10. Well Plugging Plan

10.1 Facility Information

Facility Name: Archer Daniels Midland
CCS#1 Permit: IL-115-6A-0002
CCS#2 Permit: IL-115-6A-0001
CCS#3 Permit: TBD
CCS#4 Permit: TBD
CCS#5 Permit: TBD
CCS#6 Permit: TBD
CCS#7 Permit: TBD

Facility Contact: Mr. Doug Kirk, Plant Manager
4666 Faries Parkway, Decatur, IL
(217) 454-4577, douglas.kirk@adm.com

Well Location: Decatur, Macon County, IL;
CCS#5 (Proposed): N39° 57’ 47.32”, W89° 00’ 44.33”
CCS#6 (Proposed): N39° 57’ 48.15”, W88° 58’ 48.70”
CCS#7 (Proposed): N39° 56' 54.21'', W88° 59' 36.19”

Injection well plugging will be conducted according to the procedures provided in this section, which are consistent with previously approved procedures and submittals provided to US EPA Region 5 by ADM in May of 2016.

Upon completion of the active injection phase of the project, or at the end of the life of the respective CCS injection well, the well will be plugged and abandoned to meet the requirements of 40 CFR 146.92. The plugging procedure and materials are designed and will be implemented to prevent any unwanted fluid movement, to resist the corrosive aspects of carbon dioxide/water mixtures, and to protect any USDWs. Annual testing or information derived during plugging operations may indicate the need for revisions to this plugging plan. Significant revisions will be submitted to the UIC Program Director.

10.2 Summary

After injection has ceased, the well to be plugged will be flushed with a kill weight brine fluid. A minimum of three tubing volumes will be injected without exceeding maximum bottomhole injection pressure specified by permit. Bottom hole pressure measurements will be made using wireline or slickline conveyed tools and the well will be logged and pressure tested to evaluate Part I mechanical integrity (inside) and Part II external mechanical integrity (outside) of the casing prior to plugging. If a loss of mechanical integrity is discovered, the agency will be consulted regarding findings, and the well will be repaired as necessary to allow plugging consistent with regulatory requirements prior to proceeding with the plugging operations.

A detailed plugging procedure is provided below. Well construction and completion activities are designed to bring cement to surface on all casing strings. It is not anticipated that any of the casing will be retrieved at plugging.

After injection is terminated permanently, the injection tubing and packer will be removed. After the tubing and packer are removed, the casing will be circulated clean, or fluids displaced into the injection interval, and the balanced-plug placement method will be used to plug the well by cementing the long-string casing to surface. If, after flushing, the tubing and packer cannot be released, a tubing cutter will be used to cut off the tubing above the packer and the packer will be left in the well, the well will be flushed, and the cement retainer method will be used for plugging the injection formation below the packer.

All of the casing strings will be cut off at least 4 feet 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 at the conclusion of the plugging process.

10.3 Planned Tests or Measures to Determine Bottom-hole Reservoir Pressure

ADM will record static bottom hole formation pressure using a down hole pressure gauge and calculate kill fluid density based on final ambient monitoring pressure measurements.

10.4 Planned External Mechanical Integrity Test(s)

ADM will conduct at least one of the tests in Table 10.2-1 to verify external MI prior to plugging the injection well as required in 40 CFR 146.92(a).

Table 10.2-1. External MIT Methods

Test Type	Means of Testing
Temperature Log	Along wellbore using DTS or wireline well log
Noise Log	Wireline Well Log
Oxygen Activation Log	Wireline Well Log

10.5 Information on Cement Plugs

The cement(s) formulated for plugging will be compatible with the carbon dioxide stream that has historically been injected into the well at the conclusion of the well life. The cement formulation and required certification documents will be submitted to the agency with the final well plugging plan to be submitted with the notice to plug the well. The operator will report the wet density of the cement and will retain duplicate samples of the cement used for each plug. Figures 10.5-1, 10.5-2, and 10.5-3 present plugging schematics for the CCS#5, CCS#6, and CCS#7 wells, respectively. Tables 10.5-2, 10.5-3, and 10.5-4 present the details of the cement volumes for all three wells.

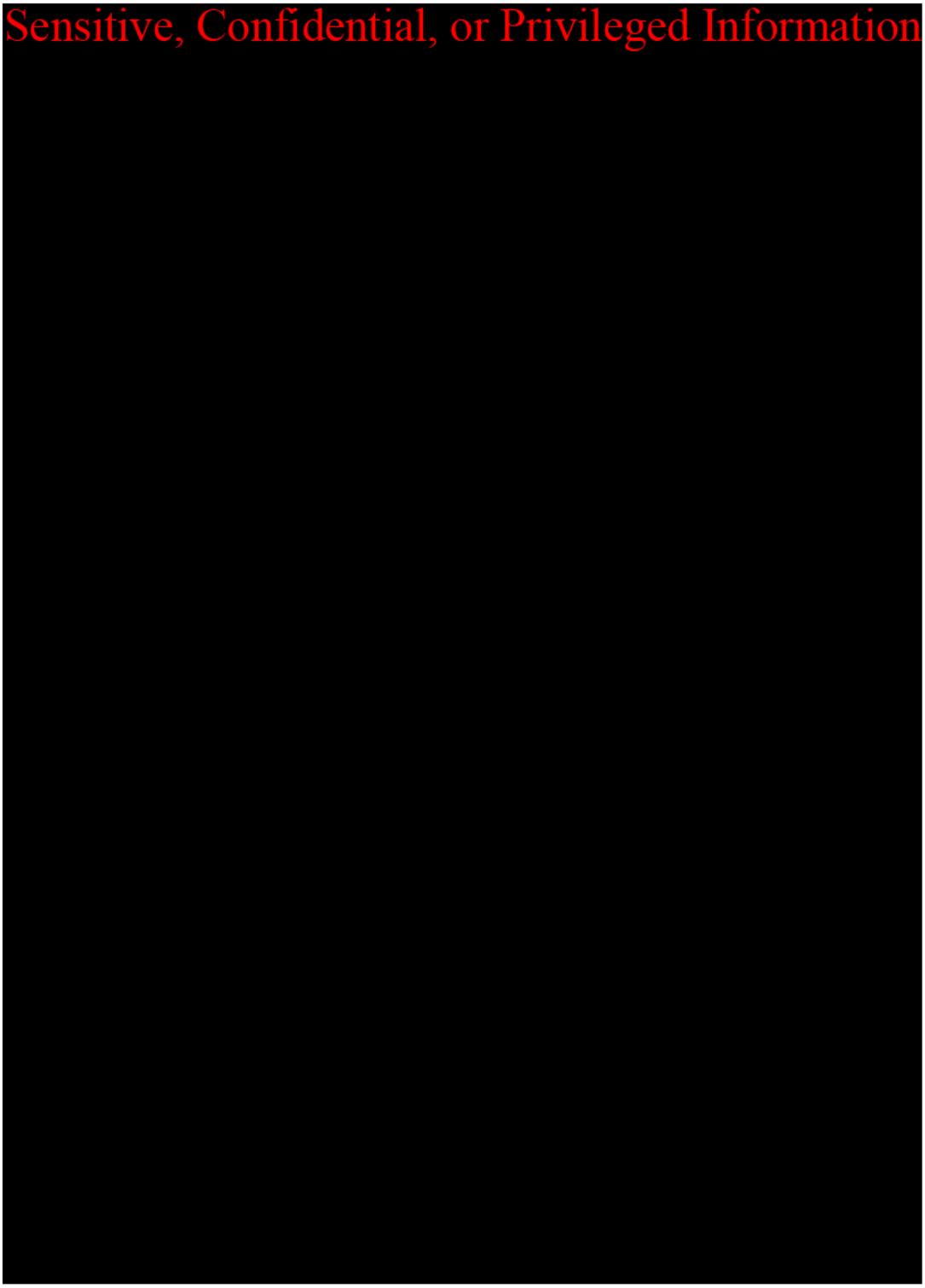

Figure 10.5-1. Proposed CCS#5 Plugging Schematic

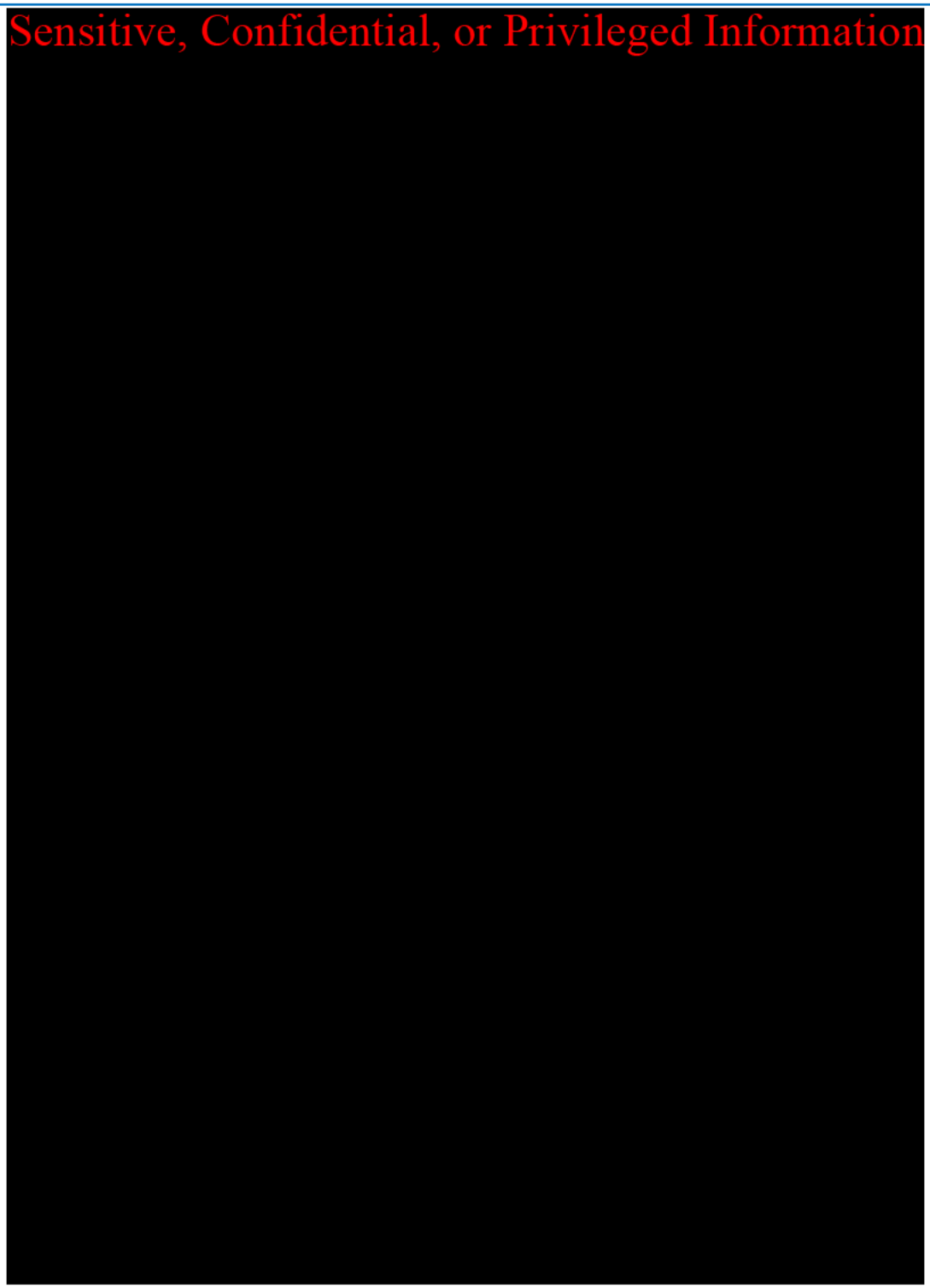

Figure 10.5-2. Proposed CCS#6 Plugging Schematic

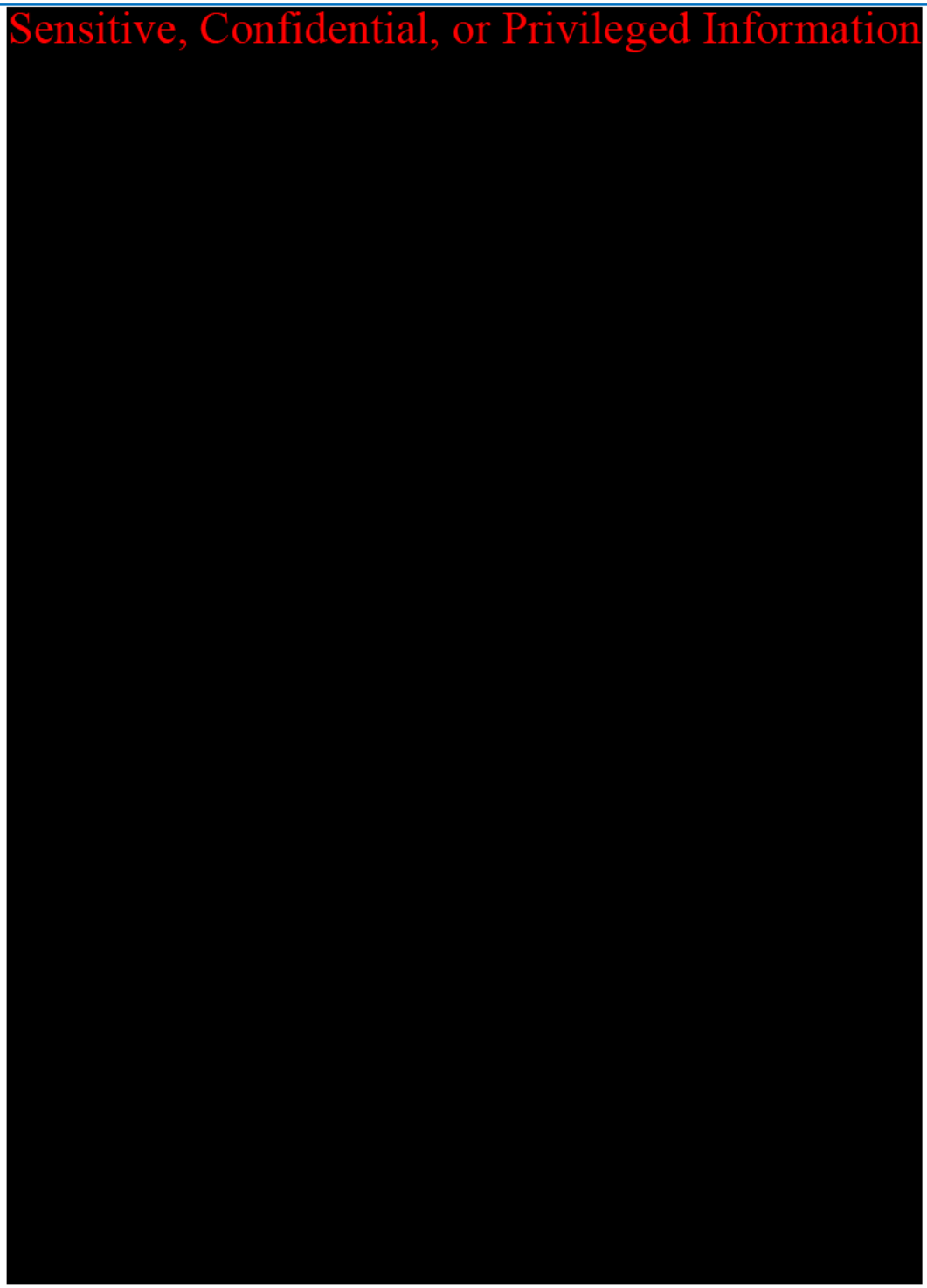

Figure 10.5-3. Proposed CCS#7 Plugging Schematic

Table 10.5-2. CCS#5 Cement Plug Details

	Plug #1	Plug #2
Inner Diameter of Casing in Which Plug Will be Placed (in)	Sensitive, Confidential, or Privileged Information	
Depth to Bottom of Tubing or Drill Pipe (ft)		
Slurry Volume to be Plumped (ft^3)		
Sacks of Cement to be Used (per plug)		
Slurry Weight (lb/gal)		
Calculated Top of Plug (ft)		
Bottom of Plug (ft)		
Type of Cement		
Method of Emplacement		

Table 10.5-3. CCS#6 Cement Plug Details

	Plug #1	Plug #2
Inner Diameter of Casing in Which Plug Will be Placed (in)	Sensitive, Confidential, or Privileged Information	
Depth to Bottom of Tubing or Drill Pipe (ft)		
Slurry Volume to be Plumped (ft^3)		
Sacks of Cement to be Used (per plug)		
Slurry Weight (lb/gal)		
Calculated Top of Plug (ft)		
Bottom of Plug (ft)		
Type of Cement		
Method of Emplacement		

Table 10.5-4. CCS#7 Cement Plug Details

	Plug #1	Plug #2
Inner Diameter of Casing in Which Plug Will be Placed (in)	Sensitive, Confidential, or Privileged Information	
Depth to Bottom of Tubing or Drill Pipe (ft)		
Slurry Volume to be Plumped (ft^3)		
Sacks of Cement to be Used (per plug)		
Slurry Weight (lb/gal)		
Calculated Top of Plug (ft)		
Bottom of Plug (ft)		
Type of Cement		
Method of Emplacement		

The first 500' plug placed in each well may include 20% excess in the volume to accommodate any issues with perforations. Tables 10.5-2, 10.5-3, and 10.5-4 all account for the 20% excess.

10.3 Narrative Description of Plugging Procedures

In compliance with 40 CFR 146.92(c), ADM will do the following:

1. Notify the regulatory agency at least 60 days before plugging the well and provide updated plugging plan, if applicable.

2. Confirm the mechanical integrity of the well by performing one of the permitted external mechanical integrity tests presented in the table under "Planned External Mechanical Integrity Test(s)" above.

3. Move-in Rig onto well and rig up (RU). All CO_2 pipelines will be marked and noted with rig supervisor prior to field work.

4. Conduct and document a safety meeting specifying requirements based on conditions noted at the well prior to plugging mobilization.

5. RU wireline or slickline equipment and required pressure control and run-in well to datum depth or suitable equivalent to record bottom hole pressure using down hole gauge. RD slickline. Calculate required kill fluid density.

6. Check pressures on the vertical run of the tree to verify wellhead equipment is sufficient for plugging activities.

7. Test the pump and lines to a minimum of 2,500 psi. Fill tubing with kill weight brine (minimum 9.5 ppg or greater, as determined by bottom hole pressure measurement). Bleeding off occasionally may be necessary to remove all gas from the system. Test casing annulus to a minimum of 1,000 psi and monitor as in annual MIT. If there is pressure remaining on tubing, rig-up equipment to pump down tubing and inject minimum of 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 (install) blowout preventers (NU BOPs). Monitor casing and tubing pressures.

8. If the well is not dead or the pressure cannot be bled off of tubing, RU slickline and set plug in lower profile nipple below packer. Circulate tubing and annulus with kill weight fluid until well is dead. After well is dead, nipple down (ND) tree, NU BOPs, and perform a function test. BOP's should have appropriately sized single pipe rams on top and blind rams in the bottom ram for tubing. Test pipe rams and blind rams to 250 psi low, 3,000 psi high. Test annular preventer to 250 psi low and 3,000 psi high. Test all TIW valves (pressure control valve), BOP choke and kill lines, and choke manifold to 250 psi low and 3,000 psi high. NOTE: Make sure casing valve is open during all BOP tests.

9. After testing BOPs pick up tubing string and unlatch seal assembly from seal bore. Rig slick line and lubricator back to well and remove X- plug from well. Rig to pump via lubricator and circulate until well is dead. During this process, annulus fluid may be bullheaded into the formation or circulated out of the well.

10. Pull out of hole with tubing laying it down. NOTE: Ensure that the well is over-balanced and add kill brine as needed to maintain fluid-filled well.

11. Pull seal assembly, pick up workstring, and trip in hole (TIH) with the packer retrieving tools. Latch onto the packer and pull out of hole laying down same.

    Contingency: If unable to pull seal assembly, RU electric line and make cut on tubing string just above packer. Note: Cut must be made above packer at least 5-10 ft MD. If unable to pull the packer, pull the work string out of hole and proceed to next step. If problems are noted, update cement remediation plan (if needed) and execute prior to plugging operations.

12. TIH with work string to tagged total depth (TD). Note that the tagged TD might be shallower than the original TD due to fill. The work string should be worked as deep as safely possible. Keep the hole full at all times. Circulate the well with fluid of sufficient weight to maintain static equilibrium and prepare for cement plugging operations.

13. The lower section of the well from the top of the confining zone to the bottom of the plug will be plugged using CO_2 resistant cement (Schlumberger Evercrete or suitable equivalent) which is expected to be from TD to a depth approximately 1,000 ft above the top of the Eau Claire formation (at approximately 4,300 ft KB). This initial stage of plugging will be accomplished by placing consecutive 500-foot balanced plugs in the casing using a cement slurry with a density of 15.9 ppg and a yield of 1.11 cubic feet per sack of cement. Note that the values used in these calculations are derived from Schlumberger's Evercrete mix. Actual cement volume will depend upon plug back total depth and wellbore fill that determine total plug length. It is anticipated that seven to eight plugs will be necessary to complete the first stage. The top depth of the plug will be verified by setting the work string down onto the plug. No more than two plugs will be set before cement is allowed to develop sufficient compressive strength (per data from testing on the specific cement blend).

14. Circulate the well and ensure it is in balance. Wait on cement for a minimum of 20 hours prior to proceeding with second stage of plugging above the confining zone to surface. Tag cement to verify depth and place work string just above the top of cement.

15. The upper section of the well from the top of the confining zone to surface will be plugged using Class A/H cement (or suitable equivalent) with a density of 15.9 ppg and a yield of 1.18 cubic feet per sack of cement. Note that the values used in these calculations are derived from Schlumberger's Class A/H blends. This stage of plugging will be accomplished by placing consecutive 500-foot balanced plugs in the casing. Actual cement volume will depend upon the top of the plug placed in the lower section of the well. It is anticipated that eight to nine plugs will be necessary to complete the second stage.

16. After each plug is set, pull out of plug and reverse circulate the work string. Repeat this operation until all the plugs have been set. If plugs are well balanced, then the reverse circulation step can be omitted until after every third plug. Lay down work string while pulling from well.

17. After the penultimate plug has been set, pull the work string from well and shut in for 12 hours.

18. Trip in hole with work string and tag cement top. Calculate volume for final plug. Pull work string back out of well.

19. ND BOPs and cut all casing strings below plow line (minimum four (4) feet below ground level or per local policies/standards and ADM requirements).

20. Lay down all work string, etc. Rig down all equipment and move out. Clean cellar to where a plate can be welded onto casing stub with well name onto lowest casing string at 4 feet, or as per permitting agency directive.

The procedures described above are subject to modification during execution, as necessary, to ensure implementation of a plugging operation that protects worker safety and effectively protects USDWs. Any significant modifications due to unforeseen circumstances will be reported to the agency during field operations and documented in the plugging report. Completed plugging forms, records and lab information will be supplied to the regulatory agency as required by permit. The plugging report will be certified as accurate by ADM and the plugging contractor, and shall be submitted to the agency within 60 days after plugging is completed.