Application No. *45079, 45080, 46169, 46170, and 46171*

INJECTION WELL CONSTRUCTION PLAN

Pelican Sequestration Project

TABLE OF CONTENTS

List of Figures

List of Tables

1.0 Facility Information

Facility name: Pelican Sequestration Project
Pelican CCS 1, Pelican CCS 2, Pelican CCS 3, Pelican CCS 4, and Pelican CCS 5 wells

Facility contacts: Tyler Spoede, Project Manager
5 Greenway Plaza Houston, TX 77046
713-985-6954 william_spoede@oxy.com

Well location: Livingston Parish, Louisiana

Well Name	Longitude (NAD 27)	Latitude (NAD 27)	Longitude (NAD 83)	Latitude (NAD 83)
Pelican CCS 1	-90° 40' 55.76"	30° 35' 19.16"	-90° 40' 56.10"	30° 35' 19.83"
Pelican CCS 2	-90° 40' 58.83"	30° 34' 53.98"	-90° 40' 59.17"	30° 34' 54.66"
Pelican CCS 3	-90° 43' 50.13"	30° 36' 10.56"	-90° 43' 50.48"	30° 36' 11.24"
Pelican CCS 4	-90° 44' 29.72"	30° 36' 41.03"	-90° 44' 30.06"	30° 36' 41.70"
Pelican CCS 5	-90° 46' 30.21"	30° 37' 35.26"	-90° 46' 30.56"	30° 37' 35.93°

Pelican Sequestration Hub, LLC, will construct CO_2 injection wells Pelican CCS 1, Pelican CCS 2, Pelican CCS 3, Pelican CCS 4, and Pelican CCS 5 according to the procedures below. This well construction document includes special construction requirements, open hole diameters and intervals, casing specifications, tubing specifications, pressure control systems, and other well construction details that meet the standards under per LAC 43:XVII.3617(A).

2.0 Overview

This Construction Plan sets forth the operational parameters and material selection requirements to provide mechanical integrity, minimize potential endangerment of the Underground Sources of Drinking Water (USDW), and optimize operation during the life of the project. While this Construction Plan describes the intended procedures for drilling and construction of the project, changes to the plan may be required based on technical, operational, or safety conditions encountered during the development and execution. The project team will notify the Louisiana Department of Conservation and Energy (C&E) office if substantial deviations from this plan are required. All phases of well construction will be supervised by a person knowledgeable and experienced in practical drilling and engineering who is familiar with the special conditions and requirements of well construction according to LAC 43:XVII.3617(A)(1).

Oxy Low Carbon Ventures, LLC, the parent company of Pelican Sequestration Hub, LLC, drilled one stratigraphic well, Pelican MLR 004, in the Pelican Sequestration Project in 2022. This well has been used to obtain site-based information and additional characterization to complement the geological and numerical simulation models. The Pelican MLR 004 stratigraphic well was designed with the goal of being converted into an in-zone monitoring well to track the CO_2 plume extension and pressure front in the injection zones, as described in the Testing and Monitoring Plan.

The project plans to drill one above-confining-zone (ACZ) and two USDW monitoring wells.

The two USDW monitoring wells will track the quality of the water and variations in geochemistry in the USDW. These shallow water wells will be produced and sampled based on the requirements described in the Testing and Monitoring Plan presented in this application.

Well schematics and construction details for the above confining zone and USDW monitoring wells are included in Injection Well Construction Plan Appendix F.

3.0 Design Considerations for CO_2 Injector Wells

Pelican CCS 1, Pelican CCS 2, Pelican CCS 3, Pelican CCS 4, and Pelican CCS 5 are designed to maximize the rate of injection and reduce the surface pressure and friction alongside the tubing, while maintaining the bottomhole pressure below 90% of the fracture gradient. A nodal analysis using PROSPER software was performed to determine sensitivities on the tubing size, rate of erosion, stresses, operating pressures, and potential movement of the tubulars.

Well materials and equipment were selected based on the maximum operating conditions expected during the life of the well and compatibility with the expected CO_2 stream, to ensure mechanical integrity and reliability of the system during the life of the project.

The selected design provides enough clearance to deploy pressure and temperature gauges on the tubing and continuous surveillance of external mechanical integrity through an external fiber optic cable.

During the design process, the project team integrated years of experience and data collected by Oxy (the parent company of Pelican Sequestration Hub, LLC) as a CO_2 operator in enhanced oil recovery (EOR) fields, with the expertise of worldwide-recognized providers of tubulars, cementing services companies, and downhole and surface equipment manufacturers, amongst others, to complete the final design of the CO_2 injectors.

The operating conditions expected during the life of the CO_2 injector wells are shown in Table CON-1, Table CON-2, Table CON-3, Table CON-4, and Table CON-5. Table CON-6 shows the CO_2 specifications of the Pelican Sequestration Project.

Table CON-1—Operating design parameters for Pelican CCS 1.

Parameter/Condition	Completion 1	Completion 2	Completion 3
Perforation Interval MD[1], top-bottom (ft)	6,859-7,500	5,953-6,387	6,387-6,859
Perforation Interval TVD[2], top-bottom (ft)	6,859-7,500	5,953-6,387	6,387-6,859
Bottomhole gauge depth MD[1]/TVD[2] (ft)	6,750	5,850	6,280
Maximum Injection Rate (metric tonnes per day)	6,850	6,850	6,850
Average Injection Rate (metric tonnes per day)	5,480	5,480	5,480
Total Volume Injected (millions of metric tonnes)	16	16	18
Operating Wellhead Surface Injection Pressure (psig)	1,200-2,000	1,100-1,700	1,100-1,700
Maximum Surface Wellhead Injection Pressure (psig)	1,500-2,400	1,300-2,000	1,400-2,000
Maximum Bottomhole Pressure at 90% of frac gradient (0.79 psi/ft) @ top of perforations (psig)	4,877	4,233	4,541
Maximum Bottomhole Pressure at 90% of frac gradient (0.79 psi/ft) @ bottomhole gauge (psig)	4,836	4,194	4,500
Minimum Annulus Pressure/Tubing Differential (psi)	100	100	100

Table CON-2—Operating design parameters for Pelican CCS 2.

Parameter/Condition	**Completion 1**	**Completion 2**	**Completion 3**
Perforation Interval MD[1], top-bottom (ft)	6,454-6931	6,931-7577	6,034-6,454
Perforation Interval TVD[2], top-bottom (ft)	6,454-6,931	6,931-7,577	6,034-6,454
Bottomhole gauge depth MD[1]/TVD[2] (ft)	6,350	6,830	5,930
Maximum Injection Rate (metric tonnes per day)	6,850	6,850	6,850
Average Injection Rate (metric tonnes per day)	5,480	5,480	5,480
Total Volume Injected (millions of metric tonnes)	16	16	18
Operating Wellhead Surface Injection Pressure @ Average Injection Rate (psig)	1,100-1700	1,200-1,900	1,100-1,700
Operating Wellhead Surface Injection Pressure @ Maximum Injection Rate (psig)	1400-2100	1,600-2,300	1,400-2,000
Maximum Bottomhole Pressure at 90% of frac gradient (0.79 psi/ft) @ top of perforations (psig)	4,589	4,928	4,290
Maximum Bottomhole Pressure at 90% of frac gradient (0.79 psi/ft) @ bottomhole gauge (psig)	4,549	4,890	4,250
Minimum Annulus Pressure/Tubing Differential (psi)	100	100	100

Table CON-3—Operating design parameters for Pelican CCS 3.

Parameter/Condition	Completion 1	Completion 2	Completion 3	Completion 4
Perforation Interval MD[1], top-bottom (ft)	5,934-6,257	6,257-6,633	6,633-6,913	7,105-7,557
Perforation Interval TVD[2], top-bottom (ft)	5,934-6,257	6,257-6,633	6,633-6,913	7,105-7,557
Bottomhole gauge depth MD[1]/TVD[2] (ft)	5,830	6,150	6,530	7,000
Maximum Injection Rate (metric tonnes per day)	6,850	6,850	6,850	6,850
Average Injection Rate (metric tonnes per day)	5,480	5,480	5,480	5,480
Total Volume Injected (millions of metric tonnes)	8	12	8	22
Operating Wellhead Surface Injection Pressure @ Average Injection Rate (psig)	1,000-1,700	1,100-1,700	1,100-1,900	1,200-2,000
Operating Wellhead Surface Injection Pressure @ Maximum Injection Rate (psig)	1,300-2,000	1,400-2,000	1,400-2,200	1,500-2,400
Maximum Bottomhole Pressure at 90% of frac gradient (0.79 psi/ft) @ top of perforations (psig)	4,219	4,449	4,716	5,052
Maximum Bottomhole Pressure at 90% of frac gradient (0.79 psi/ft) @ bottomhole gauge (psig)	4,179	4,408	4,677	5,012
Minimum Annulus Pressure/Tubing Differential (psi)	100	100	100	100

Table CON-4—Operating design parameters for Pelican CCS 4.

Parameter/Condition	Completion 1	Completion 2	Completion 3	Completion 4
Perforation Interval MD[1], top-bottom (ft)	7055-7514	5858-6220	6220-6576	6576-6869
Perforation Interval TVD[2], top-bottom (ft)	7055-7514	5858-6220	6220-6576	6576-6869
Bottomhole gauge depth MD[1]/TVD[2] (ft)	6,950	5,750	6,120	6,470
Maximum Injection Rate (metric tonnes per day)	6,850	6,850	6,850	6,850
Average Injection Rate (metric tonnes per day)	5,480	5,480	5,480	5,480
Total Volume Injected (millions of metric tonnes)	20	8	12	10
Operating Wellhead Surface Injection Pressure @ Average Injection Rate (psig)	1200-2000	1000-1700	1100-1700	1100-1800
Operating Wellhead Surface Injection Pressure @ Maximum Injection Rate (psig)	1500-2400	1300-2000	1400-2000	1400-2100
Maximum Bottomhole Pressure at 90% of frac gradient (0.79 psi/ft) @ top of perforations (psig)	5,016	4,165	4,422	4,676
Maximum Bottomhole Pressure at 90% of frac gradient (0.79 psi/ft) @ bottomhole gauge (psig)	4,976	4,124	4,384	4,636
Minimum Annulus Pressure/Tubing Differential (psi)	100	100	100	100

Table CON-5—Operating design parameters for Pelican CCS 5.

Parameter/Condition	**Completion 1**	**Completion 2**	**Completion 3**
Perforation Interval MD[1], top-bottom (ft)	5,730-6228	6,228-6776	6,776-7,384
Perforation Interval TVD[2], top-bottom (ft)	,-6228	6,228-6776	6,776-7,384
Bottomhole gauge depth MD[1]/TVD[2] (ft)	5,630	6,120	6,670
Maximum Injection Rate (metric tonnes per day)	6,850	6,850	6,850
Average Injection Rate (metric tonnes per day)	5,480	5,480	5,480
Total Volume Injected (millions of metric tonnes)	16	16	18
Operating Wellhead Surface Injection Pressure @ Average Injection Rate (psig)	1,000-1,600	1,100-1,700	1,200-2,000
Operating Wellhead Surface Injection Pressure @ Maximum Injection Rate (psig)	1,300-1,900	1,400-2,100	1,500-2,400
Maximum Bottomhole Pressure at 90% of frac gradient (0.79 psi/ft) @ top of perforations (psig)	4,074	4,428	4,818
Maximum Bottomhole Pressure at 90% of frac gradient (0.79 psi/ft) @ bottomhole gauge (psig)	4,036	4,387	4,778
Minimum Annulus Pressure/Tubing Differential (psi)	100	100	100

Table CON-6—CO_2 Specification for Pelican Sequestration Project

Component	Specification
CO_2 (% mol)	>97
Water (lbs/MMCF)	<4
Nitrogen (% mol)*	<3
Oxygen (ppm by wt)**	<30
Hydrogen (% mol)*	<1
SO_x (ppm by wt)	<1
NO_x (ppm by wt)	<1
Hydrogen Sulfide (ppmw)	<20
Hydrocarbons – Other than CH_4 (%mol)	<1
Carbon Monoxide (ppm by wt)	<4,250
Glycol (gal/MMSCF)	<0.3
Argon (%mol)*	<1
Sulfur (ppm by wt)	<35
Amines (ppmw)	<1
Alcohols (methanol + ethanol) (ppmv)	<250
CH_4 (% mol)*	<1.5
NH_3 (ppm by wt)	<50
Comp. Lube Oil (ppmw)	<50
Particulates (ppm by wt)	<1
Mercury (nanograms/liter)	<5

4.0 Well Design Pelican CCS 1 - CO_2 Injector Well

The Pelican CCS 1 well design includes three main sections: conductor casing, surface casing, and long string casing. The casing sections cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-1 shows the proposed well schematic for the Pelican CCS 1 initial completion. Recompletion well schematics are included in Section 9.0.

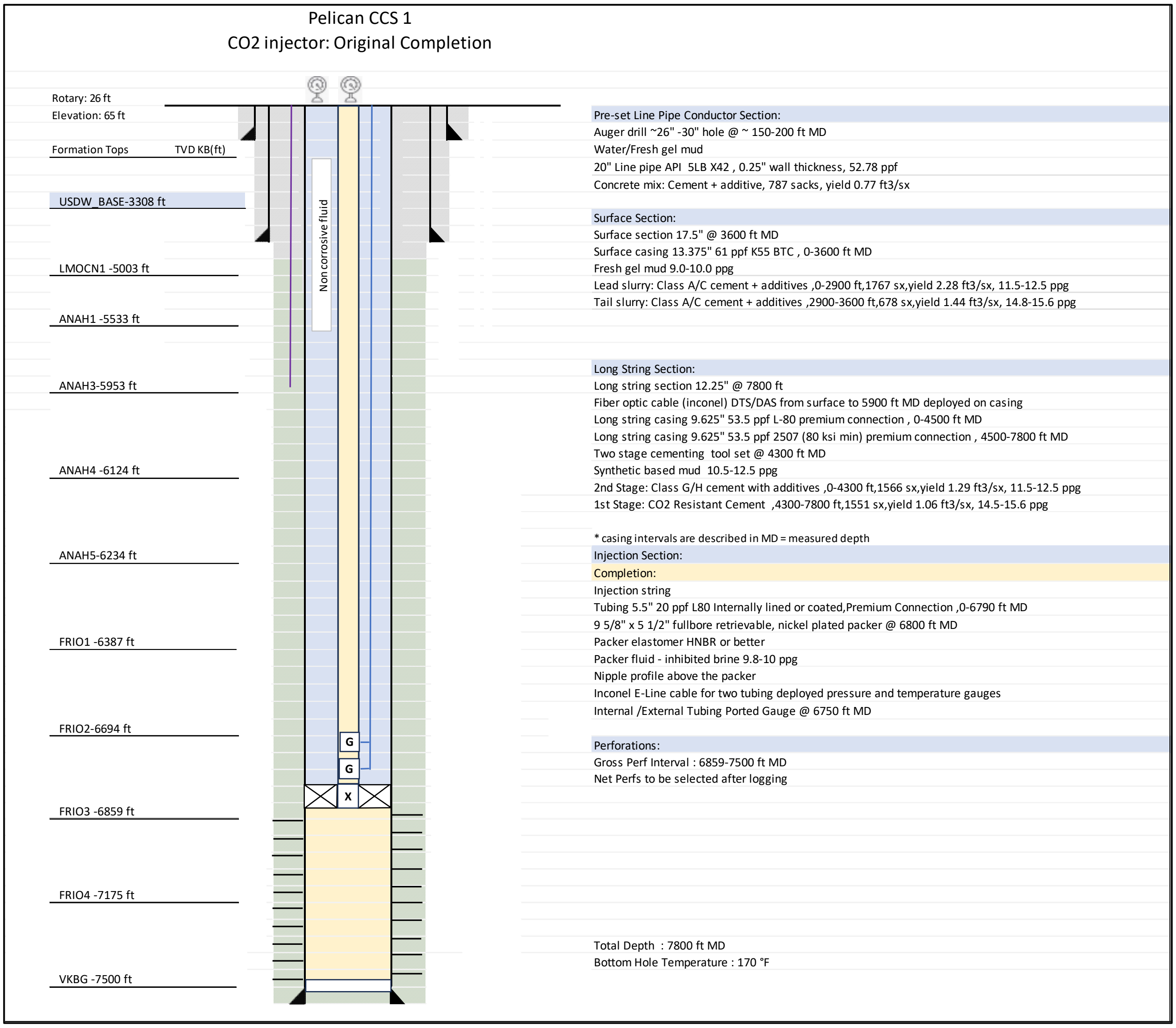

Figure CON-1—Pelican CCS 1 well schematic for initial completion.

4.1 Design Overview Pelican CCS 1

4.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20 in. line pipe and cemented with a mixture of concrete to the surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

4.1.2 Surface Section

The 17-1/2 in. vertical wellbore will be drilled to 3,600 ft to cover base of the USDW, estimated at 3,308 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken every 100 ft at a minimum while drilling. This section will be drilled with freshwater mud. Once the target depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13-3/8 in. casing will be run and cemented to the surface via circulation with conventional Portland cement slurry plus additives. If there are no cement returns to the surface, the project will inform C&E and then determine the top of cement with a temperature log, or equivalent, and complete the annular cement program with a top job procedure after approval by the Commissioner. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test the BOP and casing according to LAC 43:XVII.3617(A)(3) requirements and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

4.1.3 Long String Section

A 12-1/4 in. vertical wellbore will be drilled from 3,600 ft to 7,800 ft total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs, acquire side wall cores (SWC), and collect water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9-5/8 in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Returns will be observed at the surface. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after it is drilled.

After the cementing is complete, Section B of the wellhead will be installed and the DTS/DAS cable will be threaded through the slips and packoff. The team will install the rest of the wellhead to prepare for completions operations and test the casing per Louisiana Statutes and Regulations 3617.A.3 requirements

4.1.4 Completion

Before completion operations, the rig crew will test the casing to 1,000 psi over a 1-hour time period, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The 5-1/2 in. tubing and packer completion will be run to approximately 6,800 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular

space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

4.2 Casing, Tubing and Completion Design Pelican CCS 1

The different casing sections and completion tubing were designed to withstand expected operating loads, such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations.
- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull
- Corrosion environments

Table CON-7 shows the minimum safety factors calculated using Stress Check^{TM} software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-7—Minimum safety factors for tubular design for Pelican CCS 1.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13-3/8 in., 61.0 ppf, K-55	Buttress	0-3,600	1.18	1.31	2.51	1.32
Long String Casing	9-5/8 in., 53.5 ppf, L-80	Premium, Gas Sealing	0-4,500	2.05	1.77	2.95	2.03
Long String Casing	9-5/8 in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	4,500-7,800	1.92	1.36	3.41	1.77
Tubing	5-1/2 in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-6,800	2.44	1.39	2.06	1.57

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Injection Well Construction Plan Appendix D.

The WELLCAT™ evaluation performed for Pelican CCS 1 applies to the loads observed for Pelican CCS 2, Pelican CCS 3, Pelican CCS 4, and Pelican CCS 5 (Injection Well Construction Plan Appendix E).

The tables listed below provide further details regarding the Pelican CCS 1 well. Table CON-8 contains the open hole diameters and intervals, Table CON-9 lists the casing specifications, Table CON-10 details the conductor material, and Table CON-11 details the casing material properties.

Table CON-8—Open hole diameters and intervals for Pelican CCS 1.

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,600	17-1/2	Cover USDW
Long String Section	3,600 to 7,800	12-1/4	To Total Depth

Note—The USDW depth will be confirmed with open hole logs. The USDW is estimated at 3,308 ft TVD.

Table CON-9—Casing specifications for Pelican CCS 1.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25 in. wall thickness, 19.5 in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,600	13-3/8	12.515	12.359	61	K55	BTC
Long String	0 to 4,500	9-⅝	8.535	8.379	53.5	L80	Premium
Long String	4,500 to 7,800	9-⅝	8.535	8.379	53.5	2507 Min 80 ksi	Premium

Table CON-10—Conductor material properties for Pelican CCS 1.

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)	Elongation %
20 in. API 5LB X42 52.78 ppf	0 to 200	42	60	23

Table CON-11—Casing material properties for Pelican CCS 1.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
13-3/8 in. 61 ppf K55 BTC	0 to 3,600	3,090	1,540	962	19°	26.2
9-5/8 in. 53.5 ppf L80 Premium connection	0 to 4,500	7,930	6,620	1,244	38°	26.2
9-5/8 in. 53.5 ppf 2507 80 ksi Premium Connection	4,500 to 7,800	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~4,300 ft in the 9-5/8 in. casing to perform the two-stage cementing job.
- The centralization program will aim at minimum 70% standoff and be adjusted using the field data for deviation, caliper, and hole conditions.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-12 contains the upper completion specifications for the original completion and recompletions. Table CON-13 shows the specification of the 5-1/2 in. tubing.

Table CON-12—Upper completion specifications – initial completion and first recompletion for Pelican CCS 1.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 6,800	5-1/2	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-13—Tubing material properties for Pelican CCS 1.

Tubing	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
Injection Tubing: 5-1/2 in. 20 lb L80 Special – Coated TK-805	9,190	8,830	466	67°	26.2

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and to the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The annular space between the 5-1/2 in. tubing and 9-5/8 in. casing will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-14 shows the specifications of the injection packer.

Table CON-14—Packer specifications for Pelican CCS 1.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000

Burst Pressure (psi)	Collapse Pressure (psi)	Tensile Strength (ksi)	Comments
8,050	7,790	530	• Feed through, HNBR (RGD) elastomers

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.
- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and completion elements are included in Injection Well Construction Plan Appendix A.

4.3 Cementing Program Pelican CCS 1

Table CON-15 shows the cementing program details.

Table CON-15—Cementing program for Pelican CCS 1.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,900	11.5-12.5	1,767	2.28	100%
	Class A/C cement with additives	2,900 to 3,600	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 4,300	11.5-12.5	1,566	1.29	50%
	CO_2-Resistant Cement	4,300 to 7,8000	14.5-15.6	1,551	1.06	50%

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at 4,300 ft, but the depth will be adjusted based on final drilling conditions.

Details on the cementing operation design, materials, and additives selection are included in Injection Well Construction Plan Appendix B, with examples of the proposed cementing slurries.

4.4 Mud Program Pelican CCS 1

Table CON-16 shows the mud program details for Pelican CCS 1.

Table CON-16—Mud program for Pelican CCS 1.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17-1/2 in.	Freshwater Gel	0–3,600	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12-1/4 in.	Synthetic-Based Mud	3,600–7,800	10.5-12.5	12–20	8–12	n/a	<5	<5

4.5 Wellhead Schematic Pelican CCS 1

Figure CON-2 below is a basic mechanical drawing of the wellhead to be used for the Pelican CCS 1 well. Details on blowout preventors (BOPs) and wellhead design are included in Injection Well Construction Plan Appendix C.

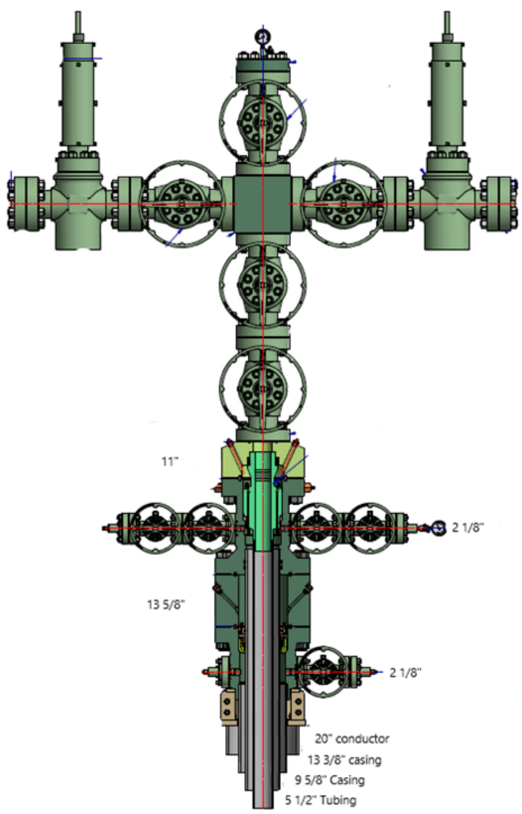

Figure CON-2—Schematic diagram of Pelican CCS 1 well.

4.6 Pelican CCS 1 Procedure

4.6.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

4.6.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.
- Make up shoe track and run 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.

- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbl of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when at 10 bbl before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.
- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the 13-5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks. Test casing to 1,500 psi and BOPE to 3,000 psi in accordance with Louisiana Statutes and Regulations 3617.A.3 requirements

4.6.3 Long String Section

- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from water-based mud (WBM) to synthetic-based mud (SBM). Ensure that all solid control equipment is installed and operating properly.
- Pick up 12.25 in. BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the plan. Surveys must be taken a minimum of every 100 ft.
- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.

- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.
- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips and test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbl before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbl before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer’s recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

Note: This is a standard process for stage tool application; however, it is recommended to evaluate the different methods in the market to include annular packers in combination with circulating ports that could improve the seal, reduce the wait on cement time, and optimize time and cost.

- Rig down cementing equipment.
- Perform nipple down safety meeting and discuss the operational plan and risks.
- Lift the BOPs.
- Install casing slips, threading the fiber optic cable through the port.
- Cut casing and install pack off and fiber optic connectors.
- Wait on cement to reach 500 psi.
- Continue installation of section B and wellhead.
- Rig down drilling equipment.

4.6.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 60 minutes with 1,000 psi. If the pressure decreases more than 5% in 60 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.
- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns. Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.

- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform and injectivity test/step rate test and falloff test.

5.0 Well Design Pelican CCS 2 - CO_2 Injector Well

The Pelican CCS 2 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-3 shows the proposed well schematic for the Pelican CCS 2 original completion. Recompletion well schematics are included in Section 9.0.

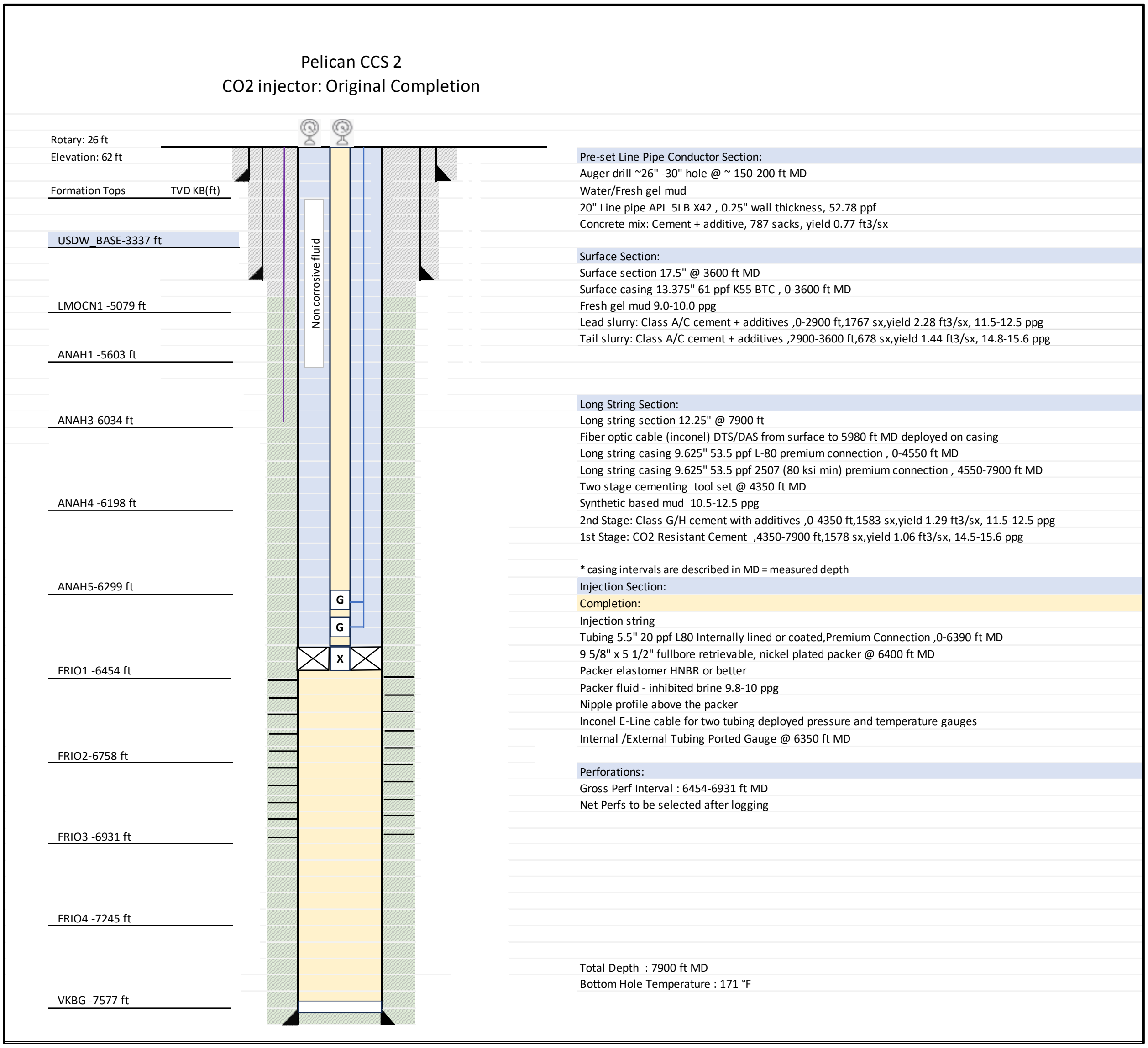

Figure CON-3—Pelican CCS 2 well schematic for initial completion.

5.1 Design Overview Pelican CCS 2

5.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20 in. line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

5.1.2 Surface Section

The 17-1/2 in. vertical wellbore will be drilled to 3,600 ft to cover base of the USDW, estimated at 3,337 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken every 100 ft at a minimum while drilling and this section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing (POT) Plan. Then, 13 3/8 in. casing will be run and cemented to surface via circulation with conventional Portland cement slurry plus additives. If there are no cement returns to the surface, the project will inform C&E, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the Commissioner. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test BOP and casing according to LAC 43:XVII.3617(A)(3) requirements and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

5.1.3 Long String Section

A 12-1/4 in. vertical wellbore will be drilled from 3,600 ft to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9-5/8 in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

After the cementing is complete, Section B of the wellhead will be installed, and the DTS/DAS cable will be threaded through the slips and packoff. The team will install the rest of the wellhead to prepare for completions operations and test the casing per Louisiana Statutes and Regulations 3617.A.3 requirements

5.1.4 Completion

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The 5-1/2 in. tubing and packer completion will be run to approximately 6,400 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular

space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

5.2 Casing, Tubing and Completion Design Pelican CCS 2

The different casing sections and completion tubing were designed to withstand expected operating loads, such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations.
- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull
- Corrosion environments

Table CON-17 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-17—Minimum safety factors for tubular design for Pelican CCS 2.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13-3/8 in., 61.0 ppf, K-55	Buttress	0-3,600	1.18	1.35	2.51	1.32
Long String Casing	9-5/8 in., 53.5 ppf, L-80	Premium, Gas Sealing	0-4,550	2.06	1.78	2.99	2.06
Long String Casing	9-5/8 in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	4,550-7,900	1.93	1.39	3.523	1.81
Tubing	5-1/2 in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-6,400	2.41	1.41	2.17	1.59

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Injection Well Construction Plan Appendix D.

The WELLCAT[TM] evaluation performed for Pelican CCS 1 applies to the loads observed for Pelican CCS 2, Pelican CCS 3, Pelican CCS 4, and Pelican CCS 5 (Injection Well Construction Plan Appendix E).

The tables listed below provide further details regarding the Pelican CCS 1 well. Table CON-18 contains the open hole diameters and intervals, Table CON-19 lists the casing specifications, Table CON-20 details the conductor material, and Table CON-21 details the casing material properties.

Table CON-18—Open hole diameters and intervals for Pelican CCS 2.

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,600	17-1/2	Cover USDW
Long String Section	3,600 to 7,900	12-1/4	To Total Depth

Note—The USDW depth will be confirmed with open hole logs. The USDW is estimated at 3,337 ft TVD.

Table CON-19—Casing specifications for Pelican CCS 2.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25 in. wall thickness, 19.5 in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,600	13-3/8	12.515	12.359	61	K55	BTC
Long String	0 to 4,550	9-5/8	8.535	8.379	53.5	L80	Premium
Long String	4,450 to 7,900	9-5/8	8.535	8.379	53.5	2507 Min 80 ksi	Premium

Table CON-20—Conductor material properties for Pelican CCS 2.

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)	Elongation %
20 in. API 5LB X42 52.78 ppf	0 to 200	42	60	23

Table CON-21—Casing material properties for Pelican CCS 2.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
13-3/8 in. 61 ppf K55 BTC	0 to 3,600	3,090	1,540	962	19°	26.2
9-5/8 in. 53.5 ppf L80 Premium connection	0 to 4,550	7,930	6,620	1,244	38°	26.2
9-5/8 in. 53.5 ppf 2507 80 ksi Premium Connection	4,550 to 7,900	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~4,350 ft in the 9-5/8 in. casing to perform the two-stage cementing job.
- The centralization program will aim at minimum 70% standoff and be adjusted using the field data for deviation, caliper, and hole conditions.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-22 contains the upper completion specifications for the original completion and recompletions. Table CON-23 shows the specification of the 5-1/2 in. tubing.

Table CON-22—Upper completion specifications – initial completion and first recompletion for Pelican CCS 2.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 6,400	5-1/2	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-23—Tubing material properties for Pelican CCS 2

Tubing	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
Injection Tubing: 5-1/2 in. 20 lb L80 Special – Coated TK-805	9,190	8,830	466	67°	26.2

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and to the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The annular space between the 5-1/2 in. tubing and 9-5/8 in. casing will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-24 shows the specifications of the injection packer.

Table CON-24:Packer specifications for Pelican CCS 2.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000
Burst Pressure (psi)	**Collapse Pressure (psi)**	**Tensile Strength (ksi)**	**Comments**		
8,050	7,790	530	• Feed through, HNBR (RGD) elastomers		

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.
- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and completion elements are included in Injection Well Construction Plan Appendix A.

5.3 Cementing Program Pelican CCS 2

Table CON-25 shows the cementing program details.

Table CON-25—Cementing program for Pelican CCS 2.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,900	11.5-12.5	1,767	2.28	100%
	Class A/C cement with additives	2,900 to 3,600	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 4,350	11.5-12.5	1,583	1.29	50%
	CO_2-Resistant Cement	4,350 to 7,900	14.5-15.6	1,578	1.06	50%

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at 4,350 ft, but the depth will be adjusted based on final drilling conditions.

Details on the cementing operation design, materials, and additives selection are included in Appendix B, with examples of the proposed cementing slurries.

5.4 Mud Program Pelican CCS 2

Table CON-26 shows the mud program details for Pelican CCS 2.

Table CON-26—Mud program for Pelican CCS 2.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17-1/2 in.	Freshwater Gel	0–3,600	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12-1/4 in.	Synthetic-Based Mud	3,600–7,900	10.5-12.5	12–20	8–12	n/a	<5	<5

5.5 Wellhead Schematic Pelican CCS 2

Figure CON-4 below is a basic mechanical drawing of the wellhead to be used for the Pelican CCS 2 well. Details on blowout preventors (BOPs) and wellhead design are included in Injection Well Construction Plan Appendix C.

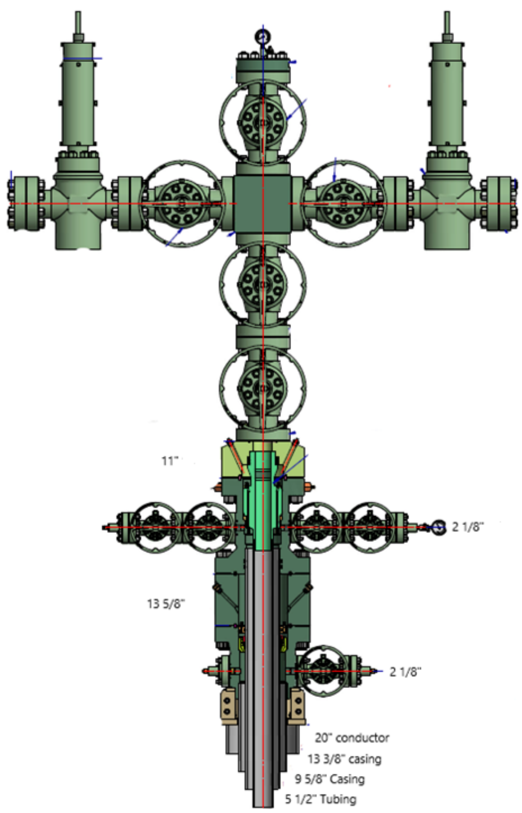

Figure CON-4—Schematic diagram of Pelican CCS 2 well.

5.6 Pelican CCS 2 Procedure

5.6.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

5.6.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.
- Make up shoe track and run 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.

- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbl of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when at 10 bbl before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.
- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the 13-5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi in accordance with Louisiana Statutes and Regulations 3617.A.3 requirements

5.6.3 Long String Section

- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from water-based mud (WBM) to synthetic-based mud (SBM). Ensure that all solid control equipment is installed and operating properly.
- Pick up 12.25 in. BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the plan. Surveys must be taken a minimum of every 100 ft.
- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.

- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.
- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips and test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbl before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.

- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbl before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer's recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

Note: This is a standard process for stage tool application; however, it is recommended to evaluate the different methods in the market to include annular packers in combination with circulating ports that could improve the seal, reduce the wait on cement time, and optimize time and cost.

- Rig down cementing equipment.
- Perform nipple down safety meeting and discuss the operational plan and risks.
- Lift the BOPs.
- Install casing slips, threading the fiber optic cable through the port.
- Cut casing and install pack off and fiber optic connectors.
- Wait on cement to reach 500 psi.
- Continue installation of section B and wellhead.
- Rig down drilling equipment.

5.6.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 60 minutes with 1,000 psi. If the pressure decreases more than 5% in 60 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.
- Run completion assembly per program.

- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns. Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform and injectivity test/step rate test and falloff test.

6.0 Well Design Pelican CCS 3 - CO_2 Injector Well

The Pelican CCS 3 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-5 shows the proposed well schematic for the Pelican CCS 3 original completion. Recompletion well schematics are included in Section 9.0.

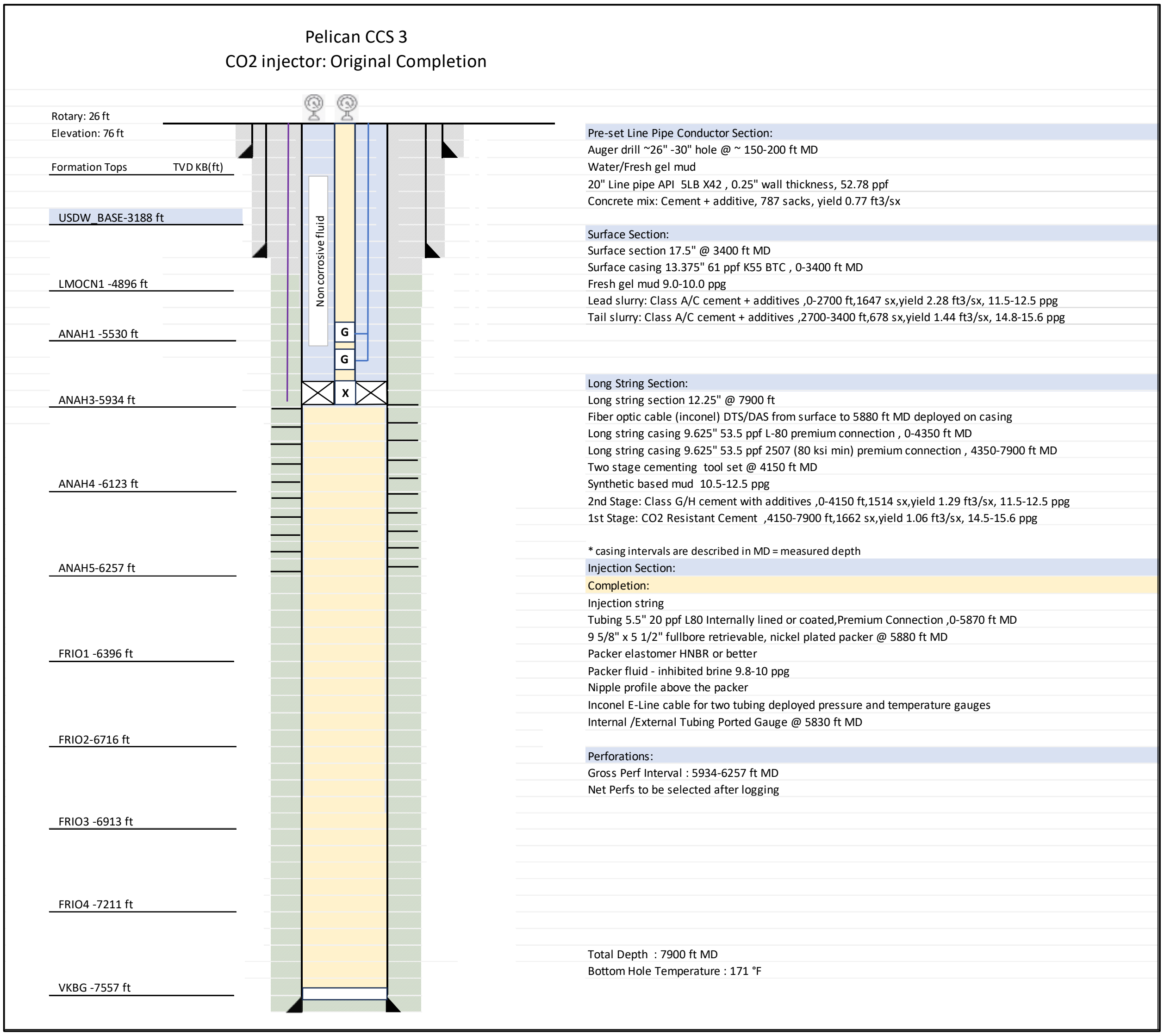

Figure CON-5—Pelican CCS 3 well schematic for initial completion.

6.1 Design Overview Pelican CCS 3

6.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20 in. line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

6.1.2 Surface Section

The 17-1/2 in. vertical wellbore will be drilled to 3,400 ft to cover base of the USDW, estimated at 3,188 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken every 100 ft at a minimum while drilling and this section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13-3/8 in. casing will be run and cemented to surface via circulation with conventional Portland cement slurry plus additives. If there are no cement returns to the surface, the project will inform C&E, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the Commissioner. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test BOP and casing according to LAC 43:XVII.3617(A)(3) requirements and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

6.1.3 Long String Section

A 12-1/4 in. vertical wellbore will be drilled from 3,400 ft to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9-5/8 in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

After the cementing is complete, Section B of the wellhead will be installed, and the DTS/DAS cable will be threaded through the slips and packoff. The team will install the rest of the wellhead to prepare for completions operations and test the casing per Louisiana Statutes and Regulations 3617.A.3 requirements

6.1.4 Completion

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The 5-1/2 in. tubing and packer completion will be run to approximately 5,880 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular

space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

6.2 Casing, Tubing and Completion Design Pelican CCS 3

The different casing sections and completion tubing were designed to withstand expected operating loads, such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations.
- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull
- Corrosion environments

Table CON-27 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-27:Minimum safety factors for tubular design for Pelican CCS 3.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13-3/8 in., 61.0 ppf, K-55	Buttress	0-3,400	1.19	1.49	2.51	1.32
Long String Casing	9-5/8 in., 53.5 ppf, L-80	Premium, Gas Sealing	0-4,350	2.06	1.77	3.25	2.09
Long String Casing	9-5/8 in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	4,350-7,900	1.95	1.56	3.56	1.97
Tubing	5-1/2 in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-5,880	2.36	1.53	2.27	1.72

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Injection Well Construction Plan Appendix D.

The WELLCAT™ evaluation performed for Pelican CCS 1 applies to the loads observed for Pelican CCS 2, Pelican CCS 3, Pelican CCS 4, and Pelican CCS 5 (Appendix E).

The tables listed below provide further details regarding the Pelican CCS 3 well. Table CON-28 contains the open hole diameters and intervals, Table CON-29 lists the casing specifications, Table CON-30 details the conductor material, and Table CON-31 details the casing material properties.

Table CON-28—Open hole diameters and intervals for Pelican CCS 3.

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,400	17-1/2	Cover USDW
Long String Section	3,400 to 7,900	12-1/4	To Total Depth

Note: The USDW depth will be confirmed with open hole logs. The USDW is estimated at 3,188 ft TVD.

Table CON-29—Casing specifications for Pelican CCS 3.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25 in. wall thickness, 19.5 in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,400	13-3/8	12.515	12.359	61	K55	BTC
Long String	0 to 4,350	9-5/8	8.535	8.379	53.5	L80	Premium
Long String	4,350 to 7,900	9-5/8	8.535	8.379	53.5	2507 Min 80 ksi	Premium

Table CON-30—Conductor material properties for Pelican CCS 3.

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)	Elongation %
20 in. API 5LB X42 52.78 ppf	0 to 200	42	60	23

Table CON-31—Casing material properties for Pelican CCS 3.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
13-3/8 in. 61 ppf K55 BTC	0 to 3,400	3,090	1,540	962	19°	26.2
9-5/8 in. 53.5 ppf L80 Premium connection	0 to 4,350	7,930	6,620	1,244	38°	26.2
9-5/8 in. 53.5 ppf 2507 80 ksi Premium Connection	4,350 to 7,900	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~4,150 ft in the 9-5/8 in. casing to perform the two-stage cementing job.
- The centralization program will aim at minimum 70% standoff and be adjusted using the field data for deviation, caliper, and hole conditions.

- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-32 contains the upper completion specifications for the original completion and recompletions. Table CON-33 shows the specification of the 5-1/2 in. tubing.

Table CON-32—Upper completion specifications – initial completion and first recompletion for Pelican CCS 3.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 5,880	5-1/2	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-33—Tubing material properties for Pelican CCS 3.

Tubing	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending °/100 ft	Thermal Conductivity @ 77°F (BTU/ft.hr.°F)
Injection Tubing: 5-1/2 in. 20 lb L80 Special – Coated TK-805	9,190	8,830	466	67°	26.2

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and to the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The annular space between the 5-1/2 in. tubing and 9-5/8 in. casing will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-34 shows the specifications of the injection packer.

Table CON-34—Packer specifications for Pelican CCS 3.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000

Burst Pressure (psi)	Collapse Pressure (psi)	Tensile Strength (ksi)	Comments
8,050	7,790	530	• Feed through, HNBR (RGD) elastomers

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.
- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and completion elements are included in Injection Well Construction Plan Appendix A.

6.3 Cementing Program Pelican CCS 3

Table CON-35 shows the cementing program details.

Table CON-35—Cementing program for Pelican CCS 3.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,700	11.5-12.5	1,647	2.28	100%
	Class A/C cement with additives	2,700 to 3,400	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 4,150	11.5-12.5	1,514	1.29	50%
	CO_2-Resistant Cement	4,150 to 7,900	14.5-15.6	1,662	1.06	50%

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at 4,150 ft, but the depth will be adjusted based on final drilling conditions.

Details on the cementing operation design, materials, and additives selection are included in Injection Well Construction Plan Appendix B, with examples of the proposed cementing slurries.

6.4 Mud Program Pelican CCS 3

Table CON-36 shows the mud program details for Pelican CCS 3.

Table CON-36—Mud program for Pelican CCS 3.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17-1/2 in.	Freshwater Gel	0–3,400	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12-1/4 in.	Synthetic-Based Mud	3,400–7,900	10.5-12.5	12–20	8–12	n/a	<5	<5

6.5 Wellhead Schematic Pelican CCS 3

Figure CON-6 below is a basic mechanical drawing of the wellhead to be used for the Pelican CCS 3 well. Details on blowout preventors (BOPs) and wellhead design are included in Injection Well Construction Plan Appendix C.

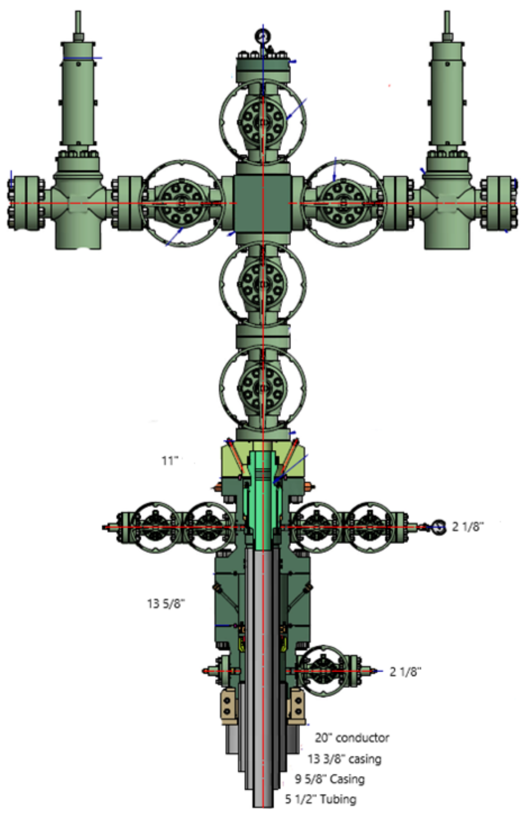

Figure CON-6—Schematic diagram of Pelican CCS 3 well.

6.6 Pelican CCS 3 Procedure

6.6.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).

- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

6.6.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.
- Make up shoe track and run 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbl of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.

- Reduce the displacement rate when at 10 bbl before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.
- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the 13-5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi in accordance with Louisiana Statutes and Regulations 3617.A.3 requirements.

6.6.3 Long String Section

- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from water-based mud (WBM) to synthetic-based mud (SBM). Ensure that all solid control equipment is installed and operating properly.
- Pick up 12.25 in. BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the plan. Surveys must be taken a minimum of every 100 ft.
- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.

- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips and test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbl before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbl before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer's recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

Note: This is a standard process for stage tool application; however, it is recommended to evaluate the different methods in the market to include annular packers in combination with circulating ports that could improve the seal, reduce the wait on cement time, and optimize time and cost.

- Rig down cementing equipment.

- Perform nipple down safety meeting and discuss the operational plan and risks.
- Lift the BOPs.
- Install casing slips, threading the fiber optic cable through the port.
- Cut casing and install pack off and fiber optic connectors.
- Wait on cement to reach 500 psi.
- Continue installation of section B and wellhead.
- Rig down drilling equipment.

6.6.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 60 minutes with 1,000 psi. If the pressure decreases more than 5% in 60 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.
- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns. Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform and injectivity test/step rate test and falloff test.

7.0 Well Design Pelican CCS 4 - CO_2 Injector Well

The Pelican CCS 4 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-7 shows the proposed well schematic for the Pelican CCS 4 original completion. Recompletion well schematics are included in Section 9.0.

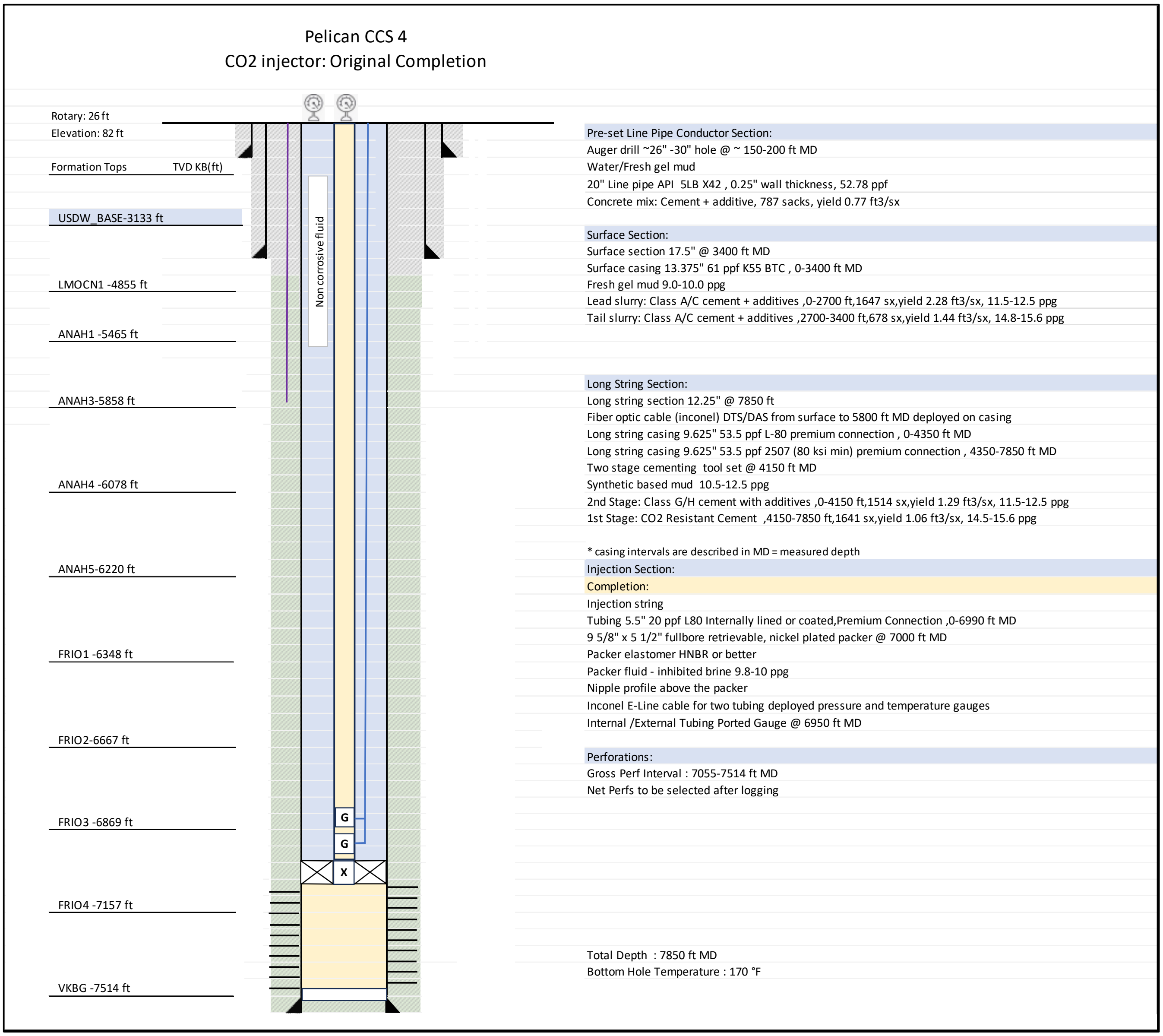

Figure CON-7—Pelican CCS 4 well schematic for initial completion.

7.1 Design Overview Pelican CCS 4

7.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20 in. line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

7.1.2 Surface Section

The 17-1/2 in. vertical wellbore will be drilled to 3,400 ft to cover base of the USDW, estimated at 3,133 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken every 100 ft at a minimum while drilling and this section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13-3/8 in. casing will be run and cemented to surface via circulation with conventional Portland cement slurry plus additives. If there are no cement returns to the surface, the project will inform C&E, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the Commissioner. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test BOP and casing according to LAC 43:XVII.3617(A)(3) requirements and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

7.1.3 Long String Section

A 12-1/4 in. vertical wellbore will be drilled from 3,400 ft to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9-5/8 in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

After the cementing is complete, Section B of the wellhead will be installed, and the DTS/DAS cable will be threaded through the slips and packoff. The team will install the rest of the wellhead to prepare for completions operations and test the casing per Louisiana Statutes and Regulations 3617.A.3 requirements

7.1.4 Completion

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The 5-1/2 in. tubing and packer completion will be run to approximately 7,000 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

7.2 Casing, Tubing and Completion Design Pelican CCS 4

The different casing sections and completion tubing were designed to withstand expected operating loads, such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations.
- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull
- Corrosion environments

Table CON-37 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-37—Minimum safety factors for tubular design for Pelican CCS 4.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13-3/8 in., 61.0 ppf, K-55	Buttress	0-3,400	1.18	1.52	2.51	1.32
Long String Casing	9-5/8 in., 53.5 ppf, L-80	Premium, Gas Sealing	0-4,350	2.07	1.78	3.29	2.10
Long String Casing	9-5/8 in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	4,350-7,850	1.96	1.58	3.75	1.99
Tubing	5-1/2 in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-7,000	2.35	1.55	2.29	1.74

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Injection Well Construction Plan Appendix D.

The WELLCAT™ evaluation performed for Pelican CCS 1 applies to the loads observed for Pelican CCS 2, Pelican CCS 3, Pelican CCS 4 and Pelican CCS 5 (Injection Well Construction Plan Appendix E).

The tables listed below provide further details regarding the Pelican CCS 4 well. Table CON-38 contains the open hole diameters and intervals, Table CON-39 lists the casing specifications, Table CON-40 details the conductor material, and Table CON-41 details the casing material properties.

Table CON-38—Open hole diameters and intervals for Pelican CCS 4.

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,400	17-1/2	Cover USDW
Long String Section	3,400 to 7,850	12-1/4	To Total Depth

Note: The USDW depth will be confirmed with open hole logs. The USDW is estimated at 3,133 ft TVD.

Table CON-39—Casing specifications for Pelican CCS 4.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25 in. wall thickness, 19.5 in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,400	13-3/8	12.515	12.359	61	K55	BTC
Long String	0 to 4,350	9-5/8	8.535	8.379	53.5	L80	Premium
Long String	4,350 to 7,850	9-5/8	8.535	8.379	53.5	2507 Min 80 ksi	Premium

Table CON-40—Conductor material properties for Pelican CCS 4.

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)	Elongation %
20 in. API 5LB X42 52.78 ppf	0 to 200	42	60	23

Table CON-41—Casing material properties for Pelican CCS 4.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
13-3/8 in. 61 ppf K55 BTC	0 to 3,400	3,090	1,540	962	19°	26.2
9-5/8 in. 53.5 ppf L80 Premium connection	0 to 4,350	7,930	6,620	1,244	38°	26.2
9-5/8 in. 53.5 ppf 2507 80 ksi Premium Connection	4,350 to 7,850	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~4,150 ft in the 9-5/8 in. casing to perform the two-stage cementing job.
- The centralization program will aim at minimum 70% standoff and be adjusted using the field data for deviation, caliper, and hole conditions.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-42 contains the upper completion specifications for the original completion and recompletions. Table CON-43 shows the specification of the 5-1/2 in. tubing.

Table CON-42—Upper completion specifications – initial completion and first recompletion for Pelican CCS 4.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 7,000	5-1/2	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-43—Tubing material properties for Pelican CCS 4.

Tubing	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
Injection Tubing: 5-1/2 in. 20 lb L80 Special – Coated TK-805	9,190	8,830	466	67°	26.2

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and to the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The annular space between the 5-1/2 in. tubing and 9-5/8 in. casing will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-44 shows the specifications of the injection packer.

Table CON-44—Packer specifications - Pelican CCS 4.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000
Burst Pressure (psi)	**Collapse Pressure (psi)**	**Tensile Strength (ksi)**	**Comments**		
8,050	7,790	530	• Feed through, HNBR (RGD) elastomers		

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.
- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and completion elements are included in Injection Well Construction Plan Appendix A.

7.3 Cementing Program Pelican CCS 4

Table CON-45 shows the cementing program details.

Table CON-45—Cementing program for Pelican CCS 4.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,700	11.5-12.5	1,647	2.28	100%
	Class A/C cement with additives	2,700 to 3,400	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 4,150	11.5-12.5	1,514	1.29	50%
	CO_2-Resistant Cement	4,150 to 7,850	14.5-15.6	1,641	1.06	50%

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at 4,150 ft, but the depth will be adjusted based on final drilling conditions.

Details on the cementing operation design, materials, and additives selection are included in Injection Well Construction Plan Appendix B, with examples of the proposed cementing slurries.

7.4 Mud Program Pelican CCS 4

Table CON-46 shows the mud program details for Pelican CCS 4.

Table CON-46—Mud program for Pelican CCS 4.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17-1/2 in.	Freshwater Gel	0–3,400	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12-1/4 in.	Synthetic-Based Mud	3,400–7,850	10.5-12.5	12–20	8–12	n/a	<5	<5

7.5 Wellhead Schematic Pelican CCS 4

Figure CON-8 below is a basic mechanical drawing of the wellhead to be used for the Pelican CCS 4 well. Details on blowout preventors (BOPs) and wellhead design are included in Injection Well Construction Plan Appendix C.

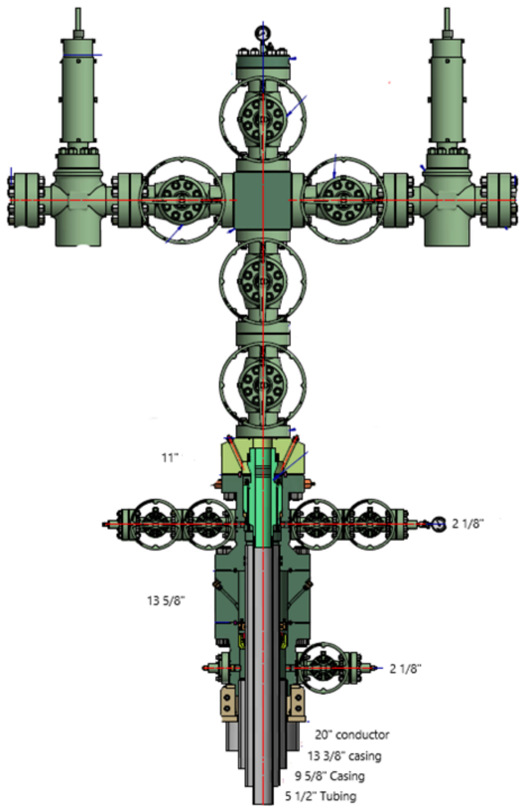

Figure CON-8—Schematic diagram of Pelican CCS 4 well.

7.6 Pelican CCS 4 Procedure

7.6.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).

- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

7.6.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.
- Make up shoe track and run 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbl of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.

- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when at 10 bbl before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.
- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the 13-5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi in accordance with Louisiana Statutes and Regulations 3617.A.3 requirements.

7.6.3 Long String Section

- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from water-based mud (WBM) to synthetic-based mud (SBM). Ensure that all solid control equipment is installed and operating properly.
- Pick up 12.25 in. BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the plan. Surveys must be taken a minimum of every 100 ft.
- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.

- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.
- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips and test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbl before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbl before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the

manufacturer's recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

Note: This is a standard process for stage tool application; however, it is recommended to evaluate the different methods in the market to include annular packers in combination with circulating ports that could improve the seal, reduce the wait on cement time, and optimize time and cost.

- Rig down cementing equipment.
- Perform nipple down safety meeting and discuss the operational plan and risks.
- Lift the BOPs.
- Install casing slips, threading the fiber optic cable through the port.
- Cut casing and install pack off and fiber optic connectors.
- Wait on cement to reach 500 psi.
- Continue installation of section B and wellhead.
- Rig down drilling equipment.

7.6.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 60 minutes with 1,000 psi. If the pressure decreases more than 5% in 60 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.
- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.

- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns. Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform and injectivity test/step rate test and falloff test.

8.0 Well Design Pelican CCS 5 - CO_2 Injector Well

The Pelican CCS 5 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-9 shows the proposed well schematic for the Pelican CCS 5 original completion. Recompletion well schematics are included in Section 9.0.

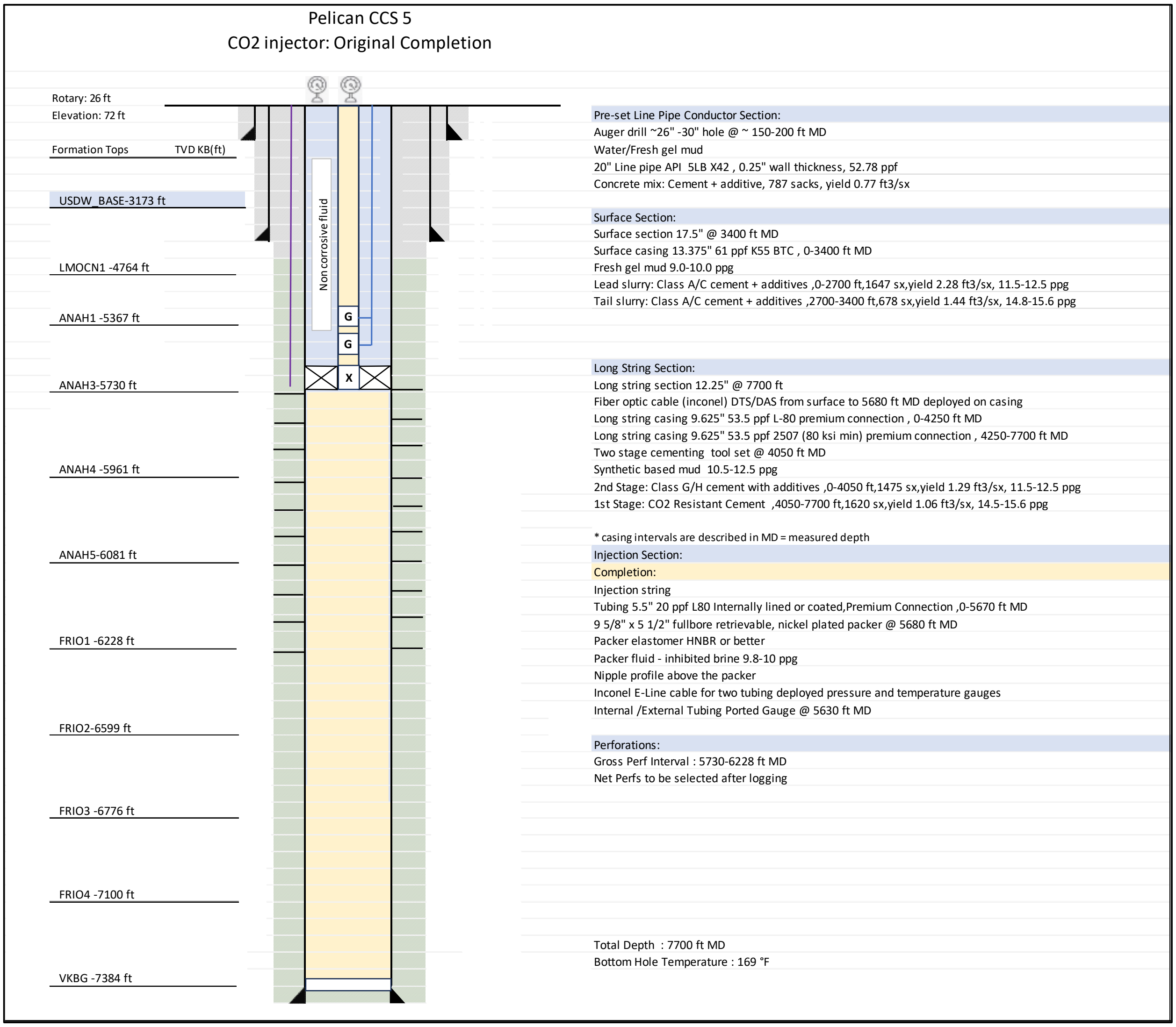

Figure CON-9—Pelican CCS 5 well schematic for initial completion.

8.1 Design Overview Pelican CCS 5

8.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20 in. line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

8.1.2 Surface Section

The 17-1/2 in. vertical wellbore will be drilled to 3,400 ft to cover base of the USDW, estimated at 3,173 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken every 100 ft at a minimum while drilling and this section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13-3/8 in. casing will be run and cemented to surface via circulation with conventional Portland cement slurry plus additives. If there are no cement returns to the surface, the project will inform C&E, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the Commissioner. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test BOP and casing according to LAC 43:XVII.3617(A)(3) requirements and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

8.1.3 Long String Section

A 12-1/4 in. vertical wellbore will be drilled from 3,400 ft to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9-5/8 in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

After the cementing is complete, Section B of the wellhead will be installed, and the DTS/DAS cable will be threaded through the slips and packoff. The team will install the rest of the wellhead to prepare for completions operations and test the casing per Louisiana Statutes and Regulations 3617.A.3 requirements

8.1.4 Completion

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The 5-1/2 in. tubing and packer completion will be run to approximately 5,680 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

8.2 Casing, Tubing and Completion Design Pelican CCS 5

The different casing sections and completion tubing were designed to withstand expected operating loads, such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations.
- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull
- Corrosion environments

Table CON-47 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-47—Minimum safety factors for tubular design for Pelican CCS 5.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13-3/8 in., 61.0 ppf, K-55	Buttress	0-3,400	1.18	1.52	2.51	1.32
Long String Casing	9-5/8 in., 53.5 ppf, L-80	Premium, Gas Sealing	0-4,250	2.07	1.78	3.29	2.10
Long String Casing	9-5/8 in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	4,250-7,700	1.96	1.58	3.75	1.99
Tubing	5-1/2 in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-5,680	2.35	1.55	2.29	1.74

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Injection Well Construction Plan Appendix D.

The WELLCAT™ evaluation performed for Pelican CCS 1 applies to the loads observed for Pelican CCS 2, Pelican CCS 3, Pelican CCS 4 and Pelican CCS 5 (Injection Well Construction Plan Appendix E).

The tables listed below provide further details regarding the Pelican CCS 5 well. Table CON-48 contains the open hole diameters and intervals, Table CON-49 lists the casing specifications, Table CON-50 details the conductor material, and Table CON-51 details the casing material properties.

Table CON-48—Open hole diameters and intervals for Pelican CCS 5.

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,400	17-1/2	Cover USDW
Long String Section	3,400 to 7,700	12-1/4	To Total Depth

Note: The USDW depth will be confirmed with open hole logs. The USDW is estimated at 3,173 ft TVD.

Table CON-49—Casing specifications for Pelican CCS 5.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25 in. wall thickness, 19.5 in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,400	13-3/8	12.515	12.359	61	K55	BTC
Long String	0 to 4,250	9-5/8	8.535	8.379	53.5	L80	Premium
Long String	4,250 to 7,700	9-5/8	8.535	8.379	53.5	2507 Min 80 ksi	Premium

Table CON-50—Conductor material properties for Pelican CCS 5.

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)	Elongation %
20 in. API 5LB X42 52.78 ppf	0 to 200	42	60	23

Table CON-51—Casing material properties for Pelican CCS 5.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
13-3/8 in. 61 ppf K55 BTC	0 to 3,400	3,090	1,540	962	19°	26.2
9-5/8 in. 53.5 ppf L80 Premium connection	0 to 4,250	7,930	6,620	1,244	38°	26.2
9-5/8 in. 53.5 ppf 2507 80 ksi Premium Connection	4,250 to 7,700	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~4,050 ft in the 9-5/8 in. casing to perform the two-stage cementing job.
- The centralization program will aim at minimum 70% standoff and be adjusted using the field data for deviation, caliper, and hole conditions.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-52 contains the upper completion specifications for the original completion and recompletions. Table CON-53 shows the specification of the 5-1/2 in. tubing.

Table CON-52—Upper completion specifications – initial completion and first recompletion for Pelican CCS 5.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 5,680	5-1/2	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-53—Tubing material properties for Pelican CCS 5.

Tubing	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
Injection Tubing: 5-1/2 in. 20 lb L80 Special – Coated TK-805	9,190	8,830	466	67°	26.2

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and to the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The annular space between the 5-1/2 in. tubing and 9-5/8 in. casing will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-54 shows the specifications of the injection packer.

Table CON-54—Packer specifications - Pelican CCS 5.

<table>
<tr><th colspan="2">Packer type and material</th><th colspan="2">Nominal casing weight (ppf)</th><th>Packer main body outer diameter (in.)</th><th>Packer main body inner diameter (in.)</th><th>Temperature rating (°F)</th><th>Pressure rating (psi)</th></tr>
<tr><td colspan="2">Full-bore retrievable, nickel-plated at all wet surfaces</td><td colspan="2">47-53.5</td><td>8.35</td><td>4.575</td><td>40-325</td><td>10,000</td></tr>
<tr><th>Burst Pressure (psi)</th><th colspan="2">Collapse Pressure (psi)</th><th colspan="2">Tensile Strength (ksi)</th><th colspan="3">Comments</th></tr>
<tr><td>8,050</td><td colspan="2">7,790</td><td colspan="2">530</td><td colspan="3">• Feed through, HNBR (RGD) elastomers</td></tr>
</table>

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.
- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and completion elements are included in Injection Well Construction Plan Appendix A.

8.3 Cementing Program Pelican CCS 5

Table CON-55 shows the cementing program details.

Table CON-55—Cementing program for Pelican CCS 5.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,700	11.5-12.5	1,647	2.28	100%
	Class A/C cement with additives	2,700 to 3,400	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 4,050	11.5-12.5	1,475	1.29	50%
	CO_2-Resistant Cement	4,050 to 7,700	14.5-15.6	1,620	1.06	50%

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at 4,050 ft, but the depth will be adjusted based on final drilling conditions.

Details on the cementing operation design, materials, and additives selection are included in Injection Well Construction Plan Appendix B, with examples of the proposed cementing slurries.

8.4 Mud Program Pelican CCS 5

Table CON-56 shows the mud program details for Pelican CCS 5.

Table CON-56—Mud program for Pelican CCS 5.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17-1/2 in.	Freshwater Gel	0–3,400	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12-1/4 in.	Synthetic-Based Mud	3,400–7,700	10.5-12.5	12–20	8–12	n/a	<5	<5

8.5 Wellhead Schematic Pelican CCS 5

Figure CON-10 below is a basic mechanical drawing of the wellhead to be used for the Pelican CCS 5 well. Details on blowout preventors (BOPs) and wellhead design are included in Injection Well Construction Plan Appendix C.

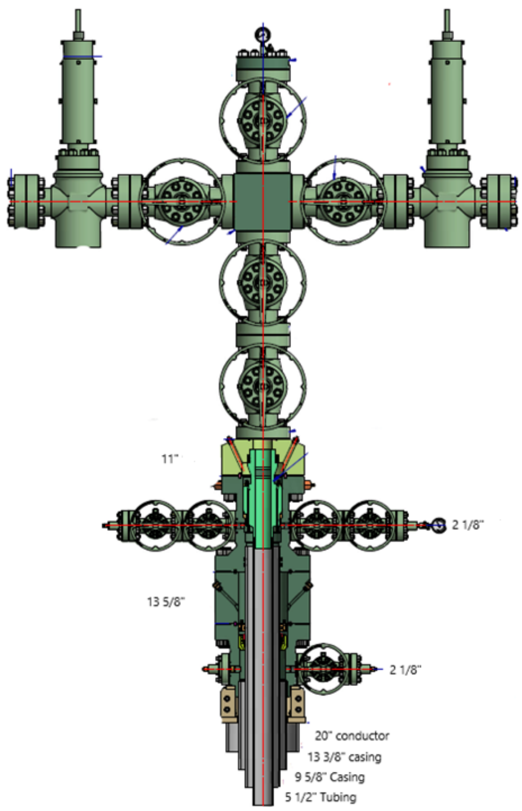

Figure CON-10—Schematic diagram of Pelican CCS 5 well.

8.6 Pelican CCS 5 Procedure

8.6.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

8.6.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.
- Make up shoe track and run 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.

- Pump 40-80 bbl of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when at 10 bbl before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.
- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the 13-5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi in accordance with Louisiana Statutes and Regulations 3617.A.3 requirements.

8.6.3 Long String Section

- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from water-based mud (WBM) to synthetic-based mud (SBM). Ensure that all solid control equipment is installed and operating properly.
- Pick up 12.25 in. BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the plan. Surveys must be taken a minimum of every 100 ft.
- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.

- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.
- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips and test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbl before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and two samples of the mixing water.

- Drop plug and displace the cement with inhibited brine. At 20 bbl before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer's recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

Note: This is a standard process for stage tool application; however, it is recommended to evaluate the different methods in the market to include annular packers in combination with circulating ports that could improve the seal, reduce the wait on cement time, and optimize time and cost.

- Rig down cementing equipment.
- Perform nipple down safety meeting and discuss the operational plan and risks.
- Lift the BOPs.
- Install casing slips, threading the fiber optic cable through the port.
- Cut casing and install pack off and fiber optic connectors.
- Wait on cement to reach 500 psi.
- Continue installation of section B and wellhead.
- Rig down drilling equipment.

8.6.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 60 minutes with 1,000 psi. If the pressure decreases more than 5% in 60 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.

- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.
- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns. Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform and injectivity test/step rate test and falloff test.

9.0 Recompletion Wellbore Diagrams

Information about squeeze plugs pumped during recompletions are available in the Injector Well Plugging Plan.

9.1 Pelican CCS 1Recompletions

9.1.1 Pelican CCS 1 First Recompletion

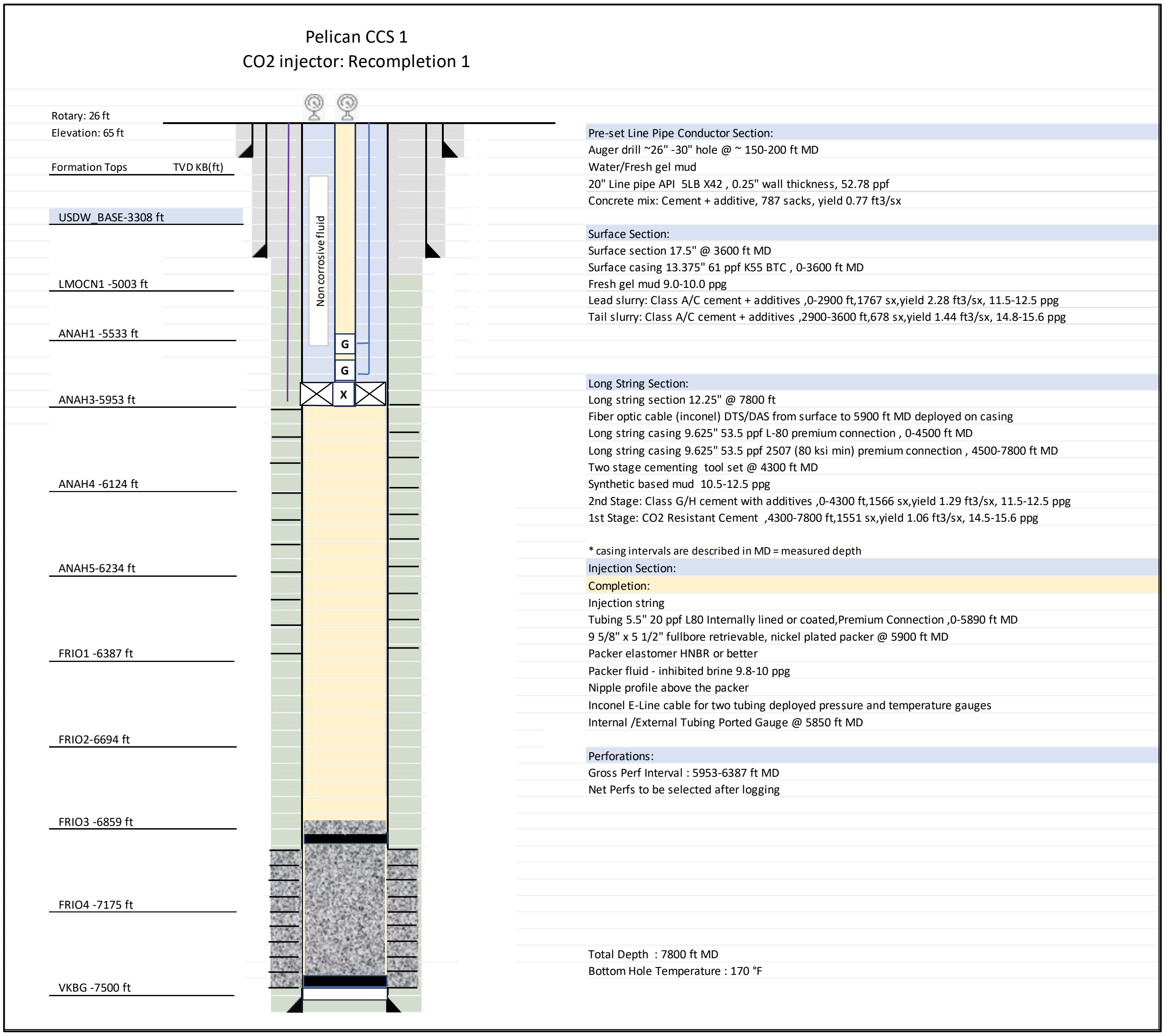

Figure CON-11—First Recompletion Schematic diagram of Pelican CCS 1 well.

9.1.2 Pelican CCS 1 Second Recompletion

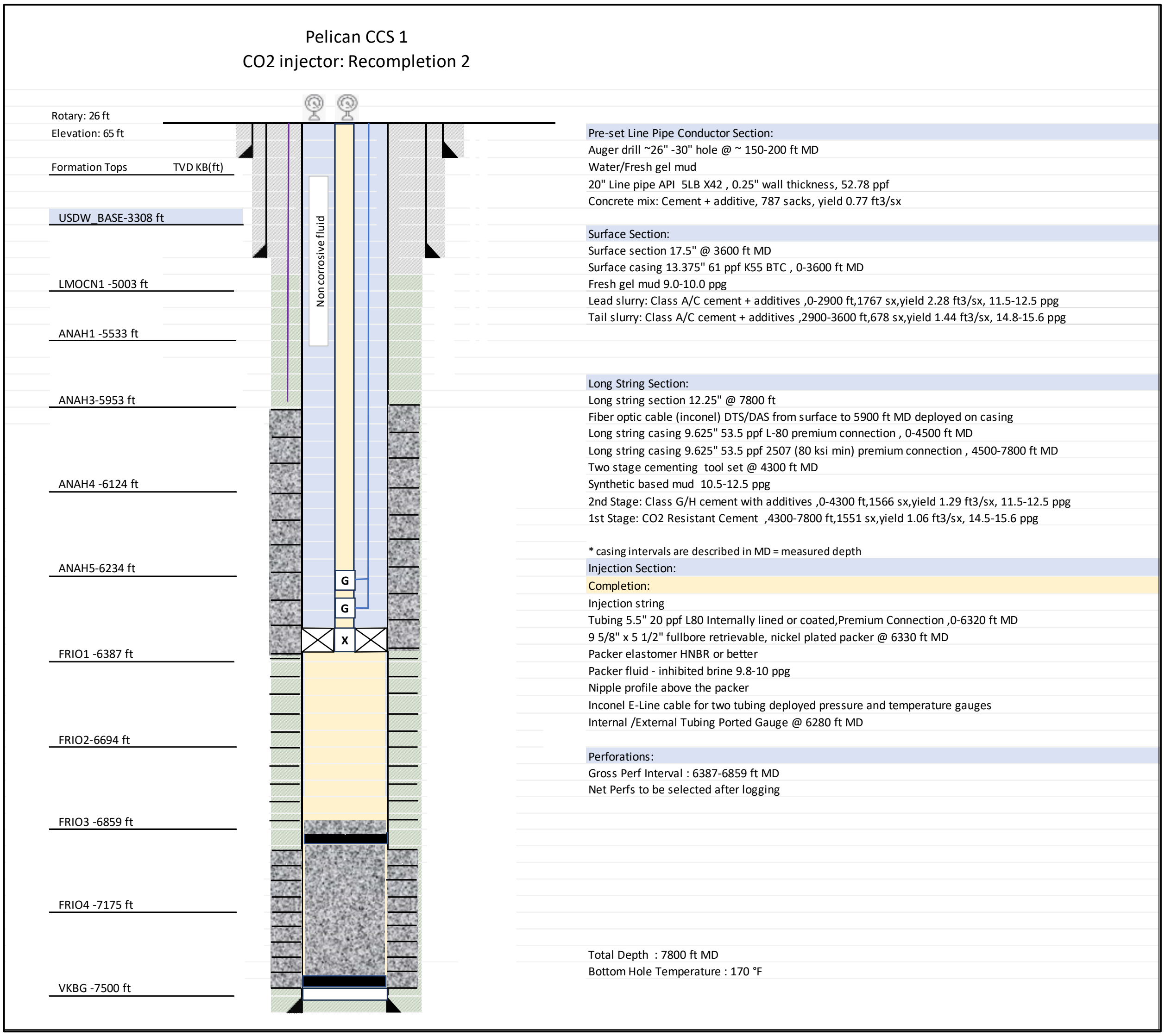

Figure CON-12—Second Recompletion Schematic diagram of Pelican CCS 1 well.

9.2 Pelican CCS 2 Recompletions

9.2.1 Pelican CCS 2 First Recompletion

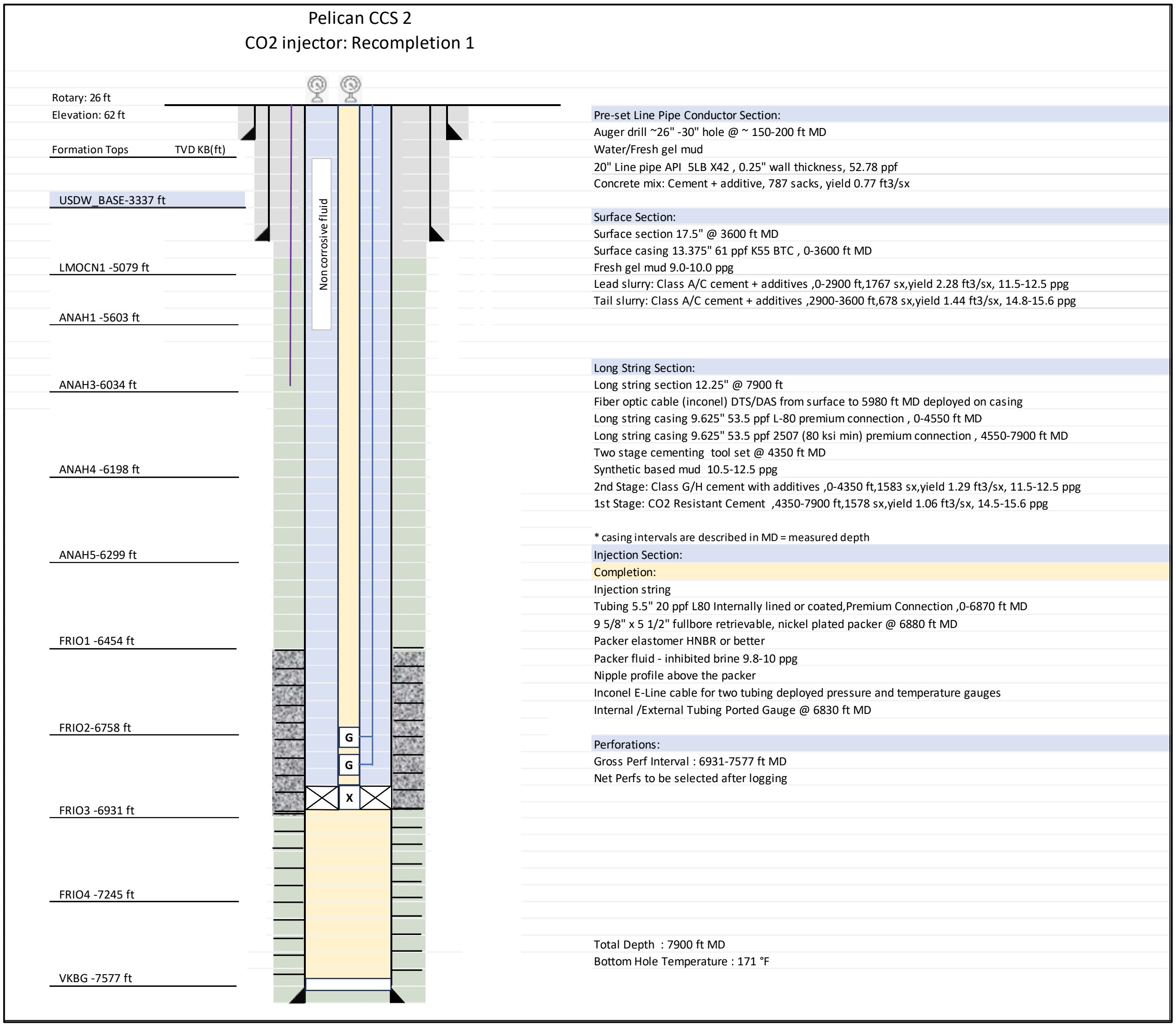

Figure CON-13—First Recompletion Schematic diagram of Pelican CCS 2 well.

9.2.2 Pelican CCS 2 Second Recompletion

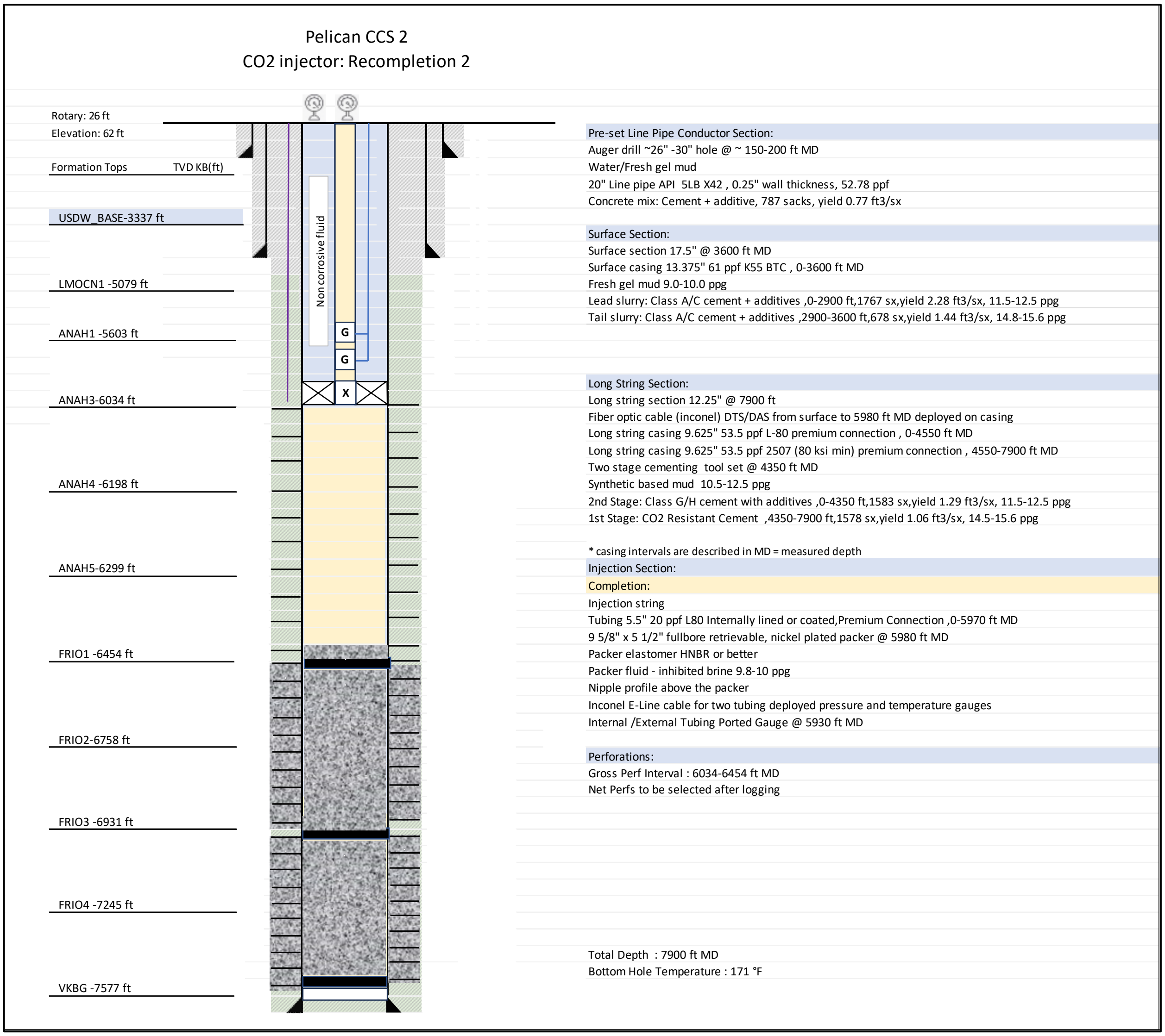

Figure CON-14—Second Recompletion Schematic diagram of Pelican CCS 2 well.

9.3 Pelican CCS 3 Recompletions

9.3.1 Pelican CCS 3 First Recompletion

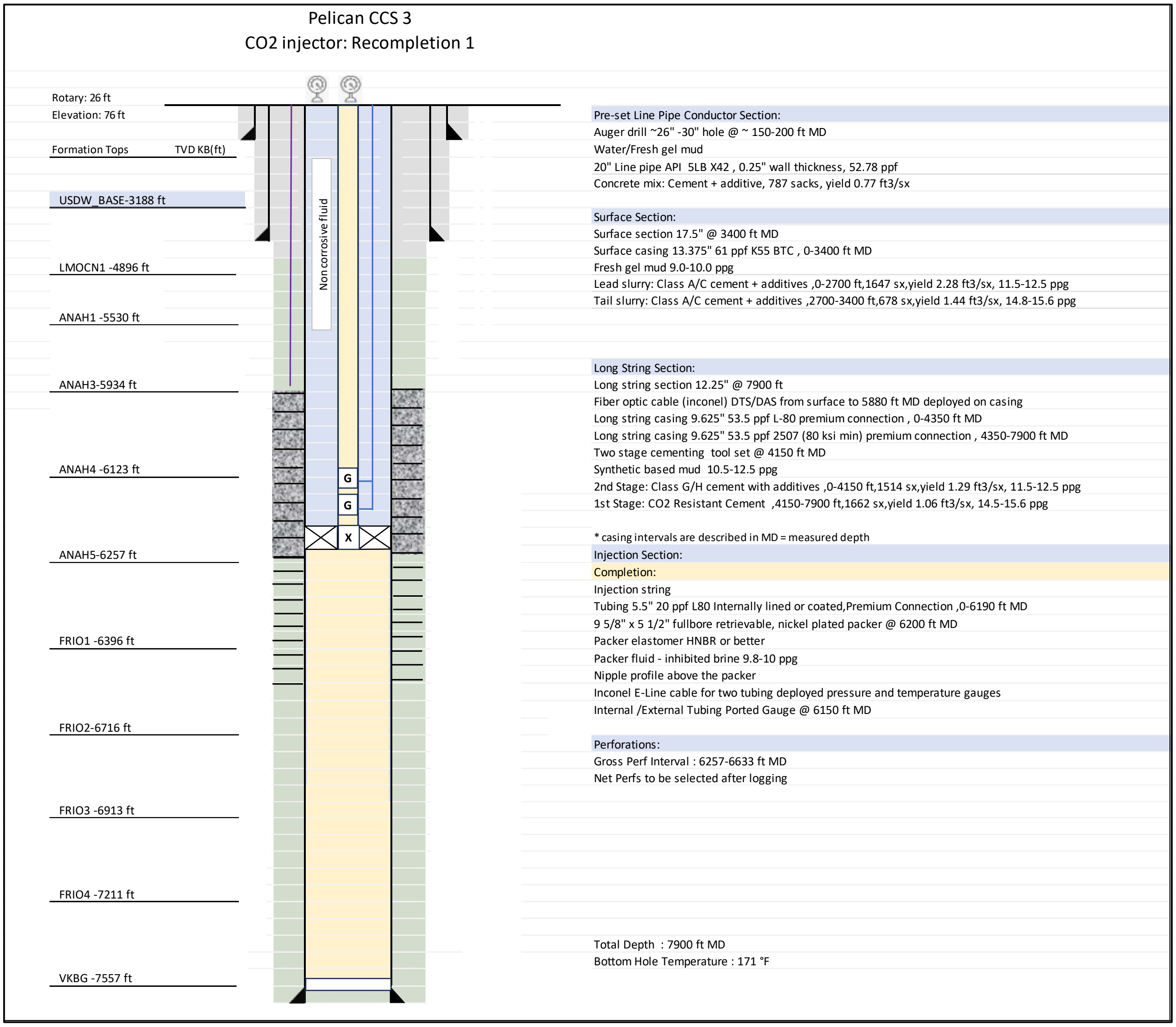

Figure CON-15—First Recompletion Schematic diagram of Pelican CCS 3 well.

9.3.2 Pelican CCS 3 Second Recompletion

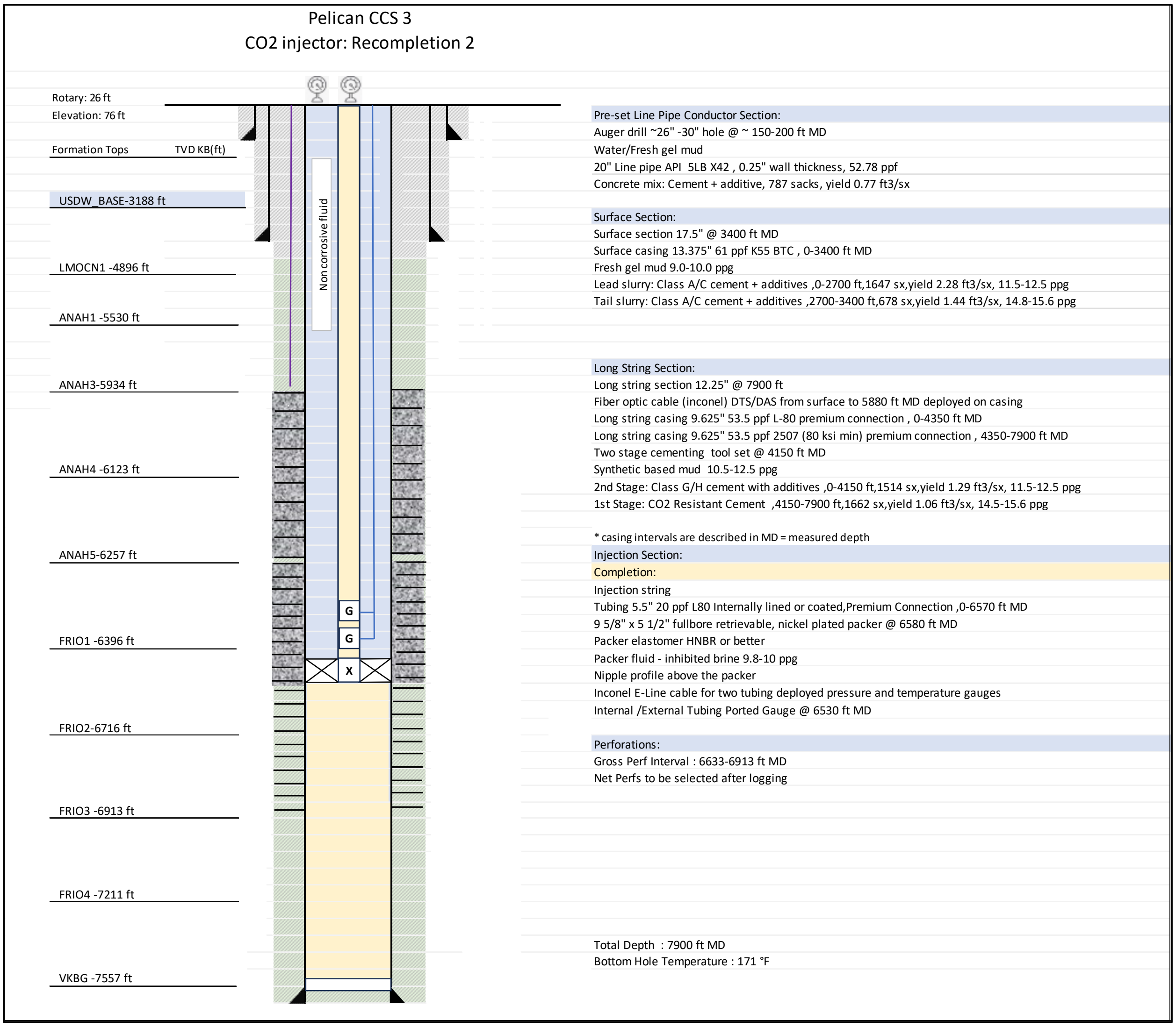

Figure CON-16—Second Recompletion Schematic diagram of Pelican CCS 3 well.

9.3.3 Pelican CCS 3 Third Recompletion

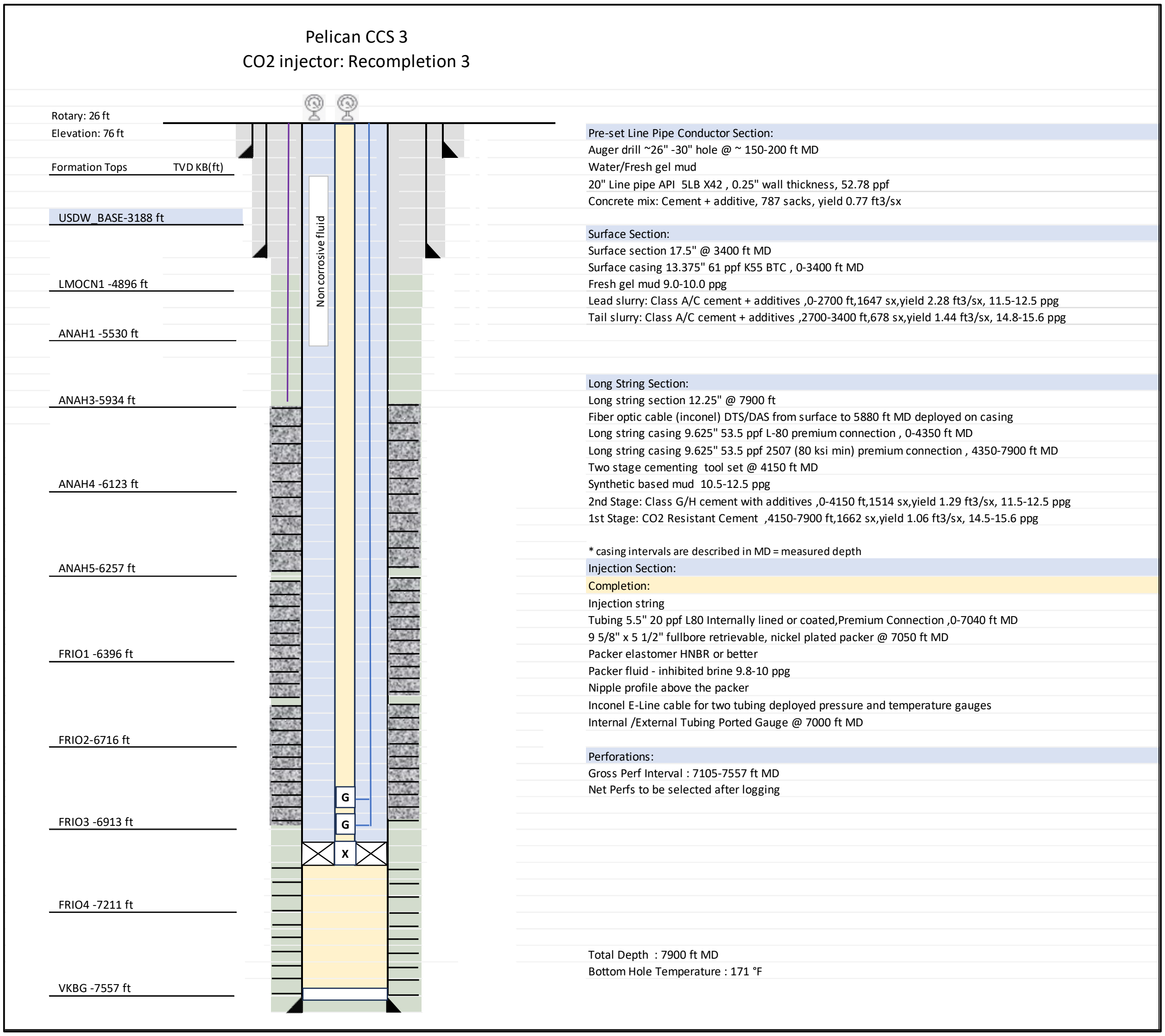

Figure CON-17—Third Recompletion Schematic diagram of Pelican CCS 3 well.

9.4 Pelican CCS 4 Recompletions

9.4.1 Pelican CCS 4 First Recompletion

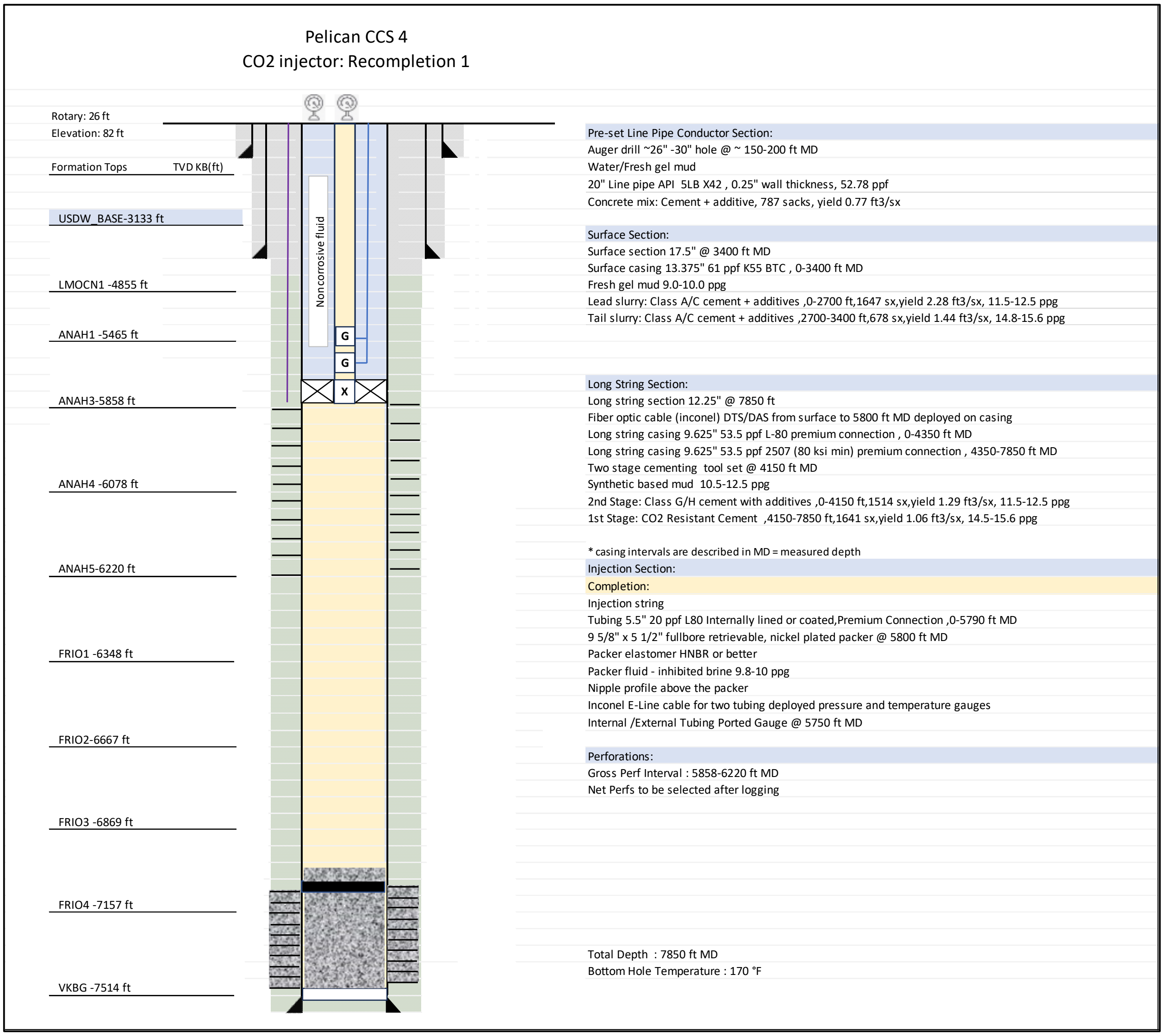

Figure CON-18—First Recompletion Schematic diagram of Pelican CCS 4 well.

9.4.2 Pelican CCS 4 Second Recompletion

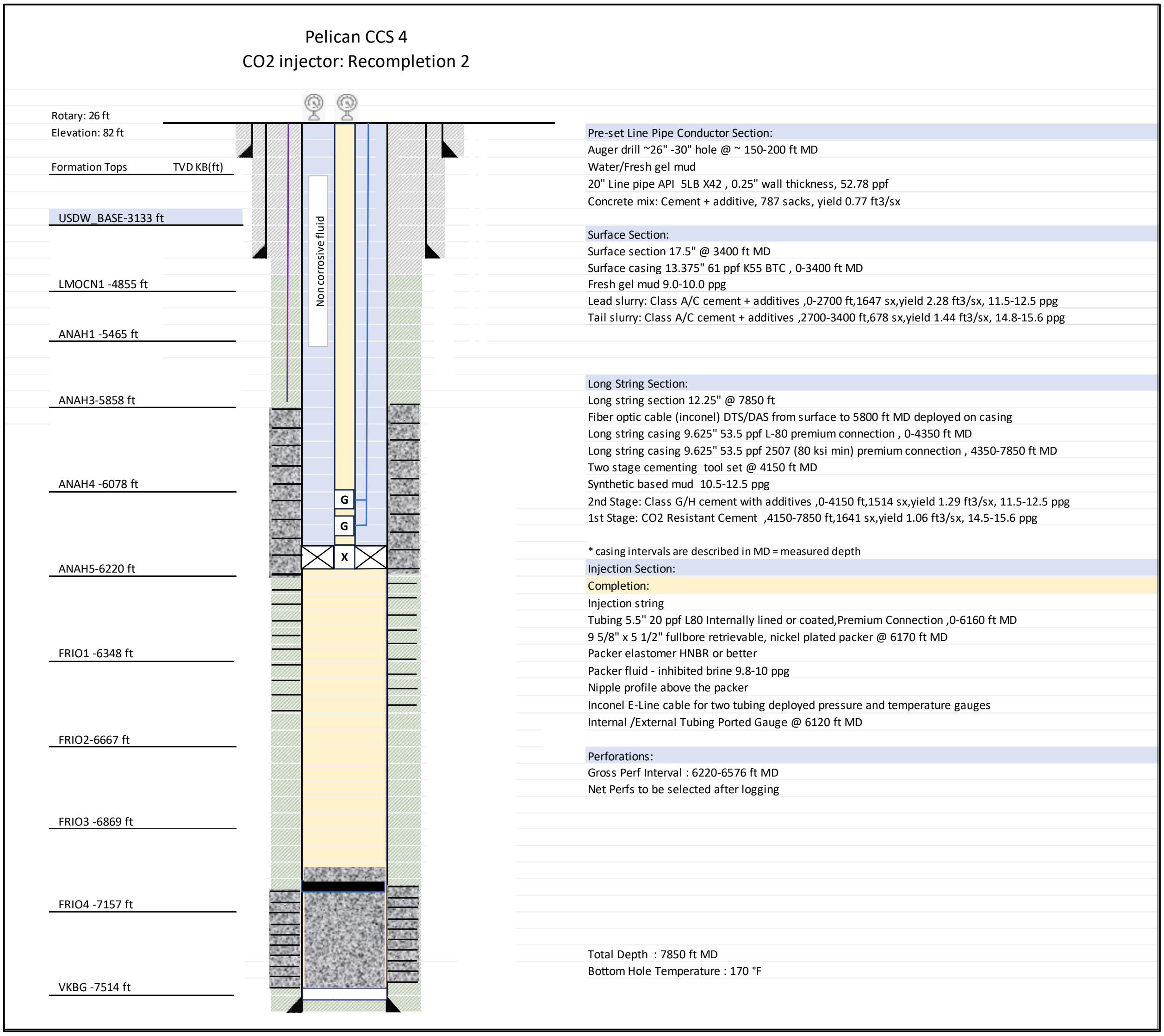

Figure CON-19—Second Recompletion Schematic diagram of Pelican CCS 4 well.

9.4.3 Pelican CCS 4 Third Recompletion

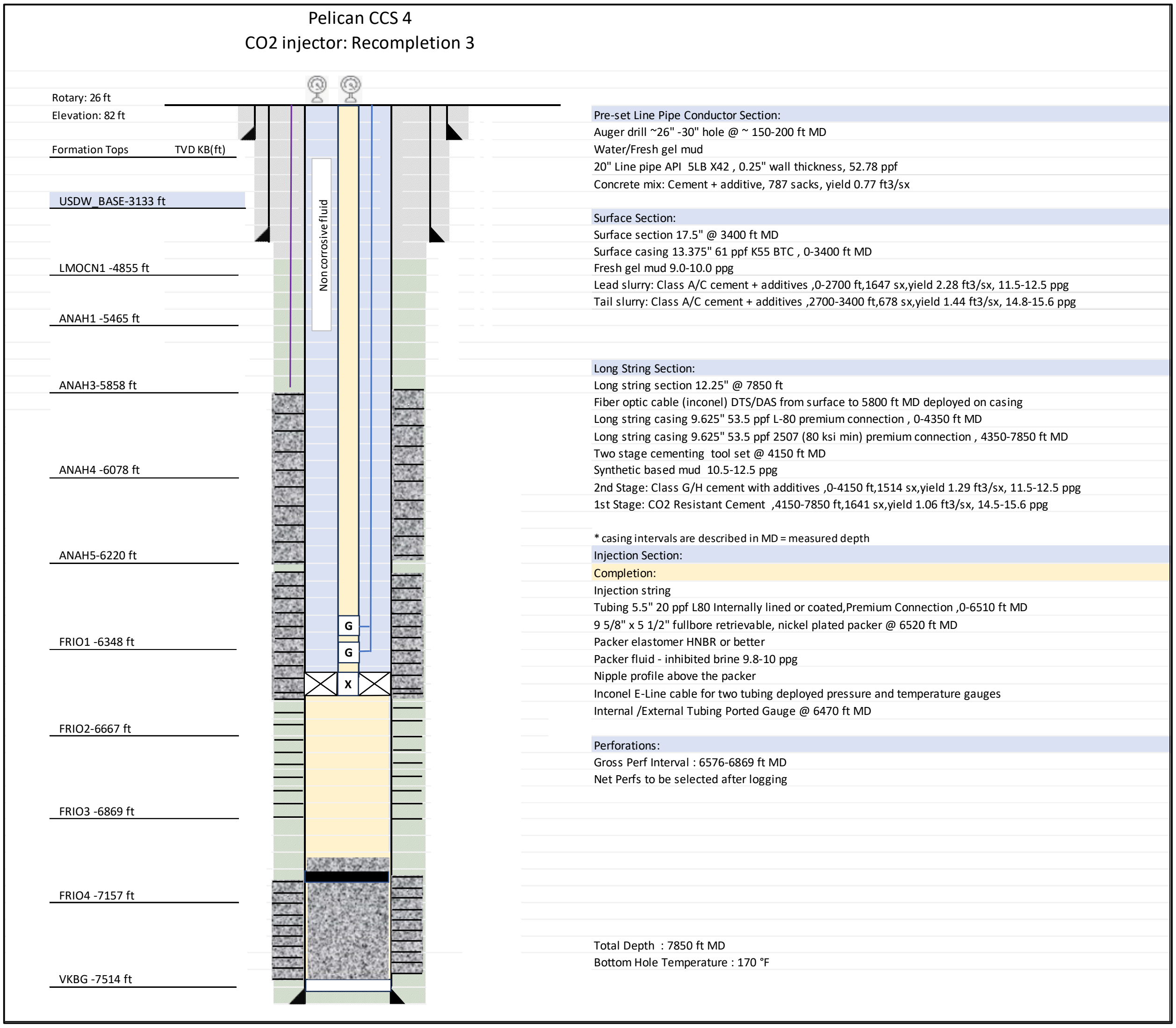

Figure CON-20—Third Recompletion Schematic diagram of Pelican CCS 4 well.

9.5 Pelican CCS 5 Recompletions

9.5.1 Pelican CCS 5 First Recompletion

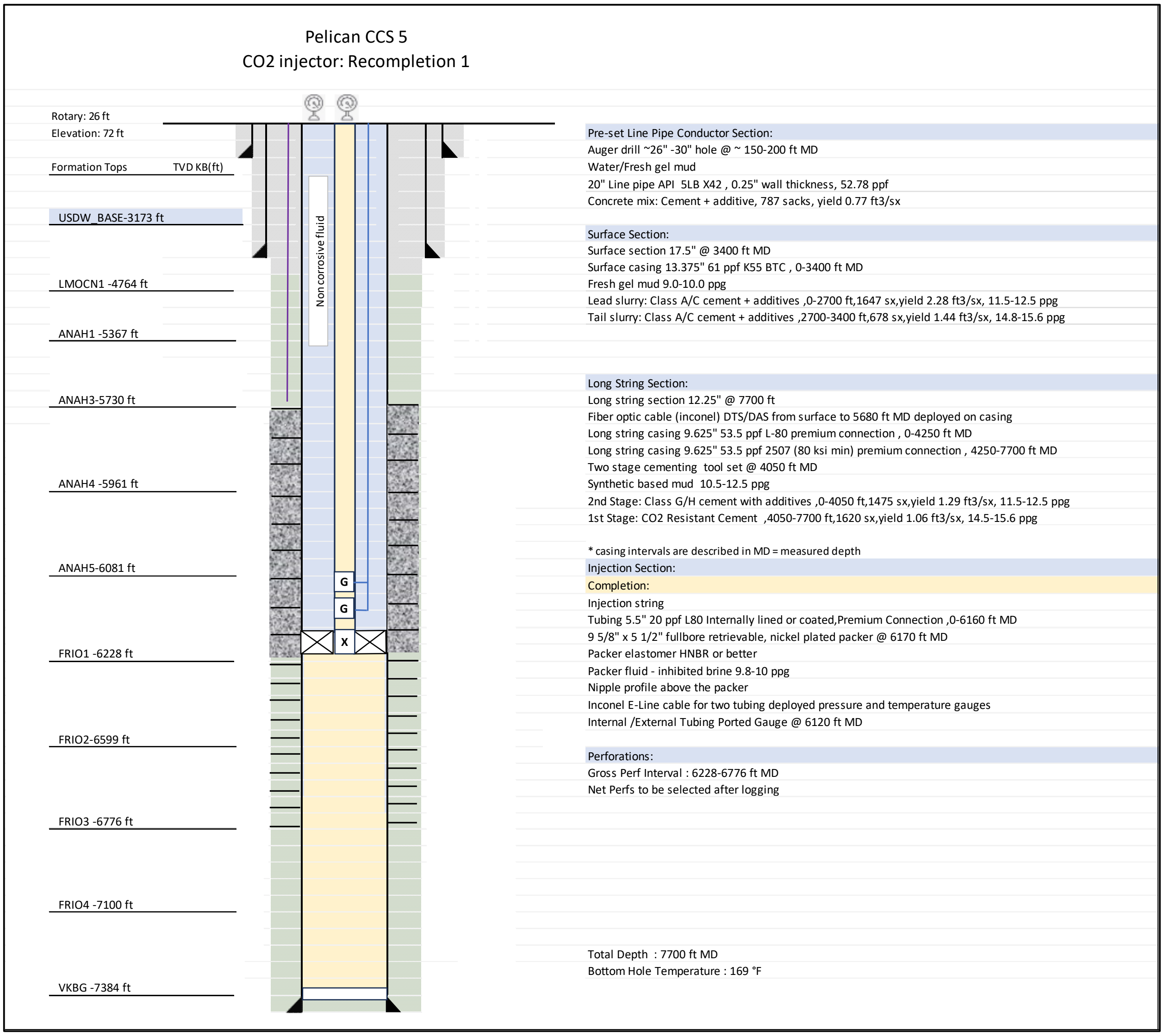

Figure CON-21—First Recompletion Schematic diagram of Pelican CCS 5 well.

9.5.2 Pelican CCS 5 Second Recompletion

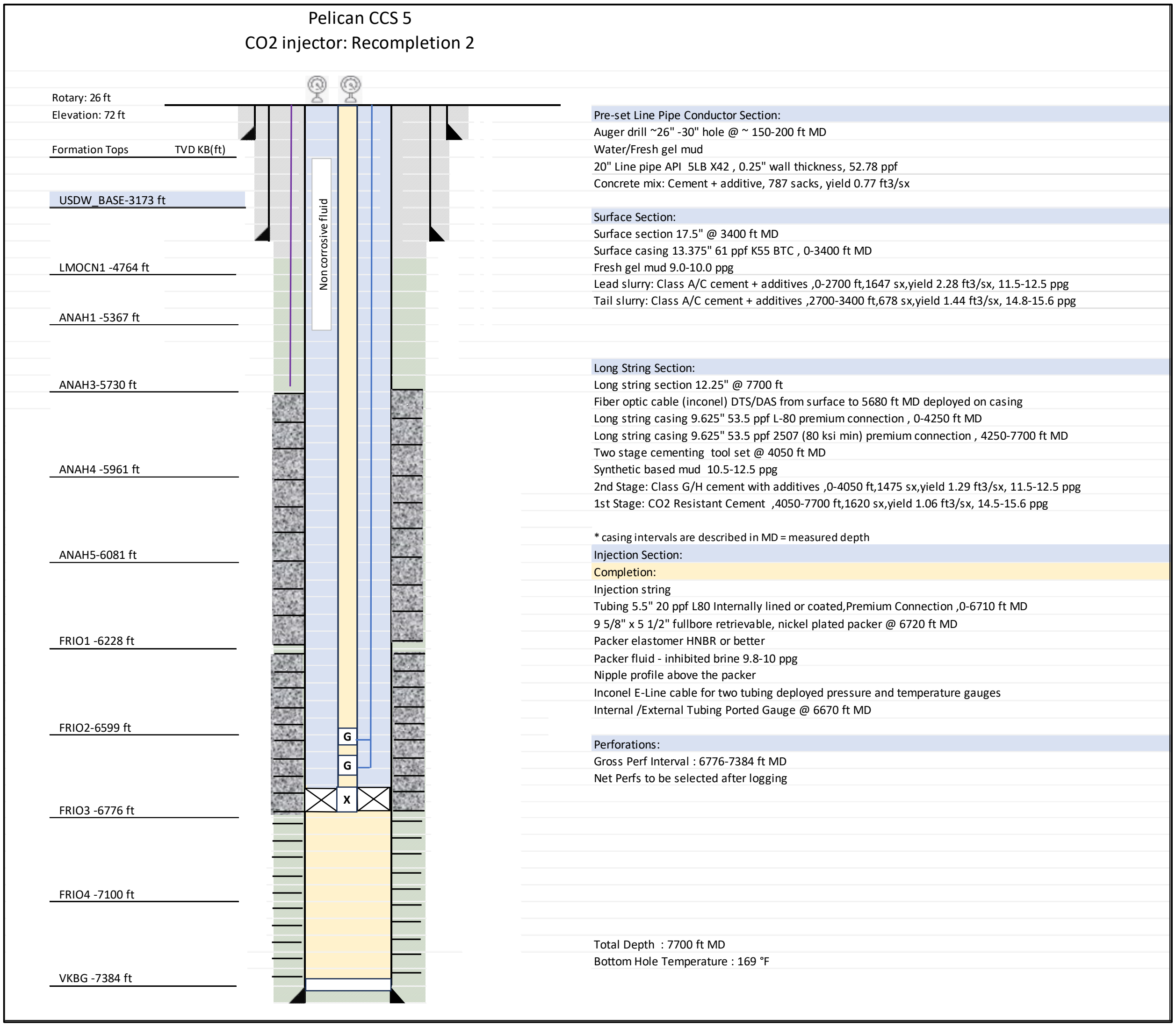

Figure CON-22—Second Recompletion Schematic diagram of Pelican CCS 5 well.