INJECTION WELL PLUGGING PLAN
40 CFR 146.92(b)

RUSSELL CO_2 CAPTURE AND SEQUESTRATION

Facility Information

Facility name: Russell CO_2 Storage Complex
CSS #1

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Well location: Un-incorporated, Russell County, Kansas
Lat: 38.8855219472 Long: -98.7504253861 NAD 83 (2011)
Sec 27 T 13 S R 13 W 0' FSL – 2005' FEL

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List of Acronyms and Abbreviations

BOP = blowout preventer	MIT = mechanical integrity test
CO_2 = carbon dioxide	NU BOP = Nipple up blowout preventer
cu ft/ft = cubic feet per foot	PCC = PureField Carbon Capture, LLC
cu ft/sx = cubic feet per sack	PISC = Post-Injection Site Care
DTS = distributed temperature sensor	ppg = pounds per gallon
ft = feet	psig = pound-force per square inch, gauge
ft NGVD = feet elevation referenced to the National Geodetic Vertical Datum of 1929	RU = rig up
lb/ft = pounds per foot	TIH = trip in hole
MI = move-in	UIC = Underground Injection Control
	USDW = Underground Source of Drinking Water

F.1. Summary

PureField Carbon Capture, LLC (PCC) will plug and abandon CSS #1 in accordance with 40 CFR 146.92. After serving as an injection well, CSS #1 will be re-purposed as a monitoring well for the post-injection site care (PISC) period. Well plugging and abandonment of CSS #1 will occur after completion of its duty as a monitoring well during PISC.

The essential steps for plugging and abandonment are:

1. Prior to well plugging, PCC will flush the well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test per 40 CFR 146.92(a).
2. PCC will prepare, maintain, and comply with this Injection Well Plugging Plan upon its acceptance of the US EPA Underground Injection Control (UIC) Program Director. This plan is submitted as part of the permit application and includes information on the following:
    a. Planned tests or measures to determine bottom-hole reservoir pressure.
    b. Planned external mechanical integrity tests (MITs).
    c. Detailed information on the plugs including:
        i. Type and number of plugs to be used.
        ii. Placement of each plug including elevations for the top and bottom.
        iii. Type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream.
        iv. Method of placement of the plugs.
3. PCC will notify the US EPA UIC Program Director in writing 60 days before plugging (or a shorter notice period per the US EPA UIC Program Director approval). An updated plan will accompany the notification, with any amendments to the plan approved by the US EPA UIC Program Director and incorporated into the permit subject to permit modification requirements of 40 CFR 144.39 or 144.41 (as appropriate).
4. Within 60 days after plugging, PCC will submit a plugging report to the US EPA UIC Program Director. The report will be certified as accurate by PCC and the person who performed the plug operation (if other than PCC). PCC shall retain the well plugging report for 10 years following site closure.

The intention of the plugging plan is to ensure the prevention of any fluid or gas migration from the injection zone, to prevent any additional crossflow as a result of the well penetrating formations above the target zone, to resist the corrosive aspects of carbon dioxide mixed with water, and to protect Underground Sources of Drinking Water (USDWs). Any revisions to the plan due to new information collected during logging and testing will be made after construction, logging, and testing of the well has been completed. The final injection well plugging plan will be provided to the US EPA UIC Program Director.

To prepare the well for plugging, it will first be flushed with a kill weight brine fluid. A minimum flushing of three tubing volumes will be completed without exceeding formation fracture pressure. Prior to plugging, bottom hole pressure measurements will be made, and the well will be logged and pressure tested to ensure mechanical integrity inside and outside of the casing. If mechanical integrity is determined to be lost, repairs will be made prior to continuation of plugging activities. The casing of this well was cemented during construction and will not be retrievable during abandonment. Internal tubing and packer will be removed as part of abandonment. The balanced plug placement method will be used to plug the well. If, after flushing, the tubing cannot be released, an electric line with tubing cutter will be used to cut off the tubing above the packer, and the cement retainer method will be used for plugging the injection formation below the abandoned packer.

Cement used for the lower most (bottom roughly 1,000 feet [ft]) cement plugs will be designed to resist any corrosive effects of contact with carbon dioxide (CO_2), carbonic acid, or other fluids or gasses associated with or generated as a direct result of the sequestration of carbon dioxide.

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

PCC will record downhole pressure throughout the operating lifetime of the well. The same pressure gauge used to measure and record CSS #1 downhole pressure will be used to determine the bottomhole reservoir pressure prior to plugging and abandonment in fulfillment of 40 CFR 146.92(b)(1). Kill fluid density and reservoir pressure can be determined from these measurements. See Sections E.6 and E.11 of the Testing and Monitoring Plan and Section E.I.1.4 of the QASP for more detail.

F.3. Planned External Mechanical Integrity Test(s)

PCC will conduct at least one of the tests listed in Table F.3-1 to verify external mechanical integrity prior to plugging the injection well as required by 40 CFR 146.92(a) and 146.92(b)(2). See Section E.4 of Testing and Monitoring Plan for further description and procedures for the external MITs.

Table F.3-1. Potential External MITs

Test Description	Location
Temperature Log	Along wellbore using distributed temperature sensor (DTS) or wireline logging
Noise Log	Wireline logging
Oxygen Activation Log	Wireline logging

F.4. Information on Plugs

This section provides information on how the requirements of 40 CFR 146.92(b)(3), (4), (5), and (6) will be met. PCC will use the materials and methods noted in Table F.4-1 and illustrated in Figure F.5-1 to plug the injection well. Plugs #1 and #2 will have multiple lifts as illustrated in Figure F.5-1. The volume and depth of the plug or plugs are based upon the geology and downhole conditions of the well as assessed during construction. The cement for Plug #1 will be CO_2 resistant since it will likely be exposed to injectate+formation fluid mixtures, while the cement for Plug #2 and #3 will use a general purpose Class G cement suitable for non-CO_2 contact applications. Final updates to the plugging plan along with details for the cement formulations will be provided to US EPA at least 30-days prior to the start of plugging activities. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

Table F.4-1. Preliminary Plugging Details

Plug Information	Plug #1	Plug #2	Plug #3
Diameter of boring in which plug will be placed, inches	6.276	6.276	6.276
Depth to bottom of tubing or drill pipe, feet	3,650	2,600	50
Sacks of cement to be used	184	406	8
Slurry volume to be pumped, cubic feet	226	549	10.7
Slurry weight, pounds per gallon	14.8	13.5	13.5
Calculated top of plug, feet	2,600	50	0
Bottom of plug, feet	3,650	2,600	50
Calculated top of plug, Elevation ft NGVD	-850	1,760	1,810
Bottom of plug, Elevation ft NGVD	-1,840	-850	1,760
Type of cement or other material	CO_2 Resistant	Neat Cement Class G	Neat Cement Class G
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug	Balanced Plug	Dump

ft NGVD = feet elevation referenced to the National Geodetic Vertical Datum of 1929

F.5. Narrative Description of Plugging Procedures

F.5.1. Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), PCC will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

F.5.2. Plugging Procedures

1. In compliance with 40 CFR 146.92(c), notify the regulatory agency at least 60 days before plugging the well and provide an updated plugging plan, if applicable.
2. Move-in (MI) rig onto CSS #1 and rig up (RU). All CO_2 pipelines will be marked and noted with rig supervisor prior to MI.
3. Conduct and document a safety meeting.
4. Record bottom hole pressure from down hole gauge and calculate kill fluid density.
5. Open up all valves on the vertical run of the tree and check pressures.
6. Test the pump and line to 2,500 pound-force per square inch, gauge (psig). Fill tubing with kill weight brine (9.5 pounds per gallon (ppg) or as determined by bottom hole pressure measurement). Bleeding off occasionally may be necessary to remove all air from the system. Test casing annulus to 1000 psig and monitor as in annual MIT. If there is pressure remaining on tubing rig to pump down tubing and inject three tubing volumes of kill weight brine. Monitor tubing and casing pressure for 1 hour. If both casing and tubing are dead then nipple up blowout preventers (NU BOPs). Monitor casing and tubing pressures.
7. If the well is not dead or the pressure cannot be bled off of the tubing, RU slickline and set plug in lower profile nipple below packer. Circulate tubing and annulus with kill weight fluid until well is dead. Calculate the fluid density of the kill weight fluid using the following formula:

$$KMW = \frac{\left(\frac{SITP}{TVD}\right)}{0.052\,\frac{psi}{(ppg * ft)}} + OMW$$

where:

KMW=Kill Fluid Density, expressed as Kill Weight (ppg)
OMW = Original fluid density, expressed as original weight (ppg)
SITP=Shut in tubing pressure (psi)
TVD = Top open perforation total vertical depth (ft)
The constant 0.052 psi/(ppg*ft) serves as a conversion factor between pressure density expressed as a pressure gradient (psi/ft) and pounds per gallon (ppg).

8. After the well is dead, nipple down tree NU BOPs, and perform a function test. Blowout preventors (BOPs) 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 psig low, 3,000 psig high. Test annular preventer to 250 psig low and 3,000 psig high. Test all pressure valves, lines, BOPs choke and kill lines, and choke manifold to 250 psig low and 3,000 psig high. NOTE: Make sure casing valve is open during all Blowout preventer (BOP) tests. 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.
9. If the well is not dead or the pressure cannot be bled off of the tubing, RU slickline and set plug in lower profile nipple below packer. Unseat tubing from packer and circulate tubing and annulus with kill weight fluid until well is dead. After the well is dead, re-land tubing, nipple down tree NU BOPs, and perform a function test. BOPs 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 psig low, 3,000 psig high. Test annular preventer to 250 psig low and 3,000 psig high. Test all pressure valves, lines, BOPs choke and kill lines, and choke manifold to 250 psig low and 3,000 psig high. NOTE: Make sure casing valve is open during all BOP tests.
10. Pull out of hole with tubing laying it down. NOTE: Ensure that the well is over-balanced so there is no backflow due to formation pressure and there are at least two well control barriers in place at all times.
11. Confirm the well's mechanical integrity by performing one of the permitted external mechanical integrity tests presented in Table F.3-1.
12. Pick up workstring, and trip in hole (TIH). Sting into the packer.
13. RU Wireline Unit and Run in Hole with retrieving tool, pull X-plug out of the packer.
14. The lower section of the well will be plugged using CO_2 resistant cement from total depth around 3650 ft to a depth of approximately 2600 ft, which corresponds to roughly 670 ft above the top of the Arbuckle formation. This will be accomplished by placing plugs in approximately 500 ft incremental lifts. The first plug is the only plug expected to come into contact with a water bearing zone, so the cement for this plug will be formulated for contact with water and pumped with ~50% excess to account for any loss into the formation. The first plug will be pumped through the tubing, below the packer. Then by releasing from the packer, a 300-foot balanced plug will be set above the permanent packer. Using a density of 14.3 ppg slurry with a yield of 1.23 cubic feet per sack (cu ft/sx), approximately 184 sacks of cement will be required. Actual cement volume will depend upon actual weight of the casing within the plugged zone as well as the length of plug set as determined during the plugging operation. It is anticipated that at least two plugs of roughly 500 ft in length will be necessary. No more than two plugs will be set before cement is allowed to set and plugs verified by setting work string weight down onto the plug. (Calculations: Assume 26 pounds per foot (lb/ft) casing for this interval 1050 ft x 0.2148 cubic feet per foot (cu ft/ft) x 1/1.23 cu ft/sx = 184 sacks.)

15. Circulate the well and ensure it is in balance. Place tubing just above cement top from previous day. Mix and spot 500 ft balanced plug in 7-inch casing (approximately 406 sacks Class G mixed at 13.5 ppg with yield 1.35 cu ft/sx). Pull out of plug and reverse circulate tubing. Repeat this operation placing plugs in approximately 500 to 520 ft incremental lifts until a total of 5 plugs have been set. If plugs are well balanced then the reverse circulation step can be omitted until after each third plug. Lay down work string while pulling from well. If rig is working daylights only then pull 10 stands and rack back in derrick and reverse tubing before shutting down for night. After waiting overnight, trip back in hole and tag plug and continue. After all plugs have been set pull tubing from well and shut in for 12 hours. Total of approximately 406 sacks total cement used in plugs above 2600 ft. (Calculations assume 26 lb/ft casing and no excess because this section is inside the intermediate casing 2550 ft x 0.2148 cu ft/ft x 1.0/1.35 cu ft/sx = 406 sacks)
16. T Trip in hole with tubing and tag cement top. Calculate volume for final plug of approximately 50 ft. Pull tubing back out of well. Nipple down BOPs and cut all casing strings below plow line (minimum 3 feet below ground level or per local policies/standards). Trip in well and set final cement 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 a depth of roughly 3 ft, or as per permitting agency directive. (Calculations assume 26 lb/ft casing and no excess because this section is inside the intermediate casing 50 ft x 0.2148 cu ft/ft x 1.0/1.35 cu ft/sx = 8 sacks)
17. The procedures described above are subject to modification during execution as necessary to ensure the plugging operation protects worker safety and is effective to protect USDWs, and any significant modifications due to unforeseen circumstances will be described in the Plugging report. The completed plugging forms will be submitted with charts and all lab information to the regulatory agency as required by the permit. The plugging report shall be certified as accurate by PCC and the plugging contractor and shall be submitted within 60 days after plugging is completed.

Figure F.5-1. CSS #1 Well Plugging Plan Schematic

Geologic Unit	Depth	Hydrogeologic Role	Hole Size	Cement Details	Casing Size
Loess, Carlile Sh, Greenhorn Ls, and Graneros Sh	surface - ~125'	Confining Unit (Great Plains confining system)	20"	150 sx.	16" 65# H-40 STC 40 ft.
Dakota Formation (Upper Dakota Aquifer/Great Plains Aquifer)	~125' - 375'	Aquifer (Great Plains aquifer system)	12 1/4"	350 sx cemented to Surface	9 5/8" 36# J-55 LTC
Kiowa Fm and Cheyenne Ss (Lower Dakota Aquifer/Great Plains Aquifer)	~375'-495' BASE OF USDW				
Nippewalla Group (Lower Permian Units)	495'-770'	Confining Unit (Western Interior Plains confining system); some interbedded carbonates have porosity and would be considered minor aquifers			
Stone Corral (Anhydrite) - Regional Seal	770'-809'				873 ft.
Ninnescah Shale	809'-948'		883 ft		
Wellington	948'-1,124'		8 3/4"	875 sx cement TOC = 1675' CBL	7" 26# 13CR-80 Wedge-513
Hutchinson Salt Mbr	1,124'-1,402'				
Geuda Springs Shale Mbr	1,402'-1,529'				
Shale and Limestone Sequences	1,529'-2,909'				
Heebner Shale Member - Secondary Confining	2,909' - 2,927'				
Lansing & Kansas City Groups Potential Secondary Sequestration Interval Iola Limestone Member	2,993' 3,080'-3,128'	First porous interval above Arbuckle			
Marmaton Group	3,262'				
Top Primary Upper Confining Zone	3,274'				
Top of Arbuckle Group	3,277'	confining unit			
Base Primary Upper Confining Zone	3,438'				
Gross Sequestration Zone	3,448'-3,606'	Aquifer in Western Interior Plains aquifer system			
Primary Lower Confining Zone	3,647'-3,659'	confining unit			PBTD = 3660'
Top Reagan Sandstone	3,659'	Aquifer			
Top of Quartzite Basement	3,735'	Basement confining system	3756'		3740'