ATTACHMENT I –
INJECTION WELL PLUGGING PLAN

40 CFR 146.92(b)

GULF COAST SEQUESTRATION
PROJECT MINERVA

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FACILITY INFORMATION

Facility name: Project Minerva
Injector Well Nos. 1 – 4

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Well Locations: [redacted]

1.0 INTRODUCTION

Gulf Coast Sequestration (GCS) will conduct injection well plugging and abandonment according to following sections.

2.0 PLANNED TESTS OR MEASURES TO DETERMINE BOTTOM-HOLE RESERVOIR PRESSURE

Sixty-day notice will be provided prior to plugging operations. Adjustments to the plugging plan will be incorporated to meet the UIC Program Director's guidance.

It is unlikely that a homogenous liquid will exist from the surface wellhead gauge down to the perforations. A homogenous liquid is required to accurately determine the downhole pressure at the perforations; a mixture of gas and super-critical phase CO_2 are not conducive to making accurate pressure calculations. Consequently, a wireline unit will deploy a tubing downhole pressure gauge with either surface read-out or recorded memory data, and the pressure at the perforations will be measured directly.

After determining the downhole pressure at perforations, the equivalent density of fluid to balance, this pressure will be calculated using the equation: Density = Pressure ÷ .052 ÷ TVD, where density is in pounds-per-gallon, pressure is psi, and TVD is feet.

A work fluid with the density calculated as above from the downhole pressure will be mixed from a freshwater base, with bentonite added for viscosity and barite added for weight. This fluid is robust at the expected temperatures and is compatible with common cement spacers and cements.

A work string likely consisting of [redacted] will be run into the well using a workover rig. If the well has an existing tubing string with packer, the workover rig will make up a work joint to the existing tubing, pull tension to unseat the tubing hanger from the wellhead, and pull further tension to unseat the packer; if the packer must be removed by milling, this can also be done with the work string. With the tubing work string in the hole or the existing tubing/packer unseated, the work fluid will be slowly pumped down the tubing towards the perforations. [redacted] The intent is not to inject into the formation at this stage but simply displace a single column of fluid from TD to surface and these measures are meant to ensure fluid can be lifted back to surface without losses. If losses are encountered, lost circulation material can be used.

3.0 PLANNED EXTERNAL MECHANICAL INTEGRITY TEST(S)

To demonstrate external mechanical integrity prior to plugging, GCS will conduct in the [redacted] from the Injection Zone to surface one of the tests described in Table I.3.0-1.

3.1 PROCEDURES THAT WILL BE FOLLOWED FOR EACH TYPE OF EXTERNAL MIT

At the end of injection activities, a (internal test) pressure test can be performed with the tubing in-place, still connected to the packer. The pressure inside the [redacted] can be increased to a value above the standard pressure applied during injection. If noise or temperature logs are deployed on wireline, the logs will be run inside the long string and require tubing to be pulled. Noise or Temperature logs acquired via [redacted] will not require tubing to be pulled or any intervention. The [redacted] can be run with either tubing in place or with tubing pulled.

3.2 WHAT CONSTITUTES A "PASS" OR "FAIL" FOR EACH TEST?

The planned mechanical integrity tests (MIT) that may be used to demonstrate external integrity are outlined in Table I.3.0-1, along with the pass/fail criteria for each. The criteria for pass/fail of each test or log are provided below.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

4.0 INFORMATION ON PLUGS

GCS will use the materials and methods noted Table I.4.0-1 to plug the injection well. It is assumed there will be two primary intervals to be perforated for CO_2 injection. The plugging plan will be performed via a bottom-up sequence.

[redacted]

[redacted]

[redacted]

[redacted]

5.0 METHODS USED FOR VOLUME CALCULATIONS

During well construction, the [redacted] will be spot-calipered to confirm that the inner diameter (ID) equals that of new pipe, [redacted]. After running casing and cementing, a casing caliper log will be run as a baseline against which to measure future corrosive and/or erosive loss of wall thickness. Prior to plugging, casing ID data will be evaluated and compared to original baseline data. Calculations to determine cement plug and displacement volumes will use the final casing ID values.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

6.0 NOTIFICATIONS, PERMITS, AND INSPECTIONS

In compliance with 40 CFR 146.92(c) (LAC 43:XVII.3631.A.4), GCS will notify the following at least 60 days before plugging the well and provide updated Injection Well Plugging Plan, if applicable:

- UIC Program Director
  Ken Johnson
  johnson.ken-e@epa.gov
  Phone (214)-665-8473
- Calcasieu Parish Office of Emergency Preparedness (OEP)
  Dick Gremillion, Director
  ohsep@calcasieuparish.gov
  Phone (337) 721-3500
- Cameron Parish Office of Emergency Preparedness (OEP)
  Danny Lavergne, Director
  oep@cameronpj.org
  Phone (337) 775-7048
- Louisiana Department of Natural Resources
  Stephen Lee, PG, Esq, Injection & Mining Division Director
  Stephen.Lee@la.gov
  Phone (225) 342-5569
- Texas Commission on Environmental Quality
  oce@tceq.texas.gov
- Railroad Commission of Texas
  UIC@rrc.texas.gov
- Orange County Office of Emergency Management

- John h. Gothia, County Judge
  jgothia@co.orange.tx.us
  Phone (409) 882-7070
- Emergency Management Coordinator (EMC)
  LEPC@co.orange.tx.us
  (409) 882-7895

7.0 PLUGGING PROCEDURES

Well plugging schematics for Injector Well Nos. 1 – 4 shown in Figures I.7.1-1, I.7.1-2, I.7.1-3, and I.7.1-4, respectively.

7.1 CEMENTING PROTOCOL

Plug and abandonment (P&A) cementing operations should occur only after fluids in the wellbore are on balance with the exposed formation, in this case, via perforations in the long string. Water is the major component of the working fluid and is the liquid component of the cement. Given that water is effectively incompressible, a barrel of water introduced into a closed system (the wellbore) will result in one barrel of water being displaced from the system.

[redacted]

[redacted]

7.2 PLUGGING PROTOCOL

After displacing the cement plug to the balanced depth, the tubing work string will be slowly pulled to a point at least 500 ft above the top of cement. The tubing work string will be circulated the long way (down the tubing and up the annulus) to clear any excess cement from the well. Reciprocate and rotate the tubing continuously during this circulation. Wait-on-cement (WOC) to harden for 24 hours, with periodic short circulations down the tubing to ensure it remains open-ended.

After WOC the requisite 24 hours (or such time recommended by cementing contractor for plug to achieve 100 Bc or 1000 psi compressive strength), run the tubing workstring slowly into the well to tag the top of cement. Circulate through the workstring during the final 90 ft (3 joints) to ensure that the tubing remains open-ended when the workstring encounters cement, and begins to move contaminated, viscous cement up and out of the wellbore.

Tagging the hardened cement top will quantify the precise location of the cement compared to desired placement. Set down 10,000 lbs of workstring weight on top of the cement plug to prove its competency[redacted]

After successfully tagging the cement plug top and proving its competency, immediately pick up the tubing workstring and circulate through it to clear any cement from the open end and to circulate any contaminated cement out of the wellbore. Mix and pump via the balanced method another 500-ft cement plug similar to the first plug, placing it on top of the first plug. Repeat the process of pulling at least 500 ft above the calculated top of cement, circulating out any excess cement. WOC while periodically circulating and tagging the top of the second plug and proving its competency.

As a conservative approach, each of the plugs will be tagged using the method described. Tagging each plug will prove its location and competency, thus removing any doubt about the success of the plugging process. It will be a time-consuming process due to the WOC intervals, but successfully placed cement plugs will ensure future protection of the USDW.

7.3 PROPOSED P&A PROCEDURE

For all four Injector Wells (Nos. 1, 2, 3, and 4) plugging is planned to be executed in the following plugging sequence, but the proposed volumes and depths will vary based on final perforated interval depths:

1. Move in (MI) rig onto injection well to be plugged and abandoned and rig up (RU). All CO_2 pipelines will be marked and noted with rig supervisor prior to MI.

2. Conduct and document a safety meeting.

3. Shut-in well and obtain static pressure.

4. Record static bottomhole pressure from downhole gauge and calculate the kill fluid density.

5. Test the cement pump and flowline to 5,000 psi.

6. Make sure tubing-casing annulus is filled to surface with inhibited packer fluid and test to 1,500 psi, or NDIC-approved test pressure, and monitor for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and connections, and repeat the test. Release pressure.

   Note 1**:** Fluid components will be selected such that the packer fluid will be compatible with low pH conditions and the presence of CO_2 and CO_2 brines. [redacted]

   Note 2**:** If the pressure test fails, the operator will prepare a plan to repair the well prior the any consideration of P&A.

   Note 3: Buffer, kill, and packer fluids will be designed to ensure the same properties of CO_2 corrosion resistance. Kill fluid weight will be determined once final reservoir / bottom-hole conditions are established after drilling.

7. Verify the well in static conditions before Install Blow-out preventers (BOP's) and pull-up tubing string.

   Contingency**:** If the well shows pressure on the X-mas tree, rig up slickline, and set plug in lower-profile nipple below the packer and bleed off pressure inside tubing and annulus space. Using Slick line, open circulating sleeve, to establish circulation between tubing and annulus. The tubing can also be punched or perforated to regain circulation. Circulate tubing and annulus with kill weight fluid until well is static. Verify there is no pressure on surface before ND X-mas tree and NU BOP's.

8. Pull out of hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release tubing and retrieve packer, and if the plug has already set in nipple, RU electric line and prepare to cut tubing string just above packer. Make a cut above the packer at least 5 to 10 ft MD, pull the tubing out of hole, and proceed to the next step. If problems are noted, update the cement remediation plan. The squeeze packer might be used to force cement in case the packer cannot be removed.

9. Pick up work string, and roundtrip in hole (TIH) with bit and scraper to condition the wellbore.

10. Once casing is scraped and no restrictions to TD are confirmed, RU slick line unit/ wireline (wireline is preferred). MU cast iron bridge plug for 9-⅝ inch casing, run and set to TD to ensure well integrity. This step can be modified based on the casing condition across the perforation interval.

11. RU logging unit. Confirm external mechanical integrity by running the tests listed below.

    - Oxygen Activation log
    - Noise log (required per 40 CFR 146.89(c) (LAC 43:XVII.3627.A.3))
    - Temperature log (required per 40 CFR 146.89(c) (LAC 43:XVII.3627.A.3))

    For the tests listed in step #11, the same procedures will be followed while rigging up, running in hole, logging, and tripping out of hole per the service provider's best practices.

    The following brief general wireline operation procedure will be followed to log/test the wells:

    a. Install wireline unit.
    b. Pick up and make up pressure lubricator and pressure test with 10% above wellhead pressure (if pressure show up at Xmas tree gauge)

[redacted]

d. Before opening master Xmas tree master valves, equalize pressure on lubricator to avoid any pressure water hammer. (Follow wireline operational procedure and best practices)

e. Run caliper with controlled speed and reduce along the well and tag TD with a reduce speed making sure tag TD with tension reduction indication. (Please follow up best practices recommendation form Service company contractor)

f. Once well/casing bottom confirmed, POOH with a controlled speed.

g. Locate tool inside pressure lubricator and close master valves. Release pressure from lubricator and laydown Caliper tool.

h. Make up logging tools as per MIT logging program listed above in item #11. The logging procedure will be dictated by the service company and will be focus on Injection and confining zone.

12. Rig down logging wireline equipment and tools.

13. **Plug #1:** TIH work string with squeeze packer to the top of the perforated interval. Circulate well, set squeeze packer, and pump injection rate to establish cement pump rate. RU equipment for cementing operations.

    Contingency: If during running of the squeeze packer, a restriction is observed or set up is impossible, POOH and replace setting tool and packer. It is recommended to have available on site a backup tool for this contingency. If a restriction is observed, evaluate the well condition for a coiled-tubing run to wash out and condition casing wall ahead of running a mechanical packer.

14. [redacted]

    During pumping operations, injection pressure will be monitored for rapid changes, which may signal difficulty with injection operations. Pumping operations will continue until either target volume has been pumped or difficulty injecting has been encountered. Unlatch from squeeze packer and circulate.

15. **Plug #2:** [redacted] slurry atop squeeze packer set in Step 13. Wait on Cement (WOC) and RIH to tag top of cement and pressure test.

    Contingency: If during the pumping process (and after waiting on cement per time suggested in the UCA chart,) a volume differential or low pumping pressure is observed, it is recommended to RIH to tag top of cement to ensure cement is in place. If no cement is found, run a Cast Iron Bridge Plug (CIBP), then spot a new cement plug atop it. This contingency applies to the placement and testing of all cement plugs planned. Well conditions should be evaluated prior to progressing with any contingency procedure.

16. Before running a second cement retainer it is recommended to run a ring-gasket to calibrate the interior of the casing and ensure the well is free of restriction up to the top of the cement Plug #2.

17. Install Cement retainer and setting tool on workstring, RIH, space out and set second cement retainer. Perform an injection test to measure injection pressure and rate.

18. **Plug #3**: [redacted] down string followed by displacement, and when the cement is close to the end of the pipe, sting-in and inject cement down the retainer observing injection pressure.

19. **Plug #4**[redacted]

20. **Plug #5**[redacted]

[redacted]

[redacted].

22. **Plug #6**: Set surface with Class H cement + CO_2 resistant additives, 16.2 ppg to isolate the top of surface casing.

23. Lay down work string. Rig down all equipment and move out. Cut casing at 5 ft below the ground. Clean cellar to where a plate can be welded with well information.

24. The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

8.0 CONTINGENCY PROCEDURES/MEASURES

The follow contingencies were listed in the Section 7.1 (Proposed P&A Procedures) as possible scenarios that may occur while implementing the step of the procedure.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]