INJECTION WELL PLUGGING PLAN
40 CFR 146.92(b)

Project Name: Tri-State CCS Redbud 1

Facility Information

Facility contact: Tri-State CCS, LLC
14302 FNB Parkway
Omaha, NE 68154
402-691-9500

Well location: Fairhaven, Hancock County, West Virginia

Well Name	Latitude	Longitude
TR1-1	40.59722582	-80.5716718
TR1-2	40.55529898	-80.6001

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ºF	Degree Fahrenheit
Ar	Argon
BGL	Below Ground Level
BHP	Bottomhole Pressure
BOP	Blowout Preventers
BPV	Back Pressure Valve
CCS	Carbon Capture and Storage

CO_2	Carbon Dioxide
ft	Feet
gal	Gallon
GL	Ground Level
in	Inch
lb	Pound
LCM	Lost Circulation Material
LIC	Lockport Injection Complex
MASP	Maximum Allowable Surface Pressure
MIT	Mechanical Integrity Testing
MIRU	Move In Rig Up
MMSCF	Million Metric Standard Cubic Feet
MMT	Million Metric Tonnes
Mol%	Molecular Percentage of Total Moles in a Mixture made up by One Constituent
Mt/y	Thousand Metric Tonnes per Year
MIC	Medina Injection Complex
MIT	Mechanical Integrity Test
N_2	Nitrogen
NIST	National Institute of Standards and Technology
N/U	Nipple Up
O_2	Oxygen
PISC	Post-Injection Site Care
PNL	Pulsed Neutron Log
POOH	Pull Out of Hole
PPMV	Parts per Million, Volume
PSI	Pounds per Square Inch
PSIA	Pounds per Square Inch, Absolute
psig	Pounds per Square Inch, Gauge
R/U	Rig Up
TD	Total depth
TIH	Tripping In Hole
TOH	Tripping Out of Hole
UIC	Underground Injection Control
USDW	Underground source of drinking water

1. Introduction

The following document describes the procedures that Tri-State CCS, LLC will follow to plug and abandon proposed CO_2 injection wells TR1-1 and TR1-2 at Tri-State CCS Redbud 1 in Hancock County, West Virginia (the "project") in accordance with the EPA's requirements under 40 CFR 146.92 and 40 CFR 146.93(e). Additionally, this plan covers West Virginia requirements for plugging injection wells under 47 CSR 13-13.4 and 47 CSR 13-14.7.f.

Plugging activities at an injection well will begin following the cessation of CO_2 injection in that well. However, in certain situations, Tri-State CCS, LLC may choose to delay plugging selected injection wells and to use them, for 5 years, to monitor in-zone reservoir conditions post-injection. See subsection 5.1 below for notifications regarding plugging and delaying plugging injection wells.

2. Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

During both injection and post-injection phases, industry-standard downhole pressure gauges will measure and record bottom-hole pressure. These gauges will be installed either in the injection tubing or the deep casing string within the injection zone, enabling continuous real-time surface readout of pressure data. The gauges allow for operational pressures that range from 15 to 5,000 psig and temperatures from -99.4 to 437 degrees Fahrenheit with an accuracy of ± 0.015% of range. The bottom-hole reservoir pressure will be obtained using the final measurements from the pressure gauges, hydrostatic pressure calculation, or a wireline deployed pressure gauge in the injection zone after the CO_2 injection period and any post-injection monitoring has ended.

Following the determination of bottom-hole pressure, a buffered fluid (brine) will be employed to flush and fill the well, ensuring pressure control. The measured bottom-hole pressure will guide the selection of the appropriate weight of brine to stabilize the well and may inform decisions regarding the blend of cement needed to plug the well and address considerations such as preventing leak-off or premature setting.

3. Planned External Mechanical Integrity Test(s)

Ensuring external mechanical integrity is necessary for Class VI wells used in the geologic sequestration of carbon dioxide (CO_2) to prevent potential CO_2 leakage into underground sources of drinking water (USDWs). Various methods, including pressure testing, cement bond logs, casing inspections, and other techniques outlined in industry best practices and regulatory guidelines, are employed to establish this integrity. Tri-State CCS, LLC will conduct at least one of the tests specified in Table 1 to verify external mechanical integrity before plugging the injection wells, as required by 40 CFR 146.92(a). Procedures for each test are outlined in subsections 3.1 - 3.4 below. Surface pressure monitoring during these tests will utilize gauges rated 0-5000 psig. This testing aims to ensure that the injection zone remains isolated from USDWs or the ground surface, as mandated by 40 CFR 146.92(b)(2), following the cessation of CO_2 injection.

Table 1. Planned Mechanical Integrity Tests (MIT).

Test Description	Pass	Fail	Location
Temperature Log	No temperature anomalies found.	Temperature anomalies found.	Long String Casing; Surface to TD
Oxygen Activation Log (PNL gas mode)	No water movement detected outside of casing beyond sequestration zones.	Water movement detected outside of casing beyond sequestration zones.	Long String Casing; Surface to top of shallowest confining formation adjacent to storage zone
Noise Log	No flowing noise detected.	Flowing noise detected.	Long String Casing; Surface to top of shallowest confining formation adjacent to storage zone
Pulsed Neutron Log	No CO_2 detected outside of casing beyond sequestration zones.	CO_2 detected outside of casing beyond sequestration zones.	Long String Casing; Surface to TD

3.1 Temperature Log General Procedure

A temperature log would be used to identify temperature anomalies that indicate fluid movement adjacent to the well bore. The general procedure for running a temperature log is as follows:

- Run a temperature log using externally mounted fiber optic cable throughout the injection well's depth.
- Evaluate the temperature curve for anomalies indicating fluid migration beyond the injection zone.
- Compare this data with baseline logs taken before CO_2 injection and promptly address any discrepancies between pre- and post-injection logs.

3.2 Activated Oxygen Log General Procedure

An activated oxygen log would be used to identify water flow inside and outside casing. The general procedure for running an activated oxygen log is as follows:

- An activated oxygen log throughout the injection well will be conducted immediately prior to cessation of CO_2 injection by utilizing a pulsed neutron spectroscopy tool following the 40 CFR 146.92(b)(2) requirements. This is done to evaluate responses compared to the baseline measurements discussed in subsection 1.1 of the Testing and Monitoring Plan.
- ^{16}O will be activated by high energy neutrons to produce ^{16}N, which emits a gamma ray signature during decay read by spaced detectors. Flow rate, velocity, and distance of water flow from the tool can be determined.
- Promptly address any issues related to well casing or cement integrity detected during the activated oxygen log.

3.3 Noise Log General Procedure

A noise log would be used to detect turbulent flow occurring along the well bore. The general procedure for running a noise log is as follows:

- Perform a noise log throughout the injection well immediately prior to cessation of CO_2 injection to detect flow along leakage pathways. As per the regulatory requirement (40 CFR 146.92(b)(2)), a noise log is conducted immediately before cessation of CO_2 injection to evaluate responses compared to baseline measurements and ensure compliance with monitoring standards.
- Evaluate log data to identify any flow outside of confining zone(s), indicating CO_2 leakage through a micro annulus.
- Promptly address any issues related to well casing or cement integrity detected during the noise log.

3.4 Pulsed Neutron Log General Procedure

A pulsed neutron log (PNL) would be used to detect CO_2 saturation changes at the well bore. The general procedure for a PNL is as follows:

- Run PNL in cased hole immediately prior to cessation of injection and compared to previous annual PNL logs.
- Evaluate for CO_2 saturations above baseline outside of storage reservoir.
- Promptly address any issues related to well casing, cement integrity, or CO_2 leakage detected during the PNL.

4. Information on Plugs

Tri-State CCS, LLC will use the materials and methods noted in Table 2 for TR1-1 and Table 3 for TR1-2 to plug the injection wells. The volume and depth of the plug or plugs will depend on the final geology and downhole conditions of the wells as assessed during construction. The cement(s) formulated for plugging across storage intervals and across confining zones will be compatible with the CO_2 stream. Shallower plugs will consist of class A neat cement or equivalent. The cement formulation and required certification documents will be submitted to the UIC Program Director with the 60-day notification described in subsection 5.1 below and an updated Injection Well Plugging Plan prior to beginning plugging activities. Tri-State CCS, LLC will report the wet density and will retain duplicate samples of the cement used for each plug.

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Table 2. Plugging details for TR1-1. [1]

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4	Plug #5	Plug #6	Plug #7
Diameter of boring in which plug will be placed (in)	6.276	6.276	6.276	6.276	6.276	6.276	
Depth to bottom of tubing or drill pipe (ft GL)	6,920	6,525	6,110	2,200	1,100	500	
Slurry volume to be pumped (bbl)	14	8	19.5	19.5	19.5	19.5	
Slurry weight (lb./gal)	15.6	15.6	15.6	15.6	15.6	15.6	
Calculated top of plug (ft GL)	6,920	6,525	5,600	1,700	600	Surf.	
Bottom of plug (ft GL)	7,081	6,607	6,110	2,200	1,100	500	
Type of cement or other material	CO_2 resistant	CO_2 resistant	CO_2 resistant	Class A	Class A	Class A	
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Retainer	Retainer	Balanced	Balanced	Balanced	Balanced	

Table 3. Plugging details for TR1-2. [1]

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4	Plug #5	Plug #6	Plug #7
Diameter of boring in which plug will be placed (in)	6.276	6.276	6.276	6.276	6.276	6.276	
Depth to bottom of tubing or drill pipe (ft GL)	6,660	6,265	5,880	2,200	1,000	500	
Slurry volume to be pumped (bbl)	14	8	19.5	19.5	19.5	19.5	
Slurry weight (lb./gal)	15.6	15.6	15.6	15.6	15.6	15.6	
Calculated top of plug (ft GL)	6,660	6,265	5,380	1,700	500	Surf.	
Bottom of plug (ft GL)	6,819	6,350	5,880	2,200	1,000	500	
Type of cement or other material	CO_2 resistant	CO_2 resistant	CO_2 resistant	Class A	Class A	Class A	
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Retainer	Retainer	Balanced	Balanced	Balanced	Balanced	

[1]Cement volumes were determined by volumetric calculations.

5. Narrative Description of Plugging Procedures

5.1 Notifications, Permits, and Inspections

The following are the notifications and reporting required for injection well plugging. These will be submitted separately for each well:

- Notification of Delayed Plugging: If delaying plugging of an injection well for more than 24 months, Tri-State CCS, LLC will comply with 47 CSR 13-14.7.f. and provide notice to the UIC Program Director with procedures and actions to be taken to ensure that well will not endanger any USDW during the period of temporary abandonment including compliance with technical requirements applicable to an active injection well unless waived by the West Virginia Department of Environmental Protection.

- 60-Day Notification: Tri-State CCS, LLC 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 per 40 CFR 146.92(c).

- Well Plugging Report: Within 60 days of plugging an injection well, Tri-State CCS, LLC will submit a well plugging report to the UIC Program Director as outlined in 40 CFR 146.92(d). The Plugging Report should include the following information:

    - Pumping charts and all lab information;
    - Plug emplacement type, depth range (top/bottom), cement type, grade, weight, and quantities used for each plug;
    - Notes on plug tagging;
    - Construction/plugging schematics with USDW depths;
    - Certification of 10-year report retention;
    - Certification as accurate by Tri-State CCS, LLC and plugging contractor;
    - Well flushing and kill fluids description along with fluids and volumes;
    - Notes on debris or tight restrictions;
    - Documentation of removed completion equipment (tubing, control lines, packers, gauges); and
    - Squeeze cementing descriptions (if applicable).

5.2 Plugging Procedures

All injection and observation wells will be plugged following the schedule outlined in the Post-Injection Site Care and Site Closure Plan [40 CFR 146.93(a)].

Upon completion of the project, or at the end of life of an injection well, the well will be plugged and abandoned to meet the requirements of 40 CFR 146.92. The plugging procedure and materials will be designed to prevent any unwanted fluid movement, to resist the corrosive aspects of

CO_2/water mixtures, and to protect any USDWs. Any necessary revisions to this plan to address new information collected during logging and testing of the well will be made after construction, logging, and testing of the well have been completed and will be submitted to the UIC Program Director for approval.

Based on bottomhole pressure measurements, the well will be flushed with a kill weight brine fluid with corrosion inhibitor. The selected brine composition will be aimed at minimizing corrosion risk over the post-injection site care (PISC) period. A minimum of two tubing volumes will be injected without exceeding fracture pressure. An external Mechanical Integrity Testing (MIT) will be conducted prior to plugging as outlined in Table 1. If a loss of mechanical integrity is discovered, the well will be repaired prior to proceeding with the plugging operations. The detailed plugging procedure is provided in subsection 5.2.1 below.

All casing in the well will be cemented to surface at the time of construction and will not be retrievable at abandonment. After injection is terminated permanently, the injection tubing and packer will be removed. After the tubing and packer are removed, a retainer squeeze will be used to plug off any perforations. The pressure used to squeeze the cement will be determined from the bottomhole pressure data measured before beginning the plugging and abandonment process. However, the injection pressure (hydrostatic weight of column plus applied surface pressure) of the cement will not exceed 90% of the fracture pressure of the section being squeezed or any underlying previously squeezed zone. If it appears that the injection pressure will exceed the fracture pressure and the planned amount of cement has not been pumped into the injection zone, cement pumping will cease. If the pressure does not dissipate, the tubing will be un-stung from the cement retainer and reversed or circulated clean. After allowing sufficient time for cement to reach appropriate compressive strength, the tubing will be re-strung through the cement retainer, and the squeeze will be tested to 90% fracture pressure, or re-squeezed if injectivity is established. A rapid increase in pressure on the tubing would indicate that the perforations have been sealed with cement, and a 50’ balanced plug will be placed on top of the retainer. Balanced plugs will be used to isolate the remainder of the well per the schedule outlined in Table 2 and illustrated in Figure 1 for well TR1-1 and Table 3 and Figure 2 for well TR1-2.

If, after flushing, the tubing and packer cannot be released, an electric line with tubing cutter will be used to cut off the tubing above the packer, and the packer will be left in the well. Then, the cement retainer method will be used for plugging the injection formation below the abandoned packer. All the casing strings will be cut off at least 5 ft below the surface, below the plow line. A blanking plate with the required permit information will be welded to the top of the cutoff casing.

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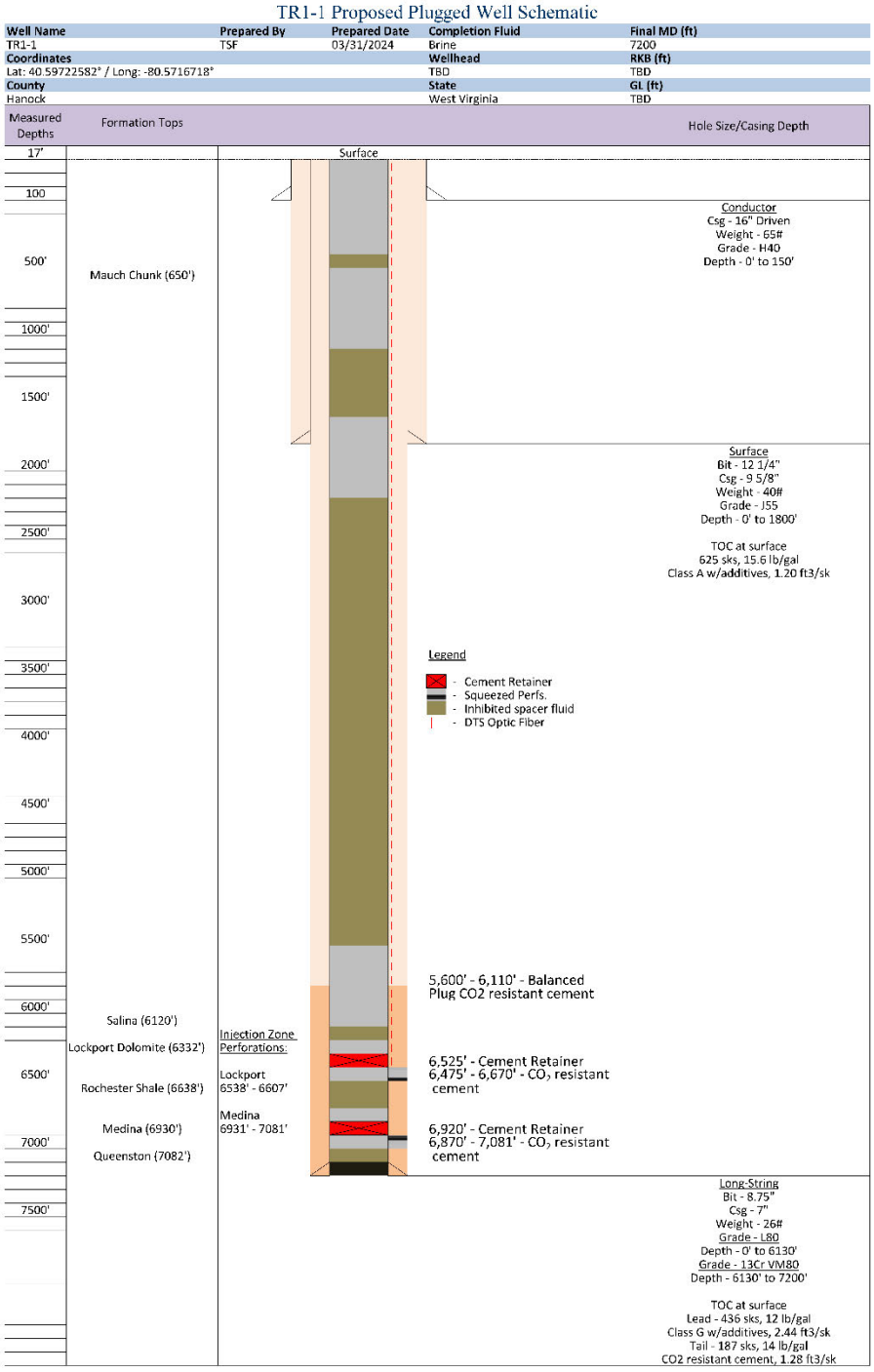

Figure 1: TR1-1 Plugged Wellbore Schematic

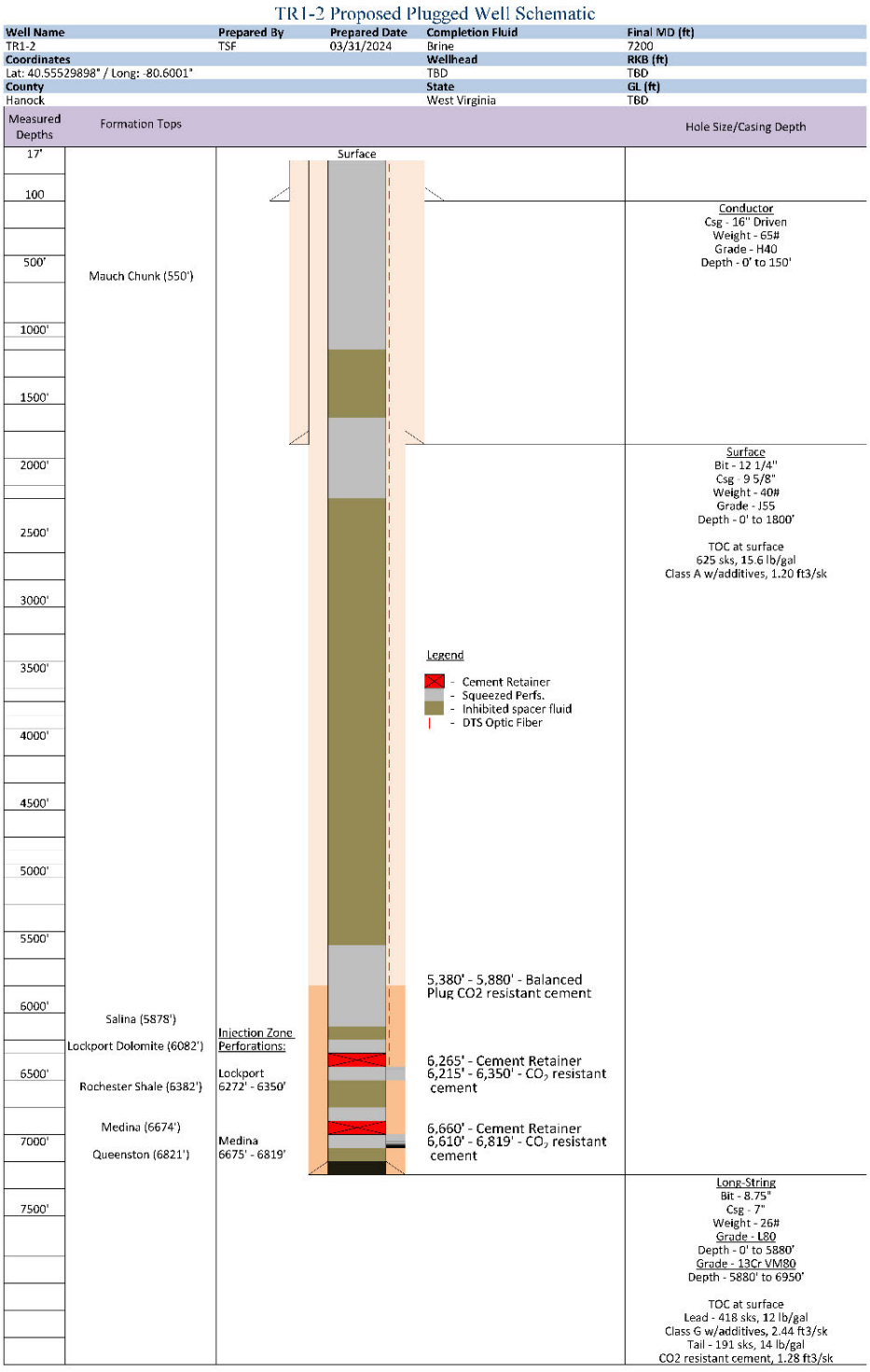

Figure 2: TR1-2 Plugged Wellbore Schematic.

5.2.1 Detailed Procedures

The following is a procedure for plugging that includes MITs and operations to place cement in the necessary intervals at critical points in the wellbore to ensure no communication from the injection zone outside of the primary confining zones. This procedure is subject to change to utilize the latest technology and best practices.

1. In compliance with 40 CFR 146.92(c), the UIC Program Director will be notified at least 60 days before plugging the well and provided an updated Injection Well Plugging Plan, if applicable. Review historic MIT data and remedial work.
2. Move In Rig Up (MIRU) onto well. All CO_2 pipelines will be marked, locked, and tagged out and noted with rig supervisor prior to mobilization of equipment onto location. Other surface hazards will be marked, removed, or barricaded as appropriate.
3. Conduct and document a safety meeting.
4. Record Bottomhole Pressure (BHP) from down hole gauge and calculate kill fluid density.
5. Open all valves on the vertical run of the tree and check pressures.
6. Rig Up (R/U) to wing valve on tree.
7. Pressure test the pump and line to 5,000 psi against master valve and wing valve at a minimum.
8. Fill tubing with kill weight brine (as determined by BHP measurement). Bleeding off tubing occasionally may be necessary to remove all air from the system. With tubing open to atmosphere, test casing annulus to 1.1 times anticipated injection pressure and monitor. If there is pressure remaining on tubing, rig to pump down tubing and inject two tubing volumes of kill weight brine. Monitor tubing and casing pressure for 1 hour. If both casing and tubing are dead, then nipple up (N/U) blowout preventers (BOPs). Monitor casing and tubing pressures.
9. If the well is not dead or the pressure cannot be bled from the tubing, consider heavier kill fluid or displacement using coiled tubing. R/U slickline and set a plug-in profile nipple. Punch tubing and circulate tubing and annulus with kill weight fluid until the well is dead.
10. Install 2-way check valve in tubing hanger and nipple down the tree.
11. N/U 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. Conduct all tests with fresh water to 250 psi low and the lower of rated working pressure of ram preventer or wellhead component for high pressure test. Low pressure test cannot exceed 350 psi, and both tests must be held for 5 minutes. Test annular preventer around tubing to 250 psi low and the lower of 70% rated working pressure or maximum allowable surface pressure (MASP) for the high pressure test. Do not test annular closed over open hole. Test all full open safety valves (TIWs), BOPs choke and kill lines, and choke manifold to 250 psi low and MASP. NOTE: Make sure a casing valve is open during all BOP tests.
12. Remove two-way check valve. Install Back Pressure Valve (BPV) if further kill operations are required.
13. Pull hanger to surface, confirm tubing is dead, and remove BPV and hanger.

14. R/U slickline and remove plug from tubing. Circulate kill fluid if needed.
15. Retrieve tubing and completion assembly.
16. Pull out of hole with tubing and control 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 Pull Out Of Hole (POOH).
17. Contingency: If unable to pull seal assembly or packer, R/U 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 UIC Program Director to acquire approval of modified plugging plan if needed.
18. Tripping In Hole (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. Tripping Out of Hole (TOH.).
19. The three lower plugs are anticipated to be 15.6 ppg, but final weight will be determined depending on additives used and other desirable cement properties determined by well conditions. Lost Circulation Material (LCM) may need to be added to squeeze cement in the event of loses while cementing.
20. Standard oilfield cement (i.e. Class A, G) will likely be used for a balanced plug across the USDW depth and at surface. It is anticipated that this will be mixed neat with a slurry weight of 15.6 ppg.
21. Actual cement volume will depend upon well conditions, completed depths, and finalized casing diameters. Balanced plugs will be tagged after setting and topped off if needed.
22. 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 below ground level (BGL), or as per permitting agency directive.

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. Anticipated changes will be submitted for approval, and any significant modifications due to unforeseen circumstances will be described in the Plugging Report described in subsection 5.1 above.