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# TESTING AND MONITORING PLAN
# 40 CFR 146.90

# PROJECT MINERVA

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# 1.0 Introduction

This Testing and Monitoring Plan describes how Gulf Coast Sequestration (GCS) will monitor the Project Minerva site pursuant to 40 CFR 146.90. In addition to demonstrating that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs, the monitoring data will be used to validate and adjust the geological models used to predict the distribution of the $CO_2$ within the storage zone to support AoR reevaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan.

## 1.1 Facility Information

| | |
|---|---|
| Facility name: | Project Minerva<br>Wells 1-4 |
| Facility contact: | Benjamin Heard, Principal<br>2417 Shell Beach Drive, Lake Charles, Louisiana 70601<br>(713) 320.2497; bheard@gcscarbon.com |
| Well location: | Calcasieu/Cameron Parish, Louisiana<br>Well No 1: [redacted]<br>Well No 2:<br>Well No 3:<br>Well No 4: |

## 2.0 Overall Strategy and Approach for Testing and Monitoring

The Testing and Monitoring Plan is adapted to site area and considers the following site: specific parameters:

1. The injection zone (Frio Formation) ranges from 1,000 to 1,600 ft gross thickness and comprises 23 zones- 12 sandstone zones alternating with 11 shale zones. Each sandstone layer acts as a discrete flow unit, while the shale layers behave as either barriers or baffles.
2. The performance of the Frio Formation in accepting $CO_2$ injection is well known. The Frio Formation has been used regionally as a target for Underground Injection Control (UIC) Class 1 injection, has hosted and extensively monitored, DOE-funded test injection project in Liberty County, Texas, and has received $CO_2$ for $CO_2$ EOR in multiple fields. Two Frio injection sites at Hastings Field and West Ranch Field received anthropogenic $CO_2$ and have been monitored as part of DOE-funded programs supporting CCUS projects.
3. The performance of the Anahuac Formation as a confining zone is well known because a) it is proven to retain hydrocarbons regionally, and 2) coring and testing programs conducted as part of the UIC Class 1 program have documented the quality of this thick, low permeability mudstone. Analysis has shown that faults in this region do not exhibit sufficient throw to create a flow path vertically through the Anahuac Formation.
4. A thick (>7,000 ft) Miocene interval overlies the Anahuac Formation and comprises highly transmissive sandstones, interbedded regional mudstone seals and local mudstone baffles. Regionally the Miocene contains hydrocarbons and is used for Class 1 injection in both Louisiana and Texas. Fluids in the Miocene are saline; therefore, the Miocene can be considered to perform as an additional barrier to vertical fluid migration as well as allowing for pressure dissipation and as a monitoring point.
5. The primary source of groundwater for the region is the Chicot Aquifer, which is contained within in the transmissive and multi-layered Beaumont Formation. Within the project area of review, however, it is sparsely used. Locally, saline waters may be present in the Chicot Aquifer due to natural salinization near salt domes (e.g. [redacted]) or as the result of legacy oil and gas production activities that failed to adequately protect underground sources of drinking water (USDW). In addition, the Chicot Aquifer is locally charged with both biogenic and thermogenic methane. The monitoring program will document the initial condition of salinization of this aquifer system so that any changes during project operation can be recognized. Available groundwater characterization data are currently limited.
6. Natural seismicity in the area is low, as is the risk of induced seismicity, owing to the high transmissivity and lack of brittle rocks within, above, or below the injection zone (Frio Formation). Previous measurements of seismicity in Gulf Coast projects have not detected events resulting from injection. Consequently, seismicity will be monitored for change in frequency; only if a change in frequency occurs will monitoring of local events be undertaken.
7. Surface monitoring at the Minerva site is designed to be responsive to the near surface setting. The area is dominated by complex surface conditions including tree- and grass-dominated high areas, intermittently flooded freshwater wetland, and perennial wetlands.

The area is expected to be dynamic in terms of $CO_2$ production and uptake from active environments including wetland bottom sediments, intermittently saturated soils, plant, and animal activities, and is used for grazing and other activities which are likely to change over time. Therefore, no systematic array of leakage detection in air or soil is proposed. We propose instead an anomaly response program, to be deployed if an incident or anomaly with possible surface impact occurs. Historic and recent oil and gas exaction operations surrounding the AoR may also have anomalous surface characteristics related to both natural processes and past fluid management practices.

Four injection wells will create two $CO_2$ plumes and one area of elevated pressure, resulting in a single merged AoR. The axis of a broad syncline structure was chosen as the site of $CO_2$ injection to minimize contact between the projected $CO_2$ plumes and AoR with existing well penetrations. Validation of the magnitude and area of pressure increase during injection is, therefore, a monitoring focus, as well as documenting plume stabilization (described in the Post-Injection Site Care and Site Closure Plan 40 CFR 146.93(a) document).

The monitoring network is composed of the following elements, listed from deepest and closest to injection to the furthest away and shallowest (see Figure 2.1).

1. Monitoring at the pipeline handoff to the injection site will determine the key parameters of mass and purity of $CO_2$ needed for accounting of mass injected and modeling of the subsurface response to injection.
2. Monitoring at injection wells will assure that the wells are performing as intended to deliver the $CO_2$ to the subsurface storage zones and measure the pressure response at the reservoir intervals (a key model match parameter). Downhole pressure gauges and injection logging in the four injection wells will be used to assess within-plume reservoir response to injection.
3. A 4-D VSP array composed of fiber optic cables installed downhole at injection wells for Distributed Acoustic Sensing and an array of fixed pads for acoustic sources will allow tracking of the area of $CO_2$ saturation over time along selected azimuths. For $CO_2$ plume tracking to match to models, good repeatability to measured change over time is more critical than imagining details of the plume. The source array is aligned to 1) document plume growth during injection and 2) plume stabilization during PISC. The spacing and location of the sources will be determined by the VSP design team and located where feasible to install and allow access in the wetland areas (Figure 2.1).
4. In-zone pressure (IZ) monitoring wells will validate the modeled growth of the AoR over time. IZ pressure-monitoring will be outside of the $CO_2$ plume areas and can be repurposed by recompletion of existing wells and fitting them with downhole pressure gauges. Change in water composition is not expected in this zone; and water will be sampled once (including for dissolved and free gases) for characterization purposes.
5. Above zone monitoring interval (AZMI) wells will be installed in areas of more abundant penetrations where concern about isolation of the injection zone is higher-than-average. IZ and AZMI monitoring points can be co-located or engineered as multi-zone completions,

if feasible. Change in water composition is not expected in this zone; and water will be sampled once (including for dissolved and free gases) for characterization purposes.

6. An airborne conductivity survey will be used to assess the expected complexity of both the groundwater system and near surface and identify areas of high salinity that may be existent. This will be used to guide finalization of ground water well placement and ecosystem survey locations. A repeat survey at project end will be used to detect changes indicative of possible out-of-zone fluid migration. The survey will be designed and conducted by a qualified vendor.
7. Water wells drilled at each injection well pad will be completed as long-term monitoring points to document changes in water chemistry. Seasonal sampling including field parameters and dissolved, and free gasses and water level monitoring will be conducted 4 times per year for 3 years for characterization. After 3 years sampling frequency will be decreased and targeted to chemical species that are indicative of leakage. Far field groundwater wells will be drilled to characterize anomalous salinity in order to deal with the expected complex salinity signal. Seasonal sampling and water level monitoring will be conducted 4 times per year for 3 years for characterization. After 3 years sampling frequency will be decreased and targeted to species that are indicative of leakage.
8. An ecosystem and land-use survey based on image analysis, followed by site visits, will be conducted over the surface projection of the AoR and adjacent areas of potential anomalous signal. This will document pre-injection (baseline) surface conditions and provide the basis for designing ecosystem surveillance areas. Sampling stations will be located in areas that represent the diversity of ecosystems including disturbed areas and wetlands (about 10 sites). Sample analyses will provide characterization of each ecosystem's respective geochemical signatures for future attribution. Repeat sampling of $CO_2$, $O_2$, $N_2$, $CH_4$, C1-C5 hydrocarbons, $\delta^{13}C$ and $^{14}C$ of $CO_2$ and $CH_4$ and $\delta D$ of $CH_4$ will be performed on carbon phases seasonally (4 times per year) over a 2-year period to provide robust characterization. Sampling will not be routinely repeated but is important to have available in case incident or anomaly occurs. Work will be conducted by a qualified vendor. Models will be developed to provide anomaly intensification thresholds and develop a protocol for incident response on an as-needed basis.

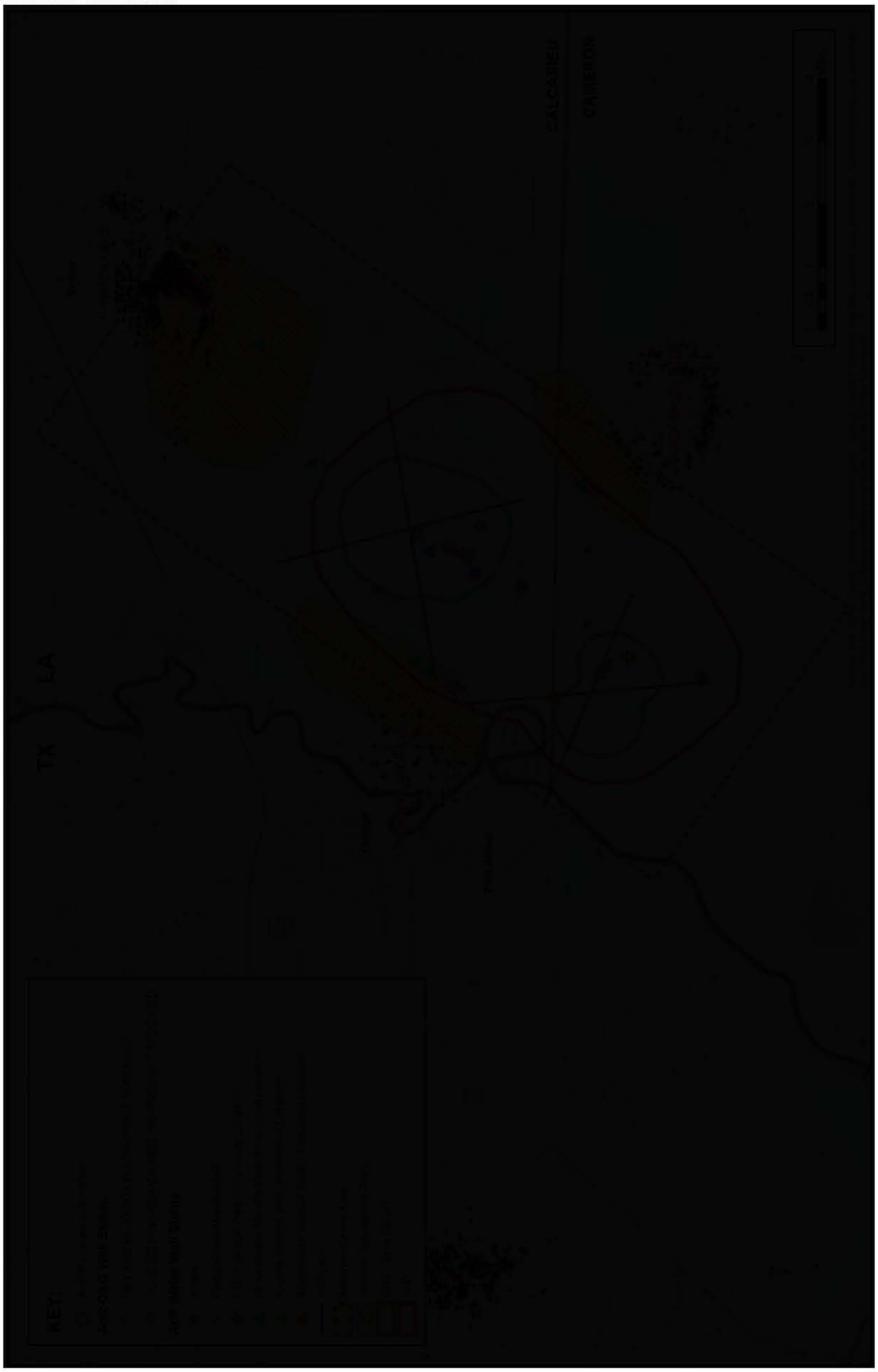


**Figure 2.1 Testing and monitoring plan overview**

## 2.1 Quality assurance procedures

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities, required pursuant to 146.90(k), is provided in 12.1 APPENDIX 1: Class VI Injection Well: Quality Assurance and Surveillance Plan.

## 2.2 Reporting procedures

GCS will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR 146.91.

# 3.0 Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

GCS will analyze the $CO_2$ stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a).

## 3.1 Sampling location

$CO_2$ stream sampling will be conducted for all four injection wells at the storage facility transfer point co-located with a mass flow meter.

## 3.2 Sampling frequency

Carbon Dioxide Stream sampling will be conducted every 3 months (quarterly) or when known changes to the injected stream occur (i.e., source changes and/or additions/deletions to the existing stream). Density measurements at the mass flow meter greater than normal variability and not correlated to thermal variations also will trigger sampling. The isotopic composition of carbon in $CO_2$ ($\delta C^{12}/C^{13}$ ratio and $C^{14}$ will be measured once and repeated only if new sources are added.

## 3.3 Analytical parameters

GCS will contract a vendor to analyze the $CO_2$ for the constituents identified in Table 3.1 using the methods listed. If the constituents are not found in initial analysis or are screened out at the source prior to $CO_2$ pipeline transport, this will be documented and, with the prior approval of the UIC Program Director, they will be removed from the list of analytical parameters.

**Table 3.1. Summary of analytical parameters for $CO_2$ stream.**

| Parameter | Analytical Methods [1] |
|---|---|
| Carbon Dioxide ($CO_2$) | ISBT[2] 2.0 Caustic absorption Zahm-Nagel<br>ALI method SAM 4.1 subtraction method (GC/DID)<br>GC/TCD |
| Water ($H_2O$) | |
| Oxygen ($O_2$) | ISBT 4.0(GC/DID) GC/TCD |
| Nitrogen ($N_2$) | ISBT 4.0(GC/DID) GC/TCD |
| Hydrogen Sulfide ($H_2S$) | ISBT 14.0 (GC/SCD) |
| Argon (Ar) | |
| Sulfur dioxide ($SO_2$) | ISBT 10.1 GC/FID) |
| Methane ($CH_4$) | ISBT 10.1 GC/FID) |
| Total hydrocarbons (C2H6, C3H8+) | ISBT 10.0 THA (FID) |
| Hydrogen ($H_2$) | |
| Carbon Monoxide (CO) | ISBT 5.0 Colorimetric ISBT 4.0(GC/DID |
| COS | |
| Nitrogen Oxides (any ($NO_x$) | ISBT 7.0 Colorimetric |
| Glycol | |
| Compressor oil | |
| Carbon isotopic composition $\delta C^{13}$ and $C^{14}$ | Measured once and when a significant new source is added. Used for attribution during monitoring |

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director
Note 2. International Society of Beverage Technologists (ISBT) Carbon Dioxide Guidelines MBAA TQ vol. 39, no. 1, 2002, pp. 32-35 as cited in ISO/TR 27921:2020(en). Carbon dioxide capture, transportation, and geological storage — Cross Cutting Issues — $CO_2$ stream composition

## 3.4 Sampling methods

The sampling system will step down pressure from pipeline pressure to atmospheric pressure sample container without loss of minor impurities. The sampler will be purged with pipeline $CO_2$ to remove contaminants prior to sample collection. All sample containers will be labeled with durable labels and indelible markings. A unique sample identification number and sampling date will be recorded on the sample containers. The sample container will be sealed and shipped to an authorized laboratory(s) in Louisiana.

## 3.5 Laboratory to be used/chain of custody and analysis procedures

Samples will be analyzed by a third party laboratory accredited by the Louisiana Department of Environmental Quality (https://internet.deq.louisiana.gov/portal/divisions/lelap/accredited-laboratories) using standardized procedures for gas chromatography, mass spectrometry, detector

tubes, and photo ionization. The sample chain-of-custody procedures described in Section 12.3.3 of the QASP will be employed.

## 4.0 Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b)]

As required at 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b), GCS will install and use continuous recording devices to monitor:

1. The mass of $CO_2$ delivered at the transfer point
2. The volume and temperature of $CO_2$ allocated to each well
3. The pressure at well head
4. The pressure on the injection tubing
5. The pressure at well head on the annulus between the tubing and the long string casing
6. The annulus fluid volume added

### 4.1 Monitoring location and frequency

GCS will perform the activities identified in Table 4.1 to monitor operational parameters and verify internal mechanical integrity of injection wells. Monitoring will take place at the locations and frequencies shown in Table 4.1.

Following conventional practices at injection sites with multiple wells, the Project Minerva will use a mass flow meter to measure $CO_2$ mass delivered to the project at the transfer point from the pipeline (same location as $CO_2$ stream analysis so that any non-$CO_2$ impurities can be subtracted from the storage accounting). Calibration will be conducted per the manufactures instructions and reported.

Additional flow meters will be installed on flow lines leading to each well to record $CO_2$ volume and temperature which will serve to guide the allocation of the $CO_2$ on a per well basis. Calibration will be conducted following the manufactures instructions and reported.

**Table 4.1. Sampling devices, locations, and frequencies for continuous monitoring.**

| Parameter | Device(s) | Location | Min. Sampling Frequency | Min. Recording Frequency |
|---|---|---|---|---|
| **Project mass flow** | Coriolis flow meter | Transfer point pipeline to injection project | Continuous | Per Archiver Program |
| **Well head flow volume** | Thermally corrected volume flow meter | On injection well, pad | Continuous | Per Archiver Program |
| **$CO_2$ stream temperature** | From flow meter | On injection well pad | Continuous | Per Archiver Program |
| **Injection pressure on tubing** | Pressure gauge | On wellhead | Continuous | Per Archiver Program |
| **Annular pressure** | Pressure gauge | On wellhead | Continuous | Per Archiver Program |
| **Annulus fluid volume** | Direct volume measure | At wellhead | When fluid is added | When fluid is added |
| **Downhole pressure** | Quartz pressure gauge | On port in tubing above packer | Continuous (3) | Per Archiver Program |
| **Downhole temperature** | Temperature gauge in same devise as pressure | on port in tubing above packer | Continuous (4) | Per Archiver Program |
| **Changes in Rayleigh scattering resulting from distributed strain indicative of wave arrival** | DAS optical fiber | Installed on outside of casing | As designed for acoustic survey | As designed for acoustic survey (3) |
| **Changes in Rayleigh scattering indicative of temperature change** | DAS optical fiber | Installed on outside of casing | Hourly (3) | Daily |

Note (3) set up to sample and record every second during well test procedures

Note (4) set up to sample and record at frequency required during test periods

## 4.2 Monitoring details

The mass flow meter will be protected against damage by lightning.

Each well will be completed with equipment needed to 1) account for per-well injection mass and pressure as inputs to fluid flow modeling to validate AoR predictions and 2) assure well integrity is maintained.

Well-head pressure and temperature gauges will be installed to detect and record changes in ($CO_2$-filled) tubing pressure and the casing-tubing anulus (filled with corrosion-inhibited fluid). Replenishment of corrosion-inhibited fluid will occur as needed, and the amounts added will be recorded. A more-rapid-than-normal change in casing-tubing anulus pressure will trigger shut in of injector and inspection of well components until failure is identified.

Downhole quartz pressure gages on wireline readout will provide the required input to models and serve as opportunities for additional calibration of fluid flow models (during injection fall-off tests and when injection is started at each injection well). Downhole pressure monitoring protects the project against over-injection as the near-well environment is cooled and $CO_2$ becomes denser. The gauge location will be on tubing above the packer where the gauge is protected by corrosion inhibited fluid, with a pass though into the tubing. Pressure gauges will be calibrated according to manufactures instructions and corrected for drift by comparison to tubing deployed gauges during MIT.

Wireline logging will be conducted at a minimum 6 months and 2 years after the start of injection at each well to assess the injection profile (which zones are being used by $CO_2$). These data will be input the into models. A commercial vendor will be selected to conduct this logging using any of the standard techniques. If the injection profile is not optimum, this log provides input to correct the strategy.

Optical fiber designed for Distributed Acoustic Sensing (DAS) will be used primarily for $CO_2$ plume tracking, however, it has a valuable secondary role in surveillance of integrity of the casing and cement sheath. Fluid migration produces distributed thermal (DT) and acoustic signals indicative a need for follow on testing. Calibration of DAS and DT surface instrumentation will be performed following the manufacturer's instructions and reported.

The DAS fiber will also be set up to detect changes in frequency of seismicity. The selected vendor will optimize many parameters, including the fiber selection; installation to assure good acoustic coupling; seismic aperture to cover the maximum plume extent at 40 years; and source type, frequency, and installation to create sufficient detection of plume extent at reservoir depth. This is a sparse array focusing on time lapse and designed to history match the model on selected azimuths.

## 5.0 Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c), GCS will monitor well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance.

GCS will monitor corrosion using coupons and collect samples according to the description below.

### 5.1 Monitoring location and frequency

Analyzing coupons of the well construction materials used in the well casing and tubing (including any other well parts in contact with $CO_2$) and inspecting the materials in the coupons for loss of mass, thickness, cracking, pitting, and other signs of corrosion. Loop and coupon details to be specified as part of pipeline and well design. These tests will be performed by qualified vendor on a quarterly calendar basis starting at the end of the first quarter month (March, June, September, December) following authorization and start-up of injection.

### 5.2 Sample description

GCS anticipates that corrosion coupon (weight loss) technique will be used for monitoring purposes as it is the best known and simplest of all corrosion monitoring techniques (alternative is to use flow line loops). The corrosion monitoring system will be located downstream of all process compression/dehydration/pumping equipment (i.e., at the beginning of the pipeline to the wellhead). This tray of coupons will operate any time injection is occurring. No other equipment will act on the $CO_2$ past the location of the tray; therefore, this location will provide representative exposure of the samples to the $CO_2$ composition, temperature, and pressures that will be seen at the wellhead and injection tubing. The holders and location of the system will be included in the pipeline design and will allow for continuation of injection during sample removal. The coupon method involves exposing a sample of material (coupon) to a process environment for a given duration, then removing the specimen for analysis. Coupons will include materials of construction for all elements in contact with the $CO_2$ stream (Table 1.3). Corrosion analysis will consist of:

1. Sample photography
2. Cleaning
3. Precision weight loss analysis
4. Corrosion rate evaluation
5. Localized corrosion (pitting) analysis

Methods for initial coupon preparation and analysis/evaluation of exposed coupons will follow ASTM G1 - 03(2017) and/or NACE Standard RP0775-2005 Item No. 21017 standards.

**Table 5.1. List of equipment coupon with material of construction.**

| Equipment Coupon | Material of Construction |
|---|---|
| Surface Piping | "As built" material in contact with $CO_2$ |
| Wellhead | Chrome14, or "as built" trim material in contact with $CO_2$ |
| Injection Tubing | Chrome14, or "as built" material in contact with $CO_2$ |
| Packer | Chrome14, or "as built" trim material in contact with $CO_2$ |
| Protection Casing below Packer | Chrome14, or "as built" material in contact with $CO_2$ |

## 5.3 Monitoring details

Per § 146.90, GCS will run a casing inspection log (internal and external) to determine the presence or absence of corrosion in the protection (longstring) casing when the tubing is pulled from the well. The log(s) will be compared to those run during construction of the well (§ 146.87). Additional inspection logging may be performed should the coupons show excessive corrosion in excess of design-life criteria.

Alternative testing other than those listed above may be conducted, with the written approval of the Administrator. To obtain approval for alternative testing, GCS will submit a written request to the Administrator setting forth the proposed test and all technical data supporting its use.

# 6.0 Above Confining Zone Monitoring

GCS will monitor two water-bearing zones in the AoR to meet the requirements of 40 CFR 146.90(d): the lower-most USDW of the Chicot Formation (fresh water) and the part of the Miocene above the Anahuac confining zone (saline water). Leakage detection strategy is different in the two zones, so they are discussed separately.

## 6.1 USDW monitoring in the lower part of the Chicot freshwater aquifer.

Monitoring location and frequency Table 6.1 shows the planned monitoring methods, locations, and frequencies for ground water quality and geochemical monitoring in the freshwater of the lower Chicot aquifer. The well location and sampling depths will be guided by an airborne conductivity and magnetic survey.

**Table 6.1. Monitoring of ground water quality and geochemical changes in the lower Chicot aquifer**

| Target Formation | Monitoring Activity | Monitoring Location(s) | Spatial Coverage | Frequency |
|---|---|---|---|---|
| Entire freshwater aquifer | Airborne conductivity and magnetic survey | Over areas of expected groundwater complexity and historical production >AoR | Flown in a grid to produce spatial coverage, as designed by vendor | Prior to project start, at project end, as needed if brine leakage is suspected. |
| Chicot Aquifer deepest freshwater sand | Groundwater sampling | GW wells 1-2 at injection wells | Over the $CO_2$ plume | Quarterly for 3 years, then once every 5 years or if an incident occurs |
| Chicot Aquifer deepest freshwater sand | Groundwater sampling | GW wells 3-5 | Over the area of elevated pressure or complexity | Quarterly for 3 years, then once every 5 years or if an incident occurs |
| Geochemical Modeling | Modeling of fluid mixing to identify diagnostic parameters | Data from GW wells 1-5 and samples from injection zone (IZ) and Above zone monitoring interval(AZMI) | Applicable for entire freshwater aquifer | Once before end of year 3. Used to validate and optimize groundwater monitoring approach. |
| Chicot Aquifer freshwater sand | Follow on monitoring to incident or anomaly | Near anomaly | Local to anomaly (for example if an existing well fails to isolate the injection zone) | Only as response to anomaly |

The goal of groundwater monitoring is to develop a strategy to detect, of either brine or $CO_2$ leakage from depth into the aquifer, should it occur, using a process known as attribution of signal. This is not simple because many factors are expected to impact groundwater quality in this project area over the coming decades, including change in water levels related to sea level change and climate changes, changes in water production in offsite industrial areas, gradual natural mitigation and dilution of likely past oilfield water contamination events, natural migration of deep basin brines toward the surface in response to basin compaction, change in freshwater chemistry related to salt dissolution at salt domes, and land use changes. The same techniques will be used, if needed, to quantify leakage, assess impacts and validate remediation

Attribution requires:

1. Characterization of injected fluids (described in sections above on Carbon Dioxide Stream Analysis)
2. Characterization of potential deep fluids in the injection zone and overburden that might migrate to the USDW (described below in Above zone monitoring and Injection zone monitoring sections

3. Characterization of the ambient areal and seasonal variability of the USDW (described in this section)
4. Modeling the signal that would allow identification of a mixture of 1 and 2, and separation from naturally driven changes (also described in this section). The same process will support detection of leakage into surface waters and soils, discussed in the ecosystem monitoring section

It is important to collect and analyze components that will be diagnostic, this will depend on the outcomes of initial characterization and monitoring, but Table 6.2 shows the analytes to be evaluated.

**Table 6.2. Summary of analytical and field parameters for near surface ground water samples (USDW), Chicot aquifer (Beaumont Formation)**

| Laboratory Parameters[5] | Analytical Methods | Sensitivity of Method |
|---|---|---|
| Dissolved $CO_2$ gas | Gas Chromatography | +/-2% |
| Dissolved Methane gas | Gas Chromatography | +/-2% |
| Dissolved Hydrocarbons (C1-C5) | Gas Chromatography | +/-5% (C1-C3), 10% C4-C5 |
| Alkalinity | Titration | |
| $\delta C^{13}$ $CO_2$ | Gas Chromatography with dual inlet isotope ratio mass spectrometer | +/- 0.1 ‰. |
| $\delta C^{13}$ Methane | Gas Chromatography with dual inlet isotope ratio mass spectrometer | +/- 0.1 ‰. |
| $C^{14}$ $CO_2$ | Accelerated mass spectrometry (AMS). | +/- 0.4 pMC |
| $C^{14}$ Methane | Accelerated mass spectrometry (AMS). | +/- 0.4 pMC |
| Major elements | | |
| Minor elements including Br, I, Sr | | |
| Isotopic composition of selected major or minor constituents (e.g. Sr $^{87/86}$, S | | |

Note 5 Parameters will be revised based on initial findings and fluid flow modeling.

GCS will contract to have an airborne conductivity survey designed to collect and interpret the conductivity signal to map and quantitatively model the areas of highest salinity at the surface and in the shallow subsurface. A magnetic survey collected at the same time will screen to detect the casings of any miss-located wells. The survey will be designed by a qualified vendor. Data collection should be planned such that a repeat survey can be conducted in 30 years as part of project closure.

Approximately 5 wells will be drilled and completed to sample fresh water in the USDW. A freshwater sampling point will be located at each of the well pads for the injection wells. Three other freshwater wells will be placed at areas of anomaly or leakage concern, based on the

interpretation of the airborne conductivity survey. Well construction will follow Louisiana monitoring well construction requirements. Well elevations will be surveyed. A logging program will be used to set screen over suitable intervals to sample and screen depths recorded. To enhance interpretability, flow zones will not be comingled.

The freshwater wells will be sampled quarterly for three years to detect seasonal variations. For attribution-based detection, pre-injection baseline is not needed. Sample procedures will be optimized to quantify dissolved gases, which includes a flow-through apparatus for collection of intact samples with headspace gas. If wells have free gas (methane is common in groundwater, regionally) sampling will be designed to sample and assess changes in gas production.

Mixing models will be constructed based on integration of the deep fluid composition with the freshwater composition to identify trends and constituents that would be diagnostic of either brine or $CO_2$ leakage into groundwater, should that occur, and be applicable to any location in the AoR or adjacent regions. Modeling will be completed prior to year 3 and will be used to 1) modify and optimize the groundwater program to the parameters that are most diagnostic and 2) design a response program such that if an incident or allegation of leakage of $CO_2$ or brine into groundwater occurs, GCS will be ready to sample, assess and report if leakage has occurred and the volume and area impact of the leakage.

A plan will be written to document the response to incident or allegation in case leakage damages fresh water and be designed to be transparent to stakeholders. The plan will include sampling design at the incident site, laboratory processes, analytical processes, and pathway to attribution of the measurements to leakage or to non-leakage causes. The plan will include remediation and remediation validation plans (for applications of leakage detection).

Following the three-year characterization and response-planning period, the sampling frequency at the eight project water wells will be decreased to every 5 years which is sufficient to identify trends and the list of analytes reduced.

## 6.2 Sampling methods

The sampling system will used to sample and quantify free and dissolved gases and the aqueous phases in equilibrium with theme. Water samples will be collected from groundwater wells according to EPA method SESDPROC-301-R4 - after purging 3 well volumes with a pump, temperature, pH, specific conductivity, dissolved oxygen will be measured in the field. Samples for isotopic analysis of DIC will be collected in 100 ml amber glass bottles with minimized headspace, and 1 drop of biocide (benzalkonium chloride) to eliminate biologic alteration of the sample. Samples will be immediately stored on ice and mailed overnight to a contracted laboratory for analysis of analytes listed in Table 6.2. All samples will be filtered in the field with a 0.45µm filter. Conditions during groundwater sampling will be recorded in the field.

All sample containers will be labeled with durable labels and indelible markings. A unique sample identification number and sampling date will be recorded on the sample containers. The sample container will be sealed and sent to an authorized laboratory.

## 6.3 Laboratory to be used/chain of custody and analysis procedures

Samples will be analyzed by a third party laboratory accredited by the Louisiana Department of Environmental Quality (https://internet.deq.louisiana.gov/portal/divisions/lelap/accredited-laboratories) using standardized procedures for gas, major, minor and trace element compositions. The sample chain-of-custody procedures described in Section 12.3.3 of the QASP will be employed.)

## 6.4 AZMI monitoring in the Miocene above the Anahuac confining system.

Above zone monitoring interval (AZMI) wells will be installed in areas of more abundant penetrations, where concern about isolation of the injection zone is higher-than-average. These can also be repurposed by recompletion of existing wells and fitting them with downhole pressure gauges. IZ and AZMI monitoring points can be co-located or engineered as multi-zone completions, if feasible. A change in water composition is not expected in this zone; and water will be sampled once (including for dissolved and free gases) for characterization purposes.

Monitoring location and frequency Table 6.1 shows the planned monitoring methods, locations, and frequencies for monitoring saline formations in the Miocene Above Zone Monitoring Interval (AZMI) above the Anahuac confining system. Modeling shows that pressure is a more robust and more diagnostic leakage detection method in deep confined saline aquifers. Under typical low flow gradients in saline formations, a $CO_2$ leakage signal is unlikely to propagate far from the leakage point and be chemically undetectable. Leakage of brine from one formation to another is also unlikely to be chemically diagnostic, and if ambient methane or $CO_2$ is present in the system, $CO_2$ may not be chemically diagnostic either. GCS will instead measure bottom hole pressure which can be robustly and continuously measured in confined saline zones in deep wells in the 2 AZMI, wells. Pressure trends indicative of leakage can be readily interpreted. If leakage trends are detected, follow up pressure transient testing, logging or geochemical measurements will be conducted to assess the signal.

A two-well array is proposed above the early-stage AoR and mature-stage plume to assure that neither brine nor $CO_2$ is migrating out of zone.

**Table 6.3. Monitoring the Above Zone Monitoring Interval (AZMI) in the Miocene**

| Target Formation | Monitoring Activity | Monitoring Location(s) | Spatial Coverage | Frequency |
|---|---|---|---|---|
| Miocene | Downhole pressure monitoring | Two deep wells | Over area of review | Real time daily read out. |
| Miocene | Baseline geochemical sampling | Same two deep wells | Over area of review | Once at project start. |
| Miocene | Follow-on testing if signal is observed | Proximal to anomaly | Proximal to anomaly | Only if anomaly is observed |
| Miocene | VSP designed for plume tracking will also detect any fluid substitution in the Miocene | Fiber optic in injection well, azimuthal receiver arrays | Azimuthal coverage of the plumes | Annually |

The goal of AZMI monitoring is to detect either brine or $CO_2$ leakage from depth into this saline zone and, should it occur, to provide a barrier to leakage into the USDW. Pressure is the main tool; and geochemical description is used to augment the leakage detection. The presence of gases ($CO_2$ or hydrocarbons) in the AZMI is the key focus to attribute sources of leakage. Above-zone gas can be a contributor to surface casing vent flow and must be properly attributed to be managed.

The pressure response of each AZMI is measured in idle (no injection and no production) wells in areas within the AoR and near the edge of the $CO_2$ plume footprint (area inside the plume footprint is coved by time lapse VSP). The wells are located where there is predicted to be higher-than-average leakage risk, such as areas with more abundant existing penetrations. Each AZMI well can be combined with the in-zone wells as dual completions or be separate wells. AZMI monitoring wells may be modified from existing wells.

AZMI wells are isolated within the Anahuac by bridge plug or packers. Wells are designed such that sufficient rat hole exists or a suitable screen is installed to prevent sanding-in by poorly consolidated Miocene sandstones. One or more transmissive Miocene sandstones are selected to serve as AZMI. Higher sensitivity to leakage is obtained by selecting sandstones that have larger areal continuity but are thinner. Selected sandstones are designed to be sparsely perforated, with a packer set above the perforations, and completed with downhole pressure gauge on tubing.

One fluid sampling event is planned. It is important to collect and analyze components that will be diagnostic, and this will depend on the outcomes of initial characterization and monitoring. Table 6.2 details the analytes to be evaluated.

**Table 6.4. Summary of analytical and field parameters for fresh ground water samples - Miocene above zone saline aquifer**

| Parameters [6] | Analytical Methods |
|---|---|
| Dissolved $CO_2$ gas by headspace | Gas Chromatography (GC) |
| Dissolved $CH_4$ gas by headspace | Gas Chromatography (GC) |
| Hydrocarbons | Gas Chromatography (GC) |
| Dissolved inorganic carbon | Combustion |
| Bicarbonate | Titration |
| $\delta D\ CH_{24}$ | Gas chromatography combustion isotope ratio mass spectrometry (GC/C/IRMS) |
| $\delta C^{13}\ CO_2$ | Gas chromatography combustion isotope ratio mass spectrometry (GC/C/IRMS) |
| $\delta C^{13}\ CH_4$ | Gas chromatography combustion isotope ratio mass spectrometry (GC/C/IRMS) |
| $C^{14}\ CO_2$ | Accelerated mass spectrometry (AMS). |
| $C^{14}$ Methane | Accelerated mass spectrometry (AMS). |
| Major cations and trace metals including Sr | inductively coupled plasma-optical emission spectrometry (ICP-OES) and inductively coupled plasma-mass spectrometry (ICP-MS) |
| Anions including Br, I, | Ion chromatography |
| Isotopic composition of selected major or minor constituents (e.g., $Sr^{87/86,}$ S) | Multicollector-Inductively Coupled Plasma Mass Spectrometer (MC-ICPMS) |

Note 6 Parameters will be revised based on initial findings

## 6.5 Sampling methods (one-time sample)

The system used to sample and quantify free and dissolved gases and the aqueous phases in equilibrium with these gasses will be supplied by a vendor using a Kuster sampler, or equivalent tool. Deep brine sampling protocols are required, and all gasses (not just hydrocarbons) will be assessed. Workflow includes:

1. Purge the casing volume to bring fresh fluids that have not reacted with casing and tubing to the sample point
2. Deploy commercial downhole sampler on slickline to collect a fluid sample at pressure and then close to retain gas phases as sample is transported to the surface
3. Reduce conserved gas volume samples to atmospheric pressure for shipping and analysis
4. Filter and conserve samples following protocols for brine sampling.

5. Label sample containers with durable labels and indelible markings - a unique sample identification number and sampling date will be recorded on the sample containers.
6. Send sealed sample container to an authorized laboratory.

Repeat sampling is not needed. If an anomalous pressure signal is detected, head spaced gas analysis plus pressure transient testing should be sufficient to detect any $CO_2$ leakage.

### 6.6 Laboratory to be used/chain of custody and analysis procedures

Samples will be analyzed by a third party laboratory accredited by the Louisiana Department of Environmental quality (https://internet.deq.louisiana.gov/portal/divisions/lelap/accredited-laboratories) using standardized procedures for gas, major, minor and trace element compositions.. The sample chain-of-custody procedures described in Section 12.3.3 of the QASP will be employed.)

## 7.0 External Mechanical Integrity Testing (MIT)

GCS will conduct at least one of the tests presented in Table 7.1 periodically during the injection phase to verify external mechanical integrity as required at 146.89(c) and 146.90.

### 7.1 Testing location and frequency

GCS will perform an annual external mechanical integrity log on each injection well. Preferred testing will be performed using a temperature survey. The principal requirement for running temperature logs is that the well be shut in long enough so that temperature effects related to well construction can dissipate, leaving a relatively simple temperature profile. Experience has shown that 36 hours is usually sufficient for the shut-in time period. Temperature survey data will be developed from the optical fiber attached to each injection well protection (longstring) casing.

Should the optical fiber not be functioning, the survey will be performed via a wireline truck and the temperature survey will be run over the entire interval of cemented casing. Note that to be effective, temperature logging tools must have good thermal coupling to the borehole environment, which means that they are not generally useful in gas or air-filled boreholes. Depending on phase of the carbon dioxide in the well, this may require that the wellbore be displaced with water or bine and allowed to thermally stabilize prior to logging. When possible, the sonde will be calibrated to a known temperature. The injection well will be logged from the surface downward, lowering the tool at a rate of no more than 30 feet per minute, which represents a practical balance between the tool response time and normal field time constraints. Note that slower logging speeds provide increasing detail. The temperature log should include both an absolute temperature curve and a differential temperature curve. A correlation log(s) should be recorded in track 1 (such as casing collar locator or gamma ray), and the two temperature curves recorded in tracks 2 and 3. The temperature log should be scaled at or about 20° F (10° C) degrees per track and the differential

curve scaled in any manner appropriate to the logging equipment design, but it must be sensitive enough to readily indicate thermal anomalies.

Testing will be scheduled to be performed on an approximate annual basis, within +/-45 days of the prior years' test. GCS will notify the Director ahead of testing should a testing event fall outside of the +/-45 day window. Should a wireline truck be needed to run the surveys, testing for each well may be consolidated to a common timetable.

Alternate logging will consist of either a tracer survey, such as either a radioactive tracer or oxygen-activation log, or noise log. GCS will notify the Director ahead of testing should an alternate testing method be employed in one or more of the injection wells.

**Table 7.1. Mechanical integrity tests**

| Test Description | Location |
|---|---|
| Temperature Survey | Each Injection Well |
| Temperature Survey | Monitoring Well |

## 7.2 Testing details

Using temperature survey data from the optical fiber attached to each injection well protection (longstring) casing in each injection well is the simplest and preferred testing methodology for the demonstration of external integrity. Data from the optical fiber will be collected starting at cessation of injection and then accrued at increasing time intervals out to approximately 36 hours of shut in. Should the optical fiber not be functioning, the temperature survey will be performed via a wireline truck.

Subsequent temperature surveys will be compared to the baseline and prior surveys in each injection well. Deviations from a predictable geothermal gradient (initial survey) indicate the effects of injection. Within the Frio Formation, deviations will occur in those sands receptive to flow. Deviations above the Anahuac Shale are anomalies. These may take the form of a nearly constant temperature between strata separated over a significant interval. In the case of the optical fiber temperature data, or if more than one log is run from a wireline truck, these anomalies are likely to "grow" as the other parts of the temperature profile returns toward the natural geothermal gradient. In addition, those areas with active flow will reach a stable temperature more quickly than other areas (zones of historical flow).

If there are unresolved temperature anomalies that cannot be explained, a failure of mechanical integrity of the injection well may be indicated. In such a case, additional logging may be necessary to show whether a loss of mechanical integrity is occurring in that injection well. Depending on the nature of the suspected movement, radioactive tracer, noise, oxygen activation, or other logs approved by the Director may be required to further define the nature of the fluid movement. Identification of flow behind the casing is always made from long-term shut-in logs. The resolution

of long-term shut-in logs for identifying the presence of flow is greater than that of logs made during injection. The temperature gradient from top to bottom within a well which has been injecting for some time is very shallow. The temperature at the injection zone may be only a few degrees different from that at the surface. The presence of a flow behind the casing will result in a fractional change in this gradient which will be proportional to the ratio of the flow rates within and outside the tubing. Therefore, only a rather substantial flow can be identified using logs made during injection.

## 8.0 Pressure Fall-Off Testing

GCS will perform pressure fall-off tests during the injection phase as described below to meet the requirements of 40 CFR 146.90(f).

### 8.1 Testing location and frequency

GCS will perform a baseline pressure falloff test using brine or water mixed with a clay stabilizer in each injection well. This will allow for baseline characterization of the transmissibility of the Frio at each injection well. The initial pressure falloff testing will be repeated using carbon dioxide within the first 60 days of injection operations. This will allow for comparison to the baseline test with the change in the injection fluid from brine water to carbon dioxide.

A subsequent pressure falloff test will be performed within +/-45 days of the 2-1/2 year anniversary of the start of carbon dioxide injection and within +/-45 days of the 5 year anniversary of the startup of injection. Thereafter, a pressure falloff test will be performed in each injection well within +/-45 days of each subsequent 5 year anniversary of the previous pressure test throughout the duration of the injection project. A final pressure falloff test will be run at the cessation of injection into each injection well.

### 8.2 Testing details

Testing procedures will follow the methodology detailed in EPA Region 6 UIC Pressure Falloff Testing Guideline-Third Revision (August 8, 2002). Bottomhole pressure measurements near the perforations are preferred due to phase changes within the column of carbon dioxide in the tubing. A surface pressure gauge may also serve as a monitoring tool for tracking the test progress.

The downhole pressure gauge can be either installed as part of the completion or can be deployed via a wireline truck. If a wireline truck deployed gauge is used, the wireline should be corrosion resistant (such as MP-35 line) and the deployed gauges should consist of a surface read-out gauge with a memory backup. Gauge specifications should be as follows or similar to those shown in Table 8.1.

**Table 8.1 Pressure Gauge Information**

| Pressure Gauge | Property | Value |
|---|---|---|
| **Surface Readout Pressure Gauge** | Range<br>Resolution | 0 – 10,000 psi/200 °C<br>+/-0.02 psi/0.005 °C |
| | Accuracy | +/-0.024% of full scale<br>(+/-2.4 psi/+/-0.25 °C) |
| | Manufacturer's Recommended Calibration Frequency | Minimum Annual |
| **Memory Pressure Gauge** | Range<br>Resolution | 0 – 10,000 psi/200 °C<br>+/-0.02 psi/0.005 °C |
| | Accuracy | +/-0.024% of full scale<br>(+/-1.4 psi/0.25 °C) |
| | Manufacturer's Recommended Calibration Frequency | Minimum Annual |

General testing procedure is as follows (presumes that a wireline deployed unit is used for the testing, note that dedicated downhole monitoring gauge may be used if installed on the injection well):

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 hole with SRO to just above the shallowest perforations in the completion while maintaining injection at a constant rate. Steady rates of injection should be maintained for at least 24 hours ahead of the planned shut-in of the injection well. Any offset injection well should 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 closest 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 falloff period. Ensure that valves on flow line to the injection well are closed and locked to prevent flow to the well during the falloff period.
7. After 24 hours, download data and make preliminary field analysis of the falloff 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 falloff test. If additional data is required, extend falloff test until radial flow conditions are confirmed. After confirmation of sufficient data acquisition, end falloff test.

Pull SRO tool up out of the well at 1,000 ft increments and allow the gauge to stabilize (5 minutes each stop). Record stabilized temperature and pressure. Repeat the process to collect stabilized pressure data (5 minute stops) at 1,000 ft intervals and in the lubricator.

## 9.0 Carbon Dioxide Plume and Pressure Front Tracking

GCS will employ direct and indirect methods to track the extent of the carbon dioxide plume and the magnitude of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g).

### 9.1 Plume monitoring location and frequency

Table 6.4 presents the 4-D seismic methods that GCS will use to monitor the position of the $CO_2$ plume. No fluid sampling of the plume in the injection zone is planned.

Quality assurance procedures for these methods are presented in 12.2.4 of the QASP.

### 9.2 Plume monitoring details

Substitution of $CO_2$ for brine in the Frio Formation at project depths is well documented to produce a strong change is acoustic impendence that can be detected by many time lapse seismic methods. Azimuthal 4-D VSP is selected as the optimal geometry, with sparse walk-away type array of acoustic source sites oriented along the maximum and minimum orientations of the modeled plume as it approaches stabilization. In this array type, DAS fiber is installed in cement behind casing, sending signal to an interrogator to detect acoustic signal; signal produced by radial arrays of well-coupled pads (e.g. an excavated pit filled with a cement pad) on which sources can be repeatably bolted. The following considerations lead to selection of this method for plume tracking:

1) Key issue is radial extent of $CO_2$ plume - azimuthal 4-D VSP is ideal for tracking plumes with a radial geometry
2) Prevalence of wetlands in the area precludes use of surface 3-D on grounds of poor access and risk of excessive environmental damage during laying out source arrays.

Also shifting climate could change surface water distribution and therefore source distribution, damaging repeatability.

3) Permanent installations for acoustic sources optimize repeatability, which is critical in time laps tracking
4) The availability and demonstrated effectiveness of DAS fiber as an acoustic receiver favors this type of installation.
5) The same arrays will be used into the PISC period

Vendors will be contracted to design the area and processing flow, install DAS fiber, supply interrogators(s) for both temperature and acoustic signals, design the source arrays including frequency and coupling to assure good signal-to-noise to detect impedance contrast at depth and thickness modeled, and data analysis. Report from azimuthal VSP will be $CO_2$ migration along the selected azimuths. These measurements can be plotted against equivalent model outputs and be used to validate or correct as needed the fluid flow model and plume tracking predictions to satisfy the requirements at 40 CFR 146.90(g).

In addition, the use of fiber will allow very wide aperture of the acoustic array and so include surveillance of Miocene strata above the $CO_2$ plume to provide that no out-of-zone $CO_2$ migration is occurring in this area.

Advanced interpretation of pressure transient testing may be used to acquire complementary information about the $CO_2$ plume geometry. Table 1.10 details the use of VSP as the plume monitoring technology. Table 1.11 affirms that no geochemical methods are deployed for plume tracking.

**Table 9.1. Plume monitoring activities.**

| Target Formation | Monitoring Activity | Monitoring Location(s) | Spatial Coverage | Frequency |
|---|---|---|---|---|
| **PLUME MONITORING USING VSP** | | | | |
| Multiple zones of Frio Formation | VSP | Fiber optic in injection well, azimuthal receiver arrays | Azimuthal coverage of the plumes | Annually |

**Table 9.2. Summary of analytical and field parameters for fluid sampling in the injection zone.**

| Parameters | Analytical Methods |
|---|---|
| **No fluid collection planned in plume** | |

## 9.3 Pressure-front monitoring location and frequency

Table 9.1 presents the well-based methods that GCS will use to monitor the magnitude of pressure change and validate model of the AoR to meet the to meet the requirements of 40 CFR 146.90(g).

These well may be recompletions of suitable existing wells, dual completions with AZMI wells, or stand-alone new drills. Pressure will be measured continuously and reported daily.

One fluid sampling event is planned. The same methods and sampling analytics will be used in both the Frio Formation and Miocene interval (Table 6.2).

## 9.4 Pressure-front monitoring details

Two wells will be sparsely perforated over the major permeable zones of the Frio Formation. A packer will be set above the perforations and completed with downhole pressure gauges on tubing.

Table 1.12 sets forth the primary monitoring activities.

**Table 9.3. Pressure-front monitoring activities.**

| Target Formation | Monitoring Activity | Monitoring Location(s) | Spatial Coverage | Frequency |
|---|---|---|---|---|
| **PRESSURE MONITORING in the Injection zone** | | | | |
| Perforated well in brine-bearing part of AoR | Pressure measurement with downhole gauges | 2 wells outside of $CO_2$ plume area | Pressure is diffusive, sample at representative points | Daily |

## 10.0 Environmental monitoring at the surface

To meet the requirements of 40 CFR 146.90(h), GCS will employ direct sampling and process-based analytical methods such that any brine or $CO_2$ leakage signal in soil or surface water can be quickly and effectively detected and isolated from background. This approach is similar to that proposed for groundwater but adapted to these sampling locations.

The Project Minerva area is expected to be dynamic in terms of $CO_2$ production and uptake from active environments including plant and animal activities, wetland bottom sediments, and intermittently saturation soils. It is also used for grazing and other activities which are likely to change over time. Salinity variations are also present in the area as a result of past oilfield activities and from natural discharge of fluids from depth and around salt domes. Given this high background variation, concentration-based detection methods are unlikely to be able to detect/distinguish Project Minerva-related leakage. We propose an anomaly response program to be deployed on an as-needed basis if an incident or anomaly with possible surface impact occurs.

### *10.1 Environmental surface monitoring location and frequency*

Approximately 10 soil monitoring locations (soil gas wells) and 10 surface water monitoring stations will be sufficient to provide representative samples of the geochemical signatures of ecosystems within the AoR. For 2 years soil gas wells will be sampled seasonally (4 times) and

analyzed for gas $CO_2$, $O_2$, $N_2$, $CH_4$, C1-C5 hydrocarbons, $\delta^{13}C$ and $^{14}C$ of $CO_2$ and $CH_4$ and $\delta D$ of $CH_4$. A similar sampling schedule will be applied to surface water assessment.

Soils will be collected during the installation of soil gas monitoring stations and may also be acquired at additional sites using hand-auger as informed by the conductivity survey. Soils will be tested for salinity according to United States Department of Agriculture methods to identify and characterize background types and occurrences of salinity and devise methods for attributing the source of salinity in the surface environment, whether natural for from industrial sources

At the end of 2 years, protocols for detection of leakage signal will be developed for soil gas, sediments, and surface water, following the same methods as used for groundwater attribution. A process-based method using ratios of $CO_2$, O2, N2, CH4, can be used across all these environments to normalize diurnal and seasonal variations in soil $CO_2$ that result from variations in soil respiration rates, possible because these ratios remain stable with reference to the respiration line. Any composition that plots to the right of the respiration line would require further assessment using isotopes $\delta^{13}C$ and $^{14}C$ of $CO_2$ and $CH_4$ and $\delta D$ of $CH_4$..

## 11.0 Sampling/Analytical Procedures and QA/QC

This section provides details on sampling and analytical procedures and associated QA/QC requirements necessary to ensure valid data are obtained from the primary measurements to be conducted during the test. Details on the methods to be used are listed in Table 11.1.

Gas, water and soil samples will be collected into the appropriate sample containers, properly preserved and shipped to the contract laboratory for compositional analysis with reference to methodologies outlined in Table 6.2, Table 6.4 and Table 11.1.

For all samples collected, general information for each sampling station location will be recorded, including project name, borehole designation, borehole total depth, date and time of completion, borehole GPS location information, and field personnel information.

**Table 11.1 Soil gas parameter and analysis method summary**

| Soil Gas Parameter | Analysis method | Method sensitivity |
|---|---|---|
| $CO_2$, $N_2$, $O_2$, | Gas Chromatography (GC) | +/- 2 %. |
| $CH_4$, $C_2$-$C_4$ | Gas Chromatography (GC) | +/- 5 %. |
| $C_5$-$C_6$ | Gas Chromatography (GC) | +/- 10 %. |
| $\delta^{13}C$ of $CO_2$ | Gas chromatography combustion isotope ratio mass spectrometry (GC/C/IRMS) | +/- 0.3 ‰ |
| $\delta^{13}C$ of $CH_4$ | Gas chromatography combustion isotope ratio mass spectrometry (GC/C/IRMS) | +/- 0.3 ‰. |
| $\delta D$ of $CH_4$ | Gas chromatography combustion isotope ratio mass spectrometry (GC/C/IRMS) | +/- 5 ‰. |
| $^{14}C$ of $CO_2$ | Accelerated mass spectrometry (AMS). | +/- 0.4 pMC |
| $^{14}C$ $CH_4$ | Accelerated mass spectrometry (AMS). | +/- 0.4 pMC |

### *11.1.1 Soil Gas Sampling Station Construction*

Geoprobe, hand auguring, or hollow-stem auger drilling (continuous-flight) by a contracted drilling company will be used to create a borehole for soil gas well installation.8-cm boreholes drilled with a hollow stem auger by a contracted drilling company will be drilled to a depth of 1 to 1.5 meters. Sampling stations will be installed in permeable soil layers and can be sampled for gas analysis whether these depths are saturated or dry using methods outlined in Table 11.2. Sample tubes will be comprised of 3 mm diameter stainless steel tubing fitted at one end with Geoprobe® 15-cm vapor implant screens. Each screen will be fitted to well tubing with Swagelok® gas-tight connectors. Sample depth intervals will be filled with a quartz-sand filter pack placed in the well annulus and isolated with bentonite. The bentonite will be used to backfill between depth intervals assuring the integrity of each sampling interval. Each well will be sealed at the top with a no-flow Swagelok® quick-connect stem which restricts exchange of gas between the gas well and the atmosphere. Gas wells will be protected at ground surface and capped.

General information for each sampling station location will be recorded, including project name, borehole designation, borehole total depth, date and time of completion, borehole GPS location information, and field personnel information.

**Table 11.2 Methodologies for obtaining samples for surface environmental monitoring**

| Sampling Approach | EPA Method(s) | Description |
|---|---|---|
| Soil gas sampling station installation and sampling protocols | LSASDPROC-307-R4 | Specific procedures methods and considerations to be used and observed when installing sampling infrastructure and collecting soil gas samples. |
| Soil pore water sampling for dissolved gases | LSASDPROC-513-R4 SESDPROC-513-R2 | Operating procedure for obtaining a pore water sample from soil or sediment |
| Dissolved gases from water samples. | RSKSOP-175RSKSOP-175-2 | Sample preparation and calculations for dissolved gas analysis in water samples using a GC headspace method |
| Surface water sample collection | SESDPROC-201-R3 | General and specific procedures, methods, and considerations to be used and observed when collecting surface water samples for field screening or laboratory analysis. |
| Soil sampling | LSASDPROC-300-R4 | Specific procedures, methods, and considerations to be used and observed when collecting soil samples for field screening or laboratory analysis. |
| Soil analysis | Corwin, Dennis L., B. A. Stewart, and T. A. Howell. "Soil salinity measurement." *Encyclopedia of Water Science. Marcel Dekker, New York, NY, USA* (2003): 852-860. | USDA method for the measurement of soil salinity and quantification of the total salts present in the liquid portion of the soil. |
| Surface water analysis | Clean Water Act Analytical methods 120.1, 150.2, 300.0, 310.2, 200.2,200.7 and those listed in Table 5. | Approved chemical methods for inorganic non-metals and metals and isotopic analysis. Preservation of samples according to Laboratory Operations and Quality Assurance Manual (ASBLOQAM). |

## 11.2 Sampling/Analytical Procedures and QA/QC

Sediment sample information will be recorded in the field, including the top and bottom depths, the depth from which sediments are sampled, and the drilling system used. Sediment lithology will be described and noted in the field and will be documented with photographs. Sediment splits, approximately 0.5 to 1 kg of sample per 10 cm of core (or another suitable interval based on sediment lithology), will be removed and stored in 500 ml HDPE containers transported to the

contracted laboratory, as warranted. Soils will be analyzed by a contracted laboratory using soil solution extracts at higher than normal water contents. Anions, pH, electrical conductance, (e.g. salinity) +/- other analytes of importance for attribution as informed by the reservoir and groundwater characterization will be analyzed and a plan for attribution of any potential contamination from industrial activities (past or future) will be devised.

## 11.3 Surface water sampling

Surface water is abundant, with freshwater and saltwater coastal marshes, rivers, lakes, bayous, tidal channels, and canals. Surface water will be sampled by either grab samples directly into the collection bottle or through peristaltic pump. Samples will be filtered and preserved according to protocol for each analyte as described in Table 6.2 and Table 11.2. The operating procedure for field sampling quality control (SESDPROC-011) will be followed as well as preservation requirements for surface water samples as outlined in USEPA Region 4 Analytical Support Branch Laboratory Operations and Quality Assurance Manual (ASBLOQAM).

Gas and water samples will be collected into the appropriate sample containers, properly preserved, and shipped to the contract laboratory for compositional analyses with reference to methodologies outlines in Table 11.3.

This section provides details on sampling and analytical procedures and associated QA/QC requirements necessary to ensure valid data are obtained from the primary measurements to be conducted during the test.

**Table 11.3 Gas sampling methods**

| Parameter | Analysis method | Method sensitivity |
|---|---|---|
| $CO_2$, $N_2$, $O_2$, | Gas Chromatography (GC) | +/- 2 %. |
| $CH_4$, $C_2$-$C_4$ | Gas Chromatography (GC) | +/- 5 %. |
| $C_5$-$C_6$ | Gas Chromatography (GC) | +/- 10 %. |
| $\delta^{13}C$ of $CO_2$ | Gas chromatography combustion isotope ratio mass spectrometry (GC/C/IRMS) | +/- 0.3 ‰ |
| $\delta^{13}C$ of $CH_4$ | Gas chromatography combustion isotope ratio mass spectrometry (GC/C/IRMS) | +/- 0.3 ‰. |
| $\delta D$ of $CH_4$ | Gas chromatography combustion isotope ratio mass spectrometry (GC/C/IRMS) | +/- 5 ‰. |
| $^{14}C$ of $CO_2$ | Accelerated mass spectrometry (AMS). | +/- 0.4 pMC |
| $^{14}C$ $CH_4$ | Accelerated mass spectrometry (AMS). | +/- 0.4 pMC |

## 11.4 Quality Assurance and Surveillance Plan

Quality assurance procedures for these methods are presented in 12.2.4 of the QASP.

## 11.5 Environmental surface monitoring Quality Management

To satisfy the project objectives, the quality and transparency data collection, data analysis, and reporting will be managed at each stage.

## 11.6 Data Review and Validation

Data will be reviewed by the project operator or designee on an ongoing basis as the data are collected in the field and as results are received from the laboratory. Data review will consist of (for example):

- Verifying that data collection and calibrations/QC checks are complete and fully documented
- Examining raw data values and trends for consistency and reasonableness
- Making comparisons between related measured parameters and calculated values for agreement within reasonable expectations
- Flagging incomplete, invalid, or suspect data and documenting the reason for the flag
- Initiating investigative or corrective actions as needed.

All valid data will be included in the data analysis and reflected in the reported results. Suspect data may or may not be considered or may receive special treatment as will be specifically indicated. The impact on data quality of any problems or issues that arise will be fully assessed, documented, and reported. Any limitations on the use of the resulting data will be fully assessed and reported.

## 11.7 Sample Handling and Custody

### *11.7.1 Chain-of-Custody (COC)*

Proper sample handling and custody procedures ensure the custody and integrity of samples beginning at the time of sampling and continuing through transport, sample receipt, preparation, and analysis. The COC [QASP Section 12.3.3] is used to document sample handling during transfer from the field to the laboratory. The sample number, location, date, changes in possession and other pertinent data will be recorded in indelible ink on the form. The sample collector will sign the COC and transport it with the sample to the laboratory. At the laboratory, samples are inventoried against the accompanying COC. Any discrepancies will be noted at that time and the COC will be signed for acceptance of custody.

### *11.7.2 Sample Handling and Labeling*

Samples will be labeled on the container with an indelible, waterproof marker. Label information will include site identification, date, sampler's initials, and time of sampling. The COC form will accompany all sets of sample containers.

Following collection, samples will be preserved and transported to the appropriate analytical laboratory for analysis under the conditions designated by the method handling criteria outlined in methods shown in Table 11.2 until analysis.

### *11.8 Audits, Quality Assessment and Response Action*

The technical systems audit is intended to ensure that the sampling, data collection and analysis, QA/QC measures, and documentation are executed in accordance with this plan and that the quality impact of any deviations from the plan is fully assessed and documented. To this end, the internal reviewer will prepare an audit checklist including all key elements of this plan and, to the extent possible, systematically verify in the field that each key element is conducted according to plan.

The audit of data quality will consist of verifying that reported results are fully supported by the data collected and traceable back to their sources in the raw data. Additionally, it must be verified that all required QA/QC is complete and documented for each data source, and that calculations are correct and results and uncertainties correctly reported.

### *11.9 Data Management and Records*

GCS will be responsible for ensuring that all electronic and hard copy data, forms, and logs are accounted for, properly completed, and stored in project files.

The level of documentation will be such that a third party may reproduce the results from the raw data. This requires that all necessary information be documented, and that the documents are organized and maintained such that the information may be practically retrieved and made use of.

Documentation will consist of instrument and other digital files, hard copy field log sheets, calibration certificates, laboratory reports, etc. All documents will ultimately be stored in electronic form; however, hard copy log sheets will be retained on file. An electronic data package will be compiled containing project documentation sufficient to allow a third party to reproduce the results and organized in such a manner that this may be done without undue effort.

### *11.10 Management of Change*

Changes or deviations from this plan may be necessitated by field conditions, unexpected events, observations, or opportunities to improve the results as determined by the project operator. In such events, the reason for the change, and the new measures implemented will be documented in a note to the project log (if the change is minor) or deviations memorandum. This will include an assessment of the impact of the change on data quality. Verification of this will be part of the internal field and data audits.

Comprehensive deviations memorandum will be prepared including an overall assessment of all changes on data quality. Any new or revised procedures will be documented. Significant deviations and their impact on data quality will also be addressed in the final report.

# 12.0 APPENDICES

## 12.1 APPENDIX 1: Class VI Injection Well: Quality Assurance and Surveillance Plan

## 12.2 Project Management

### *12.2.1 A.1. Project/Task Organization*

#### *12.2.1.1 A.1.a/b. Key Individuals and Responsibilities*

The Minerva Project is led by Gulf Coast Sequestration (GCS) and includes participation from several subcontractors. The Testing and Monitoring Activities responsibilities will be shared between GCS and their designated subcontractors and conducted in the following subcategories:

I) $CO_2$ Stream Analysis Surface Sampling
II) Continuous recording of operational parameters
III) Corrosion monitoring
IV) Above Confining zone monitoring
IV) External Mechanical Integrity Testing (MIT)
V) Pressure fall-off testing
VI) Carbon Dioxide plume and Pressure from tracking
VII) Environmental monitoring at the Surface

#### *12.2.1.2 A.1.c. Independence from Project QA Manager and Data Gathering*

The majority of the physical samples collected, and data gathered as part of the MVA program is analyzed, processed, or witnessed by third parties independent and outside of the project management structure.

#### *12.2.1.3 A.1.d. QA Project Plan Responsibility*

GCS will be responsible for maintaining and distributing official, approved QA Project Plan. GCS will periodically review this QASP and consult with US EPA if/when changes to the plan are warranted.

#### *12.2.1.4 A.1.e. Organizational Chart for Key Project Personnel*

Figure 12.1 shows the organization structure of the project. GCS will provide to the UIC Program Director a contact list of individuals fulfilling these roles.

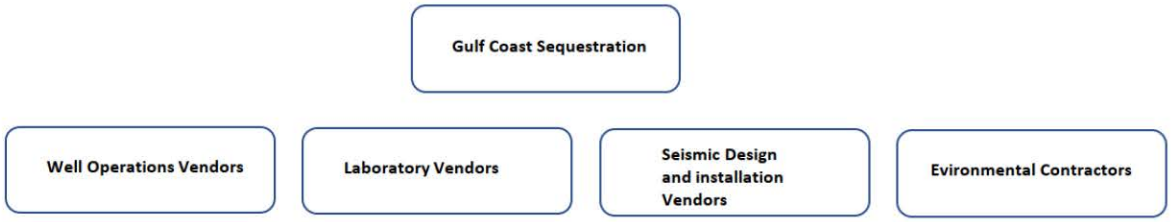


**Figure 12.1 GCS Organization**

### *12.2.2 A.2. Problem Definition/Background*

#### *12.2.2.1 A.2.a. Reasoning*

The M&T program is responsive to the requirements of the Class VI specifications and employs best practices developed in similar $CO_2$ storage projects.

#### *12.2.2.2 A.2.b. Reasons for Initiating the Project*

The M&T project goals are to comply with the Class VI protocols, to document via targeted data collection that the predictions made during characterization and modeling are correct and that $CO_2$ and brine in the injection zone will be isolated from USDW, surface and atmosphere.

#### *12.2.2.3A.2.c. Regulatory Information, Applicable Criteria, Action Limits*

The Class VI Rule requires owners or operators of Class VI wells to perform several types of activities during the lifetime of the project in order to ensure that the injection well maintains its mechanical integrity, that fluid migration and the extent of pressure elevation are within the limits described in the permit application, and that USDWs are not endangered. These monitoring activities include mechanical integrity tests (MITs), injection well testing during operation, monitoring of ground water quality, tracking of the $CO_2$ plume and associated pressure. This document details both the measurements that will be taken as well as the steps to ensure that the quality of all the data can be used with confidence in making decisions during the life of the project.

### *12.2.3 A.3. Project/Task Description*

#### *12.2.3.1 A.3.a/b. Summary of Work to be Performed*

Table 12.1 Summary of Testing and Monitoring describes the Testing and Monitoring tasks, responsible parties, locations and testing frequency.

**Table 12.1 Summary of Testing and Monitoring**

| Activity | Location(s) | Method | Analytical Technique | Lab/Custody | Purpose |
|---|---|---|---|---|---|
| Carbon dioxide stream analysis | Central sampling point | High pressure vessel | Standard gas analysis at lab | As provided by lab | Monitor injectate for accounting |
| Injection mass | Central sampling point | Mass flow meter, | Mass Measurement | NA | Measurement of $CO_2$ mass delivered to site |
| Volume in each well | Distributed meters at injection wells | distributed temperature – corrected meters at wells | Volume measurements | NA | Volume of $CO_2$ distributed to each well |
| Injection pressure | Wellhead gauge each injection well | Pressure and temperature gauge | Direct measurement | NA | Surface pressure on tubing |
| Annular pressure | Wellhead gauge each injection well | Pressure and temperature gauge | Direct measurement | NA | Surface pressure on tubing |
| Downhole pressure/ temperature | Downhole gauge on wireline each injection well | Downhole pressure and temperature gauge | Direct measurement | NA | Pressure downhole near sand face injection zone |
| Wireline logging | Conducted at each injection well | Injection profile log | Provided by vendor | NA | Model input showing which zones are accepting $CO_2$. |
| Corrosion monitoring | Holder at each injection well | Weight loss | ASTM G1 - 03(2017) and/or NACE Standard RP0775-2005 Item No. 21017 standards | As provided by lab | Monitor corrosion |

| Activity | Location(s) | Method | Analytical Technique | Lab/Custody | Purpose |
|---|---|---|---|---|---|
| Chicot water sampling | 8 selected freshwater wells | Water sampling with intact gas | Laboratory analysis | As provided by lab | Document groundwater chemistry |
| Pressure monitoring in Miocene Above-zone monitoring interval | 2 selected wells | Downhole pressure and temperature gauge, perforated in Miocene interval (s) | Direct measurement | NA | Pressure downhole above confining system |
| External Mechanical integrity | Each injection well | Temperature survey | Analysis of thermal anomaly | NA | Detect leakage in casing |
| Pressure fall-off testing | Each injection well | EPA Region 6 UIC Pressure Falloff Testing Guideline-Third Revision (August 8, 2002) | EPA Region 6 UIC Pressure Falloff Testing Guideline-Third Revision (August 8, 2002) | NA | Assess injectivity |
| In-zone pressure tracking | 2 selected wells | Downhole pressure and temperature gauge, perforated in Frio interval (s) | Direct measurement | NA | P In-zone pressure tracking |
| $CO_2$ plume tracking | Fiber in wells, sources on azimuths | Vertical seismic profile (VSP) | VSP | NA | $CO_2$ plume tracking |
| Environmental monitoring | Selected sites in AoR | Soil gas and surface water sampling | GC and laboratory analysis | As provided by lab | Environmental monitoring |

**Table 12.2 Instrumentation Summary**

| Monitoring Location | Instrument Type | Monitoring Target (Formation or Other) | Data Collection Location(s) | Explanation |
|---|---|---|---|---|
| $CO_2$ Central $CO_2$ handling | Mass flow meter | Monitor injectate for accounting | SCADA | Mass and density are basic surveillance techniques |
| | Sampling port | Monitor injectate for accounting | Via lab | Identify unacceptable impurities, $CO_2$ accounting |
| Injection Wells 1,2,3, 4 | Temperature corrected volume meter | Monitor injectate for each well | SCADA | For input to models |
| | Wellhead pressure gauge on tubing | Safely and compliance | SCADA | Safely and compliance |
| | Wellhead pressure gauge on annulus | Safely and compliance | SCADA | Safely and compliance |
| | Downhole pressure and temperature gauge | Frio | SCADA | For input to models |

| Monitoring Location | Instrument Type | Monitoring Target (Formation or Other) | Data Collection Location(s) | Explanation |
|---|---|---|---|---|
| | Fiber optic DAS and DT | Whole section | Dedicated server, designed as part of VSP array | $CO_2$ plume tracking, well integrity |
| In-zone monitoring Wells 1 and 2 | Well corrosion management program | Prevent corrosion | | Prevent corrosion |
| | Wellhead pressure gauge on tubing | Safely and compliance | SCADA | Safely and compliance |
| | Downhole pressure and temperature gauge | Frio | SCADA | For input to models |
| AZMI monitoring Wells 1 and 2 [Insert Other location] | Well corrosion management program | Prevent corrosion | | Prevent corrosion |
| | Wellhead pressure gauge on tubing | Safely and compliance | SCADA | Safely and compliance |

| Monitoring Location | Instrument Type | Monitoring Target (Formation or Other) | Data Collection Location(s) | Explanation |
|---|---|---|---|---|
| | Downhole pressure and temperature gauge | Miocene | SCADA | To show no out of zone fluid loss |
| VSP walk-way source stations | Stable platform for source relocation | Whole section | Dedicated server, designed as part of VSP array | Sources of VSP |
| Groundwater wells | Relocatable pump and groundwater level monitoring system | Chicot Aquifer | Environmental data storage | Installed system or relocated to each of the wells |
| Soil and surface water sampling locations | Shallow wells or marked sample points | Near surface water and gas | Environmental data storage | Details designed by at next stage of project development |

#### *12.2.3.2A.3.c. Geographic Locations*

See Figure 2.1.

#### *12.2.3.3A.3.d. Resource and Time Constraints*

No additional resource or time constraints have been identified for the testing and monitoring plan beyond project funding levels and the proposed timeline.

### *12.2.4 A.4.Quality Objectives and Criteria*

The objective of the Quality Assurance Plan is to validate the necessary steps and attention to detail to ensure that the overall integrity of the Testing and Monitoring Plan is implemented, measured and verified. The QASP is the mechanism by which the UIC Program Director and by extension the public has confidence that the rigor of the Testing and Monitoring Plan is being implemented.

#### *12.2.4.1A.4.a. Performance/Measurement Criteria*

To be completed as vendor selection and onboarding is advanced and relevant scope of works are adopted and implemented.

**Table 12.3 Summary of Analytical Parameters for $CO_2$ Stream**

| Parameters | Analytical Methods[1] | Detection Limit/Range | Typical Precisions | QC Requirements |
|---|---|---|---|---|
| **Carbon Dioxide ($CO_2$)** | ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID)<br>GC/TCD | Note 2 | Note 2 | Note 2 |
| **Water ($H_2O$)** | | Note 2 | Note 2 | Note 2 |
| **Oxygen ($O_2$)** | ISBT 4.0(GC/DID)<br>GC/TCD | Note 2 | Note 2 | Note 2 |
| **Nitrogen ($N_2$)** | ISBT 4.0(GC/DID)<br>GC/TCD | Note 2 | Note 2 | Note 2 |
| **Hydrogen Sulfide ($H_2S$)** | ISBT 14.0 (GC/SCD) | Note 2 | Note 2 | Note 2 |
| **Argon (Ar)** | | Note 2 | Note 2 | Note 2 |
| **Sulfur dioxide ($SO_2$)** | ISBT 10.1 GC/FID) | Note 2 | Note 2 | Note 2 |
| **Methane ($CH_4$)** | ISBT 10.1 GC/FID) | Note 2 | Note 2 | Note 2 |
| **Total hydrocarbons (C2H6, C3H8+)** | ISBT 10.0 THA (FID) | Note 2 | Note 2 | Note 2 |
| **Hydrogen ($H_2$)** | | Note 2 | Note 2 | Note 2 |

| | | | | |
|---|---|---|---|---|
| **Carbon Monoxide (CO)** | ISBT 5.0 Colorimetric<br>ISBT 4.0(GC/DID | Note 2 | Note 2 | Note 2 |
| **COS** | | Note 2 | Note 2 | Note 2 |
| **Nitrogen Oxides (any ($NO_x$)** | ISBT 7.0 Colorimetric | Note 2 | Note 2 | Note 2 |
| **Glycol** | | Note 2 | Note 2 | Note 2 |

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.
Note 2. These details to be negotiated with the selected lab (s).

**Table 12.4 Mass Flow Rate Field Gauge—$CO_2$ Mass Flow Rate.**

| Parameter | Value |
|---|---|
| Calibrated working flow rate range | Note 3 |
| Initial mass flow rate accuracy | Note 3 |
| Mass flow rate resolution | Note 3 |
| Mass flow rate drift stability | Note 3 |

Note 3. These data to be negotiated with the mass flow meter vendor.

**Table 12.5 Volume Flow Rate at each well pad**

| Parameter | Value |
|---|---|
| Calibrated working flow rate range | Note 3 |
| Initial volume flow rate accuracy | Note 3 |
| Volume flow rate resolution | Note 3 |
| Volume flow rate drift stability | Note 3 |

Note 3. These data to be negotiated during the volume flow meter vendor selection and well engineering design

**Table 12.6 Summary of Measurement Parameters for Field Gauges.**

| Parameters | Methods | Detection Limit/Range | Typical Precisions | QC Requirements |
|---|---|---|---|---|
| Injection tubing temperature | Direct measurement | Note 4 | Note 4 | Note 4 |
| Annulus pressure | Direct measurement | Note 4 | Note 4 | Note 4 |
| Injection tubing pressure | Direct measurement | Note 4 | Note 4 | Note 4 |
| Wellhead pressure | Direct measurement | Note 4 | Note 4 | Note 4 |
| Downhole temperature | Direct measurement | Note 4 | Note 4 | Note 4 |
| Injection mass flow rate | Direct measurement | Note 4 | Note 4 | Note 4 |

Note 4. These data to be negotiated during the volume flow meter vendor **selection** and well engineering design

**Table 12.7 Actionable Testing and Monitoring Outputs**

| Activity or Parameter | Project Action Limit | Detection Limit | Anticipated Reading |
|---|---|---|---|
| External mechanical integrity via temperature anomaly | Thermal anomaly is the standard method of leakage detection; observe change in response between normal and shut-in operation | Note 5 | Note 5 |
| Internal mechanical integrity | Note 5 | Note 5 | Note 5 |
| Surface pressure | Pressure approaching permitted limit | Note 5 | Note 5 |

| Activity or Parameter | Project Action Limit | Detection Limit | Anticipated Reading |
|---|---|---|---|
| Downhole pressure | Pressure approaching permitted limit | Note 5 | Note 5 |
| Groundwater or environmental parameters | Note 6 | Note 6 | Note 6 |
| Above-confining-zone pressure Miocene | Note 6 | Note 5 | Note 5 |
| Mismatch between modeled and observed IZ pressure response | Note 7 | Note 5 | Note 5 |
| Mismatch between modeled and observed plume migration | Note 7 | Note 5 | Note 5 |

Note 5. These data to be negotiated during the well engineering design, after assessment of available instruments.

Note 6. The methodology for anomaly detection and attribution requires data collection over several years to identify natural and spatial variation and comparison to deep fluid compositions to identify a leakage signal. This will be added to the monitoring plan and used to follow up incident or allegation to attribute signal.

Note 7: Actual mismatch between modeled and observed IZ pressure response or plume tracking depends on recalibration of the model with new data, followed by a forward mode to determine if any unacceptable outcomes result from the new production of pressure and plume evolution.

#### *12.2.4.2 A.4.b. Precision*

Precision will be determined because of negotiation with selected vendors and contractors.

#### *12.2.4.3 A.4.c. Bias*

Laboratory assessment of analytical bias will be the responsibility of the individual laboratories per their standard operating procedures and analytical methodologies. For direct pressure or logging measurements, there is no bias.

#### *12.2.4.4 A.4.d. Representativeness*

For groundwater sampling, data representativeness expresses the degree to which data accurately and precisely represents a characteristic of a population, parameter variations at a sampling point, a process condition, or an environmental condition. The sampling network has been designed to provide data representative of site conditions. For analytical results of individual groundwater samples representativeness will be estimated by ion and mass balances. Ion balances with ±10%

error or less will be considered valid. Mass balance assessment will be used in cases where the ion balance is greater than ±10% to help determine the source of error. For a sample and its duplicate, if the relative percent difference is greater than 10%, the sample may be considered non-representative.

### *12.2.4.5A.4.e. Completeness*

For groundwater sampling, data completeness is a measure of the amount of valid data obtained from a measurement system compared to the amount that was expected to be obtained under normal conditions. It is anticipated that data completeness of 90% for groundwater sampling will be acceptable to meet monitoring goals. For direct pressure and temperature measurements, it is expected that data will be recorded no less than 90% of the time.

### *12.2.4.6A.4.f. Comparability*

Data comparability expresses the confidence with which one data set can be compared to another. The data sets to be generated by this project will be very comparable to future data sets because of the use of standard methods and the level of QA/QC effort.

Direct pressure, temperature, and logging measurements will be directly comparable to previously obtained data.

### *12.2.4.7A.4.g. Method Sensitivity*

To be discussed with the UIC Program Director post draft approval of the Testing and Monitoring Plan

**Table 12.8 Pressure and Temperature—Downhole Gauge Specifications**

| Parameter | Value |
|---|---|
| Calibrated working pressure range | |
| Initial pressure accuracy | |
| Pressure resolution | |
| Pressure drift stability | |
| Calibrated working temperature range | |
| Initial temperature accuracy | |
| Temperature resolution | |
| Temperature drift stability | |
| Max temperature | |
| Instrument calibration frequency | |

**Table 12.9 Representative Logging Tool Specifications**

| Parameter | [Insert Tool #1] | [Insert Tool #2] | [Insert Tool #3] | [Insert Tool #4] |
|---|---|---|---|---|
| Logging speed | | | | |
| Vertical resolution | | | | |
| Investigation | | | | |
| Temperature rating | | | | |
| Pressure rating | | | | |

**Table 12.10 Pressure Field Gauge.**

| Parameter | Value |
|---|---|
| Calibrated working pressure range | |
| Initial pressure accuracy | |
| Pressure resolution | |
| Pressure drift stability | |

**Table 12.11 Pressure Field Gauge—Injection Tubing Pressure**

| Parameter | Value |
|---|---|
| Calibrated working pressure range | |
| Initial pressure accuracy | |
| Pressure resolution | |
| Pressure drift stability | |

**Table 12.12 Pressure Field Gauge—Annulus Pressure.**

| Parameter | Value |
|---|---|
| Calibrated working pressure range | |
| Initial pressure accuracy | |
| Pressure resolution | |
| Pressure drift stability | |

**Table 12.13 Temperature Field Gauge—Injection Tubing Temperature.**

| Parameter | Value |
|---|---|
| Calibrated working temperature range | |
| Initial temperature accuracy | |
| Temperature resolution | |
| Temperature drift stability | |

**Table 12.14 Summary of Analytical Parameters for Corrosion Coupons**

| Parameters | Analytical Methods | Detection Limit/Range | Typical Precisions | QC Requirements |
|---|---|---|---|---|
| Mass | | | | |
| [Insert Other parameter] | | | | |

**Table 12.15 Summary of Analytical and Field Parameters for Fluid Samples in Frio and Miocene**

| Parameters | Analytical Methods(1) | Detection Limit/Range | Typical Precisions | QC Requirements |
|---|---|---|---|---|
| Cations:<br>[List specific cations] | | | | |
| Anions:<br>[List specific anions] | | | | |
| Dissolved $CO_2$ | | | | |
| Total dissolved solids | | | | |
| Alkalinity | | | | |
| pH | | | | |
| Specific conductance | | | | |
| Temperature (at bottom hole) | | | | |

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

**Table 12.16 Summary of Analytical and Field Parameters for Fluid Samples in Chicot aquifer**

| Parameters | Analytical Methods(1) | Detection Limit/Range | Typical Precisions | QC Requirements |
|---|---|---|---|---|
| Cations:<br>[List specific cations] | | | | |
| Anions:<br>[List specific anions] | | | | |
| Dissolved $CO_2$ | | | | |
| Total dissolved solids | | | | |
| Alkalinity | | | | |
| pH (field) | | | | |
| Specific conductance (field) | | | | |
| Temperature (field) | | | | |

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

**Table 12.17 Summary of Analytical and Field Parameters for Fluid Samples in soil gas**

| Parameters | Analytical Methods(1) | Detection Limit/Range | Typical Precisions | QC Requirements |
|---|---|---|---|---|
| Cations:<br>[List specific cations] | | | | |
| Anions:<br>[List specific anions] | | | | |
| Dissolved $CO_2$ | | | | |
| Total dissolved solids | | | | |
| Alkalinity | | | | |
| pH (field) | | | | |
| Specific conductance (field) | | | | |
| Temperature (field) | | | | |
| [Insert Other parameter] | | | | |
| [Insert Other parameter] | | | | |
| [Insert Other parameter] | | | | |

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

**Table 12.18 Summary of Analytical and Field Parameters for Fluid Samples in Surface water**

| Parameters | Analytical Methods(1) | Detection Limit/Range | Typical Precisions | QC Requirements |
|---|---|---|---|---|
| Cations:<br>[List specific cations] | | | | |
| Anions:<br>[List specific anions] | | | | |
| Dissolved $CO_2$ | | | | |
| Total dissolved solids | | | | |
| Alkalinity | | | | |
| pH (field) | | | | |
| Specific conductance (field) | | | | |
| Temperature (field) | | | | |

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

#### *12.2.5 A.5. Special Training/Certifications*

##### *12.2.5.1A.5.a. Specialized Training and Certifications*

The geophysical survey equipment and wireline logging tools will be operated by trained, qualified, and certified personnel, with documentation provided by the vendor. The subsequent data will be processed and analyzed according to industry standards environmental sampling will be conducted by qualified technicians who meet Louisiana requirements.

##### *12.2.5.2A.5.b/c. Training Provider and Responsibility*

Training for personnel will be provided by the operator or by the subcontractor responsible for the data collection activity.

#### *12.2.6 A.6. Documentation and Records*

##### *12.2.6.1A.6.a. Report Format and Package Information*

Reporting at the required frequency will contain all required project data, including testing and monitoring information as specified by the UIC Class VI permit. Data will be provided in electronic or other formats as required by the UIC Program Director.

##### *12.2.6.2A.6.b. Other Project Documents, Records, and Electronic Files*

Other documents, records, and electronic files such as well logs, test results, or other data will be provided as required by the UIC Program Director.

##### *12.2.6.3A.6.c/d. Data Storage and Duration*

GCS designated contractor will maintain the required project data as provided elsewhere in the permit.

##### *12.2.6.4A.6.e. QASP Distribution Responsibility*

GCS will be responsible for ensuring that all those on the distribution list will receive the most current copy of the approved Quality Assurance and Surveillance Plan.

### 12.3 <u>B. Data Generation and Acquisition</u>

#### *12.3.1 B.1. Sampling Process Design*

##### *12.3.1.1 B.1.a. Design Strategy*

*12.3.1.1.1 $CO_2$ Stream Monitoring Strategy*

To be updated when dedicated streams of $CO_2$ have been identified and contracted for Project Minerva.

*12.3.1.1.2 Corrosion Monitoring Strategy*

To be updated when dedicated streams of $CO_2$ have been identified and contracted for Project Minerva.

*12.3.1.1.3 Shallow Groundwater Monitoring Strategy*

To be updated when dedicated streams of $CO_2$ have been identified and contracted for Project Minerva.

*12.3.1.1.4 Deep Pressure Monitoring Strategy*

To be updated when dedicated streams of $CO_2$ have been identified and contracted for Project Minerva.

### *12.3.1.2 B.1.b. Type and Number of Samples/Test Runs*

To be updated when UIC Program Director has approved draft permit for Project Minerva.

### *12.3.1.3 B.1.c. Site/Sampling Locations*

To be updated when UIC Program Director has approved draft permit for Project Minerva.

### *12.3.1.4 B.1.d. Sampling Site Contingency*

To be updated when UIC Program Director has approved draft permit for Project Minerva.

### *12.3.1.5 B.1.e. Activity Schedule*

To be updated when UIC Program Director has approved draft permit for Project Minerva.

### *12.3.1.6 B.1.f. Critical/Informational Data*

To be updated when UIC Program Director has approved draft permit for Project Minerva.

B.1.g. Sources of Variability

To be updated when UIC Program Director has approved draft permit for Project Minerva.

### *12.3.2 B.2. Sampling Methods*

### *12.3.2.1 B.2.a/b. Sampling SOPs*

This element will be negotiated with selected geochemical labs

**.Table 17, Stabilization Criteria of Water Quality Parameters During Shallow Well Purging.**

This element will be negotiated with selected geochemical labs

| Field Parameter | Stabilization Criteria |
|---|---|
| pH | |
| Temperature | |
| Specific conductance | |
| Dissolved oxygen | |
| Turbidity | |

#### *12.3.2.2 B.2.c. In-situ Monitoring*

This element will be negotiated with selected geochemical labs

#### *12.3.2.3 B.2.d. Continuous Monitoring*

This element will be negotiated with selected geochemical labs

#### *12.3.2.4 B.2.e. Sample Homogenization, Composition, Filtration*

This element will be negotiated with selected geochemical labs

#### *12.3.2.5 B.2.f. Sample Containers and Volumes*

This element will be negotiated with selected geochemical labs

#### *12.3.2.6 B.2.g. Sample Preservation*

This element will be negotiated with selected geochemical labs

#### *12.3.2.7 B.2.h. Cleaning/Decontamination of Sampling Equipment*

This element will be negotiated with selected geochemical labs

#### *12.3.2.8 B.2.i. Support Facilities*

This element will be negotiated with selected geochemical labs

#### *12.3.2.9 B.2.j. Corrective Action, Personnel, and Documentation*

This is described in section D below

### *12.3.3 B.3. Sample Handling and Custody*

#### *12.3.3.1 B.3.a. Maximum Hold Time/Time Before Retrieval*

This element will be negotiated with selected geochemical labs

#### *12.3.3.2 B.3.b. Sample Transportation*

This element will be negotiated with selected geochemical labs

#### *12.3.3.3 B.3.c. Sampling Documentation*

This element will be negotiated with selected geochemical labs

#### *12.3.3.4 B.3.d. Sample Identification*

This element will be negotiated with selected geochemical labs

**Table 12.19 Summary of Sample Containers, Preservation Treatments, and Holding Times for $CO_2$ Gas Stream Analysis.**

| Sample | Volume/Container Material | Preservation Technique | Sample Holding time (ma |
|---|---|---|---|
| $CO_2$ gas stream | | | |

**Table 12.20 Summary of Anticipated Sample Containers, Preservation Treatments, and Holding Times for Ground Water Samples**

| Target Parameters | Volume/Container Material | Preservation Technique | Sample Holding Time |
|---|---|---|---|
| Cations:<br>[List specific cations] | | | |
| Anions:<br>[List specific anions] | | | |
| Dissolved $CO_2$ | | | |
| Isotopes:<br>[List specific isotopes] | | | |
| Alkalinity | | | |
| Field Confirmation:<br>[List specific parameters] | | | |

#### *12.3.3.5 B.3.e. Sample Chain-of-Custody*

This element will be supplied by the selected geochemical labs

### *12.3.4 B.4. Analytical Methods*

#### *12.3.4.1 B.4.a. Analytical SOPs*

This element will be negotiated with selected geochemical labs

#### 12.3.4.2 B.4.b. Equipment/Instrumentation Needed

This element will be negotiated with selected geochemical labs

#### 12.3.4.3 B.4.c. Method Performance Criteria

This element will be negotiated with selected geochemical labs

#### 12.3.4.4 B.4.d. Analytical Failure

This element will be negotiated with selected geochemical labs

#### 12.3.4.5 B.4.e. Sample Disposal

This element will be negotiated with selected geochemical labs

#### 12.3.4.6 B.4.f. Laboratory Turnaround

This element will be negotiated with selected geochemical labs

#### 12.3.4.7 B.4.g. Method Validation for Nonstandard Methods

This element will be negotiated with selected geochemical labs

### *12.3.5 B.5. Quality Control*

#### 12.3.5.1 B.5.a. QC activities

##### *12.3.5.1.1 Blanks*

This element will be negotiated with selected geochemical labs

##### *12.3.5.1.2 Duplicates*

This element will be negotiated with selected geochemical labs

#### 12.3.5.2 B.5.b. Exceeding Control Limits

This element will be negotiated with selected geochemical labs

#### 12.3.5.3 B.5.c. Calculating Applicable QC Statistics

##### *12.3.5.3.1 Charge Balance*

This element will be negotiated with selected geochemical labs

##### *12.3.5.3.2 Mass Balance*

This element will be negotiated with selected geochemical labs

##### *12.3.5.3.3 Outliers*

GCS or designated vendor is responsible for assessment and documentation of outliers

#### *12.3.6 B.6. Instrument/Equipment Testing, Inspection, and Maintenance*

Element is deferred until design is advanced vendors selection

#### *12.3.7 B.7. Instrument/Equipment Calibration and Frequency*

##### *12.3.7.1 B.7.a. Calibration and Frequency of Calibration*

Element is deferred until design is advanced vendors selection

##### *12.3.7.2 B.7.b. Calibration Methodology*

Element is deferred until design is advanced vendors selection

##### *12.3.7.3 B.7.c. Calibration Resolution and Documentation*

Element is deferred until design is advanced vendors selection

#### *12.3.8 B.8. Inspection/Acceptance for Supplies and Consumables*

#### *12.3.9 B.8.a/b. Supplies, Consumables, and Responsibilities*

This design is deferred until the Testing and Monitoring Plan draft has been approved by the UIC Director.

#### *12.3.10 B.9. Non-direct Measurements*

##### *12.3.10.1 B.9.a. Data Sources*

Element is deferred until design is advanced vendors selection

##### *12.3.10.2 B.9.b. Relevance to Project*

Element is deferred until design is advanced vendors selection

##### *12.3.10.3 B.9.c. Acceptance Criteria*

Element is deferred until design is advanced vendors selection

##### *12.3.10.4 B.9.d. Resources/Facilities Needed*

Element is deferred until design is advanced vendors selection

##### *12.3.10.5 B.9.e. Validity Limits and Operating Conditions*

Element is deferred until design is advanced vendors selection

#### *12.3.11 B.10. Data Management*

##### *12.3.11.1 B.10.a. Data Management Scheme*

This design is deferred until the Testing and Monitoring Plan draft has been approved by the UIC Director.

#### *12.3.11.2 B.10.b. Recordkeeping and Tracking Practices*

This design is deferred until the Testing and Monitoring Plan draft has been approved by the UIC Director.

#### *12.3.11.3 B.10.c. Data Handling Equipment/Procedures*

This design is deferred until the Testing and Monitoring Plan draft has been approved by the UIC Director.

#### *12.3.11.4 B.10.d. Responsibility*

GCS or designated vendor is responsible for data management

#### *12.3.11.5 B.10.e. Data Archival and Retrieval*

This design is deferred until the Testing and Monitoring Plan draft has been approved by the UIC Director.

#### *12.3.11.6 B.10.f. Hardware and Software Configurations*

This design is deferred until the Testing and Monitoring Plan draft has been approved by the UIC Director.

#### *12.3.11.7 B.10.g. Checklists and Forms*

This design is deferred until the Testing and Monitoring Plan draft has been approved by the UIC Director.

## 12.4 C. Assessment and Oversight

### *12.4.1 C.1. Assessments and Response Actions*

#### *12.4.1.1 C.1.a. Activities to be Conducted*

Assessments of each of the QASP elements:

I) $CO_2$ Stream Analysis Surface Sampling
II) Continuous recording of operational parameters
III) Corrosion monitoring
IV) Above Confining zone monitoring
IV) External Mechanical Integrity Testing (MIT)
V) Pressure fall-off testing
VI) Carbon Dioxide plume and Pressure from tracking
VII) Environmental monitoring at the Surface

#### *12.4.1.2 C.1.b. Responsibility for Conducting Assessments*

GCS or its designated subcontractor will assess data

#### *12.4.1.3 C.1.c. Assessment Reporting*

GCS will coordinate reporting of assessments

#### *12.4.1.4 C.1.d. Corrective Action*

GCS will coordinate corrective actions as warranted

### *12.4.2 C.2. Reports to Management*

#### *12.4.2.1 C.2.a/b. QA status Reports*

This design is deferred until the Testing and Monitoring Plan draft has been approved by the UIC Director.

## 12.5 D. Data Validation and Usability

### *12.5.1 D.1. Data Review, Verification, and Validation*

#### *12.5.1.1 D.1.a. Criteria for Accepting, Rejecting, or Qualifying Data*

Data will be evaluated to determine of the specified QC requirements have been met before data use.

### *12.5.2 D.2. Verification and Validation Methods*

#### *12.5.2.1 D.2.a. Data Verification and Validation Processes*

Appropriate statistical software will be used to determine data consistency

#### *12.5.2.2 D.2.b. Data Verification and Validation Responsibility*

GCS or its designated subcontractor will verify and validate all data.

#### *12.5.2.3 D.2.c. Issue Resolution Process and Responsibility*

GCS or its designee will overview the data handling, management, and assessment process. Staff involved in these processes will consult with the GCS to determine actions required to resolve issues.

#### *12.5.2.4 D.2.d. Checklist, Forms, and Calculations*

Checklists and forms will be developed specifically to meet permit requirements. These will be detailed as site specific design advances.

### *12.5.3 D.3. Reconciliation with User Requirements*

#### *12.5.3.1 D.3.a. Evaluation of Data Uncertainty*

Statistical software will be used to determine data consistency using methods consistent with UIC Program Director guidance.

#### *12.5.3.2 D.3.b. Data Limitations Reporting*

GCS will be responsible for ensuring that data developed by vendors is presented with the appropriate data-use limitations.

## 12.6 References

References will be provided as vendor information is gained.

# INJECTION WELL PLUGGING PLAN
# 40 CFR 146.92(b)

## Project Minerva

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## 1.0 Facility Information

Facility name: Project Minerva
Wells 1-4

Facility contact Benjamin Heard, Principal
2417 Shell Beach Drive, Lake Charles, Louisiana 70601
(713) 320.2497; bheard@gcscarbon.com

Well location: [redacted]

Gulf Coast Sequestration (GCS) will conduct injection well plugging and abandonment according to the procedures below.

## 2.0 Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

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

It is unlikely that a homogenous liquid will exist from the surface wellhead gauge down to the perforations. The 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 2-7/8" tubing 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 has to 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. If fluid returns do not arrive back at surface, it may be necessary to add LCM (lost circulation material) to the work fluid to plug the formation porosity at the perforations until fluid returns do arrive at surface.

Pumping rate will be low so that undue friction pressures are not exerted on the formation open at the perforations; the volume to be pumped will be on the order of 700 bbls.

## 3.0 Planned External Mechanical Integrity Test(s)

GCS will conduct at least one of the tests listed in Table 3.1 to verify external mechanical integrity prior to plugging the injection well as required by 40 CFR 146.92(a).

### 3.1 Procedures that will be followed for each type of test

At the end of injection activities, the (internal test) pressure test can be performed with the tubing in-place, still connected to the packer. The pressure inside the 9-5/8" long string casing can be increased to a value above the standard pressure applied during injection. The other tests require that the tubing be pulled out of the way. The logs will be run inside the long string.

### 3.2 Gauges and/or other equipment

Injection of $CO_2$ is expected to occur at a surface pressure of 1950 psi, and the tubing/casing annular pressure is expected to be 100 psi greater, or 2050 psi. These pressures can easily be read on 0 – 3000 psi or 0 – 5000 psi gauges. The pressure test (3rd listed on table, below) could be 2200 psi, again measured with 3000 psi or 5000 psi rated gauges.

### 3.3 What constitutes a "pass" or "fail" for each test?

Cement bond log(s): significant (negative) deviation of the cement quality from the first cement bond logs run during well construction will provide an alert about this important external barrier between injection and underground sources of drinking water (USDW), but it is not necessarily a "fail". "Fail" will present itself if the subsequent acoustic log reveals moving fluids in the cemented space. "Pass" will be the result if the acoustic log does not detect fluid movement.

The pressure test and optional casing caliper log will "fail" the long string if pressure does not hold at the applied test value, or if the caliper log reveals substantial corrosion/erosion which has decreased the wall thickness enough to likely result in a hole. "Pass" will be the opposite, a pressure test that holds steady, and a caliper log which does not reveal a condemning loss of wall thickness.

| Test Description | Location |
|---|---|
| Cement Bond Log(s)<br>(external MIT) | Run CBL & Ultrasonic logs from permanent packer to surface; these will repeat the logs run when casing was first cemented prior to injection activities. Discrepancies, if any, can be noted between the logs as an indication of cement quality improvement (due to carbon hydroxide hardening of the cement) or degradation (due to casing movement or other cement sheath disturbance). |
| Acoustic Log<br>(external MIT) | Run acoustic log post-injection to register any fluid movements external to the long string casing; log from permanent packer to surface. |
| Pressure test<br>(internal MIT) | Place tubing plug in profile nipple below permanent packer; pressure test long string casing from tubing plug to surface, using packer fluid. Test pressure to be greater than annulus pressure maintained during injection activities. |
| (Optional) Casing caliper log<br>(internal MIT) | Casing caliper log optional if long string casing successfully passes the pressure test (above). Caliper log will provide information about long string casing wall thickness loss due to corrosion or erosion; information useful for future projects. Log from permanent packer to surface. |

**Table 3.1 Planned MITs**

## 4.0 Information on Plugs

GCS will use the materials and methods noted in Table 5.1 to plug the injection well. The volume and depth of the plug or plugs will depend on the final geology and downhole conditions of the well as assessed during construction. The cement(s) formulated for plugging will be compatible with the carbon dioxide stream. The cement formulation and required certification documents will be submitted to the UIC Program Director with the well plugging plan. GCS will report the wet density and will retain duplicate samples of the cement used for each plug.

## 5.0 Methods used for volume calculations

During well construction, the 9-5/8" long string casing will be spot-calipered to confirm that the i.d. equals that of new pipe, 8.535". 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 i.d. data will be evaluated and compared to original baseline data. Calculations to determine cement plug and displacement volumes will use the final casing i.d. values. An example of the possible sensitivity of one-half casing wall thickness loss:

Original Capacity = $\frac{8.535^2 \text{ in}^2}{1029.4}$ = 0.0708 bbls per foot. 1000 ft of casing holds 70.8 bbls.

Original wall thickness 0.535".

Final Capacity = $\frac{9.079^2 \text{ in}^2}{1029.4}$ = 0.0801 bbls per foot. 1000 ft of casing holds 80.1 bbls.

Final wall thickness 0.273".

Volume calculations will be based upon the final dimensions of the long string casing.

| Plug Information | Plug #1 | Plug #2 | Plug #3 | Plug #4 | Plug #5 | Plug #6 | Plug #7 |
|---|---|---|---|---|---|---|---|
| Diameter of boring in which plug will be placed (in.) | 8.535 | 8.535 | 8.535 | 8.535 | 8.535 | 8.535 | 8.535 |
| Depth to bottom of tubing or [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Sacks of cement to be used (each plug) | 160 | 160 | 160 | 160 | 160 | 200 | 200 |
| Slurry volume to be pumped ($ft^3$) | 208 | 208 | 208 | 208 | 208 | 260 | 260 |
| Slurry weight (lb./gal) | 16.2 | 16.2 | 16.2 | 16.2 | 16.2 | 16.2 | 16.2 |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Type of cement or other material | 50:50 Class H: Pozzolan (fly ash) +accelerator + gas block + bonding agent + dispersant | 50:50 Class H: Pozzolan (fly ash) +accelerator + gas block + bonding agent + dispersant | 50:50 Class H: Pozzolan (fly ash) +accelerator + gas block + bonding agent + dispersant | 50:50 Class H: Pozzolan (fly ash) +accelerator + gas block + bonding agent + dispersant | 50:50 Class H: Pozzolan (fly ash) +accelerator + gas block + bonding agent + dispersant | 50:50 Class H: Pozzolan (fly ash) +accelerator + bonding agent + dispersant + defoamer | 50:50 Class H: Pozzolan (fly ash) +accelerator + bonding agent + dispersant + defoamer |
| Method of emplacement (e.g., balance method, retainer method, or two-plug method) | Balance method | Balance method | Balance method | Balance method | Balance method | Balance method | Balance method |

**Table 5.1 Plugging details**

## 6.0 Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), GCS will notify the UIC Program Director at least 60 days before plugging the well and provide updated Injection Well Plugging Plan, if applicable.

## 7.0 Plugging Procedures

Plug-and-abandonment (P&A) cementing operations should occur when fluids in the wellbore are at balance with the exposed formation (in this case, via perforations in the long string). Water is the major component of the work fluid and is the liquid component of the cement, and water is effectively incompressible. A barrel of water introduced into a closed system will cause one barrel of water to be displaced out of the system.

All of the P&A plugs listed in Table 5.1 and planned for this well are to be placed by the Balance Method; the cement in fluid form will be precisely placed by accurately measuring the volumes of spacer, cement, and work fluid so that the cement height outside the work string will match the height inside the work string. As soon as the cement is in place, the work string will be slowly pulled from the still-fluid cement mixture, leaving a cement column of a known height.

The density difference between the work fluid and fluid cement will not cause disruption to the placement of cement, because the major component of water is incompressible, a barrel in leads to a barrel out. It is simply measurement of lengths, diameters, and volumes followed by math.

An example of the first P&A plug will be shown below. The dimensions are for the 9-5/8" long string with 8.535" i.d. Assumes zero wall thickness loss; see earlier explanation how this value will be updated as needed. The work string is intended to be a very-commonly used 2-7/8" 7.90 lb/ft tubing found on most workover rigs.

Salt can be an accelerator to the hydration process of cement, and it is possible that the work fluid might contain salt if it is made from the packer fluid used during the injection activities. To prevent cement from coming into contact with any salt in the work fluid, a fluid spacer containing no salt is pumped ("in the space") between cement and the work fluid. The standard cement plug placement thus consists of pumping accurate amounts of each of these three (3) fluids: spacer, cement, work fluid.

Notes about plug placement:

- Tubing work string joints are typically 30' long; the safest manner in which to pump fluids down the work string is to have the top of the top joint be located 3' – 4' above the rig floor, so that the cementing head and hoses can be easily connected by 5' – 6' tall personnel. The desired setting depth of a cement plug (e.g. 10,970' for the example used here) is rarely equally divided by 30', so the real-world depth will be whatever the tubing work string measures, minus the 3' – 4' above the rig floor, as close as it can get with full numbers of joints.
- Calculations to determine cement volume are performed first in barrels, then converted to $ft^3$, and finally ordered as no. of sacks from the cement supplier. In practice, a calculation resulting in 152 sacks of cement required will normally be rounded-up to the next-highest unit of ten (10), in this case, 160 sacks. There is always some cement lost during delivery to location, and also some cement lost during mixing, so the volume tends to be rounded-up.
- The desired top of cement (T.O.C.) may be, for example, 500' above the bottom of cement. By rounding-up the cement volume number, the calculated TOC may be higher than the perfect scenario of 500'. In reality, the spacer and cement are traveling face-to-face inside a tube for more than two (2) miles, and there will be some mixing. The interface between the spacer and cement normally leads to a certain amount of contaminated cement, which does not attain the desired properties of compressive strength/hardness. For deep-set cement plugs, it is very common to find the top 2 – 3 bbls of cement contaminated, even after WOC for a lengthy period of time. This contaminated cement can be circulated out of the wellbore prior to setting the next cement plug; it will be a viscous fluid. While performing this circulation, the work string tubing can be used to "tag" (i.e. land upon, touch) the hardened part of the cement plug.

Following are the calculation results for placement of the bottom P&A cement plug for the subject well.

[redacted]

**Figure 7.1 Cement plug calculations**

The desired cement plug setting depth is [redacted] As described earlier, the tubing work string may-or-may-not reach exactly [redacted], and the top of cement at [redacted] (see calculated cell above) will likely contain some contaminated cement at the top. By the time the next cement plug is placed, it is likely that the first plug's contaminated top will be circulated-out and be very close to the desired [redacted].

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, and the tubing work string will be circulated (the long way, down the tubing and up the annulus) to clear any excess cement out of the well; reciprocate and rotate the tubing continuously during this circulation. Wait-on-cement (W.O.C.) for 24 hours, with periodic short circulations down the tubing to ensure it remains open-ended. After W.O.C. 24 hours (or such time recommended by cementing contractor for plug to achieve 100 Bc or 1000 psi compressive strength), run tubing work string slowly into well to tag the top of cement. Circulate through the work string during the final 90 ft (3 joints) to ensure that the tubing remains open-ended when it encounters cement, and to begin to move contaminated, viscous cement up and out of the wellbore. Tagging the hardened cement top will determine the precise location of the cement compared to desired placement; set down 10,000 lbs of work string weight on top of the cement plug to prove its competency. The cross-sectional area of 2-7/8" tubing is approximately 2.7 $in^2$, and the force exerted on the cement top would be approximately 10,000 lbs ÷ 2.7 $in^2$ ≈ 3700 psi.

After successfully tagging the cement plug top and proving its competency, immediately pick up the tubing work string 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, W.O.C. while periodically circulating and tagging the top of 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 doubt about the suitability of the plugging process. It will be a time-consuming process due to the W.O.C. intervals, but successfully placed cement plugs will protect USDW.

## 8.0 Contingency procedures/measures

Discussed above in the bulleted points concerning real-world implications of tubing lengths, cement volumes, and spacer/cement interface contamination.

# ALTERNATIVE
# POST-INJECTION SITE CARE AND SITE CLOSURE PLAN
# 40 CFR 146.93(a)

# PROJECT MINERVA

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## 1.0 Introduction

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Gulf Coast Sequestration will perform to meet the requirements of 40 CFR 146.93. Gulf Coast Sequestration will monitor ground water quality and track the position of the carbon dioxide plume and pressure front as they stabilize. Gulf Coast Sequestration may not cease post-injection monitoring until a demonstration of non-endangerment of underground sources of drinking water ("USDW") has been approved by the Underground Injection Control ("UIC") Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, Gulf Coast Sequestration ("GCS") will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

### 1.1 Facility Information

| | |
|---|---|
| Facility name: | Project Minerva<br>Wells 1-4 |
| Facility contact | Benjamin Heard, Principal<br>2417 Shell Beach Drive, Lake Charles, Louisiana 70601<br>(713) 320.2497; bheard@gcscarbon.com |
| Well location: | Calcasieu/Cameron Parish, Louisiana<br>Well No 1: [redacted]<br>Well No 2:<br>Well No 3:<br>Well No 4: |

## 2.0 Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

[redacted]

**Table 2.1 Injection well initial pressures and pressures at return to pre-injection state, with dates**

[redacted]

[redacted]

[redacted]

**Figure 2.1 Injection well pressures at top perforations versus time**

[redacted]

**Table 2.2 Peak pressures for injection wells**

[redacted]

[redacted]

**Figure 2.2 Peak injection pressures (end of injection) per well, fracturing pressure, initial formation pressure and induced seismicity pressure limits**

[redacted]

[redacted] Peak injection pressures (end of injection) per well, fracturing pressure, initial formation pressure and induced seismicity pressure limits [redacted]

## 2.1 Predicted Position of the $CO_2$ Plume and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

[redacted]

[redacted]

Pressure plume in January 2050 – end of injection, 30 years after injection starts, layer K = 23

[redacted]

**Figure 2.3 Pressure plume at the end of injection, 1 January 2050**

[redacted]

**Figure 2.4 Pressure plume 1 years after injection stops, 1 January 2051**

[redacted]

**Figure 2.5 AoR at the end of injection, 1 January 2050**

[redacted]

**Figure 2.6 AoR 1 year after injection stops, 1 January 2051**

[redacted]

[redacted]

**Figure 2.7 CO2 plume at the end of injection, 1 January 2050**

[redacted]

**Figure 2.8 CO2 plume 1 year after injection stops, 1 January 2051**

[redacted]

[redacted]

**Figure 2.9 Top-to-bottom azimuthal length of pressure, AoR and CO2 plumes versus time**

[redacted]

**Figure 2.10 Top-to-bottom speed of pressure, AoR and CO2 plumes**

## 3.0 Post-Injection Monitoring Plan [40 CFR 146.93(b)(1)]

Modeling shows that at the Project Minerva site the pressure decreases rapidly following cessation of injection and that the rate of plume size increase begins to decrease sharply. By 10 years after the end of injection, the rate of plume size increase slows to rates which are not measurable (see Figure 2.9 and Figure 2.10 above).

Continuing azimuthal VSP and IZ pressure surveillance using the 6 in-zone wells and array of DAS receivers and sources at fixed locations deployed during the injection period during the post-injection phase will meet the requirements of 40 CFR 146.93(b)(1) (please see the Testing and Monitoring Plan). The rate of 1) in-zone pressure decrease and 2) edge of the $CO_2$ plume along selected azimuths will document the correctness of the model assumptions. After 30 years of monitoring, the site will be well understood, the model inputs and assumptions validated and the correctness of characterization in showing the absence of out-of-zone leakage pathways in the AoR validated. The rapid decrease in any new risks as the pressure magnitude and AoR decreases and plume migration decreases results in rapid decrease in risk of leakage of either $CO_2$ or brine.

The airborne conductivity survey will be repeated to determine if any changes in groundwater indicative of brine leakage have occurred. If any anomalies that are suggestive of leakage are detected, follow-up groundwater or surface analysis will be conducted following the site-specific procedures developed during year 2 and 3 of the injection phase.

Following repeat airborne survey, leakage monitoring is systematically demobilized. Groundwater monitoring will continue only at the water wells on the injection well pads (GW1 & 2) at 5-year intervals. Remote GW wells 3 - 5 will be P&A. Surface monitoring points will systematically be demobilized, leaving only representative stations of those that are showing trends in environmental changes.

The results of all post-injection phase testing and monitoring will be submitted annually, within 10-year PISC, as described under Section 3.3 Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)] below.

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities during the injection and post injection phases is provided in the Appendix to the Testing and Monitoring Plan.

### 3.1 Monitoring Above the Confining Zone

Table 3.1 presents the monitoring methods, locations, and frequencies for monitoring above the confining zone. Table 3.1 identifies the parameters to be monitored and the analytical methods GCS will employ.

Continued collection of data using the azimuthal VSP areas will confirm no changes in fluid composition are occurring above the Anahuac confining zone.

Groundwater monitoring will continue at GW wells 1 & 2.

| Target Formation | Monitoring Activity | Monitoring Location(s) | Spatial Coverage | Frequency |
|---|---|---|---|---|
| Surface water/soil/groundwater | Sample surface water and/or soil gas | As needed depending on interpreted possible leakage signal airborne survey | Assess environmental trends | One episode, to resolution |
| Chicot aquifer | Groundwater sampling | GW wells 1 & 2 | At injection wells | Every 5 years |
| Miocene<br><br>(Survey used for plume tracking as well) | VSP designed for plume tracking will also detect any fluid substitution in the Miocene | Fiber optic in injection well, azimuthal receiver arrays | Azimuthal coverage of the plumes | Annually |
| Near surface | Airborne survey | Site-wide | AOR | One time, first year after end injection |

**Table 3.1 Monitoring methods, locations, and frequencies for monitoring above the confining zone**

## 3.2 Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]

GCS will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure. Table 3.2 presents the direct and indirect methods that GCS will use to monitor the $CO_2$ plume, including the activities, locations, and frequencies GCS will employ. No fluid sampling is planned for plume tracking. Rapid stabilization of plume precludes us of this method.

Table 3.3 presents the direct and indirect methods that GCS will use to monitor the pressure front, including the activities, locations, and frequencies GCS will employ.

Quality assurance procedures for seismic monitoring methods are presented in Section 4.3 of the QASP.

| Target Formation | Monitoring Activity | Monitoring Location(s) | Spatial Coverage | Frequency |
|---|---|---|---|---|
| **PLUME MONITORING** | | | | |
| Frio | VSP designed for plume tracking | Fiber optic in injection well, azimuthal receiver arrays | Azimuthal coverage of the plumes | To be calibrated to mass injection and validated with VSP vendor |
| Frio | Pulsed neutron or other saturation lo | Injection well 1-4 | Plume center | 5-year post-closure |

**Table 3.2 Post-injection phase plume monitoring**

| Target Formation | Monitoring Activity | Monitoring Location(s) | Spatial Coverage | Frequency |
|---|---|---|---|---|
| **DIRECT PRESSURE-FRONT MONITORING** | | | | |
| Frio | Downhole pressure monitoring | Injection well 1-4. IZ 1 and 2 | Pressure is diffusive, history match whole plume | Continuous pressure, downloaded daily |

**Table 3.3 Post-injection phase pressure-front monitoring.**

## 3.3 Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]

All post-injection site care monitoring data and monitoring results collected using the methods described above will be submitted to EPA in reports submitted every other year. The reports will contain information and data generated during the reporting period i.e., well-based monitoring data, sample analysis, and the results from updated site models.

# 4.0 Alternative Post-Injection Site Care Timeframe [40 CFR 146.93(c)]

GCS will conduct post-injection monitoring for 10 years following the cessation of injection operations. A justification for this alternative PISC timeframe is provided in Section 4.1 below. Regardless of the alternative PISC timeframe, monitoring and reporting as described in the sections above will continue until GCS demonstrates, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the project does not pose an endangerment to any USDWs, per the requirements at 40 CFR 146.93(b)(2) or (3).

## 4.1 Computational Modeling Results – 40 CFR 146.93(c)(1)(i)

[redacted]

[redacted]

**Figure 4.1 Pressure plume in layer K = 23 in the model, 1 year after injection starts**

[redacted]

**Figure 4.2 Pressure plume in layer K = 23 in the model, 2 years after injection starts**

[redacted]

**Figure 4.3 Pressure plume in layer K = 23 in the model, 3 years after injection starts**

[redacted]

**Figure 4.4 Pressure plume in layer K = 23 in the model, 4 years after injection starts**

[redacted]

**Figure 4.5 Pressure plume in layer K = 23 in the model, 5 years after injection starts**

[redacted]

**Figure 4.6 Pressure plume in layer K = 23 in the model, 10 years after injection starts**

**Figure 4.7 Pressure plume in layer K = 23 in the model, 15 years after injection starts**

**Figure 4.8 Pressure plume in layer K = 23 in the model, 20 years after injection starts**

[redacted]

**Figure 4.9 Pressure plume in layer K = 23 in the model, 25 years after injection starts**

[redacted]

**Figure 4.10 Pressure plume in layer K = 23 in the model, 30 years after injection starts**

Pressure plume in January 2051, 1 year after injection stops, layer K = 23

[redacted]

**Figure 4.11 Pressure plume in layer K = 23 in the model, 1 years after injection stops**

Pressure plume in January 2052, 2 years after injection stops, layer K = 23

[redacted]

**Figure 4.12 Pressure plume in layer K = 23 in the model, 2 years after injection stops**

Pressure plume in January 2055, 5 years after injection stops, layer K = 23

[redacted]

**Figure 4.13 Pressure plume in layer K = 23 in the model, 5 years after injection stops**

Pressure plume in January 2060, 10 years after injection stops, layer K = 23

[redacted]

**Figure 4.14 Pressure plume in layer K = 23 in the model, 10 years after injection stops**

**Figure 4.15 Pressure plume in layer K = 23 in the model, 50 years after injection stops**

**Figure 4.16 Pressure plume in layer K = 23 in the model, 100 years after injection stops**

[redacted]

**Figure 4.17 $CO_2$ gas saturation plume in layer K = 23 in the model, 2 years after injection starts**

[redacted]

**Figure 4.18 $CO_2$ gas saturation plume in layer K = 23 in the model, 3 years after injection starts**

[redacted]

**Figure 4.19 $CO_2$ gas saturation plume in layer K = 23 in the model, 4 years after injection starts**

[redacted]

**Figure 4.20 $CO_2$ gas saturation plume in layer K = 23 in the model, 5 years after injection starts**

[redacted]

**Figure 4.21 $CO_2$ gas saturation plume in layer K = 23 in the model, 10 years after injection starts**

[redacted]

**Figure 4.22 $CO_2$ gas saturation plume in layer K = 23 in the model, 15 years after injection starts**

[redacted]

**Figure 4.23 $CO_2$ gas saturation plume in layer K = 23 in the model, 20 years after injection starts**

[redacted]

**Figure 4.24 $CO_2$ gas saturation plume in layer K = 23 in the model, 25 years after injection starts**

[redacted]

**Figure 4.25 $CO_2$ gas saturation plume in layer K = 23 in the model, 30 years after injection starts**

[redacted]

**Figure 4.26 $CO_2$ gas saturation plume in layer K = 23 in the model, 10 years after injection stops**

**Figure 4.27 $CO_2$ gas saturation plume in layer K = 23 in the model, 50 years after injection stops**

**Figure 4.28 $CO_2$ gas saturation plume in layer K = 23 in the model, 100 years after injection stops**

### *4.1.1 Sensitivity Study*

[redacted]

[redacted]

**Figure 4.29 Vertical X-section of pressure plume along I = 181 in the model, end of injection**

[redacted]

**Figure 4.30 Vertical X-section of pressure plume along I = 181 in the model, 1 year after injection stops**

[redacted]

**Figure 4.31 Vertical X-section of pressure plume along I = 181 in the model, 2 years after injection stops**

[redacted]

**Figure 4.32 Vertical X-section of pressure plume along I = 181 in the model, 3 years after injection stops**

[redacted]

**Figure 4.33 Vertical X-section of pressure plume along I = 181 in the model, 10 years after injection stops**

[redacted]

**Figure 4.34 Vertical X-section of pressure plume along I = 181 in the model, 20 years after injection stops**

[redacted]

**Figure 4.35 Vertical X-section of pressure plume along I = 181 in the model, 30 years after injection stops**

[redacted]

**Figure 4.36 Vertical X-section of pressure plume along I = 181 in the model, 40 years after injection stops**

[redacted]

**Figure 4.37 Vertical X-section of pressure plume along I = 181 in the model, 50 years after injection stops**

[redacted]

**Figure 4.38 Vertical X-section of pressure plume along I = 181 in the model, 100 years after injection stops**

[redacted]

[redacted]

**Figure 4.39 Vertical distribution of [redacted] $CO_2$ plume mass, with time**

[redacted]

**Figure 4.40 Vertical distribution of [redacted] $CO_2$ plume mass, with time**

[redacted]

[redacted]

[redacted]

Pressure plume in January 2150, 100 years after injection stops, layer K = 23

[redacted]

**Figure 4.41 Extent of pressure plume 100 years after injection stops, layer K = 23 in model**

[redacted]

**Injection well pressures at top perforations (see table 1 for cell indices and depths)**

[redacted]

**Figure 4.42 well pressures at top perforations versus time**

[redacted]

**Boundary cell pressures against time, in layer K = 23 of the model**

[redacted]

**Figure 4.43 dP(psi) versus time in four boundary test cells**

[redacted]

## 4.2 Predicted Rate of Plume Migration – 40 CFR 146.93(c)(1)(iii)

[redacted]

[redacted]

**Figure 4.44 Top-to-bottom azimuthal length of pressure, AoR and $CO_2$ plumes versus time**

Comparison of pressure and $CO_2$ plumes' speed of plumes (ft/year) versus time (ML Reveal model)

[redacted]

**Figure 4.45 Top-to-bottom speed of pressure, AoR and $CO_2$ plumes**

[redacted]

## 4.3 Site-Specific Trapping Processes – 40 CFR 146.93(c)(1)(iv)-(vi)

The following trapping mechanisms are considered:

1) Buoyancy trapping against the Anahuac Shale Formation;
2) Relative permeability hysteresis (capillary trapping);
3) Dissolution of gaseous phase $CO_2$ into the formation's aqueous phase;
4) Localized buoyancy trapping within 4-way closures, where they may exist.

Note: Trapping by mineralization was not modelled.

Please see Appendices 2 and 3 on relative permeability modelling and $CO_2$ dissolution – including bibliography.

Figure 4.46 shows the mass of $CO_2$ of trapped by different mechanisms against time. The results are based on the simulation model. Please see Appendices 2 and 3 for an explanation of the trapping mechanisms used and their associated data.

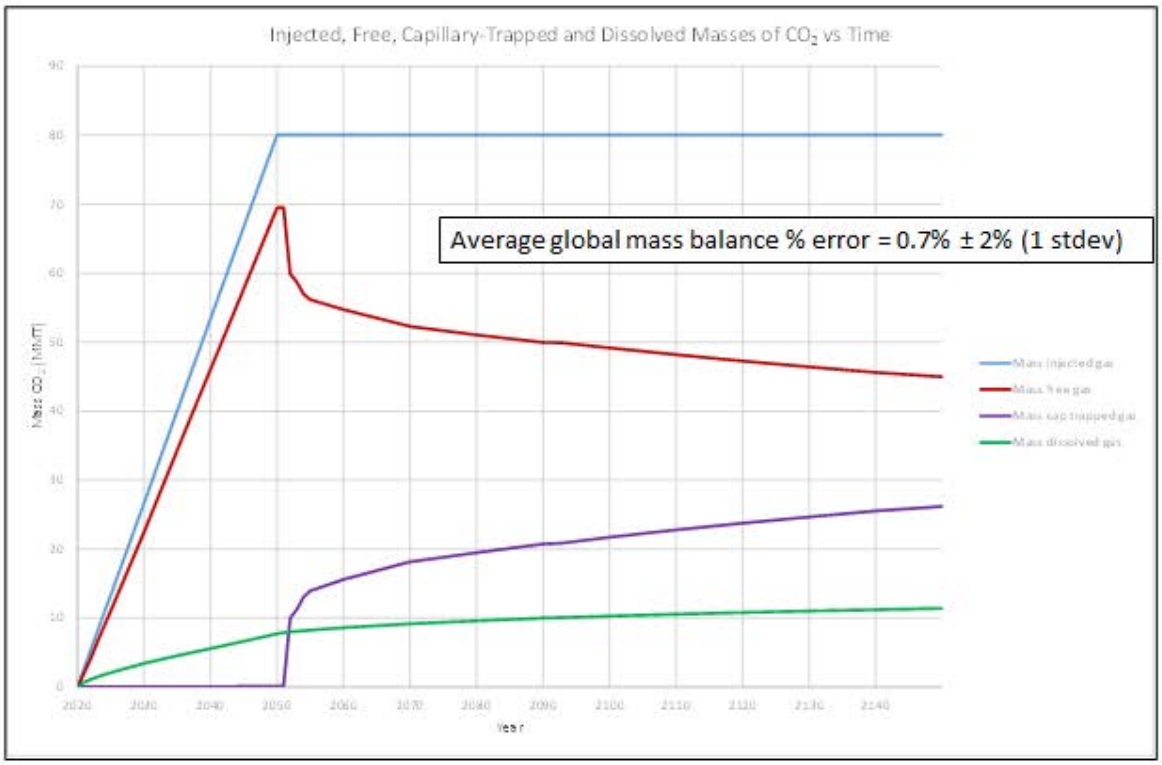


**Figure 4.46 $CO_2$ mass balance and cumulative trapping**

The trapping rates vary during the simulation. For example, capillary imbibition trapping does not occur significantly during the injection phase because it is a drainage process, the wetting phase is decreasing. When this stops, the wetting phase can move back in behind/underneath the $CO_2$ plume and it becomes an imbibition process (wetting phase increasing) and trapping of the non-wetting phase ($CO_2$) can occur through the snapping-off of some of the $CO_2$ ganglia within the pore spaces (Juanes, 2006). Some trapping can occur during injection, but it is not significant. Immediately

following the cessation of injection, the rate of capillary trapping rises rapidly and then falls to a lower value. Immediately following the cessation of injection it rises rapidly and then falls to a lower value.

Trapping by dissolution occurs at a more constant rate, although it tends to decrease after injection stops, and then falls asymptotically.

No $CO_2$ mineralization was modelled.

## 4.4 Confining Zone Characterization – 40 CFR 146.93(c)(1)(vii)

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**Table 4.6 Summary of all Frio-depth or deeper penetrations within the Area of Review**

### *4.5.3 Planned Injection Well Construction*

Injection wells will be constructed with mechanical integrity to meet-or-exceed the EPA UIC program Class VI guidance, with both internal and external components working together to ensure prevention of fluid movement into USDW. For internal integrity, concentric casing and tubing strings and wellheads of carbon steel and corrosion-resistant alloys will provide multiple barriers between the injected $CO_2$ and USDW. Tubing packers will employ nickel or corrosion-resistant alloy plus seals consisting of $CO_2$-resistant Teflon, nylon, or Buna-N rubber components. For external integrity, each casing string will be cemented from its bottom all the way to surface, using single or stage-cementing as required to emplace the cement column without causing fracture at any downhole formations. After placement of each cement column and suitable time allowed for hydration, logs will be run to confirm the competency of the cement barrier between the casing and the borehole wall.

### *4.5.4 Planned Testing and Monitoring of Barriers Between the Injection Zone and USDW*

The ability of the internal barriers to protect USDW will be confirmed by initial and subsequent testing. An example of initial tests is a pressure test of the casing string in-place after cementing, to confirm no leakage through connections, and taking the baseline caliper survey inside the casing walls for comparison to subsequent surveys. Subsequent tests, besides the caliper survey mentioned, include continuous pressure monitoring of the annulus between the tubing string and the long string; this single annulus monitors the integrity of the tubing, the packer, and the long string.

### *4.5.5 Limited Risk to Well Integrity Through $CO_2$ Interaction with Wellbore Cement*

The long-term degradation of cement by contact with $CO_2$ has been observed, but the external mechanical integrity of the injection well will be ensured by the continuous column of cement from base to surface. This length of cement will necessarily extend the full length of the confining layer, namely the Anahuac formation, several hundred feet thick. The $CO_2$ injectate, plus $CO_2$-contaminated formation brine in the Frio, will be confined at the Anahuac/Frio boundary. Cement around the casing string(s) through the confining Anahuac will not be subjected to contact with $CO_2$.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

## 4.6 Location of USDWs – 40 CFR 146.93(c)(1)(x)

Additional information and figures describing the USDW in relation to Project Minerva may be found in the Hydrologic and Hydrogeologic Information section and the Class VI Permit Application Narrative document.

### *4.6.1 Lowermost Underground Source of Drinking Water*

The primary regulatory focus of the USEPA injection well program is protection of human health and the environment, including protection of potential underground sources of drinking water (USDWs). The Underground Source of Drinking Water (USDW) is defined by the EPA as an aquifer which supplies any public water system and contains fewer than 10,000 mg/l total dissolved solids (TDS).

### *4.6.2 Regional Hydrogeology*

The regional aquifer system is called the Gulf Coast Aquifer system and stretches from Texas, across Louisiana, Mississippi, and Alabama, and includes the western most portion of Florida. Miocene and younger formations contain usable quality water (<3,000 milligrams per liter (mg/L) TDS) and potentially usable quality water (<10,000 mg/L TDS), which is defined as base of lowermost USDW within this system. These aquifer systems regionally crop out in bands parallel to the coast and consists of units that dip and thicken towards the southeast. Baker (1979) describes four major hydrogeologic units that comprise the Gulf Coast Aquifer System in the Texas and Louisiana region. In ascending order, the four units are:

- Jasper aquifer;
- Burkeville confining system;
- Evangeline aquifer;
- Chicot aquifer.

The Burkeville confining system hydrologically separates the Evangeline aquifer from the underlying Jasper aquifer. However, the Chicot and Evangeline aquifers are thought to be hydrologically connected. A hydrogeologic stratigraphic column for southwestern Louisiana is contained in Figure 4.53. The primary focus of this assessment is on the Jasper, Evangeline, and Chicot aquifers in the southwestern portion of the state.

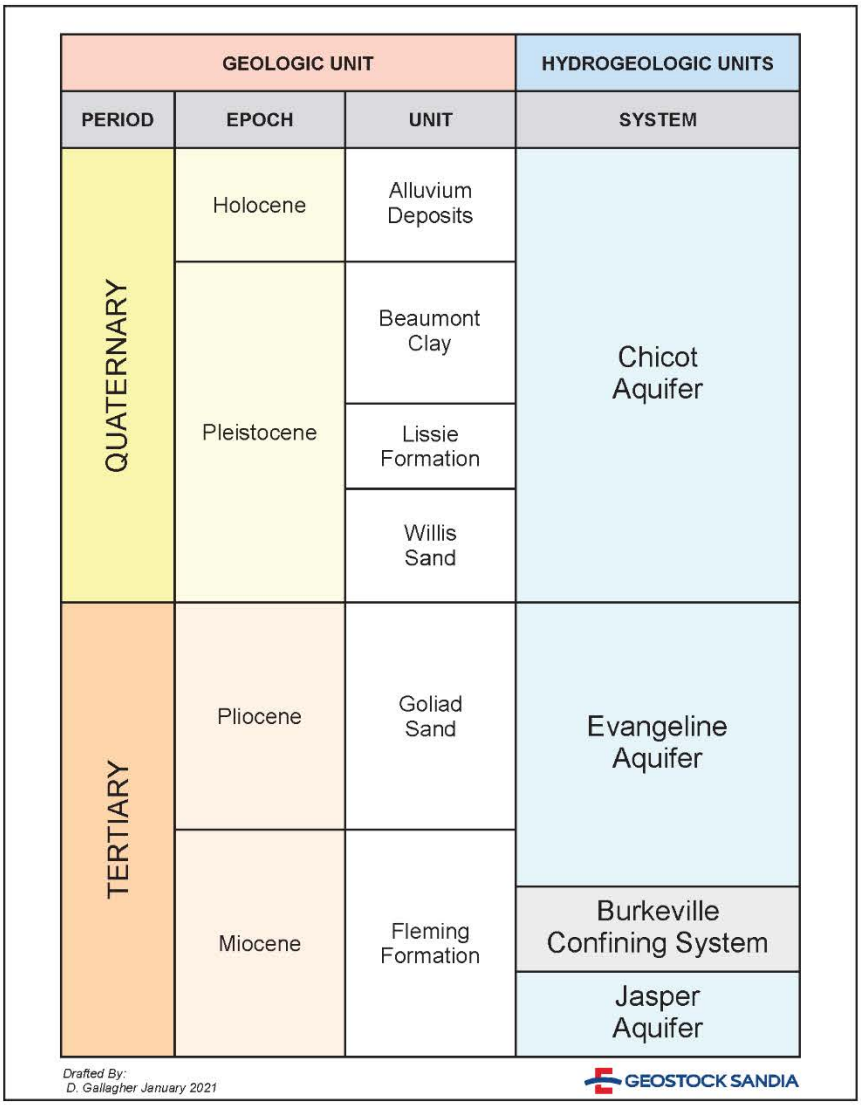


**Figure 4.53 Regional hydrostratigraphic column for southeastern Texas and southwestern Louisiana.**

The Jasper aquifer is not a major source for regional freshwater use in along the Gulf Coast, except in Beauregard, Rapides and Vernon Parishes. As the aquifer dips downwards towards the south (towards the coast), the groundwater increases in chlorides and is less commercially ideal to produce in comparison to the overlying Chicot and Evangeline aquifers. In Louisiana, the Jasper aquifer is primarily used as source only near its recharge areas. Its primary uses are for public water supply and industry with approximately 47.95 million gallons per day (Mgal/d).

Groundwater withdrawal from the Evangeline aquifer in Louisiana is almost half of that then from the Jasper aquifer. The Evangeline is used most heavily used in Evangeline Parish, as well as Allen, Avoyelles, and Beauregard Parishes for public supply and industry. It has also been used as a power supply source for the local areas. Approximately 28.56 Mgal/d were withdrawn from the aquifer in 2015.

The Chicot Aquifer yields the highest amount of groundwater for the State of Louisiana. It is the primary source of water for Calcasieu and Cameron Parishes. As the aquifer nears the coast, the lower units become saline and only the upper portions of the aquifer are used as a source of groundwater. Approximately 849.90 Mgal/d are produced from the entire aquifer. The largest contributor for withdrawal is for rice irrigation and aquaculture (crawfish harvesting), which are seasonal. As a result, during the off-peak irrigation season, the aquifer recharges, with the water level rebounding back to normal levels. The Chicot is also the largest supplier of public supply at 95.60 Mgal/day for the region and supports large cities such as Lake Charles in the area of interest.

### *4.6.3 Determination of the Lowermost Base of The USDW*

The most accurate method for determining formation fluid properties is through the analysis of formation fluid samples. In the absence of formation fluid sample analyses, data from open-hole geophysical well logs can be used to calculate formation fluid salinity by determining the resistivity of the formation fluid ($R_w$) and converting that resistivity value to salinity value. The two primary methods to derive formation fluid resistivity from geophysical logs are the "Spontaneous Potential Method" and the "Resistivity Method". The "Spontaneous Potential Method" derives the formation fluid resistivity from the resistivity of the mud filtrate, and the magnitude of the deflection of the spontaneous potential response (SP) of the formation (the electrical potential produced by the interaction of the formation water, the drilling fluid, and the shale content of the formations). The "Resistivity Method" determines formation fluid resistivity from the resistivity of the formation ($R_t$) and the formation resistivity factor (F), which is related to formation porosity and a cementation factor (Schlumberger, 1987).

### *4.6.4 Spontaneous Potential Method*

The spontaneous potential curve on an open-hole geophysical well log records the electrical potential (voltage) produced by the interaction of the connate formation water, conductive drilling fluid, and certain ion selective rocks (shales). Opposite shale beds, the spontaneous potential curve usually defines a straight line (called the shale baseline), while opposite permeable formations, the spontaneous potential curve shows excursions (deflections) away from the shale baseline. The deflection may be to the left (negative) or to the right (positive), depending primarily on the relative salinities of the formation water and the drilling mud filtrate. When formation salinities are greater than the drilling mud filtrate salinity, the deflection is to the left. For the reverse salinity contrast, the deflection is to the right. When salinities of the formation fluid and the drilling mud filtrate are similar, no spontaneous potential deflection opposite a permeable bed will occur.

The deflection of the spontaneous potential curve away from the shale baseline in a clean sand is related to the equivalent resistivities of the formation water ($r_{we}$) and the drilling mud filtrate ($r_{mf}$) by the following formula:

$$SP = -K\,Log\left(\frac{r_{mf}}{r_{we}}\right) \qquad (1)$$

For NaCl solutions, K = 71 at 77°F and varies in direct proportion to temperature by the following relationship:

$$K = 61 + 0.133\,T° \qquad (2)$$

From the above equations, by knowing the formation temperature, the resistivity of the mud filtrate, and the spontaneous potential deflection away from the shale baseline, the resistivity of the formation water can be determined (Figure 4.54). From the formation water resistivity and the formation temperature, the salinity of the formation water can be calculated (Figure 4.55).

### *4.6.5 Resitivity Method*

The Resistivity Method determines formation fluid resistivity from the resistivity of the formation ($R_t$) and the formation resistivity factor (F), which is related to formation porosity and a cementation factor (Schlumberger, 1987). The resistivity of a formation ($R_t$ in ohm-meters) is a function of: 1) resistivity of the formation water, 2) amount and type of fluid present, and 3) the pore structure geometry. The rock matrix generally has zero conductivity (infinitely high resistivity) except for some clay minerals, and therefore is not generally a factor in the resistivity log response. Induction geophysical logging determines resistivity or $R_t$ by inducing electrical current into the formation and measuring conductivity (reciprocal of resistivity). The induction logging device investigates deeply into a formation and is focused to minimize the influences of borehole effects, surrounding formations, and invaded zone (Schlumberger, 1987). Therefore, the induction log measures the true resistivity of the formation (Schlumberger, 1987). The conductivity measured on the induction log is the most accurate resistivity measurement for resistivity under 2 ohm-meters.

Electrical conduction in sedimentary rocks almost always results from the transport of ions in the pore-filled formation water and is affected by the amount and type of fluid present and pore structure geometry (Schlumberger, 1988).

In general, high-porosity sediments with open, well-connected pores have lower resistivity, and low-porosity sediments with sinuous and constricted pore systems have higher resistivity. It has been established experimentally that the resistivity of a clean, water-bearing formation (*i.e.,* one containing no appreciable clay or hydrocarbons) is proportional to the resistivity of the saline formation water (Schlumberger, 1988). The constant of proportionality for this relationship is called the formation resistivity factor (F), where:

$$F = \frac{R_t}{R_w} \tag{3}$$

For a given porosity, the formation resistivity factor (F) remains nearly constant for all values of $R_w$ below 1.0 ohm-meter. For fresher, more resistive waters, the value of F may decrease as $R_w$ increases (Schlumberger, 1987). It has been found that for a given formation water, the greater the porosity of a formation, the lower the resistivity of the formation ($R_t$) and the lower the formation factor. Therefore, the formation factor is inversely related to the formation porosity. In 1942, G.E Archie proposed the following relationship (commonly known as Archie's Law) between the formation factor and porosity based on experimental data:

$$F = \frac{a}{\phi^m} \tag{4}$$

Where:

$\phi$ = porosity

$a$ = an empirical constant

$m$ = a cementation factor or exponent.

In sandstones, the cementation factor is assumed to be 2, but can vary from 1.2 to 2.2 (Stolper, 1994). In the shallower sandstones, as sorting, cementation, and compaction decrease, the cementation factor can also decrease (Stolper, 1994).

Experience over the years has shown that the following form of Archie's Law generally holds for sands in the Gulf Coast and is known as the Humble Relationship (Schlumberger, 1987):

$$F = \frac{0.81}{\phi^2} \tag{5}$$

Combining the equations for the Humble relationship and the definition of the formation factor, the resistivity of the formation water ($r_{we}$) is related to the formation resistivity (rt) by the following:

$$R_t = \frac{R_{we}\ x\ 0.81}{\phi^2} \tag{6}$$

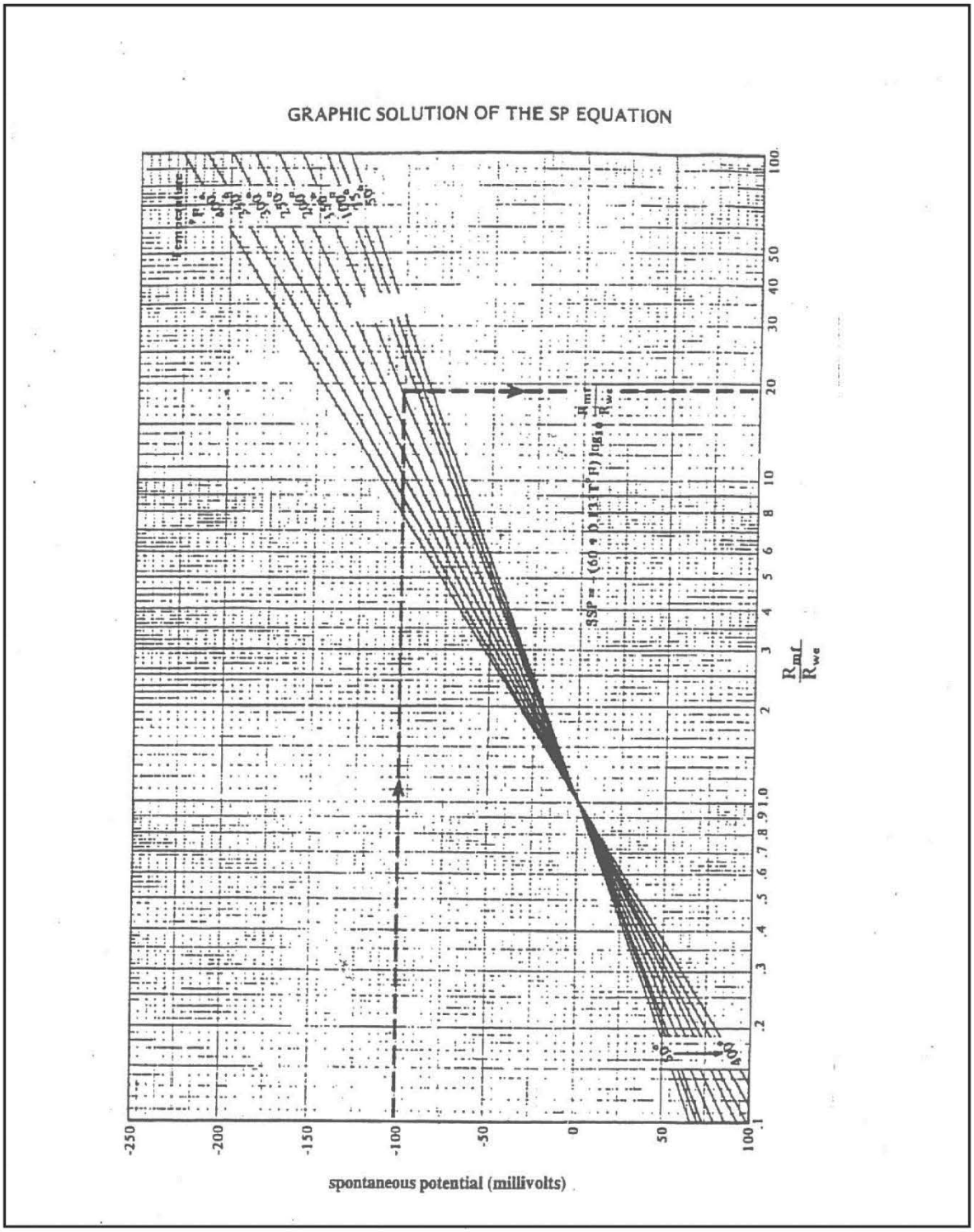


**Figure 4.54 Graphic solution of the Spontaneous Potential Equation (Schlumberger, 1987)**

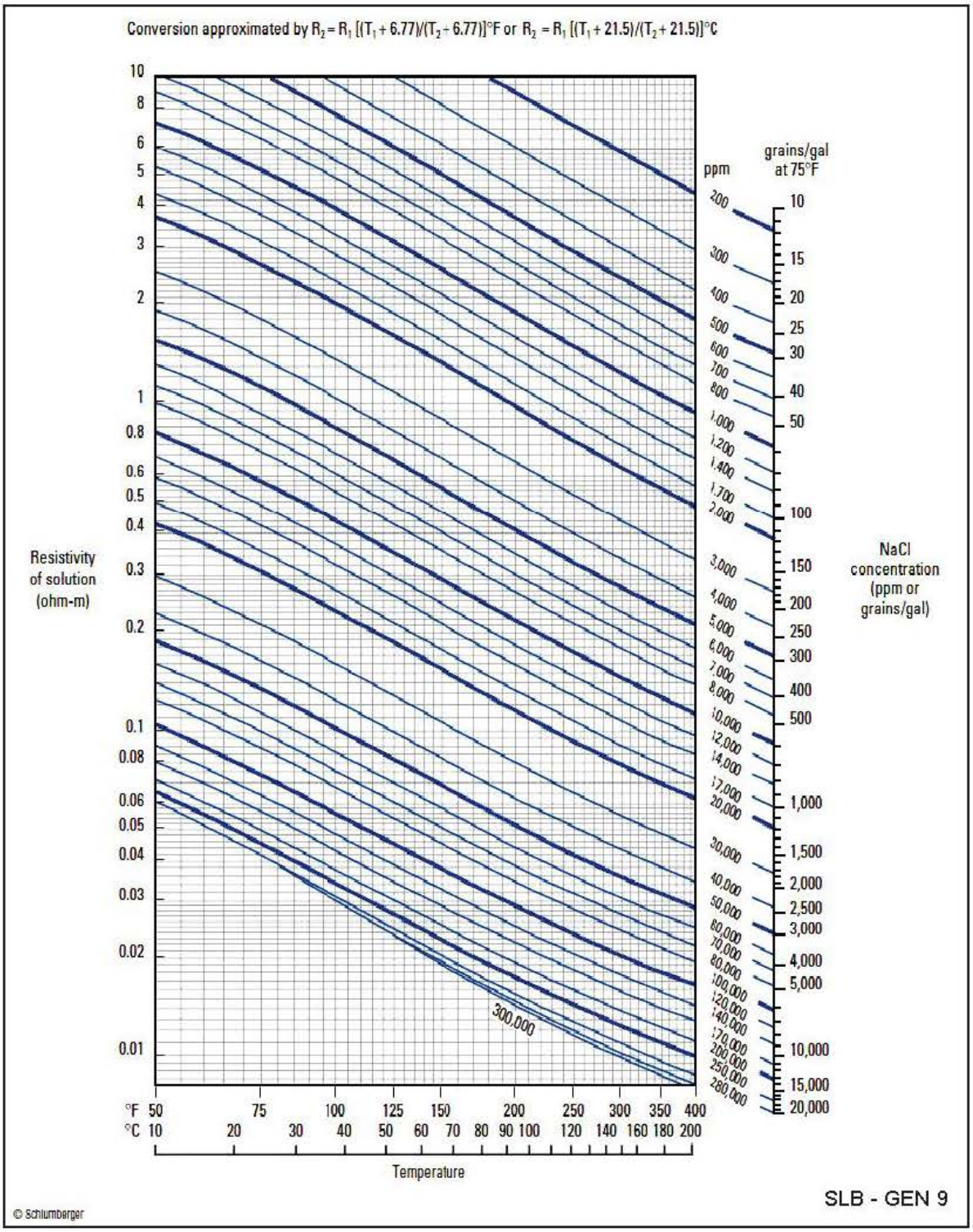


**Figure 4.55 Resistivity nomograph for NaCl solutions (Schlumberger, 1979)**

### *4.6.6 Methodology*

[redacted]

[redacted]

[redacted]

[redacted]

### *4.6.7 Water Wells within the Area of Review*

Water well data was gathered from the online database of the Louisiana Department of Natural Resources (LADNR), specifically the online GIS website SONRIS (*https://www.sonris.com/)*. For the Texas portion of the search area, water well data was gathered from files maintained by the Texas Water Development Board (TWDB) (*https://www.twdb.texas.gov/)*. The data was combined into a digital GIS format to merge the two data sets

A water well search was performed through SONRIS (Louisiana) and the TWDB (Texas). All water wells within the AOR are located within Louisiana. There are a total of 8 water wells located within the defined Area of Review ([redacted]). These wells extend from depths of 90 feet to 400 feet into the 200-Foot sand in the Chicot Aquifer. No wells are in the deeper aquifers of the Evangeline or Jasper. Five of these water wells are plugged and abandoned wells that supplied water from rigs, 1 is a current active supply for a rig, and 2 are currently used for domestic purposes.

### *4.6.8 Frio Penetrations with the Area of Review*

A full integrity review of all wells within the Area of Review penetrating to Frio Formation depth and greater was carried out. The aim of the review was to confirm that all wells demonstrate adequate barriers between the Injection Zone and USDW. Nine wells were found to reach the Frio Formation; all are plugged and abandoned and possess one or more barriers which would prevent any communication with the UDSW. Full details of the review may be found in Section 4.5.1 [redacted].

### *4.6.9 Base of the Lowermost USDW*

The base of the USDW has been projected across the Project Minerva area based upon 357 available wells logs. A base of the Lowermost USDW Map ([redacted] show the depth ranges from 850 feet ([redacted]) to 1,200 feet below mean sea level in the area (across the majority of the Area of Review around the planned injection wells).

The shallowest depth to the lowermost USDW lies across [redacted], where it is positioned within a sand package that directly overlies the top of the shallow salt. This sand is equivalent to the 700-Foot sand within the Chicot aquifer. The sand and the top of salt are separated by a thin (>10 feet) cap-rock clay bed. Saltwater encroachment occurs through vertical movement of hypersaline fluids in the area of the [redacted] through vertical leakage between the salt and the overlying strata. Sand units that directly overlay a salt bed are affected. In some instances, the conservative 2-ohm resistivity log cut off occurs within the middle of the sand package. This is an indication of a transition from freshwater to brackish/saltwater within the lower portion of the sand package. To maintain consistency, the base of the USDW was placed at the base of this sand, not at the transition point within the sand package.

[redacted], the base of the USDW deepens slightly to a range of 1,050 feet to 1,250 feet below mean sea level. The USDW is located at the base of a thick sand package that corresponds to the upper portion of the Evangeline aquifer. However, the Evangeline is not considered a "usable" aquifer with [redacted] and is not developed for use within the area. The top of salt is deeper at [redacted] and there is less influence via vertical leakage into the overlying aquifers due to a thicker cap-rock. However, as the strata dips towards the coast, saltwater encroachment into the deeper aquifers (Evangeline and Jasper) is evident in the southern portion of [redacted] due to pumping operations.

Within the AoR ([redacted]) the USDW varies between 1,080 feet to 1,130 feet depth (TVDSS). It encompasses the southern portion of the [redacted] The lowermost USDW is consistent with the base of the 700-Foot sand within this limited area. Note that the base of the USDW does NOT follow stratigraphic formation and that the units within the USDW are hydraulically connected. Thus, the USDW flows from the upper portion of the Evangeline into the base of the Chicot based upon the conservative 2-ohm resistivity cutoff.

### *4.6.10 Safety of the USDW*

Overall, regional groundwater withdrawals within the Chicot aquifer have declined since 1985. Since the water levels are stabilized, withdrawal from the aquifers is not expected to influence either the safety of the injection site (non-endangerment of USDWs) or injection operations. The safety of the manmade conduits within the AoR and surrounding oil and gas fields (active and abandoned oil and gas wells), by casing, cement, or mud plugs, is demonstrated in Section 4.5.2 [redacted] and [redacted] to [redacted]. The target Frio Injection Interval at Project Minerva is separated by over [redacted]) from the shallow USDW's (<10,000 mg/L TDS) ([redacted]). Multiple additional saline "buffer aquifers" also exist between the top of the confining zone and base of the lowermost USDW, mitigating the vertical transmission of fluids upwards.

[redacted]

[redacted]

[redacted]

## 5.0 Non-Endangerment Demonstration Criteria

Prior to approval of the end of the post-injection phase, GCS will submit a demonstration of non-endangerment of USDWs to the UIC Program Director, per 40 CFR 146.93(b)(2) and (3).

GCS will issue a report to the UIC Program Director. This report will make a demonstration of USDW non-endangerment based on the evaluation of the Project Minerva site monitoring data used in conjunction with the project's computational model. The report will detail how the non-endangerment demonstration evaluation uses site-specific conditions to confirm and demonstrate non-endangerment. The report will include all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the UIC Program Director to review the analysis. The report will include the following sections:

### 5.1 Introduction and Overview

A summary of relevant background information will be provided, including the operational history of Project Minerva, the date of the non-endangerment demonstration relative to the post-injection period outlined in this PISC and Site Closure Plan, and a general overview of how monitoring and modeling results will be used together to support a demonstration of USDW non-endangerment.

### 5.2 Summary of Existing Monitoring Data

A summary of all previous monitoring data collected at Project Minerva, pursuant to the Testing and Monitoring Plan and this PISC and Site Closure Plan, including data collected during the injection and post-injection phases of the project, will be submitted to help demonstrate non-endangerment. Data submittals will be in a format acceptable to the UIC Program Director (40 CFR 146.91(e)), and will include a narrative explanation of monitoring activities, including the dates of all monitoring events, changes to the monitoring program over time, and an explanation of all monitoring infrastructure that has existed at the site. Data will be compared with baseline data collected during site characterization in satisfaction of 40 CFR 146.82(a)(6) and 146.87(d)(3).

Currently, there is no existing monitoring data.

### *5.3* Summary of Computational Modeling History

To date there has been no $CO_2$ injection or wells drilled for data collection. Hence, there is no data for history matching. A reservoir simulation model has been built in Reveal using a variety of data sources (see bibliography) to predict the development of the AoR, pressure and $CO_2$ plumes in time.

## 5.4 Evaluation of Reservoir Pressure

There will be regular pressure build-up tests (to determine reservoir pressure and injectivity) and continuous monitoring of downhole pressures and temperatures during injection, together with measurement of injection rates, tubing head pressures, temperatures and composition. These will be used as history matching data for future versions of the dynamic model. After calibration (history matching) the model will be used to update its predictions of the development of the AoR, pressure and $CO_2$ plumes.

## 5.5 Evaluation of Carbon Dioxide Plume

There will be regular VSP surveys, timing of such surveys based on mass injected and validated with VSP vendor, to determine the presence of $CO_2$ in the vicinity of the VSP line. These data measurements will be used as history matching data for future versions of the dynamic model. After calibration (history matching) the model will be used to update its predictions of the development of the AoR, pressure and $CO_2$ plumes

## 5.6 Evaluation of Emergencies or Other Events

The wells where this data is to be collected will be modelled in the dynamic simulation model and the calculated pressures, $CO_2$ saturations and other relevant data compared with the corresponding measured values to determine the accuracy and fidelity of the dynamic simulation model. Having calibrated the dynamic model, it can be used to predict the risk to that mobilized fluids pose a danger to USDWs.

# 6.0 Site Closure Plan

GCS will conduct site closure activities to meet the requirements of 40 CFR 146.93(e) as described below. GCS will submit a final Site Closure Plan and notify the permitting agency at least 120 days prior of its intent to close the site. Once the permitting agency has approved closure of the site, GCS will plug the monitoring wells and submit a site closure report to EPA. The activities, as described below, represent the planned activities based on information provided to EPA. The actual site closure plan may employ different methods and procedures. A final Site Closure Plan will be submitted to the UIC Program Director for approval with the notification of the intent to close the site.

## 6.1 Plugging Monitoring Wells

Methods to plug monitoring wells will follow the guidance for plugging Class VI injection wells. Sixty-day notice will be provided prior to plugging operations. Adjustments to the plugging plan will be incorporated to meet the Director's guidance.

It is unlikely or uncertain that a homogenous liquid will exist from the surface wellhead gauge down to the perforations (or screen in the case of a pure monitoring well). The homogenous liquid is required to accurately determine the downhole pressure at the perforations; a mixture of gas and super-critical phase $CO_2$ cannot yield 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/screen 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.

If the monitoring well does not have an existing tubing string installed, a work string likely consisting of 2-7/8" tubing 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. With the tubing work string or the existing tubing/packer unseated, the work fluid will be slowly pumped down the tubing towards the perforations. If fluid returns do not arrive back at surface, it may be necessary to add lost circulation material (LCM) to the work fluid to plug the formation porosity at the perforations until fluid returns do arrive at surface. Pumping rate will be low so that undue friction pressures are not exerted on the formation open at the perforations; the volume to be pumped will be on the order of 200 bbls.

Note: this step should be considered as a bonus step, to be performed at the discretion of the owner/operator management and/or the Director. When the work fluid has been placed into the well and proven to balance formation pressure, and the tubing (either original or work string) have been pulled, a casing caliper log should be run on the long string. A baseline caliper log was taken when the casing was installed many years before, and possibly subsequent caliper logs have been run during the life of the well. A final caliper log would be run to determine the final condition of the long string's internal walls. It is likely that these walls have been continuously bathed by a non-corrosive fluid in the annulus between tubing and casing but obtaining the data and comparing to the years-old baseline log could provide bonus information to participants.

If the tubing existed in the wellbore with a packer attached, the tubing will be pulled and the packer removed; it is likely that any tubing joints connected to seating nipples will also be removed. The goal is to install in the wellbore a tubing work string from surface to plugged-back total depth (PBTD), which is usually the float collar of the casing long string. At this point, with no packer obstacle in the annulus, circulation will be repeated until it is confirmed that the work fluid has balanced downhole pressure at the perforations.

Circulation will be continued until fluid returns at surface appear to be clear from any debris, and pumping rates will be increased to determine the wellbore's tolerance for frictional pressures. Additions of LCM might be required to maintain circulation and this will be the time to learn the behavior of the wellbore. Determination of this tolerance and behavior will allow detail planning of the rates to be used during cementing operations.

It is proposed to set a series of balanced cement plugs inside the long string, beginning with a 500-ft cement plug across the perforations. Each cement plug will be designed by the cementing contractor to utilize cement types and additives suitable for each placement in the well; the first plug across the perforations will contain non-Portland cement components such as Pozzolan-Lime, Gypsum, Resin, or Latex to reduce or eliminate degradation by $CO_2$. No cement retainer or bridge

plug is proposed at the top of this plug, as this adds mechanical complexity in a place where a simple solid cement seal is required.

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, and the tubing work string will be circulated (the long way, down the tubing and up the annulus) to clear any excess cement out of the well; reciprocate and rotate the tubing continuously during this circulation. Wait-on-cement for 24 hours, with periodic short circulations down the tubing to ensure it remains open-ended. After W.O.C. 24 hours (or such time recommended by cementing contractor for plug to achieve 100 Bc or 1000 psi compressive strength), run tubing work string slowly into well to tag the top of cement. Circulate through the work string during the final 90 ft (3 joints) to ensure that the tubing remains open-ended when it encounters cement. Tagging the cement top will determine the precise location of the cement compared to desired placement; additionally, set down 10,000 lbs of work string weight on top of the cement plug to prove its competency. The cross-sectional area of 2-7/8" tubing is approximately 2.7 $in^2$, and the force exerted on the cement top would be approximately 10,000 lbs ÷ 2.7 $in^2$ ≈ 3700 psi.

After successfully tagging the cement plug top and proving its competency, immediately pick up the tubing work string and circulate through it to clear any cement from the open end. 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, W.O.C. while periodically circulating, and tagging the top of second plug and proving its competency.

Subsequent 500-ft high cement plugs will be planned for:

- the top of Anahuac, the confining formation above injection zone
- 250 ft above-and-below the depth of the surface casing shoe
- 250 ft above-and-below the base USDW
- at surface, from 510' to 10' below ground level.

As a conservative approach, each of the plugs will be tagged using the method described earlier. Tagging each plug will prove its location and competency, thus removing doubt about the suitability of the plugging process. It will be a time-consuming process due to the W.O.C. intervals, but successfully placed cement plugs will protect USDW.

Volume calculations will be based upon established oilfield methods, using measured pipe diameters. The series of casing caliper logs run over the life of the long string will provide the real-time inside diameter of that pipe after many years of service. The actual outside and inside diameters of the tubing work string can be measured on-site with hand calipers. An example calculation for volume of an annulus is: $(OD^2 - ID^2) \div 1029.4$ = volume in bbls per foot.

Prior to plugging, the internal competence of the long string will be tested by running a casing caliper log; this log will show remaining wall thickness. The external competence of the cement sheath around the long string will be tested by running a temperature or noise log, to determine if any fluid is moving in that cemented annulus.

During the lengthy injection period and possible monitoring period after injection, it is likely that surface equipment and infrastructure will have been upgraded, modified or replaced several times.

The plugged well would provide no usage to the owner/operator, so it is envisioned that all of the surface equipment will be removed piecemeal and the location pad and access road would be left in place.

## 6.2 Site Closure Report

A site closure report will be prepared and submitted within 90 days following site closure, documenting the following:

- Plugging of the verification and geophysical,
- Location of sealed injection well on a plat of survey that has been submitted to the local zoning authority,
- Notifications to state and local authorities as required at 40 CFR 146.93(f)(2),
- Records regarding the nature, composition, and volume of the injected $CO_2$, and
- Post-injection monitoring records.

GCS will record a notation to the property's deed on which the injection well was located that will indicate the following:

- That the property was used for carbon dioxide sequestration,
- The name of the local agency to which a plat of survey with injection well location was submitted,
- The volume of fluid injected,
- The formation into which the fluid was injected, and
- The period over which the injection occurred.

The site closure report will be submitted to the permitting agency and maintained by GCS for a period of 10 years following site closure. Additionally, the owner or operator will maintain the records collected during the post-injection period for a period of 10 years after which these records will be delivered to the UIC Program Director.

# 7.0 Quality Assurance and Surveillance Plan (QASP)

The Quality Assurance and Surveillance Plan is presented in the Appendix of the Testing and Monitoring Plan.

# 8.0 APPENDICES

## 8.1 APPENDIX 1 – Sensitivity Study on Reveal Simulation Model

### Introduction

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## 8.2 APPENDIX 2 – $CO_2$ dissolution in the Reveal Simulation Model

Please see Section 2.2.10 in the AoR and Corrective Action Plan report.

## 8.3 APPENDIX 3 – Saturation Functions in the Reveal Simulation Model

Please see Section 2.2.13 in the AoR and Corrective Action Plan report.

## 8.4 APPENDIX 4 – Area of Review Frio-depth Well Penetration Schematics

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# EMERGENCY AND REMEDIAL RESPONSE PLAN
# 40 CFR 146.94(a)

## Project Minerva

## 1.0 Facility Information

| | |
|---|---|
| Facility name: | Project Minerva<br>Wells 1-4 |
| Facility contact: | Benjamin Heard, Principal<br>2417 Shell Beach Drive, Lake Charles, Louisiana 70601<br>(713) 320-2497, bheard@gcscarbon.com |
| Well location: | Calcasieu/Cameron Parish, Louisiana<br>Well No 1: [redacted]<br>Well No 2:<br>Well No 3:<br>Well No 4: |

## 2.0 Introduction

This Emergency and Remedial Response Plan (ERRP) describes actions that Gulf Coast Sequestration (GCS) shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods.

If GCS obtains evidence that the injected $CO_2$ stream and/or associated pressure front may cause an endangerment to a USDW, GCS must perform the following actions:

1. Initiate shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize any release.
3. Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed: GCS will immediately cease injection. However, in some circumstances, GCS will, in consultation with the UIC Program Director, determine whether gradual cessation of injection (using the parameters set forth in Attachment A of the Class VI permit) is appropriate.

## 3.0 Local Resources and Infrastructure

Resources in the vicinity of Project Minerva that may be affected as a result of an emergency event at the project site include:

- Local USDW

Infrastructure in the vicinity of the Project Minerva that that may be affected as a result of an emergency at the project site include:

- Pipelines;
- Three active and two shut-in oil and gas wells in the Vinton Dome area; and
- Four active ground water wells.

Resources and infrastructure addressed in this plan are shown in Figure 3.1

**Figure 3.1 Regional map showing all active infrastructure within, or intersecting, the Area of Review**

## 4.0 Potential Risk Scenarios

The following events related to the Project Minerva that could potentially result in an emergency response:

- Injection or monitoring? (verification) well integrity failure;
- Injection well monitoring equipment failure (e.g., shut-off valve or pressure gauge, etc.);
- A natural disaster (e.g., earthquake, tornado, hurricane, lightning strike);
- Fluid (e.g., brine) leakage to a USDW;
- $CO_2$ leakage to USDW or land surface; or
- Significant induced seismic event, of level Orange or Magenta in Table 4.2.

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table 4.1

**Table 4.1 Degrees of risk for emergency events.**

| Emergency Condition | Definition |
|---|---|
| Major emergency | Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated. |
| Serious emergency | Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken. |
| Minor emergency | Event poses no immediate risk to human health, resources, or infrastructure. |

## 4.1 Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. The potential risk scenarios identified in Part 2 are detailed below.

### *4.1.1 Well Integrity Failure*

Integrity loss of the injection well may may endanger USDWs. Integrity loss may have occurred if the following events occur:

- Automatic shutdown devices are activated:
    - Wellhead pressure exceeds the specified shutdown pressure specified in the permit.
    - Annulus pressure indicates a loss of external or internal well containment.

  - Pursuant to 40 CFR 146.91(c)(3), Project Minerva must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the surface).
- Mechanical integrity test results identify a loss of mechanical integrity.

Response actions:

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency:
  - Initiate response plan.
  - If contamination is detected, identify and implement appropriate remedial actions (in consultation with the UIC Program Director).
- For a Minor emergency:
  - Conduct assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate response plan.

### *4.1.2 Injection Well Monitoring Equipment Failure*

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate an inability to monitor the well which could lead to a loss of mechanical integrity being detected.

Response actions:

- For a Minor emergency:
  - Restore monitoring capability.
  - Conduct assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate response plan.

### *4.1.3 Potential Brine or $CO_2$ Leakage to USDW*

Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or $CO_2$ leakage into a USDW.

Response actions:

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).

- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For all emergencies (Major, Serious, or Minor):
  - Initiate response plan.
  - If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan.
  - For the USDW identified in Figure 3.1 that is being utilized as potable water supply and has been caused to exceed drinking water standards, arrange for an alternate potable water supply.
  - Proceed with efforts to remediate USDW to mitigate any unsafe conditions.
  - Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by Project Minerva and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed.

#### *4.1.4 Natural Disaster*

Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster affecting the normal operation of the injection well. An earthquake may disturb surface and/or subsurface facilities; and weather-related disasters (e.g., tornado, hurricane or lightning strike) may affect surface facilities.

If a natural disaster occurs that affects normal operation of the injection well, perform the following:

Response actions:

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major emergency:
  - Initiate shutdown plan.
  - If contamination or endangerment is detected, identify and implement appropriate remedial actions (in consultation with the UIC Program Director).
- For a Major or Minor emergency:
  - Conduct assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate response plan.

### *4.1.5 Induced Seismic Event*

Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event outside the AoR. Therefore this portion of the response plan is developed for any seismic event within the AoR (see Figure 3.1).

To monitor the area for seismicity, the DAS fibre will be set to detect seismic events.

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions.

The seismic monitoring system structure is presented in Table 4.2. The table corresponds each level of operating state with the threshold conditions and operational response actions.

**Table 4.2 Seismic monitoring system, for seismic events > M1.0 with an epicenter within the AoR.**

| Operating State | Threshold Condition[1,2] | Response Action[3] |
|---|---|---|
| **Green** | Seismic events less than or equal to M1.5 | 1. Continue normal operation within permitted levels. |
| **Yellow** | Five (5) or more seismic events within a 30 day period having a magnitude greater than M1.5 but less than or equal to M2.0 | 1. Continue normal operation within permitted levels.<br>2. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well. |
| **Orange** | Seismic event greater than M1.5 and local observation or felt report<br>Seismic event greater than M2.0 and no felt report | 1. Continue normal operation within permitted levels.<br>2. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well.<br>3. Review seismic and operational data.<br>4. Report findings to the UIC Program Director and issue corrective actions. |
| **Magenta** | Seismic event greater than M2.0 and local observation or report | 1. Initiate rate reduction plan.<br>2. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well.<br>3. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary.<br>4. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director).<br>5. Determine if leaks to ground water or surface water occurred.<br>6. If USDW contamination is detected:<br>a. Notify the UIC Program Director within 24 hours of the determination.<br>7. Review seismic and operational data.<br>8. Report findings to the UIC Program Director and issue corrective actions. |

[1] Specified magnitudes refer to magnitudes determined by local Project Minerva or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.

[2] "Felt report" and "local observation and report" refer to events confirmed by local reports of felt ground motion or reported on the USGS "Did You Feel It?" reporting system.

[3] Reporting findings to the UIC Program Director and issuing corrective action will occur within 25 business days (five weeks) of change in operating state.

| Operating State | Threshold Condition[1,2] | Response Action[3] |
|---|---|---|
| **Red** | Seismic event greater than M2.0, and local observation or report, and local report and confirmation of damage[4] | 1. Initiate shutdown plan.<br>2. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well.<br>3. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary.<br>4. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director).<br>5. Determine if leaks to ground water or surface water occurred.<br>6. If USDW contamination is detected:<br>a. Notify the UIC Program Director within 24 hours of the determination.<br>7. Review seismic and operational data.<br>8. Report findings to the UIC Program Director and issue corrective actions. |
| | Seismic event >M3.5 | |

[4] Onset of damage is defined as cosmetic damage to structures, such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.

## 5.0 Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP.

Site personnel to be notified (not listed in order of notification):

1. Project Engineer(s)
2. Plant Safety Manager(s)
3. Environmental Manager(s)
4. Plant Manager
5. Plant Superintendent

A site-specific emergency contact list will be developed and maintained during the life of the project. Project Minerva will provide the current site-specific emergency contact list to the UIC Program Director.

**Table 5.1. Contact information for key local, state, and other authorities.**

| Agency | Phone Number |
|---|---|
| Local police | 337-589-3561 (Vinton Police Department) |
| State police | 337-491-2511 (Troop D, Lake Charles) |
| State emergency management agency | 337-721-3800 (Calcasieu), 337-775-7048 (Cameron) |
| Environmental services contractor | Vendor to be selected |
| UIC Program Director | |
| EPA National Response Center (24 hours) | 800-424-8802 |
| State geological survey | 225-578-5320 |

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, Project Minerva shall be responsible for its procurement.

## 6.0 Emergency Communications Plan

Project Minerva will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether or not there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

Project Minerva will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For responses that occur over the long-term (e.g., ongoing cleanups), Project Minerva will provide periodic updates on the progress of the response action(s).

Project Minerva will also communicate with entities who may need to be informed about or take action in response to the event, including local water systems, $CO_2$ source(s) and pipeline operators, land owners, and Regional Response Teams (as part of the National Response Team).

## 7.0 Plan Review

This ERRP shall be reviewed:

- At least once every five (5) years following its approval by the permitting agency;
- Within one (1) year of an area of review (AoR) reevaluation;
- Within Project Minerva following any significant changes to the injection process or the injection facility, or an emergency event; or
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, Project Minerva will provide the permitting agency with the documentation supporting the "no amendment necessary" determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within Project Minerva following an event that initiates the ERRP review procedure.

## 8.0 Staff Training and Exercise Procedures

Training and exercise procedures (with appropriate manuals) will be compiled once a clear understanding of the facilities and personel are finalized.

## Class VI UIC Project Plan Submissions

This submission is for:

Project ID: R06-LA-0002

Project Name: Project Minerva

Current Project Phase: Pre-Injection Prior to Construction

## Testing and Monitoring

Are You Making a Testing and Monitoring Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Testing and Monitoring Plan: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/ProjPlan-03-26-2021-1956/E.2.1--Testing--and--Monitoring--Plan--GSDT.pdf

Appendices and Supporting Materials Upload

## Injection Well Plugging

Are You Making an Injection Well Plugging Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Injection Well Plugging Plan: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/ProjPlan-03-26-2021-1956/E.3.1--Plugging--Plan--GSDT.pdf

Appendices and Supporting Materials Upload

## PISC and Site Closure

Are You Making a Post-Injection Site Care and Site Closure Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Post-Injection Site Care and Site Closure Plan: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/ProjPlan-03-26-2021-1956/E.4.1--Alternative--PISC--GSDT.pdf

Appendices and Supporting Materials Upload

## Emergency and Remedial Response

Are You Making an Emergency and Remedial Response Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Emergency and Remedial Response Plan: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/ProjPlan-03-26-2021-1956/E.5.1--Emergency--and--Remedial--Response--GSDT.pdf

Appendices and Supporting Materials Upload

## Complete Submission

Authorized submission made by: Benjamin Heard

For confirmation a read-only copy of your submission will be emailed to: randrews@gcscarbon.com