPE 1 Cement + Liquid Defoamer + Extender + Retarder
Tail Cement	300	14.5	1.39	6.80	428	ASTM TYPE 1 Cement+ Liquid Defoamer + Extender + Retarder

Table 15: Cement Information for Stratigraphic Well Surface Casing

Cement	Coverage (feet)	Weight (ppg)	Yield (feet³/sx)	Water (gal/sx)	Volume (sx)	Notes
Lead Cement	5,660	13.0	1.76	9.20	1275	Class H, HSR Cement + Fly Ash (Pozzolan) + Liquid Defoamer+ Viscosifier + Extender + Retarder
Tail Cement	840	16.4	1.07	4.30	356	Class H, HSR Cement +Liquid Defoamer +Viscosifier+ Fluid Loss additive + Retarder

Table 16: Cement Information for Stratigraphic Well Intermediate Casing

Cement	Coverage (feet)	Weight (ppg)	Yield (feet³/sx)	Water (gal³/sx)	Volume (sx)	Notes
Lead Cement	6,700	11.8	2.37	13.76	696	Class H, HSR Cement + Fly Ash (Pozzolan) + Liquid Defoamer+ Viscosifier + Extender + Retarder
Tail Cement	5,300	16.0	1.23	5.50	1,186	CO_2 Resistant Cement

Table 17: Cement Information for Stratigraphic Well Protective Casing

5.0 PACKER

The packer Denbury plans to use in the injection wells is the AS-1X Retrievable Production Packer and will meet CO_2 service requirements. The packer is 7 feet long and will not impact the injection volume. It is compatible with the selected wellhead materials. The packer used for the stratigraphic well is a 5-1/2" X 2-3/8" Nickel Plated Full-Bore Lockset Packer placed at ± 9,600'.

Injection Well Packer Information & Set Depths			
Injection Packer: 7" X 4-1/2" Nickel-Plated Full-Bore Lockset Packer			
	Orion #1	**Orion #2**	**Orion #3**
Perforation Interval 1	± 10,200'	± 9,860'	± 10,350'
Perforation Interval 2	± 9,840'	± 9,600'	± 9,970'
Perforation Interval 3	± 9,640'	-	± 9,800'

Table 18: Injection Well Packer Information & Set Depths

6.0 ANNULAR FLUID

The annular fluid is a corrosion inhibited brine with biocide.

7.0 WELLHEAD

Wellhead Assembly Detail

1. Wire Line Access: Companion Flange 4-1/16” 5M API. Tapped Bull Plug supports local and remote injection tubing pressure functions with a pressure gauge.
2. Valve, Gate, 5-1/8” 5M
3. Adapter, Studded top and flanged bottom, 5-1/8” 5M X 4-1/16” 5M.
4. Pneumatic Actuated Valve: 5-1/8” 5M Valve Assembly
5. Valve, Gate, 5-1/8” 5M.
6. Adapter, Tubing Head, studded top and flanged bottom, 11” 5M X 5-1/8” 5M.
7. Tubing Hanger; 5-1/2” Tubing Hanger Assembly
8. Casing Spool Assembly: 13-5/8” 5M bottom flange X 11” 5M, w/two 2-1/16” 5M, Flanged outlets, tie-down screw packing.
9. Casing Head Assembly: 13-5/8” 5M X 9-5/8” SOW w/two, 2” NPT-Line Pipe Outlets
10. Surface Casing, 13-3/8”, 54.5-ppf, J-55, ST&C
11. Intermediate Casing, 9-5/8”, 47-ppf, L-80, LT&C

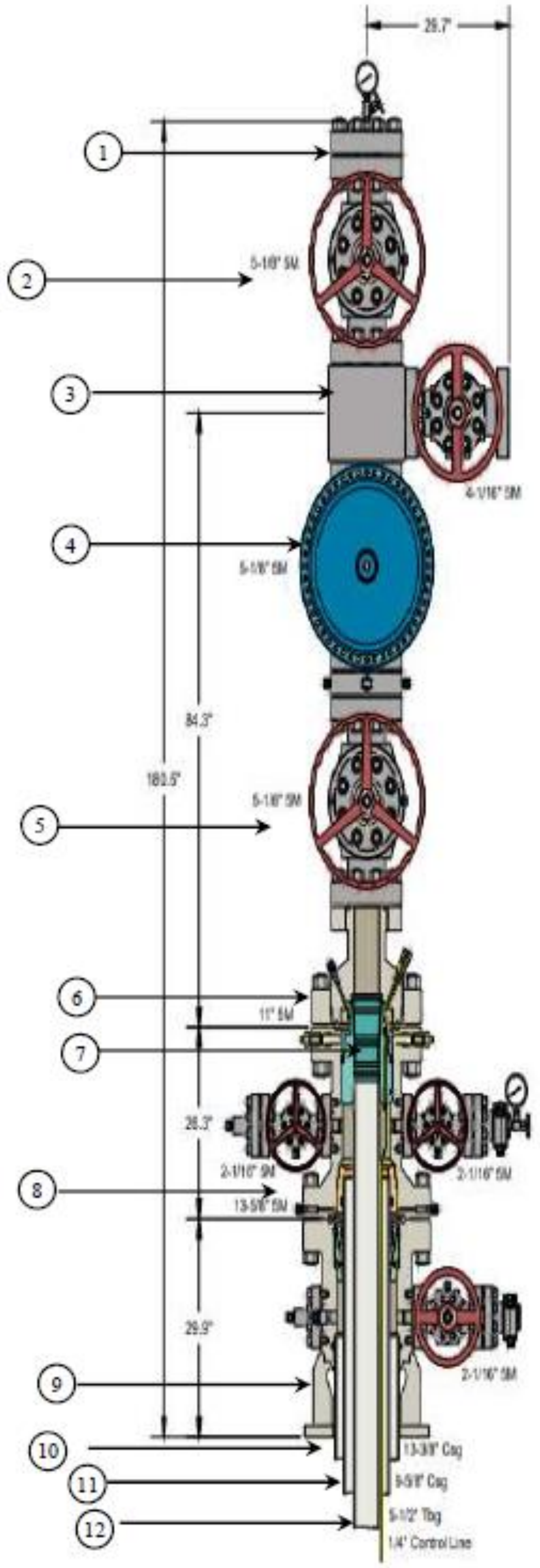
Wellhead Material Specifications

- Tubing Hanger – CC Trim – 17-4 Stainless Steel
- Tubing Head Adapter – FF Trim – 410 Stainless Steel
- Gate Valves – FF-0.5 Trim – 410 Stainless Steel Body and 17-4 Stainless Steel Gates and Seats.
- TEE, Instrument Flange, and Tree Cap – FF Trim – 410 Stainless Steel
- Ring Gaskets – 316 Stainless Steel

Proposed Injection Well Nos. Orion-1, Orion-2, Orion-3

Baldwin County, Alabama

Wellhead Schematic
Status: Proposed



WELLHEAD ASSEMBLY DETAIL

1. Wire Line Access: Companion Flange 4-1/16" 5M API. Tapped Bull Plug supports local and remote injection tubing pressure functions with a pressure gauge.
2. Valve, Gate, 5-1/8" 5M
3. Adapter, Studded top and flanged bottom, 5-1/8 5M X 4-1/16" 5M.
4. Pneumatic Actuated Valve:, 5-1/8" 5M Valve Assembly
5. Valve, Gate, 5-1/8" 5M.
6. Adapter, Tubing Head, studded top and flanged bottom, 11" 5M X 5-1/8" 5M.
7. Tubing Hanger; 5-1/2" Tubing Hanger Assembly
8. Casing Spool Assembly: 13-5/8" 5M bottom flange X 11" 5M, w/two 2-1/16 5M, Flanged outlets, tie-down screw packing.
9. Casing Head Assembly: 13-5/8" 5M X 9-5/8" SOW w/two, 2" NPT-Line Pipe Outlets
10. Surface Casing, 13-3/8", 54.5-ppf, J-55, ST&C.
11. Intermediate Casing, 9-5/8", 47-ppf, L-80, LT&C
12. Injection Tubing, 5-1/2", 17-ppf, L-80 (Internally Coated).

Denbury

Revised by: DO	Date: 11/9/2022	*Drawing not to scale*

Figure 5-7: Proposed Injection Well Nos. Orion-1, Orion-2, Orion -3 Wellhead Schematic

Figure 1: Injection Well Wellhead Schematic and Details

8.0 WELL OPENINGS TO FORMATION

The protective casing will be perforated across three different intervals throughout the life of the project. Injecting into different intervals will ensure that the horizontal migration of the CO_2 plume is managed. The initial injection target is the deepest perforation interval as shown in Table 19. The perforation interval durations are described in Table 20. At the end of each cycle, Denbury will cease injection, pull the tubing, and move up-hole to the next perforated interval. A cast iron bridge plug and 20 feet of CO_2 resistant cement will be placed above the newly abandoned perforation interval as shown in the wellbore schematics. The same process will occur when moving up-hole to the third and final perforation interval for Orion #1 and Orion #3.

	Orion Injection Well #1	Orion Injection Well #2	Orion Injection Well #3
Number of perforated intervals	3	2	3
Perforated interval 1	10,242'-10,380'	9,911'-10,002'	10,404'-10,490'
Perforated interval 2	9,887'-9,979'	9,642'-9,728'	10,023'-10,109'
Perforated interval 3	9,685'-9,777'	-	9,843'-9,929'

Table 19: Orion Wells #1, #2, & #3 Perforations Summary

Injection Duration by Perforation Interval (years)			
Interval	**Orion #1**	**Orion #2**	**Orion #3**
Perforated Interval 1	8	5	5
Perforated Interval 2	7	15	8
Perforated Interval 3	5	-	7

Table 20: Perforated Interval Durations

9.0 SCHEMATICS OF THE SUBSURFACE CONSTRUCTION DETAILS

The casing set depths and cement plan will protect the lowest USDW (deepest 1,300 ft). Formation tops will be confirmed at the time of drilling. Denbury will install electronic temperature, pressure, and flowmeters transmitters to continuously monitor the CO_2 stream and annulus pressure. A quartz type permanent downhole gauge (PDHG) will be set above the packer. In addition to these continuous recording devices, alarms and automatic shut-off systems will be installed pursuant to 40 CFR 146.88(e). For the injection wells, 15 centralizers will be used for the surface casing, 42 centralizers will be used for the intermediate casing, and 39 centralizers for the protective liner. The stratigraphic well will use 15 centralizers for the surface casing, 42 centralizers for the intermediate casing, and 78 centralizers for the protective casing. Exact locations of the centralizers are described in Figures 2 through 10.

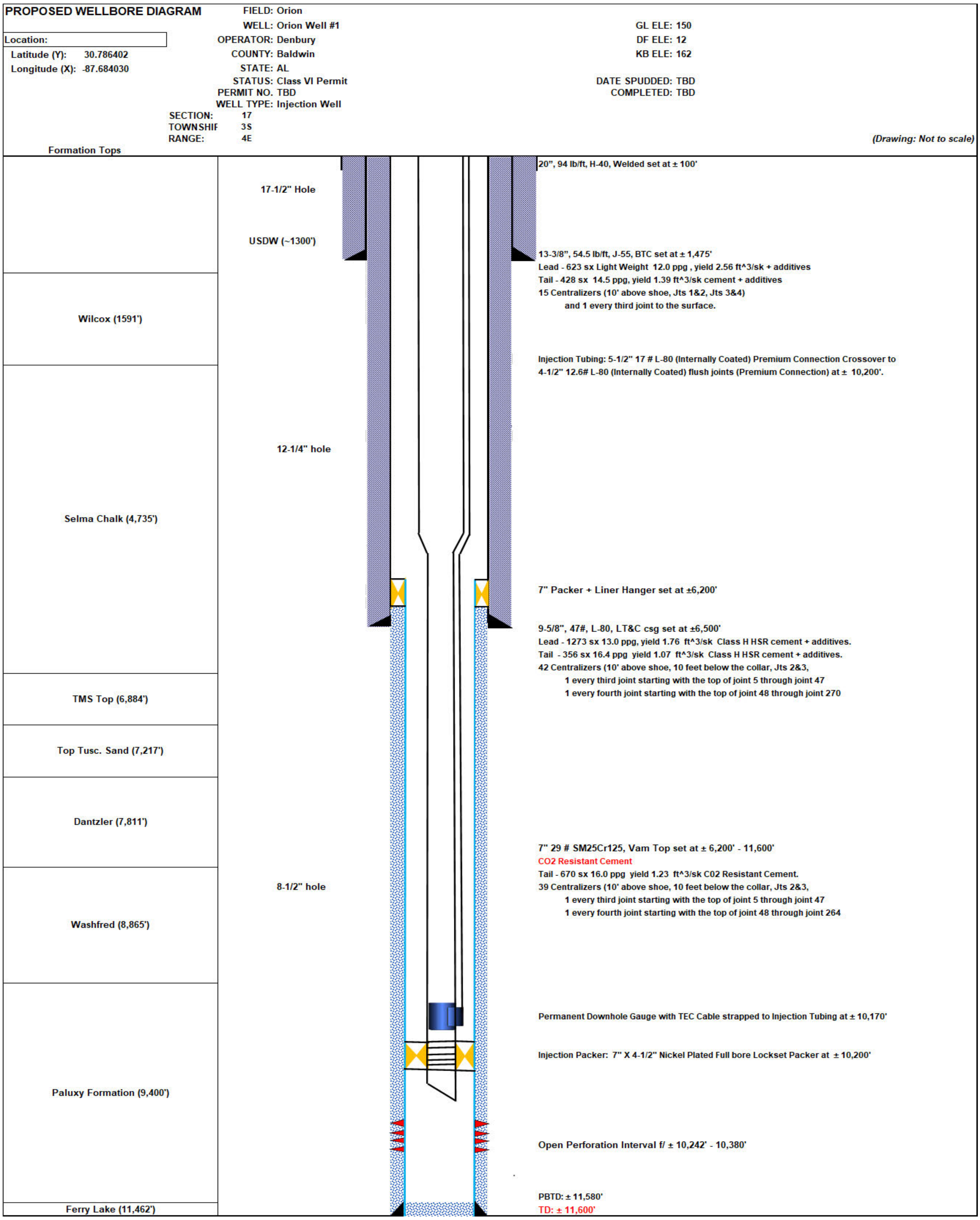


Figure 2: Orion #1 Injection Well Schematic (Perforated Interval 1)

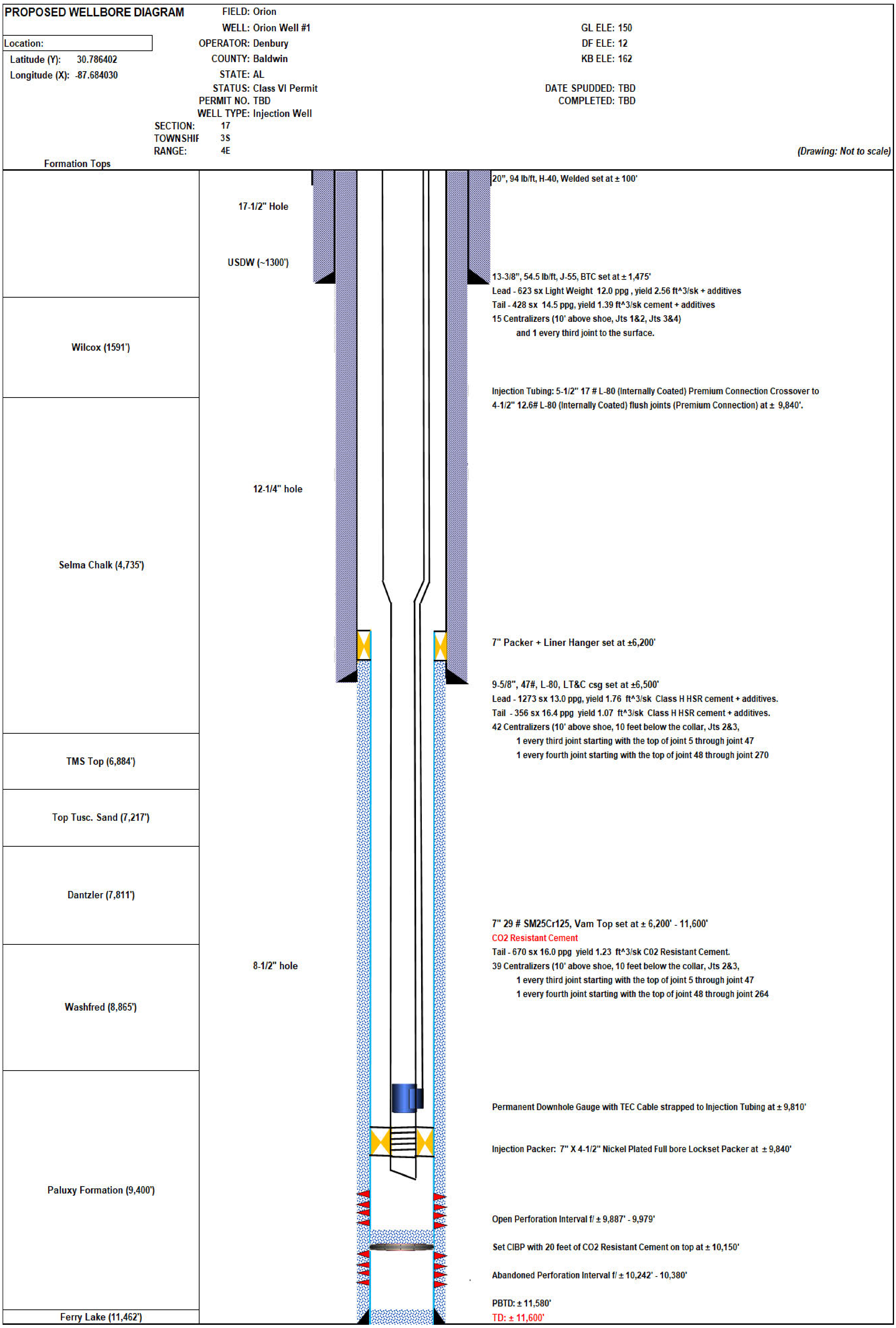


Figure 3: Orion #1 Injection Well Schematic (Perforated Interval 2)

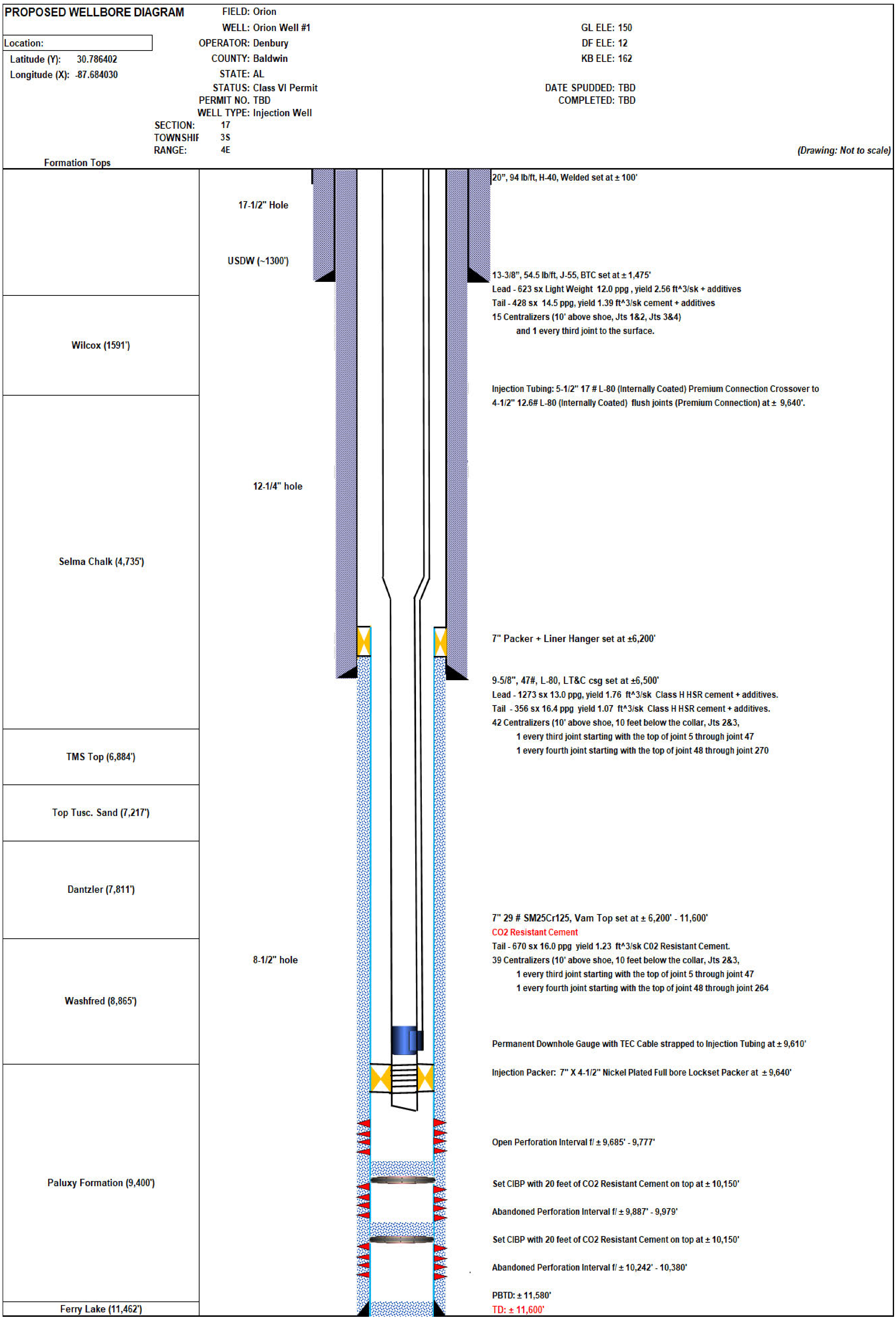


Figure 4: Orion #1 Injection Well Schematic (Perforated Interval 3)

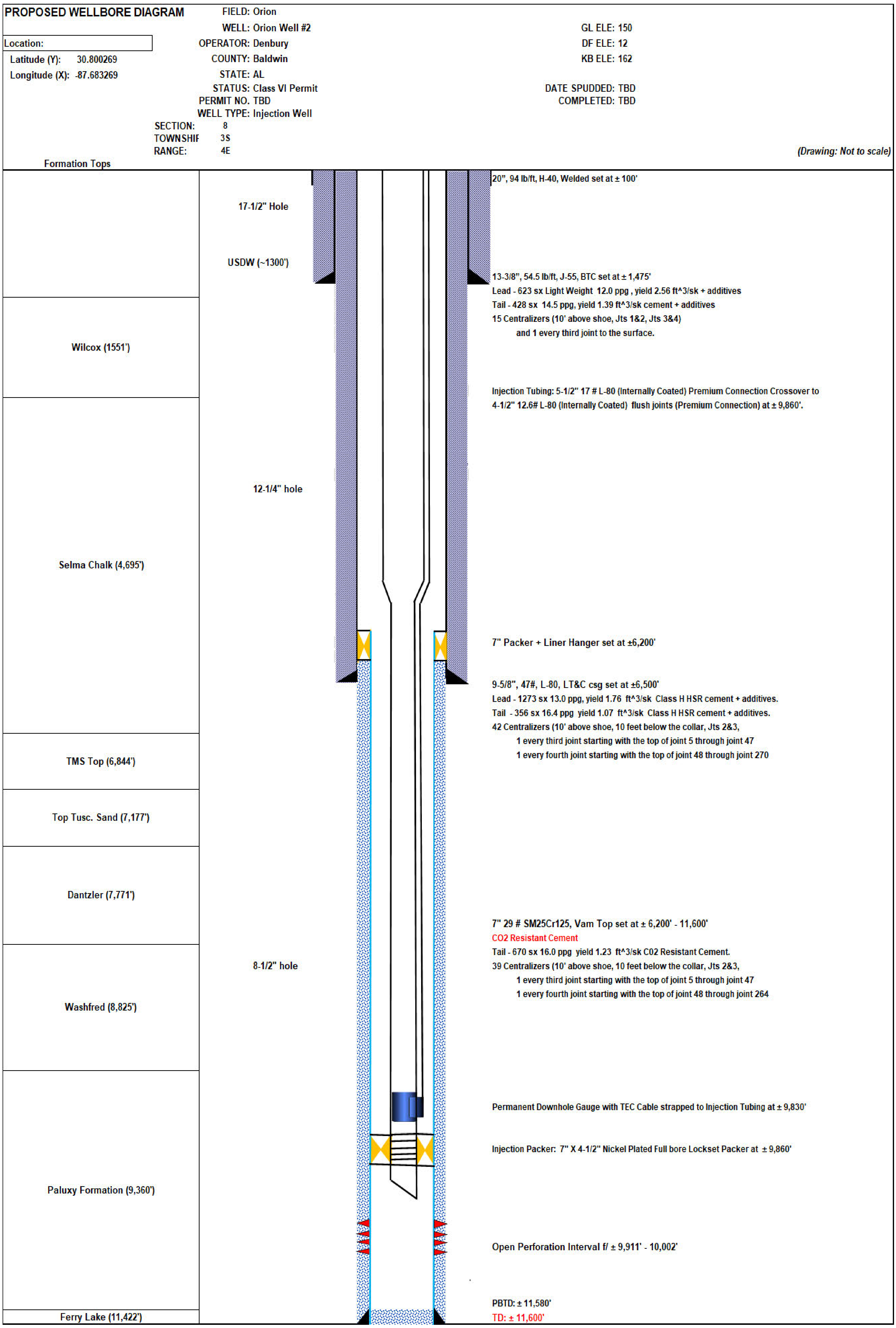


Figure 5: Orion #2 Injection Well Schematic (Perforated Interval 1)

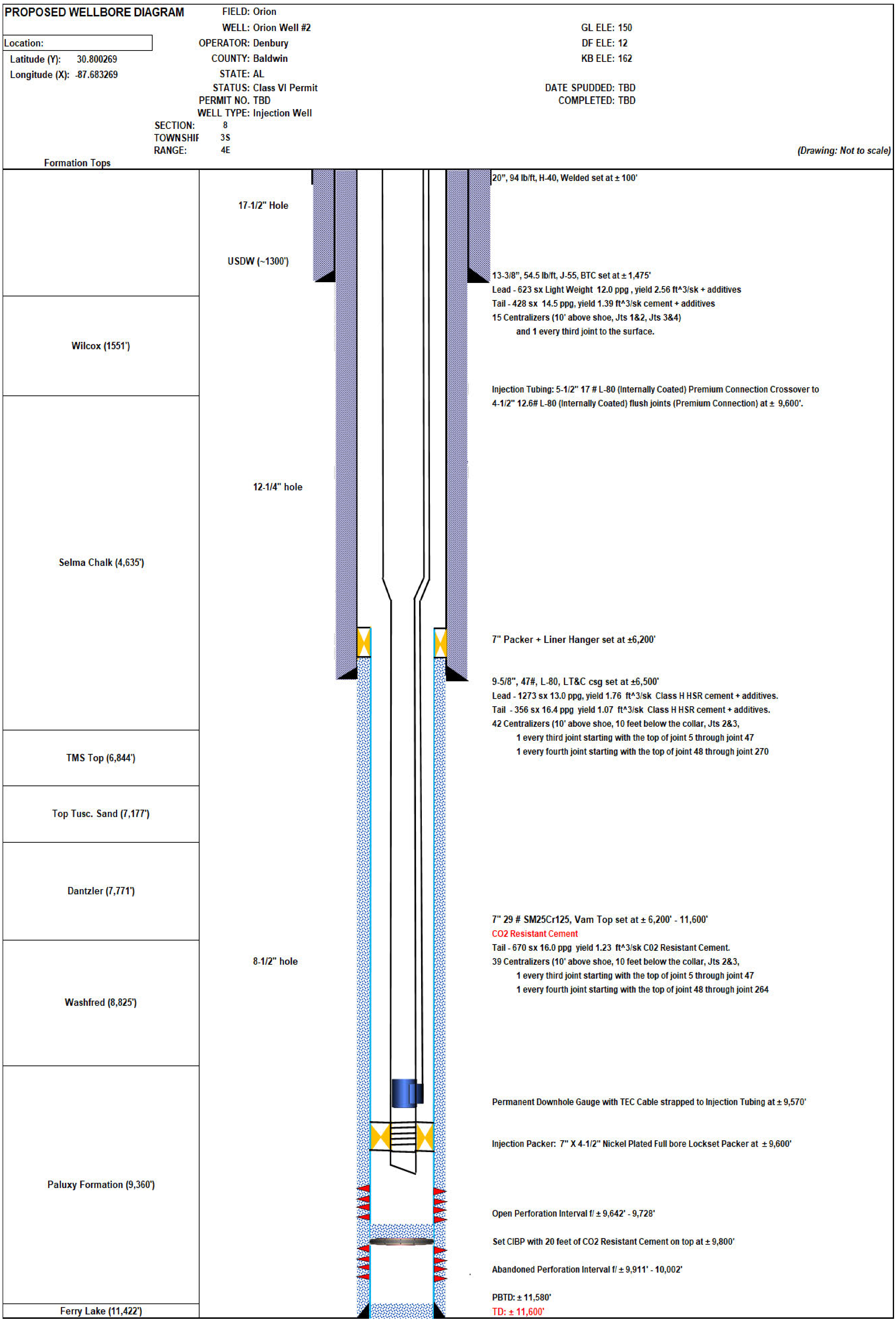


Figure 6: Orion #2 Injection Well Schematic (Perforated Interval 2)

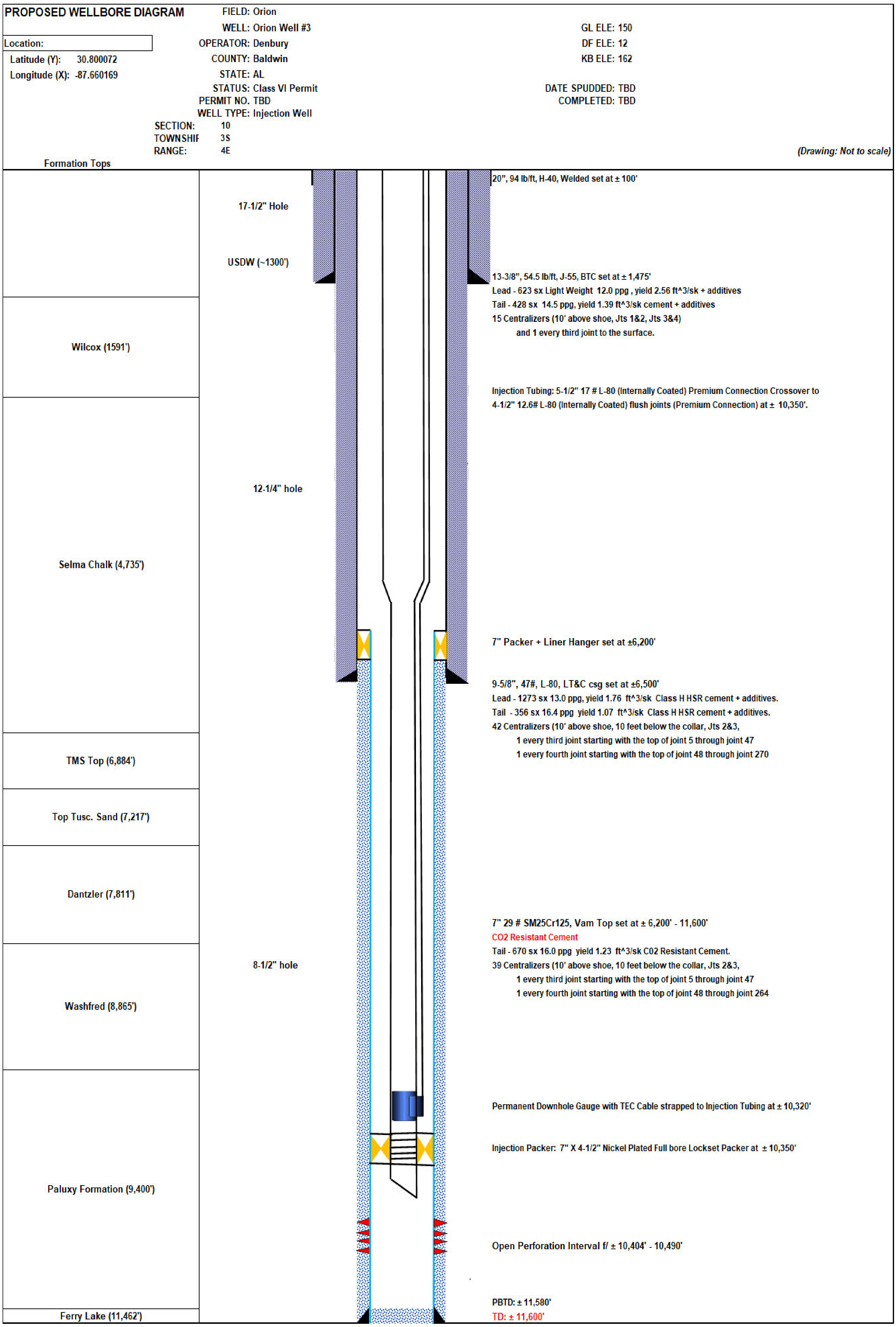


Figure 7: Orion #3 Injection Well Schematic (Perforated Interval 1)

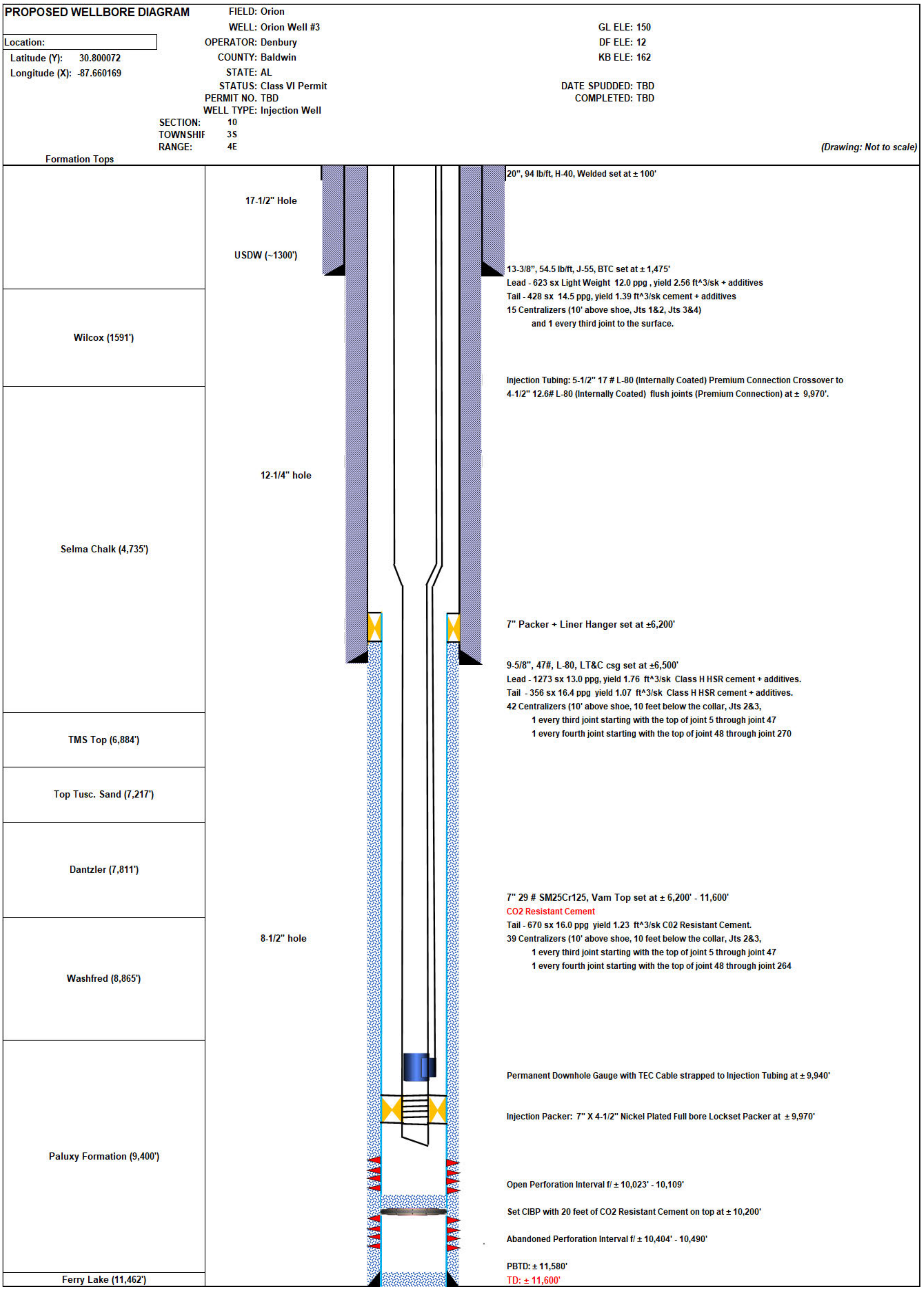


Figure 8: Orion #3 Injection Well Schematic (Perforated Interval 2)

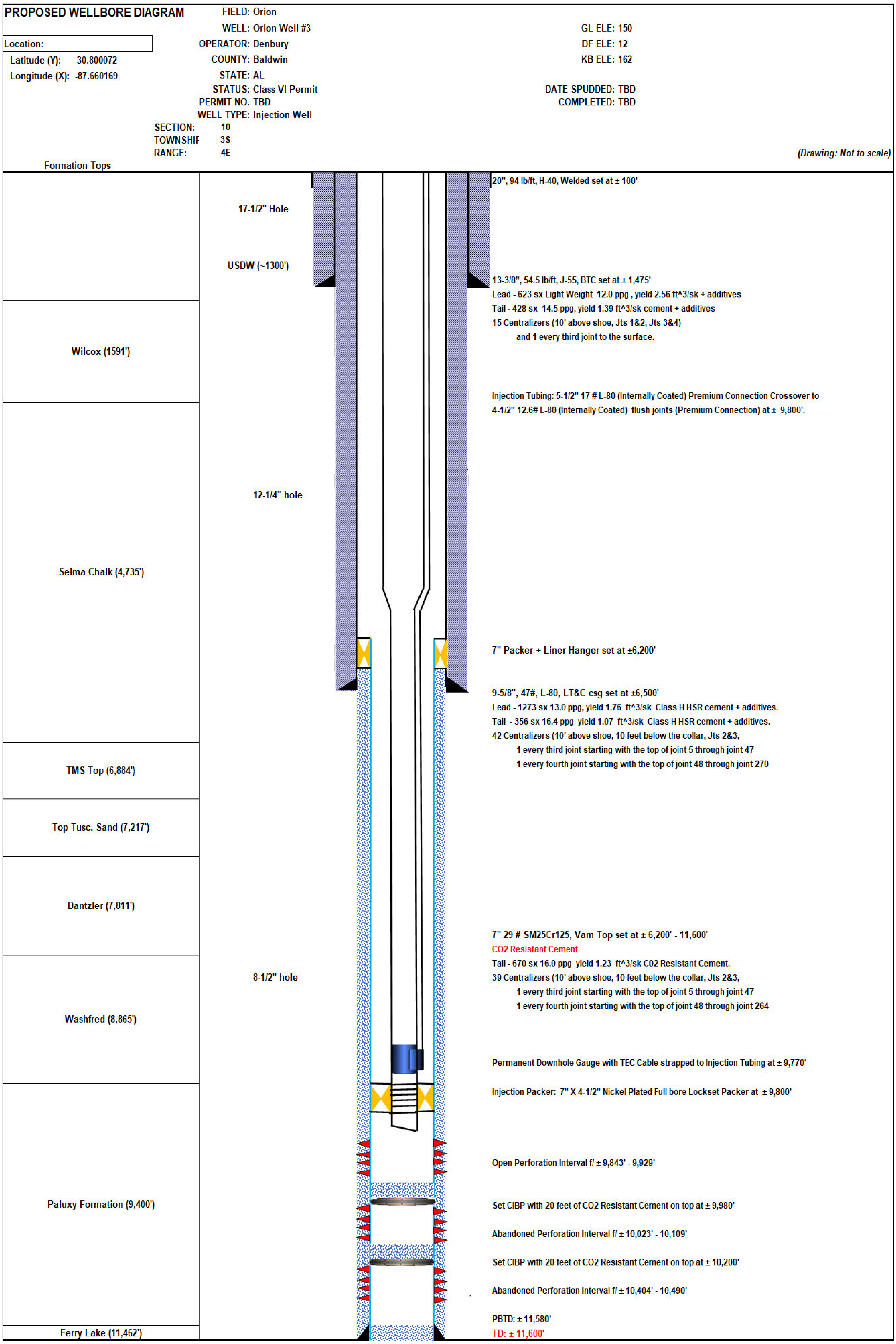


Figure 9: Orion #3 Injection Well Schematic (Perforated Interval 3)

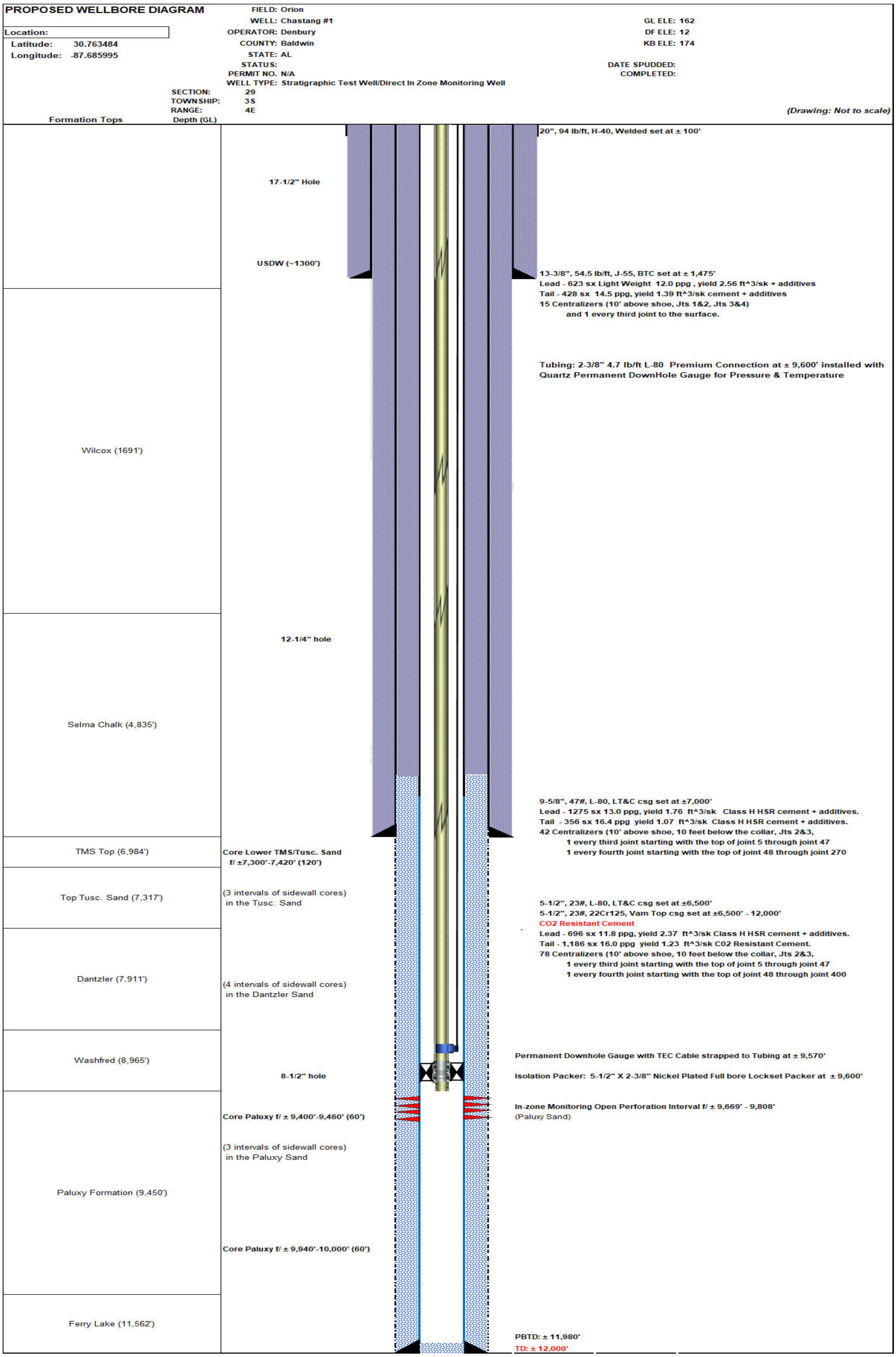


Figure 10: Chastang #1 Stratigraphic Well Schematic

10.0 REFERENCES

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