ATTACHMENT F –
PRE-OPERATIONAL TESTING PROGRAM

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

Project Minerva will be comprised of four individual Injector Wells: [redacted] The four injection wells were selected to maximize access to the available pore volume [redacted] Project Minerva is designed to operate for [redacted]

The proposed Injection Zone, [redacted]. The Confining Zone is [redacted]

To obtain the necessary permits from the EPA and LDNR to commence full scale CO_2 injection operations, GCS must first undertake a comprehensive Pre-operational Testing Plan (Attachment F) across both the Injection and Confining Zones to substantiate geological and reservoir modelling assumptions that form the current basis for well construction, injection rates, injection volumes, CO_2 migration (and associated pressure pulse) and surface facilities designs.

GCS plans [redacted], which will have data collection and analysis according to the guidance given in EPA 816-R-13-004. This data will be used to lower uncertainties and validate/update geologic models of the region, as well as potentially raise new questions that will be addressed via data collection [redacted]. Attachment F (Pre-operational Testing Program) also describes [redacted]

2.0 INJECTION WELL PRE-OPERATIONAL TESTING PLAN

GCS plans to drill Injector Well No. 2 first. The pre-operational testing plan is identical in all four injectors, with the exception being the cutting of conventional core samples, discussed further in Section 2.2.3.2 (Whole Coring Details).

All four injection wells are anticipated [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

2.1 DEVIATION CHECKS

Deviation measurements will be conducted approximately every 500 ft while drilling surface hole, and approximately every 100 ft during construction of the remainder of the well.

2.2 CORING, LOGGING, AND TESTING

Logs will be run, surveys conducted, and tests performed to determine/verify the depth, thickness, porosity, permeability, lithology, and chemistry of any formation fluids in all relevant geologic formations:

1. Injection Zone [redacted]
2. Confining Zone [redacted]
3. Secondary Confining Zone [redacted]
4. Base of the lowermost Underground Source of Drinking Water (USDW)

Table F.2.2-1 lists the logs and other downhole tools run, and the approximate combination in which they will be run, as well as the technical information that the tools will deliver.

2.2.1 Conductor Casing

[redacted]

[redacted]

2.2.2 Surface Casing

2.2.2.1 Borehole Drilling

The surface casing borehole is planned to be drilled from approximately [redacted] The borehole will [redacted] A deviation survey will be conducted every 500 feet. [redacted]

2.2.2.2 Open-hole Logging

The quad-combo logs described below are utilized to correlate tops, calculate porosity, predict lithology, measure travel time, and estimate permeability. A pre-spud meeting will ensure basic quality control is maintained: there will be sufficient communication with the vendor to choose correct scales, and logs will be corrected for the effects of borehole size, mud properties, and salinity.

Log Run #1

The following are logs which will be run simultaneously as [redacted]

- Spontaneous Potential ("SP"), to determine formation salinities as compared to the drilling mud. Formations such as sands will contain ample amounts of water which may be either fresh (less salty) or saline compared to the water-based drilling mud
- Gamma Ray ("GR"), for stratigraphic correlation (shales defined by high gamma counts due to radioactivity inherent in clay minerals)
- Resistivity ("RES"), to measure formation fluid resistivity to electrical current, which identifies conductive (water-bearing) vs. non-conductive (hydrocarbon) zones

- Neutron Density ("ND") log to identify lithology, identify porous rocks, and determine apparent porosity. These logs work together to identify porosity, as the density log measures combined bulk density of the rock and fluids, and the neutron log measures the hydrogen ion counts in fluid-filled porosity
- Cross-dipole Sonic ("Sonic") to measure P-wave and S-wave travel time
- Caliper, to measure borehole diameter for accurate cement calculations
- Temperature, to record borehole temperature

2.2.2.3 Casing and Cementing

[redacted]; it is common practice to pump excess amounts of cement to ensure that good-quality, uncontaminated cement reaches surface.

[redacted]. Every effort will be made to allow sufficient time for the surface casing cement to hydrate (harden) into an effective sheath. Rig activities such as installation of the blowout preventers and testing of same typically take a day, simultaneous with the cement hydration.

2.2.2.4 Cased-hole Logging

Log Run #2

As required, a temperature log will be run as Log Run #2:

- GR, to allow correlation with Log Run #1
- Temperature/Noise log measures the (increased) temperature induced upon the casing and formation by cement heat of hydration.

While waiting on the cement to fully hydrate, the surface casing borehole final position will be measured by conducting a gyroscopic multishot survey inside the surface casing. The X, Y, and Z positions are determined by gyroscopes that are unaffected by the steel casing. The results of this survey will be compared to the earlier calculations made from 500 ft interval single shot surveys. The gyroscopic survey becomes the definitive survey for surface casing borehole position.

After at least 24 hours of cement hydration, cased-hole logs will be run inside the casing to assess the quality of the cement job.

Log Run #3

Log Run #3 consists of the following:

- GR, for stratigraphic correlation; this log allows correlation with the GR run previously in open-hole, so that the quality of the cement at any depth can be correlated to those formations logged at that depth.
- The Segmented Bond Tool™ (SBT™) is a cement bond integrity tool patented by Baker Hughes. It quantitatively measures cement bond in six angular segments around the casing, which allows the user to confirm adequate hydraulic seal or to find and define channels in the cement annulus. It offers operating advantages over traditional cement bond log (CBL) tools due to its insensitivity to borehole fluids, dense muds, emulsions, temperature and pressure variations and moderate tool eccentering.

  The SBT™ provides variable-density log (VDL) measurements using a 5-foot spacing between the transmitter and receiver. This measurement is used to qualitatively understand the bonding between cement and the formation. Additionally, the tool can also be used on heavyweight casings up to 1-in. thick and can evaluate cement behind casings sizes larger than 13-⅜-in.

For ease of interpretation, the SBT™ measurements are displayed in two log presentations. Both presentations are available in logging mode as the SBT™ data is acquired, processed, and plotted in real time. The secondary presentation consists of six segmented arrays, a variable-attenuation cement map, and a tool orientation trace overlay.

2.2.3 Long-String

2.2.3.1 Borehole Drilling

Upon drilling out of the surface casing, a formation integrity test will be conducted after drilling approximately 5 to 10 ft of a new borehole. Approximately 2,000 psi will be exerted against the formation (combined drilling mud hydrostatic plus applied pressure) to confirm the compressive strength at this depth. This data serves dual purposes of proving that the formation is strong enough to withstand expected drilling forces to TD and providing a data point for estimating formation fracture pressure.

2.2.3.2 Coring and Testing

<u>Whole Coring Details</u>

GCS plans to [redacted]

The core data will be used to determine more accurate rock properties, that can be used to refine in the geological model and reservoir simulation model, and any other studies for which accurate rock data is required, for example geomechanical assumptions, facies analysis, and reservoir properties such as relative permeability. Obtaining whole core will allow the wireline log data to be accurately calibrated, and thus assumptions from his core analysis can be extrapolated with a high degree of confidence to other wells in the area. Whole cores will allow calibration of the sonic, and density data for use in geomechanical studies, the image log data for facies and fracture definition and analysis, the magnetic resonance data for reservoir properties, and in addition calibrate mineral composition to logs such as the spectral gamma ray.

As the expected geology (of the confining and injection intervals) in all of these wells are along depositional strike and within the same facies types, the chance of significant variation of rock properties is expected to be low. As such the extensive suite of newly acquired logs from the injection wells and existing wireline logs from existing artificial penetrations, correlated to core data as described above will be sufficient to adequately describe these variations.

Confining and Secondary Confining Zones

It is anticipated that Core #1 will utilize the following:

- Conventional core barrel assembly, with sealed inner barrel

- 4-inch diameter inner barrel
- 60 ft barrel length
- Mechanism to secure core in place to prevent loss of unconsolidated formation, if any
- Tripping-time schedule, to allow in-situ gases to release slowly as the core barrel is brought to surface, to eliminate damage to the core due to gas expansion
- On-site evaluation of the whole core still contained within the inner barrel, by characterization of the exposed ends as the inner barrel is cut into 3 ft lengths. A gamma ray (GR) log can also be obtained with the core barrel at surface
- Sealing all exposed ends of the whole core at surface, for transportation to the laboratory

On-site evaluation of the recovered core plus comparison to offset well logs will confirm that a suitable section of the Confining Zone was recovered.

Injection Zone

Drilling will continue to the next core point within the Injection Zone. This depth will be chosen by evaluating the mudlogger cuttings samples with comparisons to the offset well logs to confirm the injection zone has been reached. It is anticipated that Core #2 will utilize the following:

- Conventional core barrel assembly, with sealed inner barrel
- 4-inch diameter inner barrel
- 60 ft barrel length
- Mechanism to secure core in place to prevent loss of unconsolidated formation, if any
- Tripping-time schedule, to allow in-situ gases to release slowly as the core barrel is brought to surface, to eliminate damage to the core due to gas expansion
- On-site evaluation of the whole core still contained within the inner barrel, by characterization of the exposed ends as the inner barrel is cut into 3 ft lengths. A gamma ray (GR) log can also be obtained with the core barrel at surface

- Sealing all exposed ends of the whole core at surface, for transportation to the laboratory

Lower Confining Zone

There is no plan to acquire core beneath the Injection Zone.

Whole Coring Procedure

The coring procedure will be further developed in tandem with a selected vendor prior to operations. The coring program will be submitted with drilling plans at the time of execution.

The coring specialist must discuss the hole condition with the operator representative and submit the coring plan for the run. The general best practice is to have performed a wiper trip with the drilling BHA prior to making up coring tools to provide the best possible hole conditions and minimize the risks of reaming with the coring assembly.

- Offset information available for the same or similar formation. While drilling, call out for coring point should be received from GCS. Circulate to ensure hole is clean and there are no tight points while tripping. If tight points are observed, back ream and circulate out.
- Pick up and make up coring bit and barrels depending on the length of coring per plan.
- Tripping speed for the assembly: If there are no specific tripping speeds delivered by the customer or the coring coordinator during the planning of the coring operation the following example can be used to agree on a set tripping speed. Example: 30 m/min. (100 ft/min.) in casing and 15 m/min. (50 ft/min.) in open hole. Especially important for the first core run (if multiple runs are expected) to minimize excess impact potential if a bridging event is encountered. Any depths of tight hole encountered on the trip out of the hole should be given extra attention.

Tagging of the bottom can be performed while rotating or nonrotating. This will depend on the wellbore conditions, but it is recommended to rotate while tagging bottom hole.

- Utilize a minimum rotation (20-30 rpm).

- Ensure that bottom is tagged with lightweight, up to 5 klb/2.2 metric tons. When nearing the bottom and contact is made with cavings, it is necessary to rotate and circulate.
- The flow rates should be equal to the coring flow rates that are planned to be used.
- Carefully monitor the weight on bit (WOB), hook-load, and SPP, since bottom may not be indicated by a single parameter but is usually identified by an accumulation of parameter changes and the pipe tally.
- Touch bottom at least 2-3 times to confirm depths. Mark the pipe.

The drop ball performs the primary function of a pressure relief valve during coring, allowing drilling fluid to exit the inner barrels as core enters and preventing drilling fluid flow through the inner barrel during the coring process as well. The action during a coring operation is to drop and circulate the ball to the core barrel once pre-coring circulation is completed. Once the ball has landed in the pressure relief plug, indicated by an increase in SPP, the core assembly is ready to start the coring run.

- Ensure all fill has been circulated from the bottom of the hole prior to launch. After the last stand of drill pipe has been placed in the hole and the Kelly or top drive attached and circulation has been established, ensure that all measurements are correct to determine the exact bottom of the hole.
- Stop the pumps, set the slips, and break out the lower Kelly/top drive connection.
- Drop the ball down the string and make up any drill pipe or pup joints to maximize spacing and allow the maximum amount of core to be cut before having to stop and make a connection.
- Record the time the ball was introduced to the drill string. As a rule of thumb, the drop ball will fall at approximately 3 feet per second whilst free falling, allow 60 seconds per 1,000 ft (305 m) if pumping the ball down, and 60 to 90 seconds per 1,000 ft (305 m) if free falling.
- Reset the mud pump stroke counter on the PVT/Drilling Recorder and engage the mud pumps at the same reduced flow rate used to previously record the RSPP (Reduce Surface Pump Pressure)

Having previously established bottom hole, circulating, and hole cleaning prior to dropping the ball, coring can begin after the drop ball has seated in the pressure relief plug and all baseline values have been recorded. While rotating at a reduced rpm (30–50 rpm) and circulating at the coring flow rate, slowly lower the string to bottom and tag bottom with minimal weight (2,000–3,000 lb) and allow the bit to create a new bottom hole pattern before continuing with additional WOB and RPM changes.

Gradually increase WOB, RPM and fluid volume until optimum coring conditions are found.

- Circulation rates can be reduced as a remedy for fluid erosion in the core, but care must be exercised to prevent burning of the bit. Consideration should be given to the cutting of short cores (30-ft lengths/9.14 m) when coring soft formations.
- At the start of every core, rotary speed should be kept to a minimum where possible for the first 3 to 5 ft (1.0 to 1.5 m) to allow the inner barrels sufficient time to stop rotating with the outer barrels
- Proper weight on bit for each core run can be determined by increasing the weight on bit in increments of 1,000 to 2,000 lb (0.5 to 1.0 metric tons) with a constant RPM.

At the end of the coring run, when the decision has been made to come off bottom, the following steps are recommended:

- Mark the Kelly or drill pipe at the rotary table.
- Allow the weight to drill off momentarily; make note of the total depth.
- Slow the rotary and then stop the rotary, taking caution for any trapped torque in the drill string.
- Reduce the pump rate to a reduced rate.
- Begin hoisting slowly, observing the weight indicator for over pull which is over and above what any hole drag values were as previously recorded. Some formations can break core before achieving any over pull which is over and above what your hole drag values are, in these instances a core break can usually be felt by placing a bare hand on the Kelly bar or drill pipe while hoisting.

- Not to rotate during POOH unless conditions require to do.
- Recover cores as per service company recommendation and best practices. Core recovery operations on the rig floor are dependent on the type of inner barrel in use. Disposable aluminum inner barrels are recommended. Alternatives include disposable steel or fiberglass inner barrels.

Rotary Sidewall Coring

GCS plans to acquire rotary side wall cores in Injector Well Nos. 1 – 4 (see Figures F.2.0-1, F.2.0-2, F.2.0-3, and F.2.0-4). These sidewall cores will be used to calibrate the newly acquired log suite in the injector wells to accurately calculate reservoir properties such as mineralogy, porosity, permeability. The rotary sidewall coring program allows core data to be obtained and calibrated to the data set in the Confining and Injection Zones not covered by the whole core.

After reaching total depth of the well and running all open-hole wireline logs, rotary sidewall cores will be collected to supplement the whole core already sampled. A tool capable of collecting at least 60 sidewall cores will be used (actual recovery may be less). The purpose of this run is to sample formations outside the conventionally cored interval, both within the Confining Zone and Injection Zone, but also within the overlying Secondary Confining Zone (Miocene interval). The existing log data will be used to optimize the sidewall core depths and the number of sidewall cores necessary to characterize the variety of rock types, textures, and inferred depositional environments. If required, rotary sidewall cores will be collected during Log Run #7 outlined in Section 2.2.3.3 (Open-hole Logging).

Core/Fluid Analysis

Detailed core analyses will be done by a core laboratory to characterize both the Injection Zone, Confining Zone, and Secondary Confining Zone. The selected samples will cover the range of rock properties found in each zone. All zones will be characterized via petrology and mineralogy; petrophysical properties like porosity and permeability, and capillary pressure. Geomechanical measurements will be taken to determine reservoir fracture gradient and pore volume compressibility [40 CFR 146.82(a) (LAC 43:XVII.3607.A) and (c). (LAC 43:XVII.3619.A)]. Laboratory results of geomechanics tests can be compared with in situ measurements for a strong baseline.

Tests to assess petrology and mineralogy include lithologic core description, making thin sections to determine optical mineralogy, descriptions of grain size, shape, and sorting. XRD and XRF will offer more quantitative descriptions of mineralogy. This information will be integrated to infer the depositional environment and used to calibrate the geological model. Good understanding of the depositional environment can improve the model and reduce uncertainty in the range and distribution of the geological and petrophysical properties.

Tests to assess porosity, permeability and capillary pressure measurements will be made from conventional whole core and rotary sidewall cores. In case of poor recovery, the dataset will be supplemented with a higher number of rotary sidewall cores and will impact the coring program in successive wells. Percussion sidewall core will not be used for these measurements. The core data measurements will be calibrated against log measurements to generate a core-log model.

Effective and relative permeability measurements in the Injection Zone will be used to better define the Area of Review ("AoR") (EPA 816-R-13-004 Section 2.3.5.2) since dynamic modeling of the CO_2 front is a key part of the model. Therefore, these tests will be included in the core analysis program as well.

Injection and Confining Zone Rock Strength

The following laboratory analysis will be performed on core samples acquired in Injector Well No. 2, taken from both the [redacted] and the [redacted]

<u>Tensile Strength</u>**:** In order to establish the tensile strength of the Confining Zone [redacted], a Brazilian Tensile Strength Test will be performed at multiple sample points from whole core within the Confining Zone. Brazilian Tensile Strength is performed with a disc shape specimen between two opposing strip loads. The load will be continuously increased until failure of the sample occurs and tensile strength is calculated.

<u>Compressive Strength</u>**:** In order to establish the compressive strength of the Confining Zone [redacted], a Single Stage Triaxial Confined and/or Unconfined Test will be performed at multiple sample points from whole core within the Confining Zone. Triaxial compressive strength tests are commonly used to simulate reservoir stress conditions to measure static mechanical properties (e.g., compressive strength, Young's modulus of elasticity and Poisson's ratio). Dynamic measurements (Vp/Vs) can be made concurrently for acoustic (sonic) log applications.

Shear Strength: Shear strength will be calculated using the Mohr-Coulomb equation with inputs from Multi Stage or Multi Sample Triaxial laboratory analysis that will be performed at multiple sample points from whole core within the Confining Zone itself. Mohr-Coulomb Failure Envelopes are derived from triaxial compressive strength experiments and provide input data for wellbore stability analysis and safe mud- weight window design, sand control analysis, reservoir subsidence/compaction analysis and well casing and cement design. The preferred procedure for **Mohr-Coulomb failure analysis** is to perform four single-stage triaxial compressive strength tests on adjacent, lithologically similar or mutually representative samples. Generally, the experiments are conducted at confining pressures from 0 psi, representing the unconfined compressive strength case, to 150% of the minimum horizontal stress. Data are also obtained at 50% and 100% of minimum horizontal stress. Mohr-Coulomb failure envelope is developed graphically by plotting normal stress vs. shear stress.

Impact Strength: In order to establish the impact strength of the Confining Zone ([redacted]), a Brinell Hardness test will be performed at multiple sample points from whole core within the Confining Zone. The Brinell hardness test is performed by applying measured load to a spherical steel-ball (indenter) that is in contact with the sample. The depth of ball penetration is recorded along with the applied load. The hardness value is determined from the ratio of applied load to the indentation area and is expressed as kg/mm^2.

Ductility: Ductility of the injection and confining zones will be calculated by measuring the uniaxial compressive strength during the triaxial single stage geomechanical test.

Geochemical Analysis and Modeling

Additional site-specific data and analysis gathered as part of the Pre-operational Testing Program 40 CFR 146.87 (LAC 43:XVII.3617.B) will be used to validate geochemical compatibility assumptions relating to formation water, injection and confining zone mineralogy and the CO_2 stream itself.

The data acquisition for the proposed injection well includes:

- Downhole and wellhead samples of formation water (Log Run #6) and gas from the injection and observation zones (Injector Well Nos. 1 – 4)

- Core sampling over the injection and confining zone. [redacted]

Once these samples have been obtained, the following analysis will be performed:

- Detailed mineralogical analyses of the recovered core.
- Chemical analysis of the formation water.
  - Determine major anions and cations (Na^+, K^+, Mg^+, Cl^-, CO_3/HCO_3^-, SO_4^-), pH, temperature, pressure, alkalinity, SC, TOC, and total inorganic carbon
  - Lab solubility and compatibility tests will be performed to confirm CO_2 solubility in order to increase confidence in the geologic model. A compatibility analysis for the CO_2 with the injection formation fluids will assist in determining plume flow and extent, which is also used to define the AoR more accurately
- Petrophysical studies to measure core and borehole, including porosity and permeability measurements.
- Identification of relevant reactions by batch simulation model (contingent on results from detailed mineralogical analysis from recovered core and chemical analysis of formation water). Proposed to be run on whole core samples acquired in Injector Well No. 2
- Geochemical modeling to aid understanding of the processes occurring and to predict long term behavior.

Additional Analyses

Petrographic image analysis could be used as complementary form of porosity and permeability measurement.

Reporting

The results of the core analysis will help reduce uncertainty and improve the geological model and reservoir simulation. As requested, a report prepared by a qualified analyst [40 CFR 146.87(b) (LAC 43:XVII.3617.B.2)] will be submitted. It will include information on methods, notes on quality assurance samples and calibration of instrumentation as appropriate, results in tabular or graphic form, and photographs as appropriate.

Formation Testing

The owner or operator must determine or calculate the fracture pressure of the injection and confining zones. This information, in conjunction with predictions of pore pressures within the Injection Zone, is used to support the determination of an appropriate injection pressure.

This can be achieved by using a straddle packer and downhole gauges with the formation testing tool and doing a microfrac test. This is done in open-hole and is listed in the Downhole Data Acquisition Summary (Table F.2.2-1). Microfrac delivers in situ stress measurements and has a real-time pressure decline analysis which allows one to assess formation breakdown pressure and determine fracture closure pressure. From this test one can derive pore pressure, an indication of dynamic reservoir horizontal and vertical perm (K_h and K_v), skin, and can source additional parameters to aid in calibrating a geomechanical model.

Microfracs will be performed in the open-hole for Confining and Injection Zones. Locations and probability of microfracs will be determined based on borehole stability and integrity. Microfracs will determine fracture pressures for the regulatory zones and provide closure gradients. However, downhole conditions will need to be assessed as the program develops during drilling operations.

Density logs can be integrated over the desired depth to determine the vertical stress (S_v). Additionally, image logs will be run through the Confining and Injection Zones in open-hole conditions which will identify any borehole breakouts or fractures.

This test will be performed during Log Run #6 described in Section 2.2.3.3 (Open-hole Logging). At least one microfrac will be conducted from each well pad allowing the fracture pressures to be determined for each of the North and South sites.

Reporting

The results of the microfrac analysis will help provide information on pressure limits for injection of CO_2 which will be used to reduce uncertainty, improve the model, and develop an injection program. Documentation guidelines will be followed by submitting the requested information at the conclusion of testing, including:

- Type and location of the pressure gauge
- Type of flow meter and calibration records
- Raw pressure and flow data
- Plot of flow rate versus pressure data
- Discussion of any anomalous data

2.2.3.3 Open-hole Logging

After whole cores (Injector Well Nos. 2 and 3) and sidewall cores (Injector Well Nos. 1 – 4) are recovered, each of the proposed injection wells will be [redacted]

The following logging runs will be conducted in Injector Well Nos. 1-4 from the end of the surface casing to the total depth:

Log Run #4

Log Run #4 consists of the following logs:

- Spontaneous Potential ("SP"), to determine formation salinities as compared to the drilling mud. Formations such as sands will contain ample amounts of water which may be either fresh (less salty) or saline compared to the water-based drilling mud.
- Gamma Ray ("GR"), for stratigraphic correlation (shales defined by high gamma counts due to radioactivity inherent in clay minerals).
- Resistivity, to measure formation fluid resistivity to electrical current, which identifies conductive (water-bearing) vs. non-conductive (hydrocarbon) zones.
- Neutron Density ("ND"), to identify lithology, identify porous rocks, and determine apparent porosity. These logs work together to identify porosity, as the density log measures combined bulk density of the rock and fluids, and the neutron log measures the hydrogen ion counts in fluid-filled porosity.
- Caliper, to measure borehole diameter for accurate cement calculations.

- Temperature Log, to record borehole temperature.
- Nuclear Magnetic Resonance ("NMR") log, to measure porosity independent from lithology, permeability, and to characterize formation fluids.

The results of Log Run #4 will be immediately analyzed and evaluated to guide subsequent decisions for the logs that follow.

Log Run #5

Log Run #5 consists of the following logs:

- GR, for correlation of formation depths from previous log
- Acoustic (Sonic) log, to acquire high-quality shear wave data. The tool consists of X and Y dipole transmitters and receivers placed to deliver a cross-dipole measurement of shear waves. Using techniques similar to seismic processing, the log measurements can be used to locate formation features such as fractures or faults.
- Resistivity Imaging, to create a high-resolution borehole image. The image can be used to identify structural dip, fractures, faults, bedding planes, crossbedding, and borehole wall break-out.

Real-time evaluation and analysis of all logs will be performed in order to inform decision-making for subsequent logs. To enable characterization of the Injection Zone formation fluids, suitable upper Frio sands will be selected for additional logging runs:

Log Run #6 and Sampling

Log Run #6 consists of the following logs and sample collection:

- GR, for correlation of formation depths from previous logs
- Formation testing tool (Section 2.2.3.2) to measure formation pressure and collect formation fluid samples. The tool uses downhole automation to affect a seal against the formation face and pump samples of formation fluid into multiple chambers. Multiple downhole in situ pressures will be measured in order to establish a pressure gradient across the Injection Zone.
- Submit formation fluid (brine) sample to laboratory see Section 2.2.3.4 (Geochemical Analysis and Modeling). Two types of analysis are typically performed on formation brines:

- Geochemical analysis will be performed to determine major anions and cations (Na^+, K^+, Mg^+, Cl^-, CO_3/HCO_3^-, SO_4^-), pH, temperature, pressure, alkalinity, SC, TOC, and total inorganic carbon
- Lab solubility and compatibility tests will be performed to confirm CO_2 solubility in order to increase confidence in the geologic model. A compatibility analysis for the CO_2 with the injection formation fluids will assist in determining plume flow and extent, which is also used to define the AoR more accurately

<u>Log Run #7 and RSWC</u>

Finally, if log analysis reveals either upper Frio (Injection Zone) or Anahuac Formation (Confining Zone) intervals of interest which were not recovered as whole cores, formation samples can be obtained as follow from Log Run #7:

- GR, for correlation of formation depths from previous logs
- Rotary Sidewall Cores ("RSWC"), downhole electric drills capable of obtaining up to sixty (60) small core samples from selected intervals - see Section 2.2.3.2 (Rotary Sidewall Coring). These samples can be evaluated in much the same way as 4 inch whole core at the laboratory.

<u>Reporting</u>

Report results will be used to update the model and to modify data collection programs in successive wells. After the conclusions of drilling, GCS will prepare a report that includes an interpretation of the results of the logs. The report will be in electronic format and will include:

- The date and time of each test, the date of wellbore completion, and the date of installation of all casings and cements
- Chart (graphical) results of each log and any supplemental data
- The name of the logging company and log analyst and information on their qualifications
- Interpretation of the well logs by the log analyst, including any assumptions, determination of porosity, permeability, lithology, thickness, depth, and formation fluid salinity of relevant geologic formations

- Any changes in interpretation of site stratigraphy based on formation testing logs

The results of the fluid analyses will help reduce uncertainty, improve the model, and define the AoR. Documentation guidelines will be followed. When this phase of work is complete, the following information will be submitted:

1. Type of sampling equipment used and field procedure
2. If the sample was pumped, flow rate, type of pump, location of the pump, and geochemical modeling results indicating the likely geochemical makeup of the fluids at downhole conditions
3. Data for field measurements (pH, SC, temperature, pressure)
4. Laboratory results, including QA samples
5. Notes on any anomalous data

2.2.3.4 Casing and Cementing

A cement stage tool will possibly be installed on the long-string run to TD in the borehole. This device allows cement to be pumped from TD to surface (as required by regulations) in two stages to ensure successful placement of the cement sheath around the casing. The stage tool will be located substantially above TD, and once it is activated, it creates a barrier inside the casing between surface and TD. Prior to any cased-hole logging inside the long string casing, the stage tool will need to be drilled-out (as it is designed to do) to allow access to the bottom of the long string casing.

Vibrations from drilling-out the stage tool could possibly compromise the seal of the cement sheath around the casing, while the cement is undergoing hydration (hardening). It is possible that the drilling rig will be released from the well and a workover rig will be rigged up over the well afterwards. The cement will have had ample time to form its crystalline structure and develop strength. The workover rig can drill-out the stage tool, allowing access to the bottom of the long string. A casing pressure test will be conducted at this time, with the water-based fluid (liquid) used during the drilling of the stage tool. The test pressure will not exceed 80% of the casing burst pressure (satisfies 40 CFR 146.87(a)(4)(i). (LAC 43:XVII.3617.B.1.d.i)).

Fiber Optic Cable Installation

Fiber optic cable will be attached to the outside of the 9-⅝ inch long string casing. This cable, along with a temporary surface monitoring package, will allow temperature to be measured along the entire length of the casing. This satisfies 40 CFR 146.87(a)(4)(iii) (LAC 43:XVII.3617.B.1.d.iii).

2.2.3.5 Cased-hole Logging

Log Run #8

Once the long string casing access is clear, Log Run #8 will consist of the following:

- GR, for stratigraphic correlation; this log allows correlation with the GR run previously in open-hole, so that the quality of the cement at any depth can be correlated to those formations logged at that depth.
- Temperature/Noise log measures the (increased) temperature induced upon the casing and formation by cement heat of hydration.
- The Segmented Bond Tool™ (SBT™) is a cement bond integrity tool patented by Baker Hughes. It quantitatively measures cement bond in six angular segments around the casing, which allows the user to confirm adequate hydraulic seal or to find and define channels in the cement annulus. It offers operating advantages over traditional cement bond log (CBL) tools due to its insensitivity to borehole fluids, dense muds, emulsions, temperature and pressure variations and moderate tool eccentering.

  The SBT™ provides variable-density log (VDL) measurements using a 5-foot spacing between the transmitter and receiver. This measurement is used to qualitatively understand the bonding between cement and the formation. Additionally, the tool can also be used on heavyweight casings up to 1-in. thick and can evaluate cement behind casings sizes larger than 13-⅜-in.

Log Run #9

Information about formation properties can be determined through the casing and cement by the logs run on Log Run #9:

- GR, for stratigraphic correlation; this log allows correlation with the GR run previously in open-hole.

- Reservoir Performance Monitor (RPM), or industry equivalent to measure gas and three-phase fluid saturations in the cased-off formations.

Log Run #10

After all other logging runs have been completed, a baseline survey of the inside of the long string casing will be conducted as Log Run #10 to satisfy 40 CFR 146.87(a)(4)(iv). (LAC 43:XVII.3617.B.1.d.iv)

- GR, for stratigraphic correlation; this log allows correlation with the GR run previously in open-hole.
- High-Resolution Vertilog (VRT), or industry equivalent, which provides a 360-degree map of any casing defects, internal or external.
- Multi-finger Imaging Tool (MFT), or industry equivalent, a mechanical tool which can detect very small changes in the casing's internal surface. This run will provide a baseline for the 30-year project.

This work will be conducted in Injector Well Nos. 1 – 4.

2.3 MECHANICAL INTEGRITY DEMONSTRATION

2.3.1 Hydrogeologic Testing

After running casing but before injection can begin, hydrogeologic tests will be performed on the Injection Zone in Injector Well Nos. 1 – 4. The tests will consist of a pressure fall-off test and a step-rate injectivity test. The tests will measure transmissibility, skin effects due to well construction and near borehole effect, injectivity of the formation, injection flowing and static pressures of the formation, and determine Maximum Surface Injection Pressures (MSIP) for the well. These tests will provide a baseline into well and reservoir performance over time. The following sections describe the tests that will be performed in cased downhole conditions after perforation.

2.3.1.1 Pressure Fall-Off Test

A short-term injection/fall-off test will be performed in Injector Well Nos. 1 – 4 to analyze reservoir permeability, determine injection potential, and evaluate skin damage (completion efficiency) of the wellbore for each injection well. The initial test will provide a baseline standard for each well to measures the effects of CO_2 injection into the near wellbore. Subsequently, a pressure fall-off test will be performed every five years or more frequently if required by the UIC Program Director [40 CFR 146.90(f) (LAC

43:XVII.3625.A.6)]. All this information will help improve the model and provide learnings for future data collection.

A fall-off test is conducted by a long period of injection, followed by a long period of well shut in. Pressures are monitored prior to injection, during injection, and the observed drop of time period until the formation reaches the initial static pressures. The test will be designed in accordance with the USEPA Region 6 UIC Pressure Fall-off Testing Guidance (Third Revision – August 8, 2002). The wells will be shut-in for a sufficient period to allow for static conditions (*i.e.,* no injection prior to test). Two gauges will be installed downhole at the injection interval to obtain the initial bottomhole pressure. Continuous injection will occur at a steady pre-defined rate for an acceptable duration to produce a measurable pressure transient that will produce a fall-off test. The gauges downhole will monitor the flowing bottomhole pressures. The well will be shut in at the wellhead (to minimize wellbore storage effects). The pressure fall-off will be monitored until the well reaches radial flow (pressure response for the reservoir) and a final bottomhole pressure is measured. Note, no injection will occur from offset wells during the pressure fall-off tests. The injection will be isolated to the well actively being tested.

In performing a fall-off test analysis, a series of plots and calculations will be prepared to QA/QC the test, identify flow regimes, and determine well completion and reservoir parameters. It will also be used to compare formation characteristics such as transmissivity and skin factor of the near-wellbore for changes over time. Skin effects due to drilling and completion (possible damage from perforation) will be assessed for the wells injectivity and potential well cleanouts in the future. These tests can also measure drops in pressure due to potential damage/leakage over time. In CO_2, it is anticipated that pressure drops may indicate multiple fluid phases. The analysis will be designed to consider all parameters.

Testing Procedure

As outlined in Attachment G, Testing and Monitoring Plan, the general pressure fall-off testing procedure is as follows:

1. Mobilize wireline unit to the injection well and rig up on wellhead.
2. Rig up a wireline lubricator containing a calibrated downhole surface-readout pressure gauge ("SRO") with memory gauge installed in the tool string as a backup, to the adapter above the crown valve. Each gauge should have an

operating range of 0-10,000 psi. Reference the gauge to kelly bushing ("KB") reference elevation and the elevation above ground level.

3. Open crown valve, record surface injection pressure, and run-in borehole with SRO to just above the shallowest perforations in the completion while maintaining injection at a constant rate. Steady rates of injection will be maintained for at least 24 hours ahead of the planned shut-in of the injection well. Any offset injection well will be either shut-in or maintaining a constant rate of injection for the entire duration of the testing. This will minimize any cross-well interference effects.

4. With the SRO positioned just above the perforations, monitor the bottom-hole injection pressure response for ±1 hour to allow the gauge to stabilize (temperature and pressure stabilization). Ensure that the injection rate and pressure are stable.

5. Cease injection as rapidly as possible (controlled quick shut-in); close the control valve and the manual flowline valve at well site (start with the valve <u>closest</u> to the wellhead so that wellbore storage effect in early time is minimized). Conduct the pressure fall-off test for approximately 24 hours, or until bottomhole pressures have stabilized.

6. Lock out all valves on the injection annulus pressure system so that annulus pressure cannot be changed during the fall-off period. Ensure that valves on flow line to the injection well are closed and locked to prevent flow to the well during the fall-off period.

7. After 24 hours, download data and make preliminary field analysis of the fall-off test data with computer-aided transient test software to estimate if or when radial flow conditions might be reached. If sufficient data acquisition is confirmed, end fall-off test. If additional data is required, extend fall-off test until radial flow conditions are confirmed. After confirmation of sufficient data acquisition, end fall-off test.

8. Pull SRO tool up out of the well at 1,000 ft increments and allow the gauge to stabilize (five minutes each stop). Record stabilized temperature and pressure. Repeat the process to collect stabilized pressure data (five-minute stops) at 1,000 ft intervals and in the lubricator.

Recording

A record of test dates and data of each fall-off test will be kept by the site operator and maintained until project completion and be available to USEPA or LDNR upon request.

Reporting

Reports will be submitted to the UIC Program Director within 30 days of the test [40 CFR 146.91(e) (LAC 43:XVII.3629.A.5) and 146.91(b)(3) (LAC 43:XVII.3629.A.3)].

Documentation guidelines will be followed by submitting the requested information at the conclusion of testing each well. Data submitted for pressure fall-off test include:

- Raw pressure data
- Flow data from the injection part of the test. For the Injectivity or pump test, include rates and times
- Test parameters (injection time, shut-in time, fluid viscosity, temperature, wellbore diameter, pressure gauge type and location)
- Semi-log plots used for data analysis
- Parameters calculated from the analysis
- Discussions of the results, including data quality and any anomalous values

2.3.1.2 Step-Rate Injectivity Testing

The injectivity test will also support the fracture pressure measurements discussed in Section 2.2.3.2 (Coring and Testing- Formation Testing).

A step-rate test (SRT) (usually performed after the fall-off test) will be performed on Injector Well Nos. 1 – 4 and used to determine the Maximum Surface Injection Pressure (MASIP), which will be less than or equal to the measured fracture closure pressure of the injection interval. A step-rate test will be developed for the Injection Zone (upper Frio Formation) in each well. Injection rates will be developed to span the initial pressures (minimum rate) and estimated fracture pressure (maximum rate).

Testing Procedure

1. Shut-in wells long enough- but not less than 48 hours- so that the BHP is near the shut-in formation pressure. The wells may need to be backflowed if the shut-in pressure is above the expected fracture pressure.

2. Start the SRT at a suitably low rate such that at least two injection rate steps are below the formation fracture pressure and at least three rates are above the formation fracture pressure. A plot of the injection rate versus surface pressure and BHP will facilitate the determination of the formation fracture pressure. The point at which the slope of the lower fracture rates intersects the slope of the higher fracture rates is the formation fracture pressure, which can be expressed as a fracture gradient (psi/ft.).

   Allow each injection rate step to stabilize before proceeding to the next higher rate. Each step should have a duration of 60 minutes for formations with permeability of less than 10 millidarcies, and 30 minutes for formations with permeability of greater than 10 millidarcies. Each step should last exactly as long as the preceding step.

3. Once enough data points (rates) have been obtained to provide a clear intersection of rates below versus rates above the fracture pressure, the SRT will be terminated. Surface pressure and BHP measurements will be recorded at shut-in (instantaneous shut-in pressure, ISIP), after 5 minutes of shut-in, and after 10 minutes of shut-in.

4. A pressure recorder chart and a bottom-hole pressure gauge will be used to document the testing process as recommended.

5. Fluid will be injected in steps, plotting the injection pressure versus the injection rate (unconsolidated formations may require a tubing/packer setup).

6. Injection will be held constant for each step for equal length of time.

7. Injection steps will be designed with a minimum of 5 steps with 20 percent rate increases.

8. Injection steps will be tailored to each well to optimize data collection and may result in more steps and a lower percent increase over time.

9. Rates and pressures will be recorded downhole and at surface.

10. Injection rates and pressures will be plotted at the end of each step and analyzed for either a constant slope or a decrease in slope (which identifies when the formation fractures and loses the pressure held).

Recording

A record step-rate test will be kept by the site operator and maintained until project completion and be available to USEPA or LDNR upon request. Documentation guidelines will be followed by submitting the requested information at the conclusion of testing each well. Data submitted for step-rate injectivity test include:

- Raw pressure data
- Flow data from the injection part of the test. For the Injectivity or pump test, include rates and times
- Test parameters (injection time, shut-in time, fluid viscosity, temperature, wellbore diameter, pressure gauge type and location)
- Semi-log plots used for data analysis
- Parameters calculated from the analysis
- Discussions of the results, including data quality and any anomalous values

Reporting

All SRT documents will be prepared, signed, and sealed by a Professional Engineer. The following SRT data will be submitted to UIC Program Director:

- The formation fracture pressure,
- Fracture gradient analysis and determination,
- A plot of injection rate versus pressure, and
- A plot and table of the SRT data (injection rate and pressure versus time).

2.3.2 Casing and Tubing Pressure Test Procedures

Table F.2.3-1 provides a summary of the pre-operational tests that will be performed on.

GCS will perform three pressure tests during the drilling of Injector Well Nos. 1 – 4 prior to injection to satisfy the requirements of 40 CFR 146.89(a)(1) (LAC 43:XVII.3627.A.1.a). The first test will occur shortly after the well is drilled and the other two tests (packer and tubing) after all permits for injection have been obtained and the injection well has been completed. GCS will notify the UIC Program Director least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notice and the opportunity to witness these tests/logs shall be provided to UIC regulatory authority at least 48 hours in advance of a given test/log.

The first pressure test will be performed before drilling the plug after cementing. Pressure tests must be conducted on all casing strings, except for the drive or structural casing.

1. The conductor casing should be tested to a minimum of 200 psi. All casing strings below the conductor casing must be tested to 500 psi or 0.22 psi/ft, whichever is greater. If there is no oil or gas present in the cap rock, the production liner does not need to be cemented in place, and therefore, not subject to pressure testing.

2. If the pressure drops by more than 10% within 30 minutes or if any leaks are detected, the casing may need to be recemented, repaired, or an additional casing string run. The casing will need to be tested again after remedial operations are performed. These procedures must be repeated until a satisfactory test is achieved.

3. The driller's report should record the time, testing conditions, and results of all casing pressure tests.

4. Hydrostatically test surface casing to a stabilized pressure of 500 psi.

5. Hold pressure for one hour, with no more than 5% decrease (25 psi).

6. Record and report to UIC Program Director.

The second test will be performed once the tubing and packer are installed in the long-string.

1. Test the packer seal against the long string casing wall by applying pressure to the annulus between the casing and injection tubing above the packer.

2. It is important to perform the packer pressure test/tubing annular pressure test with the lateral valve on the Xmas tree open to detect any leak-offs.

3. The pressure to be tested should range from 1000 to 1500 psi within 30 minutes.

4. If the pressure holds and no leak is detected or pressure drops, the test is considered successful.

5. Chart the test to record that no leakage occurs.

6. Finally, bleed off the pressure.

7. In addition, the fiber optic cable attached to the outside of the long string casing will be able to monitor the temperature along the entire length of the casing (distributed array temperature) and will detect any leakage by showing a temperature change at the leak point.

The third test will be performed to test tubing integrity.

1. Install tubing plug in an internal profile seat near the bottom of the tubing string.

2. Apply pressure above tubing plug.

3. Test pressure will not exceed 80% of the tubing burst rating.

Gulf Coast Sequestration LLC will notify the UIC Program Director at least 30 days prior to conducting these tests and provide a detailed description of the testing procedure. Notice and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

3.0 MONITOIRING WELL PRE-INJECTION TESTING PLAN

The number and location of all deep monitoring wells associated with the Minerva project are yet to be finalized and are pending review by the regulator. The details provided in this section are broadly applicable to monitoring wells drilled into the Injection Zone (In-Zone, IZ). Additional data specific to each well will be provided as an update once the Testing and Monitoring Plan has been approved.

3.1 DEVIATION CHECKS

Deviation measurements will be conducted approximately every 500 ft while drilling surface casing borehole, and approximately every 1,000 ft during construction of the remainder of the well if the monitoring well happens to be vertical. Deviated Monitoring wells will have deviation checks approximately every 100 ft when drilling below surface casing borehole.

3.2 DRILLING, CORING, AND LOGGING

3.2.1 Surface Casing

Each IZ monitoring well will duplicate most of the logging runs performed in the Class VI injection well. The purpose for such duplication is to characterize the formation for comparison to the injection well, so that inferences can be made about the formations in between the wells. Additionally, the logging runs which serve to establish mechanical integrity will be performed on the In-Zone well because it will penetrate the Injection Zone. These logging runs are summarized in the following subsections.

3.2.1.1 Open-hole Logging

Log Run #1

Log Run #1, at surface casing depth:

- Spontaneous Potential, to determine formation salinities as compared to the drilling mud. Formations such as sands will contain ample amounts of water which may be either fresh (less salty) or saline compared to the water-based drilling mud.
- Gamma Ray, for stratigraphic correlation (shales defined by high gamma counts due to radioactivity inherent in clay minerals).
- Resistivity, to measure formation fluid resistivity to electrical current, which identifies conductive (water-bearing) vs. non-conductive (hydrocarbon) zones.
- Neutron Density, to identify lithology, identify porous rocks, and determine apparent porosity. These logs work together to identify porosity, as the density log measures combined bulk density of the rock and fluids, and the neutron log measures the hydrogen ion counts in fluid-filled porosity.
- Caliper, to measure borehole diameter for accurate cement calculations.
- Temperature, to record borehole temperature.

3.2.1.2 Cased-hole Logging

Log Run #2

Log Run #2, also at surface casing depth, after casing:

- Gamma Ray, to allow correlation with Log Run #1

- Temperature, to measure the (increased) temperature induced upon the casing and formation by cement heat of hydration.

Log Run #3

Log Run #3, at surface casing depth, after casing:

- Gamma Ray, for stratigraphic correlation; this log allows correlation with the gamma ray run previously in open-hole, so that the quality of the cement at any depth can be correlated to those formations logged at that depth.
- The Segmented Bond Tool™ (SBT™) is a cement bond integrity tool patented by Baker Hughes. It quantitatively measures cement bond in six angular segments around the casing, which allows the user to confirm adequate hydraulic seal or to find and define channels in the cement annulus. It offers operating advantages over traditional cement bond log (CBL) tools due to its insensitivity to borehole fluids, dense muds, emulsions, temperature and pressure variations and moderate tool eccentering.

  The SBT™ provides variable-density log (VDL) measurements using a 5-foot spacing between the transmitter and receiver. This measurement is used to qualitatively understand the bonding between cement and the formation. Additionally, the tool can also be used on heavyweight casings up to 1-in. thick and can evaluate cement behind casings sizes larger than 13-⅜-in.

3.2.2 Long-String Casing

3.2.2.1 Open-hole Logging

Log Run #4

Log Run #4 will be run from the end of surface casing to TD:

- Spontaneous Potential, to determine formation salinities as compared to the drilling mud. Formations such as sands will contain ample amounts of water which may be either fresh (less salty) or saline compared to the water-based drilling mud.
- Gamma Ray, for stratigraphic correlation (shales defined by high gamma counts due to radioactivity inherent in clay minerals).

- Resistivity, to measure formation fluid resistivity to electrical current, which identifies conductive (water-bearing) vs. non-conductive (hydrocarbon) zones.
- Neutron Density, to identify lithology, identify porous rocks, and determine apparent porosity. These logs work together to identify porosity, as the density log measures combined bulk density of the rock and fluids, and the neutron log measures the hydrogen ion counts in fluid-filled porosity.
- Caliper, to measure borehole diameter for accurate cement calculations.
- Temperature, to record borehole temperature.
- Nuclear Magnetic Resonance log, to measure porosity independent from lithology, permeability, and to characterize formation fluids.

Log Run #5

Log Run #5, at total depth:

- Gamma Ray, for correlation of formation depths from previous log
- Acoustic [Sonic], to acquire high-quality shear wave data. The tool consists of X and Y dipole transmitters and receivers placed to deliver a cross-dipole measurement of shear waves. Using techniques similar to seismic processing, the log measurements can be used to locate formation features such as fractures or faults.
- Resistivity Imaging tool (STAR), or industry equivalent, to create a high-resolution borehole image. The image can be used to identify structural dip, fractures, faults, bedding planes, crossbedding, and borehole wall break-out.

Log Run #6

Log Run #6, at total depth:

- Gamma Ray, for correlation of formation depths from previous logs
- Reservoir Characterization Explorer (RCX), or industry equivalent, to measure formation pressure and recover formation fluid samples. The tool uses downhole automation to affect a seal against the formation face and pump fluid samples into multiple chambers.

These six log runs conclude the logging program planned for the In-Zone well prior to running casing.

3.2.2.2 Cased-hole Logging

Log Run #7

Log Run #7, run inside casing to the deepest point:

- Gamma Ray, for stratigraphic correlation; this log allows correlation with the GR run previously in open-hole, so that the quality of the cement at any depth can be correlated to those formations logged at that depth.
- The Segmented Bond Tool™ (SBT™) is a cement bond integrity tool patented by Baker Hughes. It quantitatively measures cement bond in six angular segments around the casing, which allows the user to confirm adequate hydraulic seal or to find and define channels in the cement annulus. It offers operating advantages over traditional cement bond log (CBL) tools due to its insensitivity to borehole fluids, dense muds, emulsions, temperature and pressure variations and moderate tool eccentering.

  The SBT provides 5 ft-spaced variable-density log (VDL) measurements used to qualitatively understand the bonding between cement and the formation. Additionally, the tool can also be used on heavyweight casings up to 1-in. thick and can evaluate cement behind casings sizes larger than 13-⅜-in.

Log Run #8

Log Run #8, inside casing, across the proposed injection zone:

- Gamma Ray, for stratigraphic correlation; this log allows correlation with the GR run previously in open-hole.
- Reservoir Performance Monitor (RPM), or industry equivalent, an advanced pulse neutron tool. The log assists with measuring gas and three-phase fluid saturations in the cased-off formations.

Log Run #9

Log Run #9, inside casing:

- Gamma Ray, for stratigraphic correlation; this log allows correlation with the GR run previously in open-hole.

- High-Resolution Vertilog (VRT), or industry equivalent, which provides a 360-degree map of any casing defects, internal or external.
- Multi-finger Imaging Tool (MFT), or industry equivalent, a mechanical tool which can detect very small changes in the casing's internal surface.

3.2.2.3 Fiber Optic Cable Installation

Fiber optic cable will be attached to the outside of the 9-⅝ inch long string casing. This cable, along with a temporary surface monitoring package, will allow temperature to be measured along the entire length of the casing. This satisfies 40 CFR 146.87(a)(4)(iii).

3.3 MECHANICAL INTEGRITY DEMONSTRATION

Table F.3.3-1 provides a summary of the MITs to be performed on the deep monitoring well(s), after installation and prior to commencing CO_2 injection operations.

A casing pressure test on the long string (In-Zone) casing was conducted when the cement stage tool was drilled out; the pressure was applied with the water-based fluid (liquid) used during the drilling of the stage tool. The casing pressure test was charted for proof that no leakage has occurred. This test satisfies 40 CFR 146.87(a)(4)(i).

To verify hydrogeologic characteristics of the injection zone formation fluids (fall-off test, injectivity test), suitable Frio sands will be selected after careful log and core sample analysis. The following test will be performed after perforating the long string casing at the desired Frio sands to satisfy 40 CFR 146.87(e)(1)

- GR, for correlation of formation depths from previous logs
- Reservoir Characterization Explorer (RCX), to measure formation pressure and recover formation fluid samples. The tool uses downhole automation to affect a seal against the casing wall and pump fluid samples from the formation into multiple storage chambers for the fall-off test, and to pump fluids into the formation for injectivity tests. These results will be compared to the results from the Class VI injection well nearby.

Notice and the opportunity to witness the test/log shall be provided to EPA at least 48 hours in advance of a given test/log.

3.3.1 Annulus Pressure Test Procedures

Similar to the Class VI injection well, the In-Zone monitoring well will have tubing and a packer set inside the long string casing. The packer seal against the long string casing wall will be tested by applying pressure to the annulus between the casing and injection tubing above the packer; the test will be charted to record that no leakage occurs.

4.0 REFERENCES

USEPA Region 6 UIC Pressure Fall-off Testing Guidance (Third Revision – August 8, 2002)