Longleaf CCS Hub

Longleaf CCS, LLC

Injection Well Plugging Plan

40 CFR 146.92

Facility Information

Facility Name:	Longleaf CCS Hub
Facility Contact:	Longleaf CCS, LLC 14302 FNB Parkway Omaha, NE 68154
Well Locations:	Mobile County, Alabama LL#1: Latitude: 31.071303^o N Longitude: -88.094703^o W LL#2: Latitude: 31.070774^o N Longitude: -88.074523^o W LL#3: Latitude: 31.0447129^o N Longitude: -88.0736318^o W LL#4: Latitude: 31.0569516^o N Longitude: -88.1047433^o W

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List of Acronyms/Abbreviations

AoR	Area of Review
CCS	Carbon capture and storage
CO_2	Carbon dioxide
CMG	Computer Modelling Group
DOE	Department of Energy
DAS	Distributed Acoustic Sensing
DTS	Distributed Temperature Sensing
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response
ft	Feet
LL	Longleaf
MIT	Mechanical Integrity Test
MMcf/d	Million cubic feet/day
mg/l	Milligrams per liter
mt	Metric tons
Mt	Millions of metric tons
mt/d	Metric tons per day
mt/y	Metric tons per day
MT/y	Millions of metric tons per year
PISC	Post-Injection Site Care
PNC	Pulsed Neutron Capture Log
psi	Pounds per square inch
psi/ft	Pounds per square inch per foot
SS	Sub-Sea
TVD	True Vertical Depth
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water

A. Introduction

Outlined in the following document is the description of the process that the Longleaf CCS Hub will follow to plug proposed CO_2 injection wells LL#1, LL#2, LL#3, and LL#4 in accordance with the EPA's requirements under 40 CFR 146.92 and 40 CFR 146.93(e) and the State of Alabama's requirements under ASR 400-1-4-.15-.16 to ensure that the abandoned wells maintain integrity and will not pose a threat to USDWs. Plugging activities at an injection well will begin following the cessation of CO_2 injection in that well. However, in certain situations, Longleaf CCS, LLC may choose to delay plugging selected injection wells and to use them, for some period of time, to monitor in-zone reservoir conditions post-injection. If delaying plugging of an injection well, per ASR 400-1-4-.17, Longleaf CCS, LLC will submit a request to the Alabama Oil and Gas Board for the well to be placed into a temporarily abandoned injection well status for a period of not more than a year, with a subsequent request submitted for a 1-year extension.

Following are notifications and reporting required with plugging an injection well, which shall be submitted separately for each well:

- **60-Day Notification**: The Longleaf CCS Hub will notify the UIC Program Director in writing at least 60 days prior to the plugging of an injection well. Any changes to this plan shall be submitted no later than with the notification (40 CFR 146.92(c)).
- **Well Plugging Report**: Within 30 days of plugging an injection well, Longleaf CCS Hub will submit a well plugging report using OGB AL Form OGB-11 to the UIC Program Director and Alabama Oil and Gas Board (40 CFR 146.92(d); ASR 400-1-4-.15).

A.1 Injection Well Configuration

Prior to plugging, the injection well configuration will include conductor casing, surface casing, and long string casing, all cemented to surface. The wells will also have an injection tubing string. LL#2, LL#3, and LL#4 without sliding sleeves in the tubing string will have a configuration as shown in **Figure 1**. LL#1 that utilizes sliding sleeves in the tubing string will have a configuration as shown in **Figure 2**.

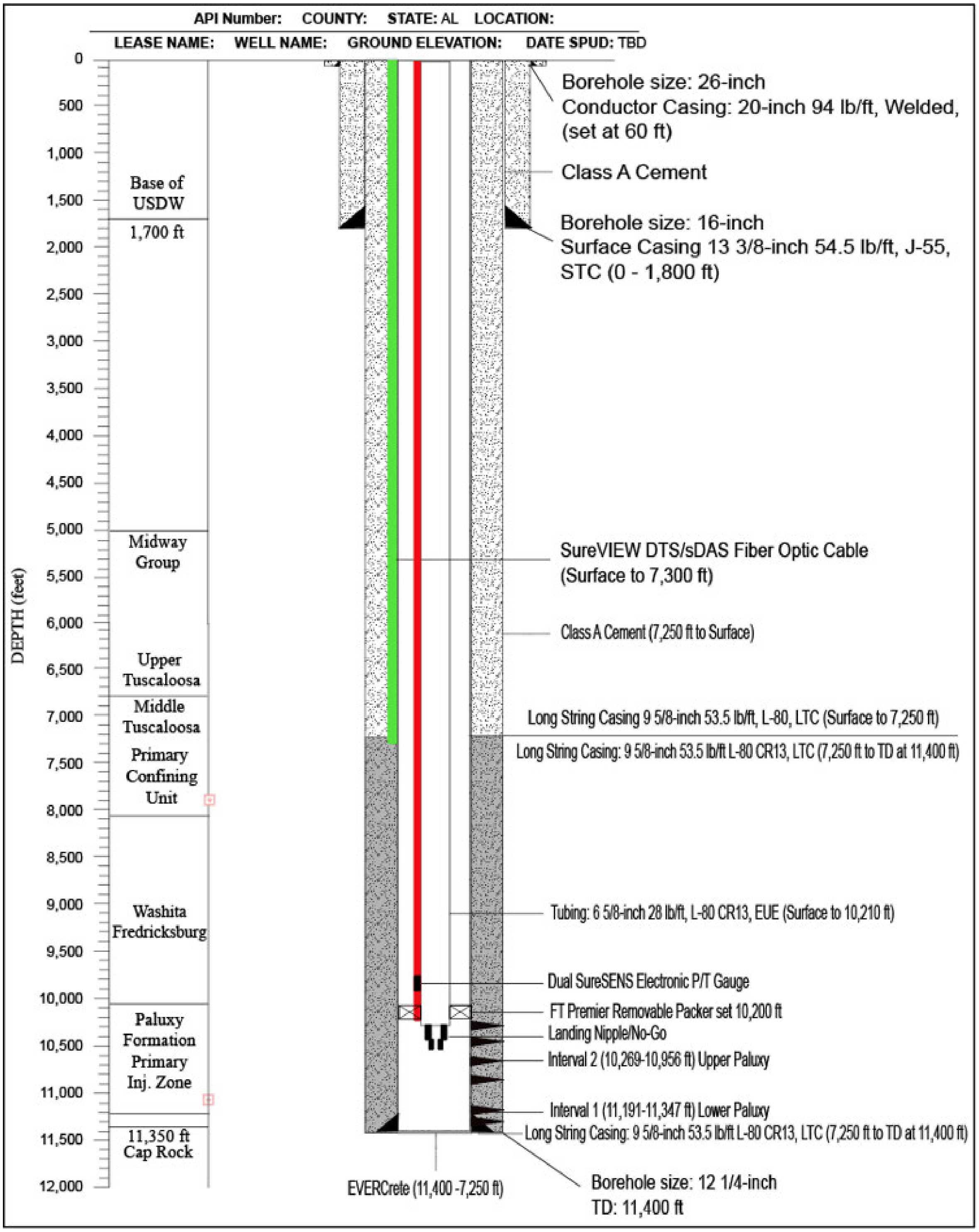

Figure 1. Injection Wells LL#2, LL#3, and LL#4 Configuration, without Sliding Sleeves

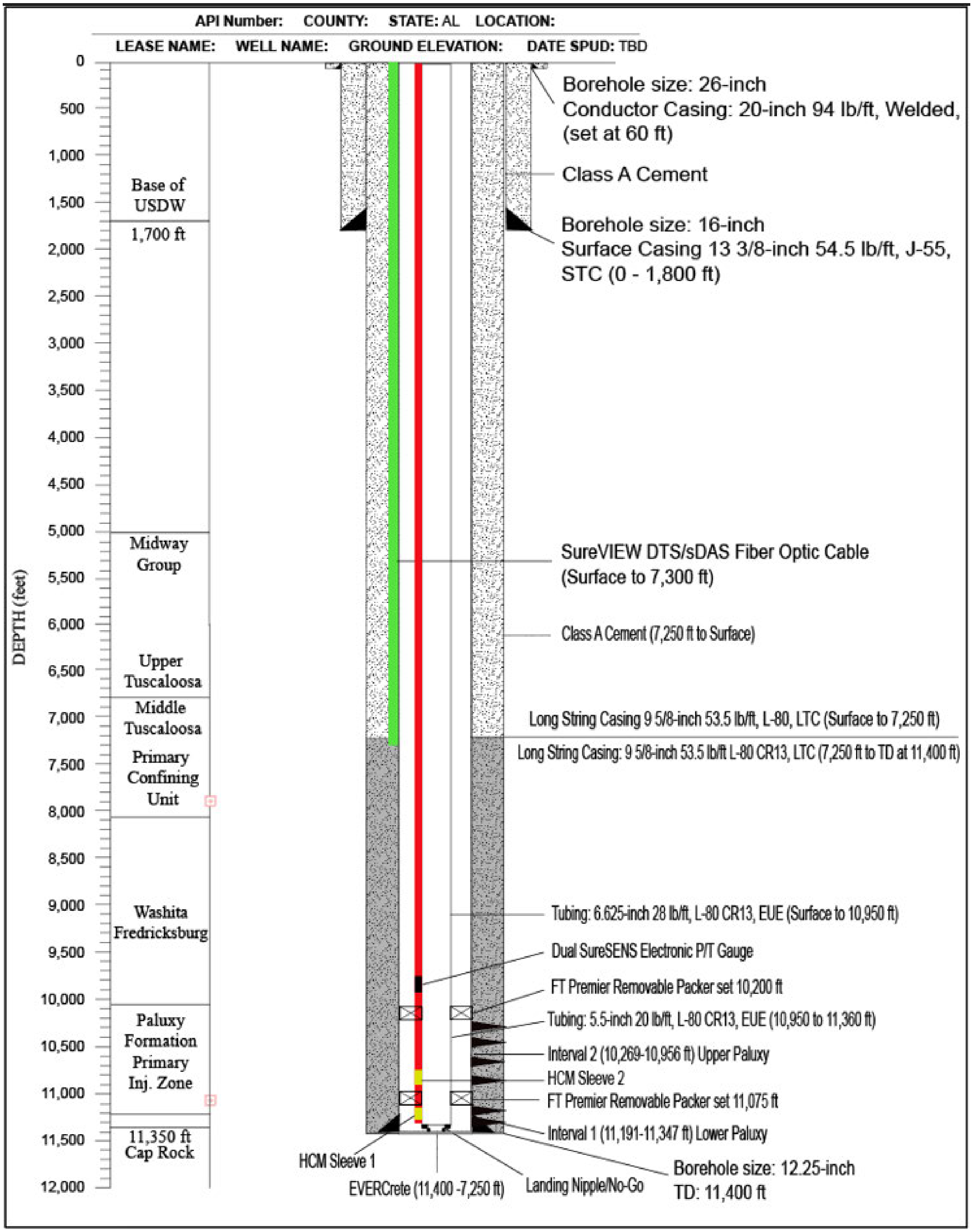

Figure 2. Injection Well LL#1 Configuration, with Sliding Sleeves

B. Injection Well Tests

B.1. Tests or Measures for Determining Bottom-Hole Reservoir Pressure

Bottom-hole pressure measurements will be performed and recorded throughout the project. Pressure gauges will be placed in the injection tubing or in the deep casing string within the injection zone. These pressure-measurement devices will allow for continuous, real-time, surface readout of the pressure data. The bottom-hole reservoir pressure will be obtained using the final measurements from the pressure gauges in the injection zone after the CO_2 injection period has ended.

After the bottom-hole pressure is determined, a buffered fluid (brine) will be used to flush and fill the well to maintain pressure control of the well. The measured bottom-hole pressure will be used to determine the proper weight brine that should be used to stabilize the well. These data may also be used to determine the blend of cement to be used to plug the well (i.e., weight range of cement to prevent leak-off into formation or flowing of well, or to prevent premature setting and curing of the cement).

B.2 Testing Method to Ensure External Mechanical Integrity

The mechanical integrity of the well will be demonstrated after CO_2 injection and prior to the plugging of the well to ensure no communication has been established between the injection zone and the USDWs or ground surface (per 40 CFR 146.92(b)(2)). Such well integrity testing will use a temperature log, noise log, or an activated-oxygen log to be run in the well. A temperature log will be run over the entire depth of the injection well. Data from the logging run will be evaluated for anomalies in the temperature curve, which would be indicative of fluid migration outside of the injection zone. This data will also be compared to the information gathered from the baseline logs performed prior to injection of CO_2 into the well. Should deviations be noted between the temperature logs performed before and after the injection of CO_2 raise issues related to the integrity of the well casing or cement, this topic will be addressed promptly.

C. Plugging Plan

C.1 Procedures/Etc.

The methods and materials described in this part are based upon current understanding of the geology at the site and the current well designs. If necessary, the plan will be updated to reflect the latest well designs. Any changes to the plan will be submitted at least 60 days prior to the plugging of well and approved by the UIC Program Director prior to commencing plugging activities in compliance with 40 CFR 146.92(c). This plan also complies with Alabama Oil and Gas Board requirements in ASR 400-1-4-.14(1)-(2) that state:

> “A cement plug shall be placed across each hydrocarbon-bearing, abnormally pressured, or injection zone or a permanent-type bridge plug shall be placed at the top of each hydrocarbon-bearing zone or injection zone, but in either event a cement plug at least two hundred (200) feet in length shall be placed immediately above the uppermost hydrocarbon-bearing or injection zone. When the base of fresh water is penetrated, a cement plug at least two hundred (200) feet in length shall be placed at least fifty (50) feet below and shall extend to at least one hundred fifty (150) feet above the base of fresh water.”

This plugging plan meets and exceeds EPA recommended plug placement locations and plug height as follows:

> “The EPA recommends that owners or operators emplace plugs: (1) above any production or injection zones; (2) above, below, and/or through each USDW; (3) at the bottom of intermediate and surface casings; (4) across any casing stubs (pulled casing sections); and (5) at the surface (USEPA, 1989).” (UIC Program Class VI Well Plugging, Post-Injection Site Care, and Site Closure Guidance pg. 17)

> “EPA recommends that plugs in GS settings be at least 100 feet long and extend, at a minimum, from the base of the surface casing (required to be set at some distance below the base of the lowermost USDW) up through the base of the

lowermost USDW." (UIC Program Class VI Well Plugging, Post-Injection Site Care, and Site Closure Guidance pg. 18)

The following procedure includes operations to place a solid column of cement from the total depth of the well to the top of the production casing string.

1. MIRU onto Long Leaf Injection Well. All CO_2 pipelines will be marked, locked, and tagged out and noted with rig supervisor prior to MI. Other surface hazards will be marked, removed, or barricaded as appropriate.

2. Conduct and document a safety meeting.

3. Record bottomhole pressure (BHP) from down hole gauge and calculate kill fluid density.

4. Open all valves on the vertical run of the tree and check pressures.

5. R/U to wing valve on tree and casing valve.

6. Pressure test the pump and line to 5,000 psi against master valve and wing valve at a minimum.

7. Perform 1,000psi test on casing annulus for 30 minutes to ensure tubing, casing, and packer pressure integrity.

8. Inject kill weight brine down the tubing (as determined by BHP PT Gauge measurement).

9. Monitor tubing and casing pressure for 30 minutes, to ensure kill fluid weight is sufficient.

   NOTE: If the well is not dead or the pressure cannot be bled from the tubing, consider heavier kill fluid or displacement using coiled tubing

10. If both casing and tubing are dead, then Rig up (RU) wireline/slickline and set a plug in profile nipple.

11. Punch tubing and circulate kill weight into casing/tubing annulus fluid until the well is dead.

12. Install 2-way check valve in tubing hanger and nipple down the tree.

13. NU BOPs and perform a function test on the BOPs. BOPs should have appropriately sized single pipe rams on top and blind rams in the bottom ram for tubing. Close and pressure test blind rams through BOP side outlet valve.

Open blind rams and use tubing pup or joint to test pipe rams. Make sure a casing valve is open during all BOP tests.

14. Remove two-way check valve and install BPV.

15. Pull hanger free of bowl, confirm tubing is dead, and remove BPV.

16. Remove slickline plug from profile nipple in tubing. Circulate kill fluid if needed.

17. Perform internal cut of packer with wireline mechanical pipe cutter to release packer.

18. Contingency: If unable to release packer, RU electric line and make cut on tubing string at free point leaving enough room for fishing tools if required.

    NOTE: Ensure clear and timely communication with regulatory agencies to acquire approval of modified plugging plan if needed

19. RU spooling unit for control/electric lines deployed on the tubing OD.

20. Retrieve tubing and completion assembly.

21. Pull out of hole with tubing and control/electric lines, laying down as tubing is removed. NOTE: Ensure that the well remains over-balanced for the duration of abandonment. Circulate continuously through fill up line and ensure hole fill tracks with displacement. If weighted slug is required to avoid pulling wet, ensure displacement is calculated and accounted for, and sufficient time is allowed for equalization before continuing to POOH.

22. TIH with work string to total depth (TD) with bit and scraper. Fill tubing every 5 stands, break circulation periodically. and keep the hole full at all times. Work scraper across any tight spots. Circulate the well and prepare for cement plugging operations. TOH.

23. RIH with open ended tubing to TD in order to perform bradenhead squeeze and balance plugs

24. Circulate approximately 109 bbls of CO2 resistant cement down the work string in 400-500’ lifts until cement top is at approximately 9,900’

25. Close BOP and casing valve and inject down work string to squeeze cement into Paluxy formation.

    NOTE: The maximum pressure threshold of 90% of the determined reservoir fracture pressure for the Paluxy Sandstone will be utilized to constrain pressure during the cement injection process.

26. Once bradenhead squeeze is complete, continue performing balance plugs with CO2 resistant cement in 500’ lifts to approximately 7,000’ (the top of the confining zone).

27. From 7,000’ to surface, the remaining balance plugs will be completed using class A cement.

28. Nipple down BOPs and cut all casing strings below plow line (min 5 ft below ground level or per local policies/standards and other identified requirements) prior to pumping top plug. Lay down all work string, etc. Rig down all equipment and move out. Clean cellar to where a plate can be welded with well name onto lowest casing string at 5 ft BGL, or as per permitting agency directive.

NOTE: The procedures described above may be modified during execution as necessary to ensure a plugging operation that protects worker safety as well as all identified USDWs. For example, in the event future wellbore conditions prevent the proposed plugging plan from being executed as stated above, additional isolation devices such as bridge plugs and cement retainers may need to be incorporated into the well abandonment. Anticipated changes will be submitted for approval, and any significant modifications due to unforeseen circumstances will be described in the Plugging Report.

Table 1 presents the intervals that will be plugged and the materials and methods that will be used to plug the intervals. The portion of the well corresponding to the injection zone will be plugged using Schlumberger’s EverCRETE or similar CO_2-resistant cement Approximately 109 barrels of CO_2-resistant cement will be used to plug the Paluxy injection interval using a bradenhead squeeze balance for plugs 1, 2, and 3 providing a 10 percent excess volume to be squeezed through the perforations into the Paluxy Sandstone.

Table 1. Intervals to Be Plugged and Materials/Methods Used

Description	Top (ft)	Bottom (ft)	Type	Approximate Weight (lb)	Quantity (Sacks)	Volume (bbls)	Casing ID (in)
Balance Plug 1 (10% Excess)	11,000	11,400	EverCRETE	15.9	162	31	8.535
Balance Plug 2 (10% Excess)	10,500	11,000	EverCRETE	15.9	202	39	8.535
Balance Plug 3 (10% Excess)	10,000	10,500	EverCRETE	15.9	202	39	8.535
Balance Plug 4	9,500	10,000	EverCRETE	15.9	184	35	8.535
Balance Plug 5	9,000	9,500	EverCRETE	15.9	184	35	8.535
Balance Plug 6	8,500	9,000	EverCRETE	15.9	184	35	8.535
Balance Plug 7	8,000	8,500	EverCRETE	15.9	184	35	8.535
Balance Plug 8	7,500	8,000	EverCRETE	15.9	184	35	8.535
Balance Plug 9	7,000	7,500	EverCRETE	15.9	184	35	8.535
Balance Plug 10	6,500	7,000	Class A	15.6	168	35	8.535
Balance Plug 11	6,000	6,500	Class A	15.6	168	35	8.535
Balance Plug 12	5,500	6,000	Class A	15.6	168	35	8.535
Balance Plug 13	5,000	5,500	Class A	15.6	168	35	8.535
Balance Plug 14	4,500	5,000	Class A	15.6	168	35	8.535
Balance Plug 15	4,000	4,500	Class A	15.6	168	35	8.535
Balance Plug 16	3,500	4,000	Class A	15.6	168	35	8.535
Balance Plug 17	3,000	3,500	Class A	15.6	168	35	8.535
Balance Plug 18	2,500	3,000	Class A	15.6	168	35	8.535
Balance Plug 19	2,000	2,500	Class A	15.6	168	35	8.535
Balance Plug 20	1,500	2,000	Class A	15.6	168	35	8.535
Balance Plug 21	1,000	1,500	Class A	15.6	168	35	8.535
Balance Plug 22	500	1,000	Class A	15.6	168	35	8.535
Balance Plug 23	0	500	Class A	15.6	168	35	8.535

Figure 3 shows the details of the injection well after plugging and abandonment.

After the remainder of the casing has been filled with cement, the casing sections will be cut off approximately 5 ft below surface and a steel cap will be welded to the top of the deep casing string. The cap will have the well identification number, the Class VI UIC well permit number, and the date of plug and abandonment inscribed on it. Soil will be backfilled around the well to bring the area around the well back to pre-well-installation conditions. This area will then be planted with natural vegetation.

C.2 OGB AL Documents and Forms

After the completion of the plugging activities, a plugging report (OGB AL Form OGB-11) will be submitted to the UIC Program Director, as well as the Alabama Oil and Gas Board, describing the methods and tests that were performed on the well during plugging. This report will be submitted to the UIC Program Director within 60 days of completing the plugging activities.

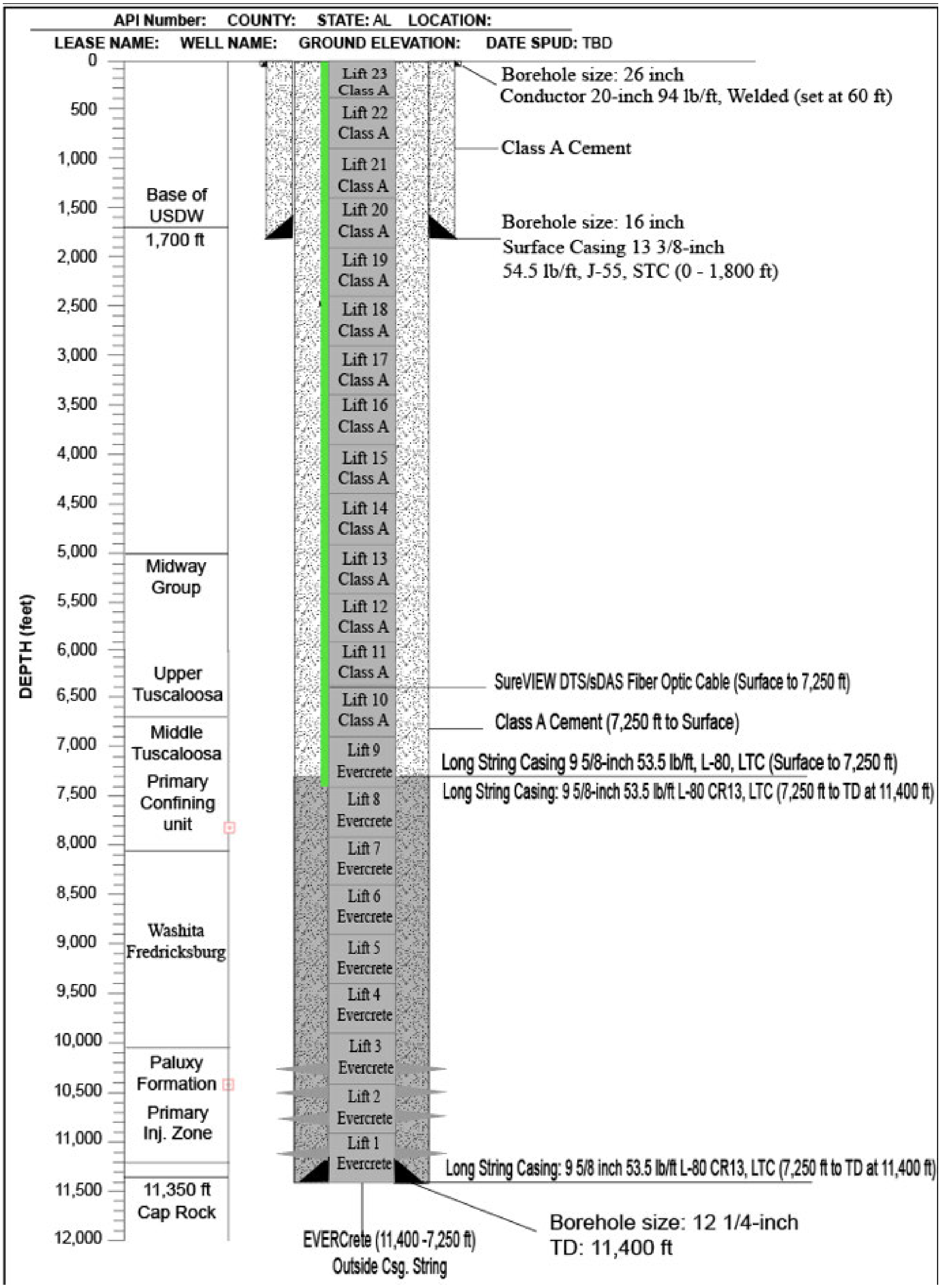

Figure 3. Diagram of the Injection Well After Plugging and Abandonment