Class VI UIC Area of Review and Corrective Action

This submission is for:

Project ID: R06-LA-0002

Project Name: Project Minerva

Current Project Phase: Pre-Injection Prior to Construction

Overview

Simulator Used for AoR delineation modeling: Other

Other Simulator: REVEAL

Version Used: IPM V12.0 Reveal V9.0

Simulator Description/Documentation: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--1.pdf

Description of File Contents: Complete user manual for Reveal V9

Total Simulation Time From Start of Injection: 130 yrs

Additional AoR Delineation Information: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--2.pdf

Model Domain

Coordinate System: State Plane

Horizontal Datum: NAD27

Coordinate System Units: ft

Vertical Datum: Reference Elevation

Describe Vertical Datum: NAVD 88

Zone: Louisiana South

FIPSZONE: 1702 ADSZONE: 4051

Mesh Type: Hexahedral Curvilinear

Domain Size in Global Units Specified Above

Domain Coordinates File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--37.pdf

Grid Size

Number of Nodes in x: 340 y: 232 z: 28

Grid Spacing: Variable

Grid File Format: Eclipse Keyword File

Grid File Description: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--3.pdf

Eclipse Keyword File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--4.pdf

Faults Modeled: Yes

Fault Coordinates File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--5.pdf

Caprock Modeled: Yes

Image File(s) for Model Domain Grid: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--6.pdf

Processes Modeled by Simulator

Reservoir Conditions:

Supercritical CO2 Conditions

Phases Modeled:

Aqueous Supercritical CO2

Aqueous Phase:

Phase Compressibility: Compressible

Compressibility Value: -999 1/psi

Phase Composition: Compositional

Aqueous Phase Components:

CO2 Water Salt

Supercritical CO2 Phase:

Phase Compressibility: Compressible

Phase Composition: Compositional

Supercritical CO2 Phase Components:

CO2 Methane

Equation of State Description Including Reference: Please see CBI submission

File with EOS Reference or Documentation: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--7.pdf

Multifluid Flow Processes:

Advection Buoyancy

Non-wetting Fluid Trapping Pore Compressibility

Thermal Conditions: Non-Isothermal

File Describing Thermal Conductivity Function including Parameters: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--8.pdf

Heat Transport Processes:

Advection Conduction

Geochemistry Modeled: Yes

File Describing Geochemistry Modeling: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--9.pdf

Geomechanical/Structural Deformations Modeled: Yes

File Describing Geomechanical/Structural Modeling: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--10.pdf

Rock Properties and Constitutive Relationships

Porosity/Permeability Model

Single Porosity

Porosity Distribution: Heterogeneous

Porosity included in Eclipse Keyword File: Yes

Porosity Variable Name in Eclipse Keyword File: PORO

File Describing how Porosity was Determined and Assigned to Numerical Model: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--11.pdf

Image Files for Porosity Distributions: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--12.pdf

Permeability Distribution: Heterogeneous

Permeability included in Eclipse Keyword File: Yes

Permeability Variable Name in Eclipse Keyword File: PERMX, PERMY, PERMZ

File Describing how Permeability was Determined and Assigned to Numerical Model: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--13.pdf

Image Files for Permeability Distributions: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--14.pdf

Number of Rock Types Modeled: 1

Description of Rock Type Selection and Assignment: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--15.pdf

Rock Type Distribution Data File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--16.pdf

Image Files for Rock Type Distribution: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--17.pdf

Rock Type #1

Rock Compressibility: Pore

Rock Compressibility Distribution: Single Value

Compressibility Value: -999 1/psi

Compressibility included in Eclipse Keyword File: No

Constitutive Relationships

Aqueous Saturation vs. Capillary Pressure: Table

Tabular Format File for Aqueous Saturation vs Capillary Pressure: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--18.pdf

Aqueous Trapped Gas Modeled: Yes

Hysteresis other than non-wetting fluid trapping: No

Aqueous Relative Permeability: Table

Tabular Format File for Aqueous Relative Permeability: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--19.pdf

Hysteresis other than non-wetting fluid trapping: No

Gas Relative Permeability: Table

Tabular Format File for Gas Relative Permeability: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--20.pdf

Hysteresis other than non-wetting fluid trapping: Yes

File Providing Both Drainage and Imbibition Curves: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--21.pdf

Porosity and Permeability Reduction Due to Salt Precipitation

Boundary Conditions

Attach Boundary Conditions Description File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--22.pdf

Initial Conditions

Initial Phases in Domain: Aqueous

Initial Aqueous Pressure: Varying with Depth, Temperature, and Salinity

Initial Aqueous Pressure: -999 psi at Reference Elevation: -999 ft

Initial Temperature: Varying with Depth

Initial Temperature: -999 C at Reference Elevation: -999 m Gradient: -999 deg C/m

Initial Salinity: Spatially Constant

Initial Salinity: -999 ppm

Operational Information

Number of Injection Wells: 4

Injection Well #1

Well Direction: Vertical

Location: X: -999 UTM Y: -999 UTM

Wellbore Diameter: Constant

Wellbore Diameter: 8.5 in

Well Screen Interval Provided as: Single Interval

Elevation of Top of Screened Interval: -999 Elevation of Bottom of Screened Interval: -999 ft

Mass Rate of Injection: -999 MMT/yr

Total Mass of Injection: -999 MMT

Actual Injection Temperature: -999 C

Modeled Injection Temperature: -999 C

Fracture Gradient: -999 psi/ft

Maximum Injection Pressure: -999 psi Elevation Corresponding to Pressure: -999 ft

Description of How Fracture Gradient and Maximum Injection Pressure were Determined File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--23.pdf

Composition of Injectate: Pure CO2

Injection Schedule Provided as: Single Injection Period

Injection Start Date: 01/01/2020 Stop Date: 01/01/2050

Injection Well #2

Well Direction: Vertical

Location: X: -999 UTM Y: -999 UTM

Wellbore Diameter: Constant

Wellbore Diameter: 8.5 in

Well Screen Interval Provided as: Single Interval

Elevation of Top of Screened Interval: -999 Elevation of Bottom of Screened Interval: -999 ft

Mass Rate of Injection: -999 MMT/yr

Total Mass of Injection: -999 MMT

Actual Injection Temperature: -999 C

Modeled Injection Temperature: -999 C

Fracture Gradient: -999 psi/ft

Maximum Injection Pressure: -999 psi Elevation Corresponding to Pressure: -999 ft

Description of How Fracture Gradient and Maximum Injection Pressure were Determined File:

https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--24.pdf

Composition of Injectate: Pure CO2

Injection Schedule Provided as: Single Injection Period

Injection Start Date: 01/01/2020 Stop Date: 01/01/2050

Injection Well #3

Well Direction: Vertical

Location: X: -999 UTM Y: -999 UTM

Wellbore Diameter: Constant

Wellbore Diameter: 8.5 in

Well Screen Interval Provided as: Single Interval

Elevation of Top of Screened Interval: -999 Elevation of Bottom of Screened Interval: -999 ft

Mass Rate of Injection: -999 MMT/yr

Total Mass of Injection: -999 MMT

Actual Injection Temperature: -999 C

Modeled Injection Temperature: -999 C

Fracture Gradient: -999 psi/ft

Maximum Injection Pressure: -999 psi Elevation Corresponding to Pressure: -999 ft

Description of How Fracture Gradient and Maximum Injection Pressure were Determined File:

https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--25.pdf

Composition of Injectate: Pure CO2

Injection Schedule Provided as: Single Injection Period

Injection Start Date: 01/01/2020 Stop Date: 01/01/2050

Injection Well #4

Well Direction: Vertical

Location: X: -999 UTM Y: -999 UTM

Wellbore Diameter: Constant

Wellbore Diameter: 8.5 in

Well Screen Interval Provided as: Single Interval

Elevation of Top of Screened Interval: -999 Elevation of Bottom of Screened Interval: -999 ft

Mass Rate of Injection: -999 MMT/yr

Total Mass of Injection: -999 MMT

Actual Injection Temperature: -999 C

Modeled Injection Temperature: -999 C

Fracture Gradient: -999 psi/ft

Maximum Injection Pressure: -999 psi Elevation Corresponding to Pressure: -999 ft

Description of How Fracture Gradient and Maximum Injection Pressure were Determined File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--26.pdf

Composition of Injectate: Pure CO2

Injection Schedule Provided as: Single Injection Period

Injection Start Date: 01/01/2020 Stop Date: 01/01/2050

Number of Production/Withdrawal Wells: 0

Model Output/Results

Provide file name and corresponding spatial location for each file: Please see CBI submission

Time-Series File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--27.pdf

Provide file name and corresponding variable and time stamp for each file: Please see CBI submission

Snapshot File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--28.pdf

Provide file name and corresponding description of surface for each file: Please see CBI submission

Surface Flux File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--29.pdf

Sensitivity Analysis Description/Results: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--30.pdf

AoR Pressure Front Delineation

Lowermost USDW:

Name of Lowermost USDW: PLIOCENE

Water Density: -999 kg/m^3 at Elevation: -999 ft

Location of Measurement for Density: -999

Temperature: -999 C at Elevation: -999 ft

Location of Measurement: -999

Pressure: -999 psi at Elevation: -999 m

Location of Measurement: -999

Salinity: -999 ppm at Elevation: -999 m

Location of Measurement: -999

Elevation of bottom of USDW: -999 ft

Injection Zone:

Name of Injection Zone: Frio Formation

Water Density: -999 kg/m^3 at Elevation: -999 m

Location of Measurement: -999

Temperature: -999 C at Elevation: -999 m

Location of Measurement: -999

Pressure: -999 psi at Elevation: -999 m

Location of Measurement: -999

Salinity: -999 ppm at Elevation: -999 m

Location of Measurement: -999

Elevation of top of Injection Zone: -999 ft

Method of Estimating Critical Pressure: Dynamic Modeling

Describe Model Used: -999

File Describing Critical Pressure Estimation: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--31.pdf

Estimated Critical Pressure: -999 psi

Delineated AoR:

Shapefile or KML File Showing Delineated AoR: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--32.pdf

Corrective Action

File with Location of All Penetrations within AoR: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--33.pdf

File with Location of Wells Requiring Corrective Action: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--34.pdf

Supporting Documentation: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--35.pdf

Area of Review and Corrective Action Plan [40 CFR 146.82(a)(13) and 146.84(b) or applicable state requirements]

Are you making an Area of Review and Corrective Action Plan submission at this time?: Yes

Reason for Project Plan Submission: Permit application submission

Project Plan Upload

Attach the Area of Review and Corrective Action Plan: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/AoRModeling-03-19-2021-1221/GCS--AoR--CBI--36.pdf

Appendices and Supporting Materials Upload

Area of Review Reevaluation [40 CFR 146.84(e) or applicable state requirements]

Minimum fixed frequency of AoR reevaluation: 5 Years

Are you making an Area of Review reevaluation submission at this time?: No

Reevaluation Background

Reevaluation Materials

Please upload your amended AoR and Corrective Action Plan on the previous tab.

Complete Submission

Authorized submission made by: Benjamin Heard

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

ENVIRONMENTAL PROTECTION AGENCY ("EPA")
UNDERGROUND INJECTION CONTROL PROGRAM

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GULF COAST SEQUESTRATION LLC
PROJECT MINERVA

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UNDERGROUND INJECTION CONTROL PROGRAM

CLASS VI PERMIT (40 CFR SUBPART H § 146.81- 146.95)

GULF COAST SEQUESTRATION LLC
PROJECT MINERVA

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Relative permeability model

Drainage Curves

As for capillary pressures, this data is separated into three sets; one is where it has been sourced for a generic CCS study; a second is from core data unrelated to the Frio formation directly but useful as analogue data; and third, where the data is specific to the Frio formation.

In the first group we have data from **(Kumar, 2005)** who looked at storage in deep saline aquifers and neglected capillary pressures. (**Ghanbari, 2006)** studied CO_2 storage in saline aquifers, with no particular storage system modelled and also ignored capillary pressure. **(Juanes, 2006)** looked at hysteresis effects in the context of a CCS, using generic data. **(Zeidouni, 2009)** conducted a sensitivity analysis of salt precipitation and CO_2-brine displacement in saline aquifers but with no particular storage system modelled. They neglected capillary pressure. The data from **(Zeidouni, 2009)** was used in a study of CCS in the Lower Miocene in the Texas Gulf of Mexico **(Wallace, 2017)**.

There have been two definitive, long running studies on measuring relative permeability in CO_2/brine core systems.

The first was conducted by Bachu and Bennion, between early to mid-2000's, and summarised in **(Bennion, 2008)** where 14 sets of relative permeabiity curves (7 drainage only and 7 drainage and imbibition) were measured on cores from rocks in central Alberta, Canada. The rocks tested were sandstones, carbonates, shales and anhydrites. Between 2008 and 2010 a second set of relative permeability measurements (drainage and imbibition). New measurements were made on 8 carbonate rocks and, together with the results of measurements on 5 carbonate rocks from the first programme, the results were published in **(Bennion, 2010)**.

A second series of independent measurements of relative permeabilities were made between 2009 and 2012 at Stanford University on cores from 5 samples of rock from Berea, Mt. Simon and Tuscaloosa sandstones in the USA and the Otway and Paaratte sandstones in Australia **(Perrin, 2010)**, **(Zuo, 2012)** and **(Krevor, 2012)**. The Stanford team reached the conclusion that sub-core scale heterogeneity and rock structure and mineralogy, hence wettability, impact the relative permeability characteristics of CO_2/brine systems as identified by **(Müller, 2011)**.

(Mathias, 2013) analysed all 25 sets of relative permeability data (drainage only) for the CO2/brine system and reached the following conclusions:

- *There is no difference between the steady-state and unsteady-state measurement methods used in obtaining the two data sets;*
- *there is no link between relative permeability characteristics and rock porosity and/or permeability, similar to the findings of **(Bennion, 2008)** and **(Bennion, 2010)**.*
- *there is no marked difference between sandstone and carbonate rocks;*
- *there is no link (during the drainage cycle) between the pressure increase as a result of injection, and lithology, permeability, porosity and/or interfacial tension (IFT) of CO_2 and brine;*

- *and Injectivity uncertainty due to relative permeability can be as high as close to 60% for open aquifers and for low-permeability (k < 50 mD) closed aquifers, and as low as 6% for high permeability (k > 100 mD) closed aquifers, where compressibility effects are more significant than relative permeability effects.*

(Bachu, 2013) presented a new set of measurements of CO_2/brine system relative permeabilities from 16 previously unreported sandstone rocks and combined the results with 6 sandstone rocks from his first measurement programme **(Bennion, 2008)** for a total of 22 tests. The test data covered a wide range of permeabilities from less than 0.1 mD to > 500 mD.

His conclusions were:

- *No clear, direct relationships or dependencies were found between any of the relative permeability characteristics of the CO_2/brine systems (irreducible saturations, relative permeability at irreducible saturations, Corey coefficients, trapping efficiency, Land coefficient) and any of the commonly-measured rock petrophysical properties (pore size distributions, porosity and absolute permeability) or IFT, confirming the findings of **(Mathias, 2013)** based on results reported in **(Bennion, 2008)** and **(Perrin, 2010)**, **(Zuo, 2012)** and **(Krevor, 2012)**.*

- *Generally, the data display a broad scatter in a wide range. CO_2 irreducible saturation varies in the range 0.102 to 0.519, with an average of 0.314, comparable with results obtained by Australia **(Perrin, 2010)**, **(Zuo, 2012)** and **(Krevor, 2012)**, **(Akbarabadi, 2013)**, **(Suekane, 2008)** and **(Shi, 2011)**. However, the irreducible brine saturation **(Bachu, 2013, Table 3)** broadly increases with increasing absolute permeability, likely due to channeling and bypassing of zones of lower permeability in the core.*

- *Trapping efficiency (defined as the ratio of the maximum CO_2 saturation at the end of the imbibition cycle to the maximum CO_2 saturation at the end of the drainage cycle **(Akbarabadi, 2013)**), **(Bachu, 2013, Table 4)** also displays a broad trend of increasing in value with increasing absolute permeability. Except for two very high values of 5.37 and 8.56, the Land coefficient, C, (see below) varies between 0.177 and 2.213, with eleven values less than 1 and six values greater than 1, and with an average for these 17 cases of C = 1.054.*

- *Excluding the two cases with very high values for the Land coefficient, there is a broad trend of increasing CO_2 irreducible saturation with increasing maximum CO_2 saturation, as noted also by **(Krevor, 2012)**. However, no relationship was found between maximum CO_2 saturation or the Land coefficient and absolute permeability, as found by **(Krevor, 2012)** on four tested sandstone samples.*

The conclusion we take from this is that whilst analogue data is useful as a sense-check, site-specific data is required for the accurate characterisation of relative permeability and, by extension, capillary pressure data.

Studies specific to the Frio Formation include **(Doughty, 2007)**, **(Ghomian, 2008)** and **(Jung, 2018)**. In addition, we have relative permeability data from data from the GEM simulation model from the Bureau of Economic Geology **(Hosseini, 2019)**. This data had been history matched to measured data from the Frio CO_2 CCS pilot project. It therefore has added weight. There were data for two rock types. Rock type 2 data appeared to be for a sandstone, whereas rock type 1 was for a tighter (shale or mud stone?) rock with a lower relative permeability to water and much larger capillary pressures.
All the relative permeability curves for both the aqueous and gaseous phases are plotted in figure 42 to give an idea of the variability in the data.

All relative permeability data

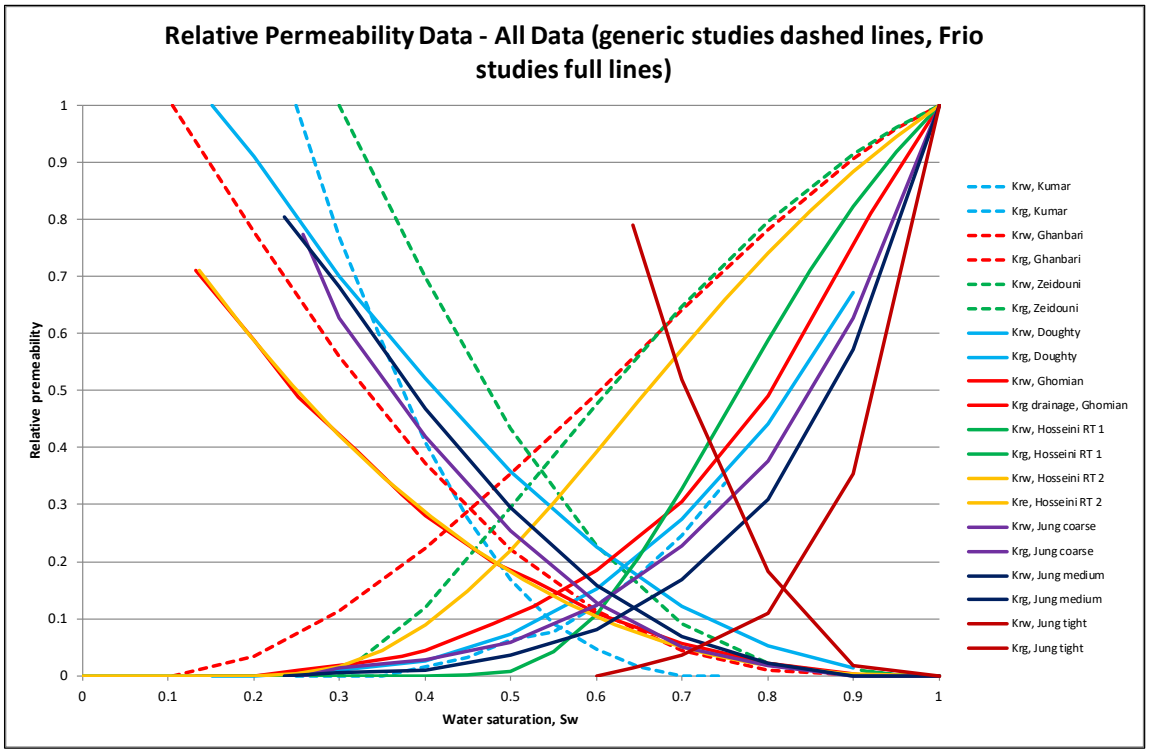

Figure 42: All relative permeability data; generic and Frio studies

In figure 43 we plot only the Frio specific data.

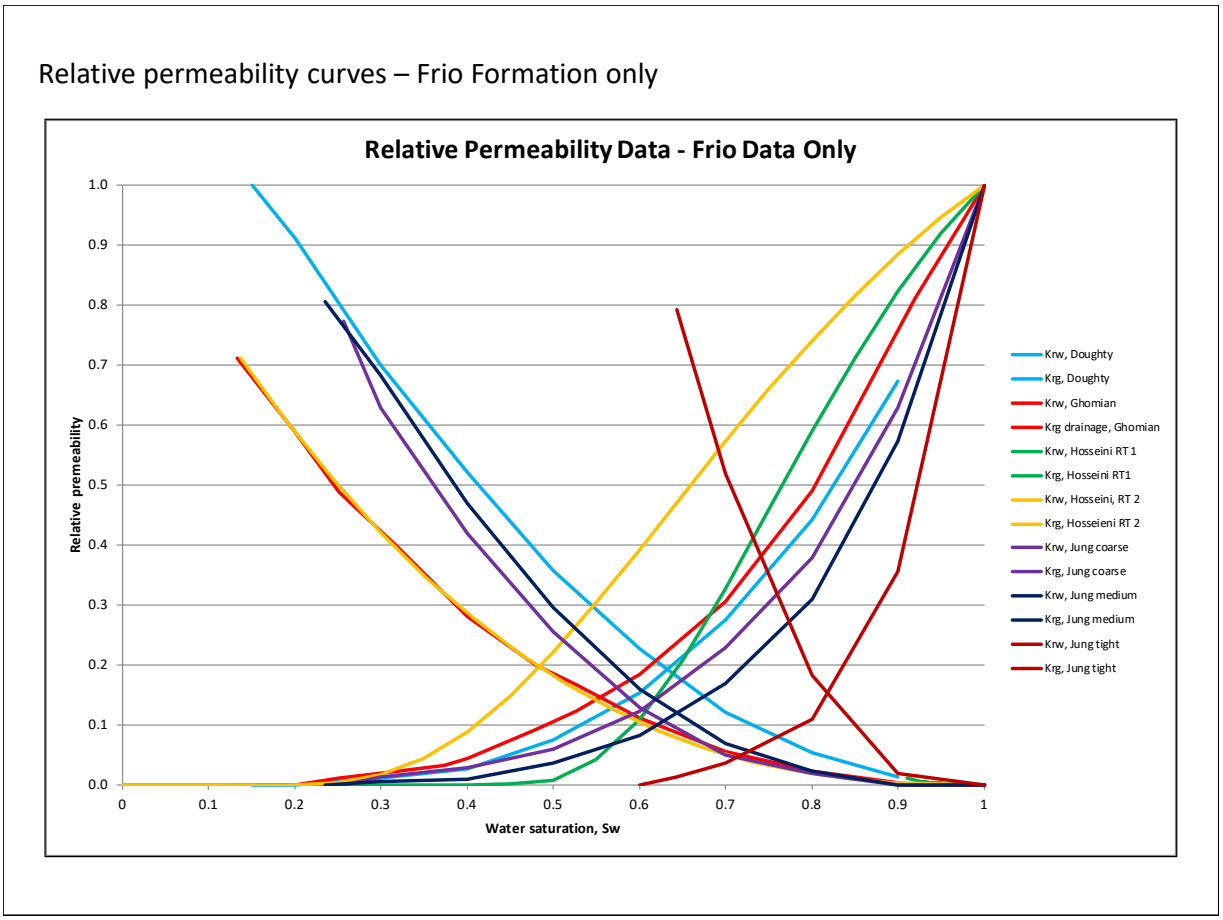

Figure 43: Relative permeability curves; Frio Formation data only

The k_{rg} curve from **(Ghomian, 2008)** and the rock type 2 GEM data set from BEG **(Hosseini, 2019)** are representations of the same function. In contrast, the water relative permeability data in the GEM data from the BEG differed from the function used by **(Ghomian, 2008)**.

We now define three sets of relative permeability data, a minimum, most likely and maximum cases. For our most likely case we take the relative permeabilities in the BEG's GEM model, rock type 2 **(Hoesseini, 2019).** In terms of the distribution of gas phase relative permeability curves, the Krg used by **(Hosseini, 2017)** is the lowest but it has been calibrated (history matched) to observed data from wells injecting CO_2 into the Frio Formation which gives it more weight than the other data. The Krg curve can be modelled with a Corey function using an exponent of 2.45 and a maximum relative permeability of 0.71 at the residual water saturation to gas of 0.133. It is difficult to fit the corresponding Krw curve using a Corey relative permeability curve.

Sw	Krw	Krg	Pc
			psia
0.133	0	0.71	
0.15	0.000001	0.676376	40.28467
0.2	0.0001	0.583018	6.471009
0.25	0.002924	0.49775	3.077211
0.3	0.016392	0.420341	1.914769
0.35	0.04432	0.350549	1.350389
0.4	0.088235	0.288126	1.024212
0.45	0.147653	0.232809	0.814691
0.5	0.220387	0.184327	0.670168
0.55	0.303071	0.142391	0.565228
0.6	0.391806	0.106699	0.486014
0.65	0.482781	0.076927	0.424376
0.7	0.572719	0.05273	0.375227
0.75	0.659104	0.033734	0.335242
0.8	0.740229	0.019527	0.30216
0.85	0.815104	0.00965	0.274397
0.9	0.883313	0.003574	0.25081
0.92	0.90793	0.002069	0.242348
0.95	0.944855	0.000654	0.230556
1	1	0	0.213

Table 13: Most likely relative permeabilities and capillary pressures

For our maximum case (maximum relative permeability to gas) we take the k_{rg} and k_{rw} from **(Doughty, 2017)**. Values are given in table 14.

Sw	***Krw***	Krg	Pc
			psia
0.15	0	1	
0.2	0.000204	0.8912	62.1
0.25	0.001628	0.788352	24.6
0.3	0.005496	0.691497	14.3
0.4	0.025443	0.515931	7.3
0.45	0.043965	0.437314	5.7
0.5	0.069815	0.364877	4.6
0.55	0.104213	0.298681	3.9
0.6	0.148382	0.238791	3.3
0.65	0.203542	0.185282	2.9
0.7	0.270914	0.13824	2.5
0.75	0.35172	0.097766	2.3
0.8	0.447181	0.063982	2.0
0.85	0.558518	0.037041	1.8
0.9	0.686953	0.017144	1.7
0.95	0.833706	0.004594	1.5
1	1	0	1.4

Table 14: Maximum relative permeabilities (to gas) and capillary pressures

The k_{rg} curve is modelled with a Corey function using an exponent of 1.9 and a maximum relative permeability of 1.0 at the residual water saturation to gas of 0.15. The k_{rw} curve is modelled with a Corey exponent of 3.0.

For our minimum case (minimum relative permeability to gas) we assume a data set, figure 44 and table 15. The reasons for choosing this curve are set out below. The k_{rg} curve was modelled with a Corey function using an exponent of 4.6 and a maximum relative permeability of 1.0 at the residual water saturation to gas of 0.1. The k_{rw} curve is modelled with a Corey exponent of 1.2 with an end point relative permeability of 0.3 at $S_w = 1$.

Sw	Krw	Krg	Pc
			psia
0.05	0	1	
0.1	0.009	0.780	1.349
0.2	0.033	0.454	0.450
0.25	0.046	0.337	0.337
0.3	0.060	0.245	0.270
0.35	0.075	0.175	0.225
0.4	0.091	0.121	0.193
0.45	0.106	0.081	0.169
0.5	0.122	0.052	0.150
0.55	0.139	0.032	0.135
0.6	0.156	0.019	0.123
0.65	0.173	0.010	0.112
0.7	0.190	0.005	0.104
0.75	0.208	0.002	0.096
0.8	0.226	0.001	0.090
0.85	0.244	0.000	0.084
0.9	0.263	0.000	0.079
0.95	0.281	0.000	0.075
1	0.3	0	0.071

Table 15: Minimum relative permeabilities (to gas) and capillary pressures

These data sets apply to the Frio Formation. We have not defined a set of relative permeability curves for the Anahuac Shale.

One of the sensitivities affecting relative permeability is the wettability of the formation. In water wet systems capillary forces assist water in entering pores, whereas in the oil wet case they tend to prevent water entering the pores. Systems may also be of intermediate wettability. Usually, the Frio Formation is assumed to be strongly water wet. The following definitions of whether a system id water or oil wet are commonly applied in the oil and gas industry (www.perminc.com).

	Water Wet	**Oil Wet**
S_{wc}	> 20-25% of pore volume	< 10-15% of pore volume
S_w when $k_{rw} = k_{ro}$	> 50%	<50%
k_{rw} at max S_w	< 30%	>50% (can be 100%)

Figure 44 plots the three sets of relative permeability curves (minimum, most likely and maximum) and the curves used in previous Frio studies.

Minimum, most likely and maximum relative permeability curve sets

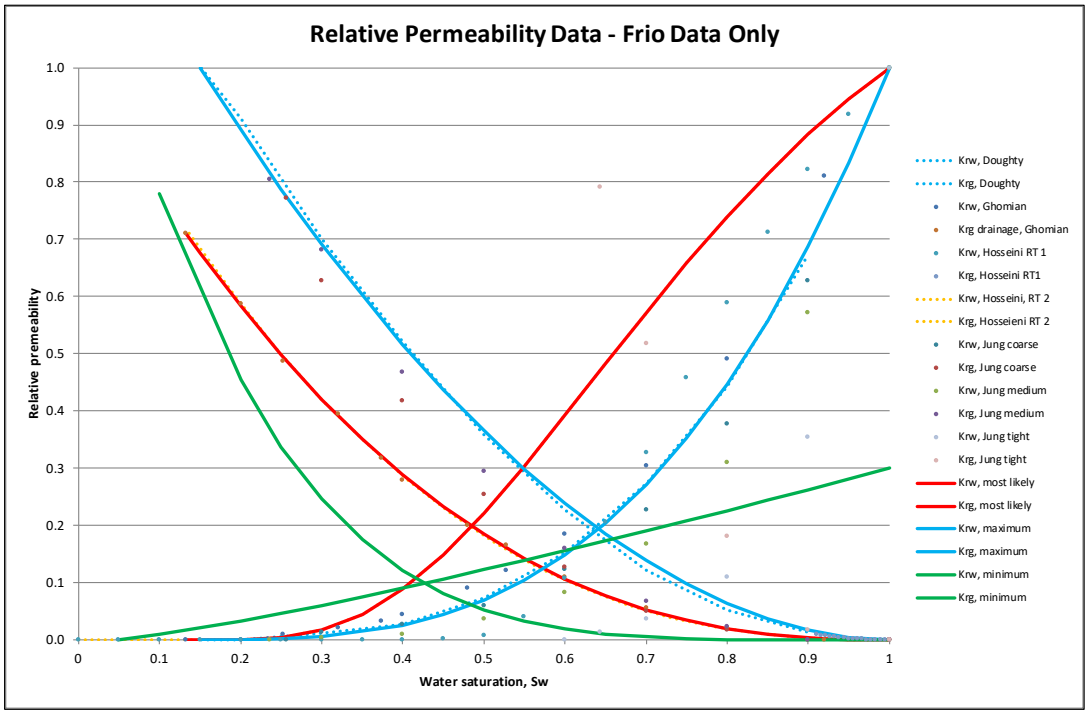

Figure 44: Plots of the three sets of relative permeability curves used in this study

The maximum case, after **(Doughty, 2007)**, is the most water wet. The most likely case, after **(Hosseini, 2019)** is less water wet and the minimum case has been defined to be of mixed or intermediate wettability (i.e. not water wet). This is, we are setting this as a sensitivity to be tested. An example of this type of rock is the Mt. Simon sandstone from Illinois **(Krevor, 2012)** which is illite-rich. This rock forms the storage reservoir for the Illinois basin – Decateur CCS Project **(Yang, 2019), (Leetaru, 2009)**. Another factor affecting the shape of relative permeability curves is the ratio of Darcy (or viscous) forces to capillary pressure forces **(Krevor, 2012)**. This is measured by the dimensionless capillary number, N_c;

$$N_c = v\mu/\sigma \qquad (22)$$

where v (m/s) is the Darcy speed of the flow, μ is the viscosity (Pa s) and σ is the interfacial tension (N/m). The effect of this parameter is to straighten the relative permeability curves (for $N_c >> 10^{-6}$) when capillary forces become much smaller than the imposed Darcy forces. In our system, for CO_2, μ ~ 0.05E-3 Pa s (0.05 cP) and σ ~ 0.033 N/m (33 mN/m). For $N_c > 1$, then v must be greater than ~ 1000 m/s, which it cannot be, so even a high-speed CO_2 plume would not affect the shape of the relative permeability curves.

We can set-up a special relative permeability function locally to the well bores to allow a grid cell near a well bore to be completely dried-out by the injected CO_2.

The initial temperature and pressure at the injection point of our proposed site are ~3660 psia and ~80 ^oC. The viscosity of the CO_2 is ~ 0.05 cP and that of the formation water is ~ 0.5 cP at this temperature

and pressure. At 50 °C, the injection temperature of the CO_2, and at an injection pressure of, say, 4000 psia, the viscosity of the CO_2 is ~ 0.07 cP and that of the formation water is ~ 0.8 cP. So, the ratios of the viscosities of the two phases (water: CO_2) is ~ 10.

The fractional flow of water, f_w, is defined as:

$$f_w = 1 / [1 + \{\mu_w k_{rg}/\mu_{CO2} k_{rw})\}] \quad (23)$$

Here, μ_w is the viscosity of the water, k_{rg} is the relative permeability to gas (CO_2 phase), μ_{CO2} is the viscosity of the CO_2 and k_{rw} is the relative permeability to water.

Figure 45 plots the fractional flow of the water for each of the three sets of relative permeability data, using a viscosity ratio of 10 (water: CO_2).

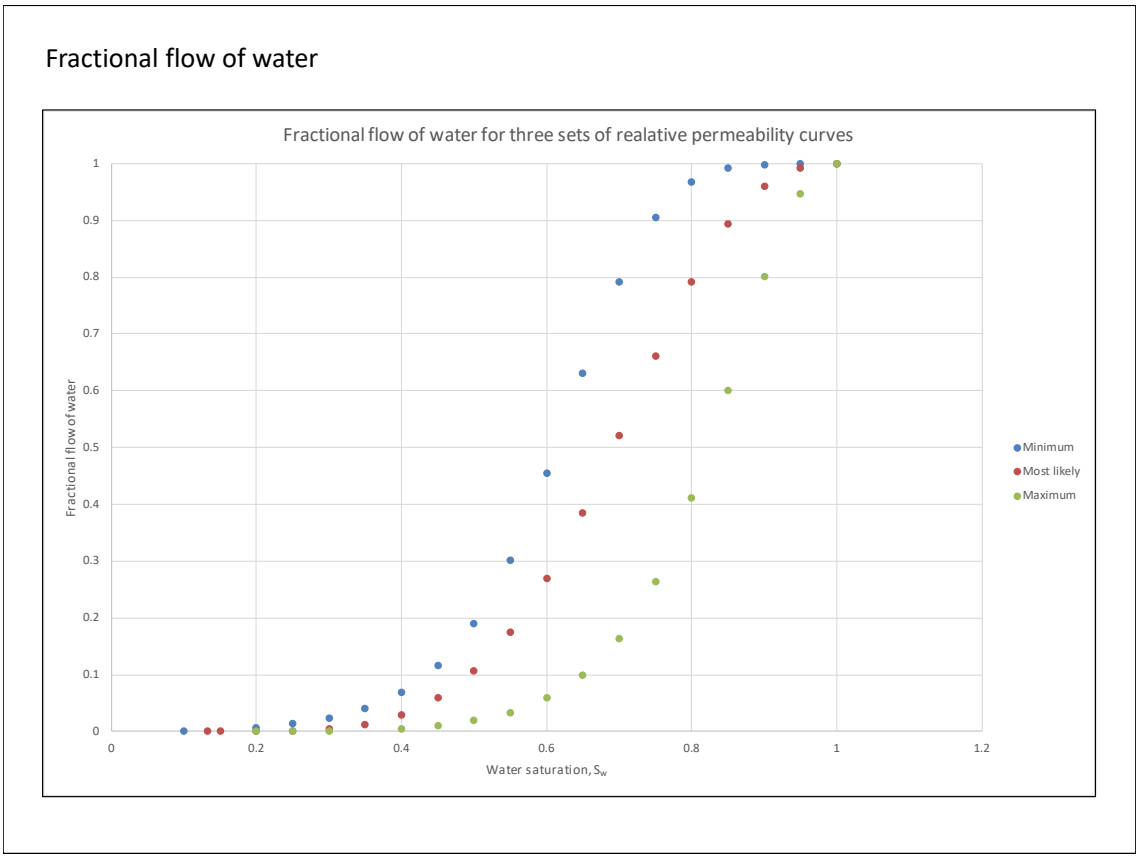

Figure 45: Fractional flow of water for three sets of relative permeability curve

The fractional flow of water increases as we move from the maximum cases to the most likely and the minimum cases. The mobility of the water increases allowing for a higher CO_2 phase saturation behind the leading point of the CO_2 plume, leading to a reduced plume size.

Figure 46 plots the fractional flow of water for the three cases (minimum, most likely and maximum) and compares them to experimental data from **(Krevor, 2012)**. The samples used by **(Krevor, 2012)** are very strongly water wet, as can be seen from figure 47, taken **from (Krevor, 2012, figure 13)**. Our maximum case is reasonably close to Krevor's cases.

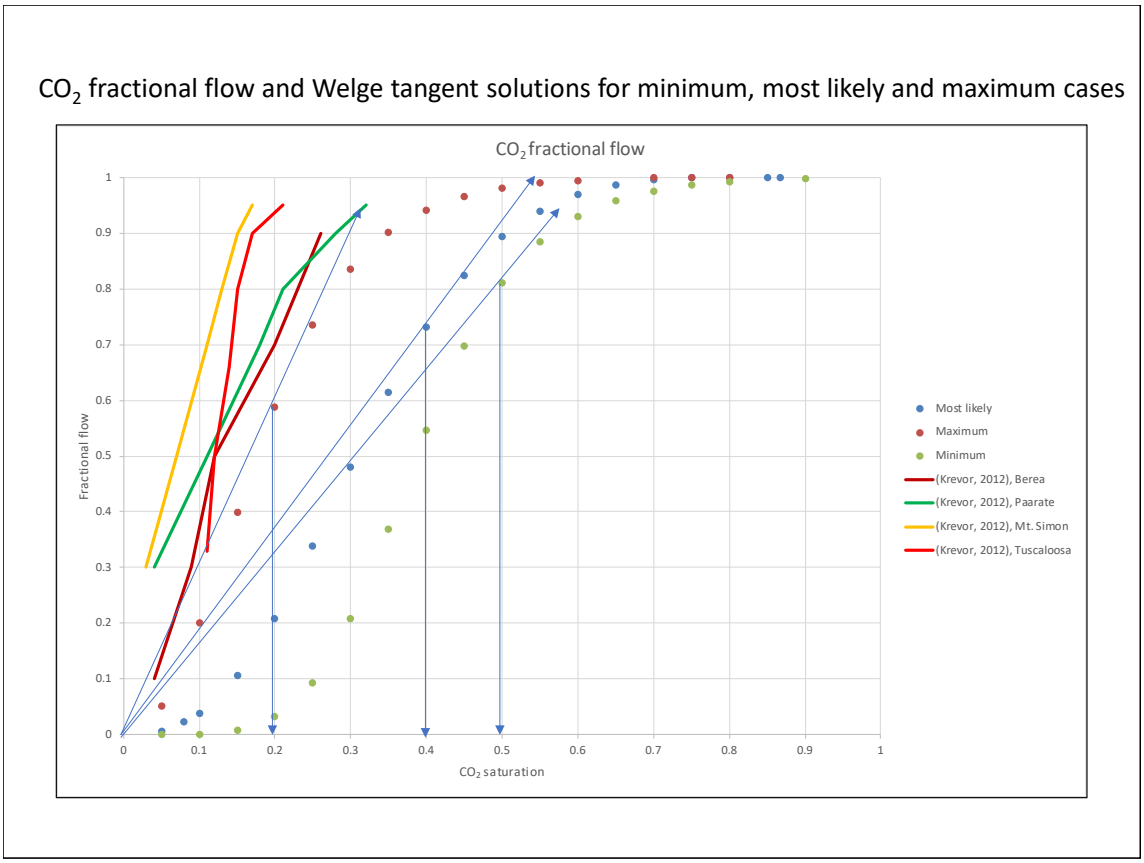

Figure 46: Comparing CO_2 fractional flows for min, ML and max cases with (Krevor, 2012)

(Krevor, 2012) best fit relative permeability curves (drainage)

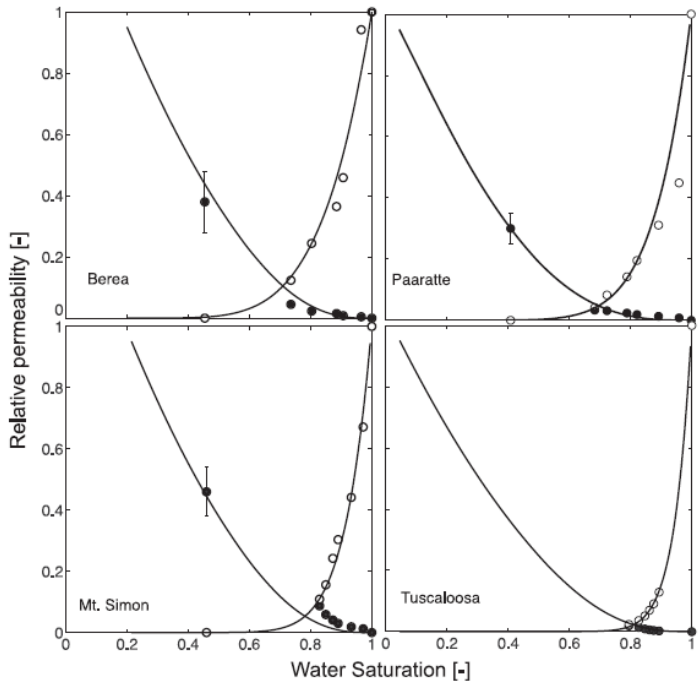

Figure 13. Drainage CO_2 (solid circles) and water (open circles) relative permeability data for the four samples. Solid black lines are best fit Brooks-Corey curves with best-fit parameters provided in Table 4.

Figure 47: (Krevor, 2012) best fit drainage curves for Berea, Paarate, Mt. Simon and Tuscaloosa samples

Welge **(Welge, 1952)** tangent solutions applied to the minimum, most likely and maximum CO_2 fractional flow curves indicate that, in a homogeneous one dimensional linear system the CO_2 shock front would occur at CO_2 saturations of 0.5 (minimum, most confined plume), 0.4 (most likely) and 0.2 (maximum, most dispersed plume). The experimental data from (Krevor, 2012) is difficult to analyse in the same manner but CO_2 saturations at the shock front in the range 0.15 to 0.25 seem reasonable estimates. In reality, inhomogeneities would prevent these ideal solutions occuring, as can be seen in the **(Krevor, 2012, figure 11)** which shows large variations in CO_2 saturation within the flooded cores. Also, the simple Welge solution omits the effects of gravity and capillary pressure.

Hysteresis in Relative Permeability – Imbibition Curves

During the injection of CO_2, the formation water is forced to move away from the well. Water is normally assumed to be the wetting phase and the process in which water saturation decreases is called drainage.

At the periphery of the CO_2 plume, and at the well after injection stops, the plume may ascend. As the lower part of the plume ascends past a fixed point in the formation, the CO_2 saturation there may fall and the water saturation increase as water flows back in behind the ascending plume. The process in which the wetting phase (here, by assumption, water) increases is called imbibition.
The fixed point will have had an initial water saturation of $S_w = 1.0$. S_w falls (drainage) as the CO_2 plume moves into the region but may increase again (imbibition) as the plume disperses.
In consequence, the relative permeability to water will fall and then rise whereas the relative permeability to gas will rise and then fall. For a system which is strongly water wet, the relative permeability to water will be essentially reversible; it will take the same value for a given S_w whether the water saturation has been decreasing or increasing. In contrast, the relative permeability to gas may have different values for a given S_w depending on whether water saturation has been decreasing or increasing. It is not reversible and depends on the saturation history of the point of interest in the formation. This is called hysteresis.

Hysteresis in the (non-wetting) gas phase occurs after the initial increase in CO_2 saturation when the influx of water during imbibition pinches off the continuous gas phase in pore throats creating discontinuous blobs of gas within the pores which are isolated and trapped and which cannot flow through the action of fluid pressure. The presence of these isolated bubbles of gas reduces the relative permeability to gas below that which existed when the gas was in a fully connected, continuous phase, at the same vale of S_w. This process traps CO_2 indefinitely. It is called capillary trapping and it may make a large contribution to the total volume of trapped CO_2.

A second source of hysteresis **(Juanes, 2006, citing (Gennes, 2004))** is contact angle hysteresis within the pores. The advancing contact angle, of the wetting phase displacing a non-wetting phase, is larger than the receding contact angle, of the wetting phase retreating from the non-wetting phase invasion, because of chemical heterogeneities or surface roughness.

To model it, we require two sets of relative permeability data for the gas. (We assume there is no significant hysteresis in the water phase, even for our minimum case set of relative permeability curves which are nominally CO_2-wet). We ignore capillary pressure hysteresis too.

The first set of curves are the drainage curves and these were defined in a previous section of this report.

The second set of data required is the imbibition relative permeability curves for the gas phase. There are different ways of doing this in Reveal. In addition to the "legacy" version of hysteresis in Reveal **(Reveal manual, Petroleum Experts, Edinburgh)**, it also supports Killough's method **(Killough, 1976)** and Carlson's method **(Carlson, 1981)**.

Following **(Juanes, 2006)** we used Killough's model **(Killough, 1976)**.

In Killough's method, the hysteresis model allows both capillary pressures and relative permeabilities to range between drainage and imbibition curves via intermediate scanning curves. Required inputs are the bounding imbibition and drainage curves. The model then interpolates between these curves to provide the actual values used in the simulation.

The most important parameter determining the significance of hysteresis effects the the trapped saturation after a flow reversal (from drainage to imbibition) **(Juanes, 2006)**.

We take, along with for example, **(Killough, 1976)** and **(Juanes, 2016)**, Land's model **(Land, 1968)**. The trapped gas saturation, S_{gt}, is

$$S_{gt} = S_{gi}/(1 + CS_{gi}) \qquad (23)$$

Here, S_{gi} is the actual gas saturation at flow reversal, when drainage stops and imbibition starts. The constant C is the Land trapping coefficient, given by;

$$C = (1/S_{gt,max}) - (1/S_{g,max}) \qquad (24)$$

In this equation, $S_{gt,max}$ is taken from the bounding imbibition curve and is the maximum gas saturation for that curve, see figure 51, taken from **(Juanes, 2006)**. $S_{g,max}$ is the maximum gas saturation for the bounding drainage curve, see figure 51, taken from **(Juanes, 2006)**.

(Juanes, 2006) state that, "The Land trapping model has been validated by comparison with experiments **(Land, 1968)**, **(Jerauld, 1997)** and **(Spiteri, 2006)**, and pore-network simulations **(Spiteri, 2005)** for water-wet rocks." **(Juanes, 2006, figure 3)** also report experimental data **(Oak, 1990)** which showed Land's constant, C, with a value ~ 1. **(Oak, 1990)** measured the imbibition relative permeability curve to gas in a water-wet Berea sandstone core. The trapped gas saturation was ~0.42, **(Juanes, 2006, figure 3)**.

(Land, 1968) cites five sources of data, **(Holmgren, 1951)**, **(Dyes, 1954)**, **(Kyte, 1956), (Dardaganian, 1957)** and **(Crowell, 1966)** which show that the difference in the reciprocals of the initial and residual gas saturations are approximately constant for a given sand. **(Land, 1964, figure 1)** shows six sets of data which fit equation (24) well. No values for C are given explicitly.

$S_{gt,max}$ is the maximum gas saturation on the bounding imbibition curve for gas relative permeability. This is calculated from Land's equation once a value of C has been chosen and $S_{gi,max}$ is given.
The problem is to ascertain the correct value for Land's constant, C. C can take any value ≥ 0. If C = 0, then all the gas is trapped; if C -> ∞, there is no trapped gas. For any value in between, residually trapped gas increases with increasing initial gas saturation, for water wet systems. For intermediate and mixed-wet systems, pore modelling indicates a different behaviour, where a quadratic function in the initial gas saturation may give a more accurate correlation **(Spiteri, 2008)**;

$$S_{gt} = \alpha S_{gi} + \beta S_{gi}^2 \qquad (25)$$

with α and β to be determined. It is just a different correlation.

One of the issues in applying these correlations, even to the results of a well-executed experiment, is: how do you define the initial and trapped CO_2 saturations when the saturation varies so much within a

small core, on the scale of centimetres? **(Krevor, 2012)** used core averaged values to circumvent this issue.

Table 16 is adapted from (Krevor, 2012, Table 5). We have back calculated the maximum CO_2 saturation at the end of the drainage process, $S_{gi,max}$, using the tabulated values of C and trapped CO_2 saturation, $S_{gt,max}$, during the imbibition process.

	Sgi, max	Sgt, max	C
(Krevor, 2012), Berea	0.45	0.31	1.00
(Krevor, 2012), Paarate	0.58	0.33	1.30
(Krevor, 2012), Mt. Simon	0.38	0.21	2.10
(Krevor, 2012), Tuscaloosa	0.66	0.31	1.70

Table 16: $S_{gi,max}$, $S_{gt,max}$ and Land's constant (Krevor, 2012)

Land's constant varies between 1 and 2.1.

In **(Bachu, 2013)**, Land's constant varies between 0.177 and 2.213 but with two high values of 5.37 and 8.56. The average, excluding the two high values was 1.054 with eleven values less than 1.0 and six values greater than 1. The trapped CO_2 saturations varied from 0.102 to 0.519, with an average of 0.314. These results are similar to **(Krevor, 2012)** but no strong trend or correlation with core properties was discerned.

To create our data set we assumed three values of C which, taking $S_{gi\ max}$ from the bounding drainage curves. Gave reasonable values for Sgt,max, taking into account the data from **(Krevor, 2012)** and **(Bachu, 2013)**. Our results are shown in table 17.

	Minimum	ML	Maximum
Sgi, max	0.95	0.867	0.85
C	1.5	2	3
Sgt,max	0.392	0.317	0.239

Table 17: Assumed values of C, to give $S_{gt,max}$

To create Killough's model for a simulation, we require a bounding imbibition curve for the gas (non-wetting) phase, k^i_{rg}.

Firstly, we tried to calculate this using **(Land, 1968)**, equation (6):

$$k^i_{rg} = k^d_{rg,i}\, S_{gf}{*}^2\, [\, 1 - (1 - S_{gf}{*})^{\varepsilon-2}\,] \qquad (26)$$

Here, $k^d_{rg,i}$ is the maximum relative permeability to gas on the drainage curve and S_{gf}* is the free or mobile gas saturation which lies in the range ($S_{gi,max} - S_{gt,max}$).

$S_{gi,max}$ is the maximum gas saturation on the bounding drainage cure for gas relative permeability (or, equivalently, the minimum gas saturation on the bounding imbibition curve for gas relative

permeability, see figure 51). $S_{gi,max}$ is for the minimum, most likely and maximum cases; 0.95, 0.867 and 0.85 respectively (see tables 13, 14 and 15).

The parameter ε = (2/λ) + 3, where λ is a pore-size distribution factor **(Brooks, 1964)**, equal to the slope of a plot of log(1/P_c) versus log S^*_w (S^*_w= (S_w – S_{wc})/(1 – S_{wc}), and S_{wc} is the connate water saturation) . Figure 48 shows plots of log(1/P_c) versus log S^*_w for the minimum, most likely and maximum Frio formation P_c curves.

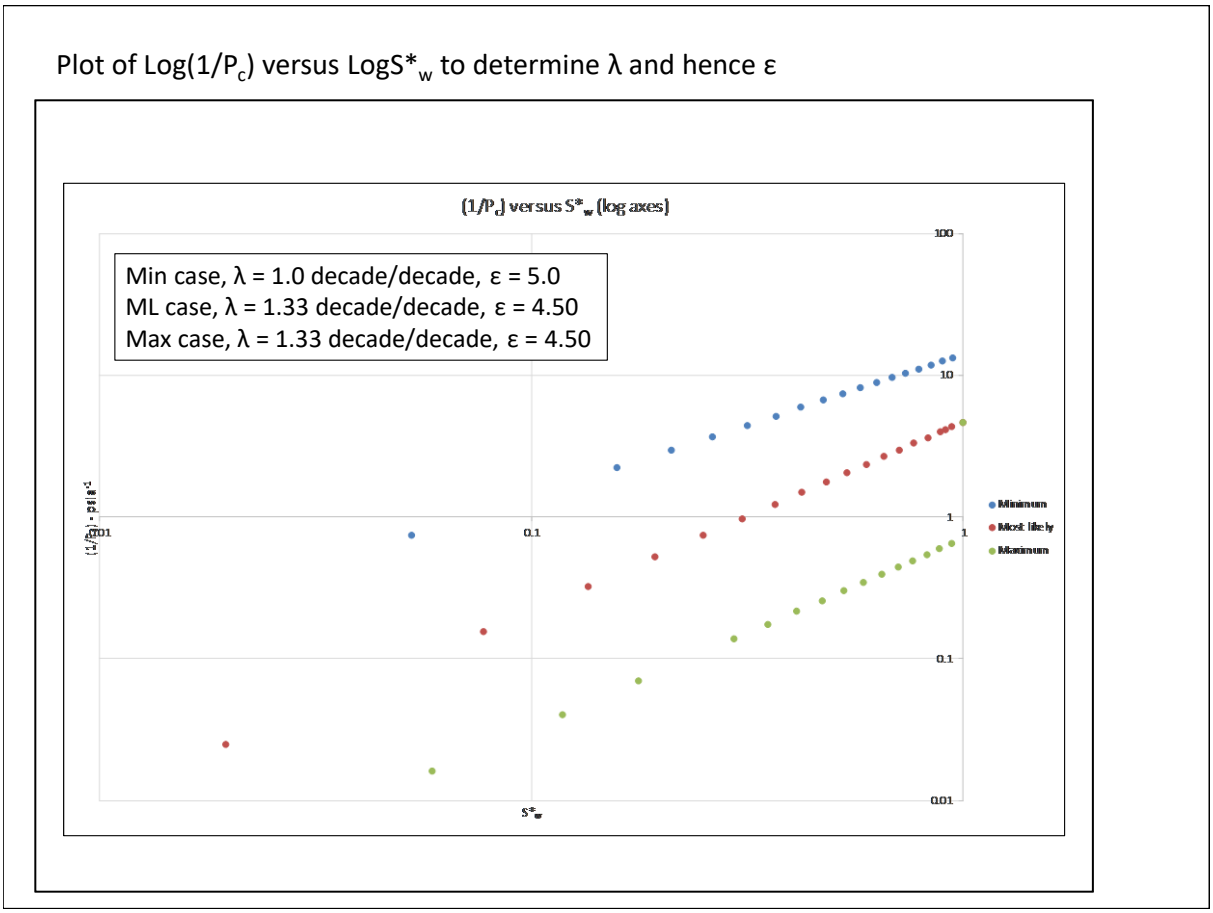

Figure 48: Calculation of λ for minimum, most likely and maximum P_c curves

The resulting imbibition curves are plotted in figure 49. The method works well for the most likely and maximum cases but overestimates the Corey coefficient for the minimum case. We therefore reduced the Corey coefficient from 3.0 to 1.0. The resulting curves are plotted in figure 50 and tabulated in table 18.

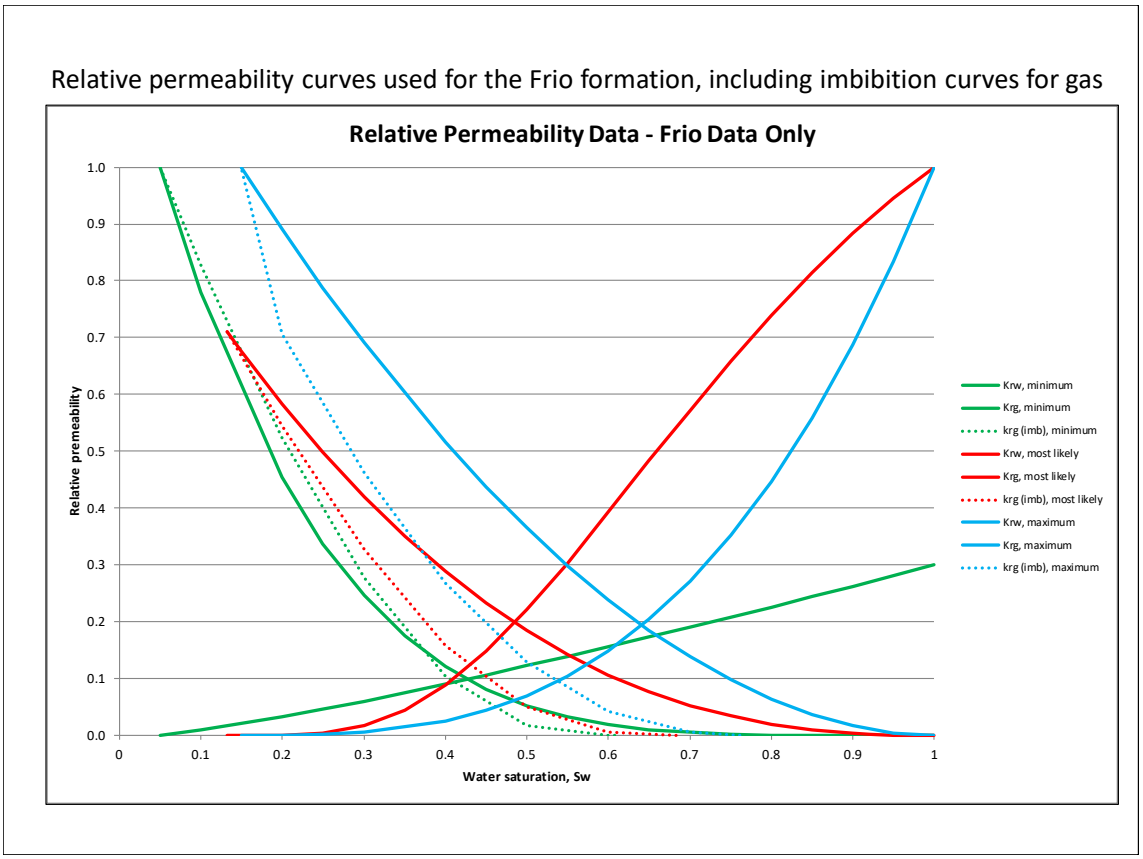

Figure 49: Bounding relative permeability curves for the Frio formation – minimum case unphysical

Relative permeability curves used for the Frio formation, including imbibition curves for gas
Modified minimum imbibition curve

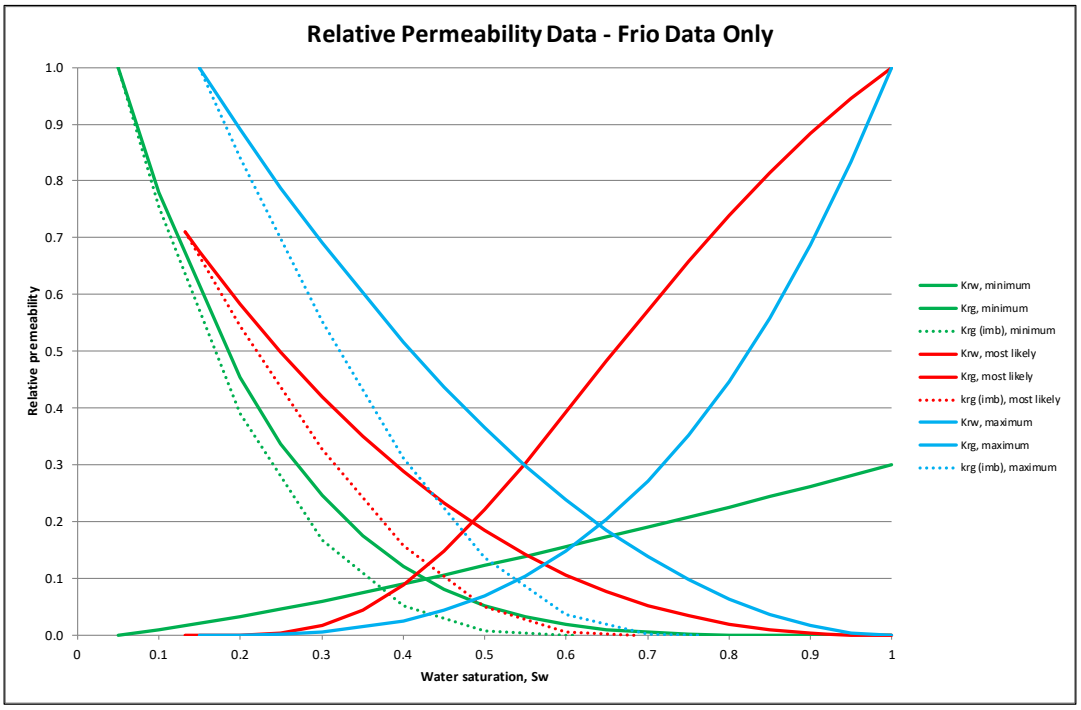

Figure 50: Bounding relative permeability curves for the Frio formation

Minimum				Most Likely				Maximum			
Sw	Sg	Sgf*	krg (imb)	Sw	Sg	Sgf*	krg (imb)	Sw	Sg	Sgf*	krg (imb)
1	0			1	0			1	0		
0.9	0.1			0.9	0.1			0.9	0.1		
0.8	0.2			0.8	0.2			0.8	0.2		
0.7	0.3			0.7	0.3			0.761	0.239	0	0
0.608	0.392	0	0	0.683	0.317	0	0	0.7	0.3	0.099836	0.002305
0.6	0.4	0.014337	2.95E-06	0.6	0.4	0.150909	0.005427	0.6	0.4	0.263502	0.037112
0.5	0.5	0.193548	0.007251	0.5	0.5	0.332727	0.050014	0.5	0.5	0.427169	0.137156
0.4	0.6	0.37276	0.051795	0.4	0.6	0.514545	0.157112	0.4	0.6	0.590835	0.311702
0.3	0.7	0.551971	0.16817	0.3	0.7	0.696364	0.326804	0.3	0.7	0.754501	0.552272
0.2	0.8	0.731183	0.390911	0.2	0.8	0.878182	0.544718	0.2	0.8	0.918167	0.841416
0.1	0.9	0.910394	0.754551	0.133	0.867	1	0.71	0.15	0.85	1	1
0.05	0.95	1	1	0	1			0	1		

Table 18: Values for the bounding imbibition curves for the gas phase

Finally, figure 51 shows how Killough's method uses the parameters and the bounding drainage and imbibition curves to interpolate a new, scaled hysteresis curve for the gas relative permeability during imbibition.

Taken from (Juanes, 2006), figure 4 and equations (5) and (6)

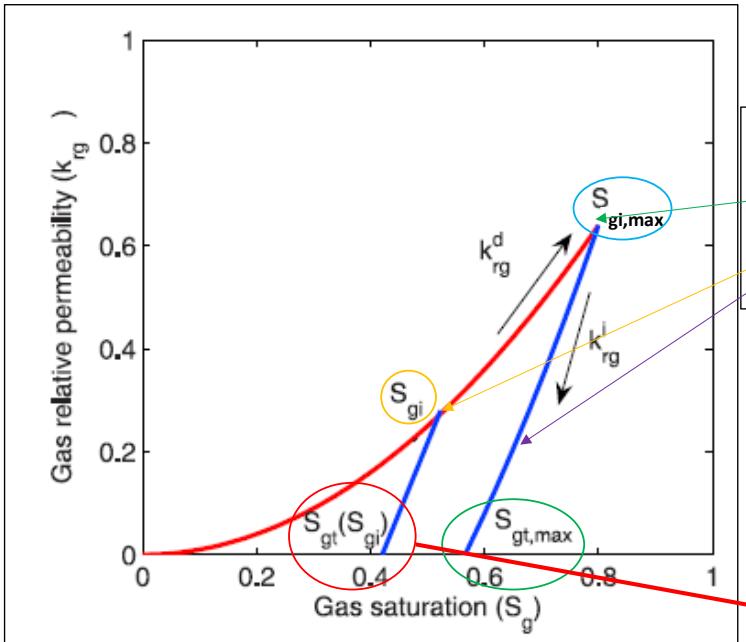

Figure 4. Parameters required in the evaluation and application of the Land trapping model.

$$k^i_{rg}(S_g) = k^{ib}_{rg}(S^*_g)\frac{k^d_{rg}(S_{gi})}{k^d_{rg}(S_{gi,\max})}, \quad (3)$$

where

$$S^*_g = S_{gt,\max} + \frac{(S_g - S_{gt})(S_{gi,\max} - S_{gt,\max})}{S_{gi} - S_{gt}}. \quad (4)$$

Killough's model of relative permeability hysteresis for the non-wetting phase

Value from Land's equation

Figure 51: Killough's method for interpolating a hysteresis relative permeability curve for gas during imbibition

These data are then entered into Reveal.
We used the same relative permeability model for the Frio formation and the Anahuac shale (but different capillary pressure functions). This presents no problem unless CO_2 enters the Anahuac shale, at which point we would have to review the model and provide relative permeability curves specifically for the Anahuac shale.

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Corrective Action

Tabulation of Wells within the AoR

[Note to user: blue text indicates suggestions, please delete text when complete]
Note: Files with the locations of all wells within the AoR should be uploaded to the GSDT. The operator is encouraged to provide a map of these wells as part of this plan.

Wells within the AoR

[Note to user: blue text indicates suggestions, please delete text when complete]
Recommended considerations include:

- What databases or other information sources were used to identify these wells?
- What is the type and status of each well (e.g., operating Class II injection well, temporarily abandoned oil well, etc.)? (Attach tables as necessary.)
- Are there historical wells believed to be in the area that may not be captured in available data sources?

Wells Penetrating the Confining Zone

[Note to user: blue text indicates suggestions, please delete text when complete]
Recommended considerations include:

- How were the depths of these wells determined?
- What is the type and status of each well (e.g., operating Class II injection well, temporarily abandoned oil well, etc.)? (Attach tables as necessary.)
- What is the condition of each well?
- If corrective action is needed, what activities will be completed and when?

Plan for Site Access

[Note to user: blue text indicates suggestions, please delete text when complete]
Recommended considerations include:

- What agreements have been made for access so that corrective action can be performed?
- For what period of time has site access been guaranteed?

Corrective Action Schedule

[Note to user: blue text indicates suggestions, please delete text when complete]

Recommended considerations include:

- Will phased corrective action be conducted? What is the specific schedule that will be implemented? How will the proposed phased corrective action schedule protect USDWs?
- What benchmarks or triggers are included as part of a phased corrective action plan? What information was used to determine these triggers?
- How might the results of testing and monitoring, and/or AoR reevaluation inform changes to the phased corrective action plan?

Reevaluation Schedule and Criteria

AoR Reevaluation Cycle

INSERT PERMIT APPLICANT NAME will reevaluate the above described AoR every X years during the injection and post-injection phases.
[Note to user: blue text indicates suggestions, please delete text when complete]
Note: Pursuant to 40 CFR 146.84(e), AoR reevaluation must occur at least once every five years. The operator is also required to include in the reevaluation plan any benchmarks or milestones (e.g., from testing and monitoring) that may trigger additional AoR reevaluations.
Recommended considerations include:

- What are the specific procedures that will be followed for the AoR reevaluation? (Provide a list of steps or similar description.)
- What monitoring and operational data will be used? What specific thresholds or benchmarks will be used to determine if the testing and monitoring data are consistent with the model predictions?
- How will new data be incorporated into the model?
- How will model reevaluations be compared to the initial AoR modeling and delineation?

Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

[Note to user: blue text indicates suggestions, please delete text when complete]
Recommended considerations include:

- What changes in what specific parameters (temperature, pressure, RST saturation, etc.) would trigger a reevaluation? What are the quantitative thresholds for these determinations?
- What other events (e.g., a seismic event) would trigger an AoR reevaluation?

INSERT PERMIT APPLICANT NAME will discuss any such events with the UIC Program Director to determine if an AoR reevaluation is required. If an unscheduled reevaluation is triggered, INSERT PERMIT APPLICANT NAME will perform the steps described at the beginning of this section of this Plan.

SIMULATOR DESCRIPTION / DOCUMENTATION

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Simulator Description / Documentation 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 Simulator Description / Documentation

GEMS V2020.10 was used for the reservoir simulation. A description of the simulator and the settings used for the project is included in Section 2.1.2 Description of Model, in the Area of Review and Corrective Action Plan document of this permit. That document is included in the Confidential Business Information folder.

ADDITIONAL AoR DELINEATION INFORMATION

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Additional AoR Delineation Information 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
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713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 Additional AoR Delineation Information

This does not apply as no state has primacy in the project area as of submittal.

DOMAIN COORDINATES FILE

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Domain Coordinates File 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 Domain Coordinates File

A file with the domain coordinates is included in the project Confidential Business Information file.

GRID FILE DESCRIPTION

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Grid File Description 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 Grid File Description

See the Eclipse keyword file in the Confidential Business Information file.

ECLIPSE KEYWORD FILE

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Eclipse Keyword File..... 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
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713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 Eclipse Keyword File

See the Eclipse keyword file in the Confidential Business Information file.

IMAGE FILE(S) FOR MODEL DOMAIN GRID

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Image File(s) for Model Domain Grid 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 Image File(s) for Model Domain Grid

An image file for the model domain grid is included in the Confidential Business Information file.

FILE WITH EOS REFERENCE OR DOCUMENTATION

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 File with EOS Reference or Documentation 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 File with EOS Reference or Documentation

The simulation uses the Peng Robinson equation of state, as referenced in section 2.1.2 Description of Model, in the Area of Review and Corrective Action Plan document in the Confidential Business Information file.

FILE DESCRIBING GEOCHEMISTRY MODELING

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 File Describing Geochemistry Modeling 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 File Describing Geochemistry Modeling

Details on the geochemistry modeling are provided in section 2.1.2 Description of Model in the Area of Review and Corrective Action Plan document in the Confidential Business Information file.

FILE DESCRIBING HOW POROSITY WAS DETERMINED AND ASSIGNED TO NUMERICAL MODEL

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 File Describing how Porosity was Determined and Assigned to Numerical Model 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
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Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 File Describing how Porosity was Determined and Assigned to Numerical Model

The porosity was distributed spatially in the geologic model and then directly imported into the numerical model. Details of the porosity distribution is provided as Section 2.4 Porosity and Permeability in the AoR and Corrective Action Plan document in the Confidential Business Information files.

IMAGE FILES FOR POROSITY DISTRIBUTIONS

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Image Files for Porosity Distributions 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 Image Files for Porosity Distributions

The porosity distribution is imaged as Figure AOR-20 in the AoR and Corrective Action Plan document in the Confidential Business Information file.

FILE DESCRIBING HOW PERMEABILITY WAS DETERMINED AND ASSIGNED TO NUMERICAL MDOEL

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 File Describing how Permeability was Determined and Assigned to Numerical Model 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 File Describing how Permeability was Determined and Assigned to Numerical Model

The permeability was distributed in the geologic model and directly imported into the numerical model. Details on the permeability distribution are included as Section 2.4 Porosity and Permeability in the AoR and Corrective Action Plan document in the Confidential Business Information files.

IMAGE FILES FOR PERMEABILITY DISTRIBUTIONS

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Image Files for Permeability Distributions 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 Image Files for Permeability Distributions

The porosity distribution is imaged as Figure AOR-23 in the AoR and Corrective Action Plan document in the Confidential Business Information file.

DESCRIPTION OF ROCK TYPE SELECTION AND ASSIGNMENT

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Description of Rock Type Selection and Assignment 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 Description of Rock Type Selection and Assignment

Net sand was distributed using a fractional NTG property. The NTG distribution is described in section 2.4 Porosity and Permeability in the AoR and Corrective Action Plan document in the Confidential Business Information files.

ROCK TYPE DISTRIBUTION DATA FILE

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Rock Type Distribution Data File 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 Rock Type Distribution Data File

The rock type distribution data file is included as NTG_Keyword_File_cbi.txt in the Confidential Business Information file.

IMAGE FILES FOR ROCK TYPE DISTRIBUTION

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Image Files for Rock Type Distribution 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 Image Files for Rock Type Distribution

An image file for the rock type distribution is included in the project Confidential Business information file.

FILE FOR AQUEOUS SATURATION VS CAPILLARY PRESSURE

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 File for Aqueous Saturation vs Capillary Pressure 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
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Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 File for Aqueous Saturation vs Capillary Pressure

Capillary pressure tables are included in RelPerm_Pc_Tables_cbi.txt file in the confidential business information.

FILE FOR AQUEOUS RELATIVE PERMEABILITY

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 File for Aqueous Relative Permeability 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
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Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 File for Aqueous Relative Permeability

Aqueous relative permeability tables are included in RelPerm_Pc_Tables_cbi.txt file in the confidential business information

FILE FOR GAS RELATIVE PERMEABILITY

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 File for Gas Relative Permeability 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
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Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 File for Gas Relative Permeability

Gas relative permeability tables are included in RelPerm_Pc_Tables_cbi.txt file in the confidential business information.

BOUNDARY CONDITIONS DESCRIPTION FILE

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Boundary Conditions Description File 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 Boundary Conditions Description File

The boundary conditions are described in Section 2.6 Boundary Conditions in the Area of Review and Corrective Action Plan document. This document is found in the Confidential Business Information file.

TIME-SERIES FILE

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Time-Series File 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 Time-Series File

A time-series file is included in the Confidential Business Information file.

SNAPSHOT FILE

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Snapshot File..... 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 Snapshot File

Snapshot data is included in the Confidential Business Information file.

SURFACE FLUX FILE

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Surface Flux File 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 Surface Flux File

Surface flux data is not applicable to the project model.

SENSITIVITY ANALYSIS DESCRIPTION / RESULTS

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Sensitivity Analysis Description / Results 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 Sensitivity Analysis Description / Results

A description of the sensitivity analysis is included in section 3.2.1 Sensitivity to Input Parameters in the Area of Review and Correction Action Plan document in the Confidential Business Information file.

FILE DESCRIBING CRITICAL PRESSURE ESTIMATION

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 File Describing Critical Pressure Estimation 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 File Describing Critical Pressure Estimation

The calculation method for the critical pressure estimation is described in section 4.1 Critical Pressure Calculations in the Area of Review and Corrective Action Plan document in the Confidential Business Information file.

SHAPEFILE OR KML FILE SHOWING DELINEATED AoR

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Shapefile or KML File Showing Delineated AoR 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 Shapefile or KML File Showing Delineated AoR

A shapefile showing the delineated Area of Review is included in the Confidential Business Information file.

FILE WITH LOCATION OF ALL PENETRATIONS WITHIN AOR

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 File with Location of All Penetrations within AOR 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 File with Location of All Penetrations within AOR

The Area of Review and Corrective Action Plan document of this permit is included in the project Confidential Business Information file and has details of all penetrations within the Area of Review (AOR).

A file named 1101_Location_Penetrations_AOR_YAMScbi.kml with the location of all penetrations within the AOR is included in the project Confidential Business Information file and includes any oil and gas or water wells.

FILE WITH LOCATION OF WELLS REQUIRING CORRECTIVE ACTION

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 File with Location of Wells Requiring Corrective Action..... 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 File with Location of Wells Requiring Corrective Action

The Area of Review and Corrective Action Plan document of this permit is included in the project Confidential Business Information file and has details of wells requiring corrective action.

A file named 1102_Location_Corrective_Action_YAMScbi.kml with the location of wells requiring corrective action is included in the project Confidential Business Information file.

SUPPORTING DOCUMENTATION

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Supporting Documentation 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 Supporting Documentation

Details of the corrective action plan are included in the Area of Review and Corrective Action Plan document of the permit.

APPENDICES AND SUPPORTING MATERIALS

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Appendices and Supporting Materials 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This document was created to satisfy requirements of the Geologic Sequestration Data Tool (GSDT) Area of Review and Corrective Action module.

2.0 Appendices and Supporting Materials

The Area of Review and Corrective Action Plan document of this permit is included in the project Confidential Business Information file. No appendices and supporting materials are provided.

AREA OF REVIEW AND CORRECTIVE ACTION PLAN SUMMARY
40 CFR 146.84(b)

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Overall Summary of the Area of Review and Corrective Action Plan 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

2.0 Overall Summary of the Area of Review and Corrective Action Plan

The plan deals with delineating the Area of Review (AoR) and provides corrective actions that are needed in the wells that penetrate the upper confining zone within the AoR. Delineation of the AoR is one of the key elements in Class VI Rule to ensure USDWs in the region surrounding the geologic sequestration project may not be endangered by the injection activity.

The AoR is defined as the larger of the maximum extent of the a) free-phase CO_2 plume or b) pressure boundary within which brines from the injection zone can migrate into overlying USDW via leaky wells, faults, or breaches of the confining zone. Both the CO_2 plume and the critical pressure front are determined using a multiphase CO_2-brine transport model, which is constructed from a sophisticated geologic model that accounts for site-specific hydrogeology. The methods and approaches for developing this complex multiphase simulation model and delineating the AoR are defined below.

Control of the pore space, into which the free-phase CO_2 plume is predicted to migrate, is a requirement for a Class VI permit. In Louisiana, the pore space is owned by the surface owner of the land. An agreement has been made with the landowners regarding pore space ownership in the YAMS CO_2 Sequestration Project.

The proposed AoR includes legacy wells, according to the records obtained from LDNR. A detailed analysis was performed to evaluate the risk and timing of the plume and/or pressure front reaching wells inside the AoR, relative to the project schedule, to propose corrective actions and a timeline for these procedures.

Oxy Low Carbon Ventures, LLC will re-evaluate the AoR every five years during the injection and post-injection phases. In addition, monitoring and operational data will be reviewed periodically by Oxy Low Carbon Ventures, LLC during the injection and post-injection phases.

Additional details for the AoR and corrective actions are included in the project Area of Review and Corrective Action Plan document of the permit.

Class VI UIC Area of Review and Corrective Action

This submission is for:

Project ID: R06-LA-0004

Project Name: YAMS CO2 Sequestration Project

Current Project Phase: Pre-Injection Prior to Construction

Overview

Simulator Used for AoR delineation modeling: GEM

Version Used: 2020.10

Simulator Description/Documentation: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0201_Simulator_Description_Documentation_YAMS.pdf

Total Simulation Time From Start of Injection: 44194 days

Additional AoR Delineation Information: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0202_Add_AOR_Delineation_Info_YAMS.pdf

Description of Information Submitted: This does not apply as no state has primacy in the project area as of submittal.

Model Domain

Coordinate System: State Plane

Horizontal Datum: NAD83

Coordinate System Units: ft

Vertical Datum: Mean Sea Level

Describe Vertical Datum: All grid and well depths in TVDSS

Zone: Louisiana South

FIPSZONE: 1702 ADSZONE: 4501

Mesh Type: Other

Describe Mesh Type: corner-point grid

Domain Size in Global Units Specified Above

Domain Coordinates File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0301_Domain_Coordinates_File_YAMS.pdf

Grid Size

Number of Nodes in x: 110 y: 173 z: 236

Grid Spacing: Constant

Grid Spacing in x: 500 y: 500 z: 10

Grid File Format: Eclipse Keyword File

Grid File Description: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0302_Grid_File_Description_YAMS.pdf

Eclipse Keyword File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0303_Eclipse_Keyword_File_YAMS.pdf

Faults Modeled: No

Caprock Modeled: No

Image File(s) for Model Domain Grid: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0304_Image_File_YAMS.pdf

Processes Modeled by Simulator

Reservoir Conditions:

Supercritical CO2 Conditions

Phases Modeled:

Aqueous Supercritical CO2

Aqueous Phase:

Phase Compressibility: Compressible

Compressibility Value: 0.000003 1/psi

Phase Composition: Non-Compositional

Supercritical CO2 Phase:

Phase Compressibility: Compressible

Phase Composition: Compositional

Supercritical CO2 Phase Components:

CO2 Methane

Equation of State Description Including Reference: Peng-Robinson EOS

File with EOS Reference or Documentation: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0401_File_with_EOS_YAMS.pdf

Multifluid Flow Processes:

Advection Buoyancy

Non-wetting Fluid Trapping Pore Compressibility

Thermal Conditions: Isothermal

Heat Transport Processes:

Geochemistry Modeled: Yes

File Describing Geochemistry Modeling: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0402_File_Describing_Geochemistry_Modeling_YAMS.pdf

Geomechanical/Structural Deformations Modeled: No

Rock Properties and Constitutive Relationships

Porosity/Permeability Model

Single Porosity

Porosity Distribution: Heterogeneous

Porosity included in Eclipse Keyword File: Yes

Porosity Variable Name in Eclipse Keyword File: POR

File Describing how Porosity was Determined and Assigned to Numerical Model: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0501_Porosity_Determined_Assigned_YAMS.pdf

Image Files for Porosity Distributions: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0502_Image_Files_Porosity_Distribution_YAMS.pdf

Permeability Distribution: Heterogeneous

Permeability included in Eclipse Keyword File: Yes

Permeability Variable Name in Eclipse Keyword File: PERMI

File Describing how Permeability was Determined and Assigned to Numerical Model: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0503_Permeability_Determined_Assigned_YAMS.pdf

Image Files for Permeability Distributions: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0504_Image_Files_Permeability_Distribution_YAMS.pdf

Number of Rock Types Modeled: 1

Description of Rock Type Selection and Assignment: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0505_Description_Rock_Type_YAMS.pdf

Rock Type Distribution Data File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0506_Rock_Type_Distribution_YAMS.pdf

Image Files for Rock Type Distribution: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0507_Image_Files_Rock_Type_YAMS.pdf

Rock Type #1

Rock Compressibility: Pore

Rock Compressibility Distribution: Single Value

Compressibility Value: 0.000005 1/Pa

Compressibility included in Eclipse Keyword File: Yes

Compressibility Variable Name in Eclipse Keyword File: CPOR

Constitutive Relationships

Aqueous Saturation vs. Capillary Pressure: Table

Tabular Format File for Aqueous Saturation vs Capillary Pressure: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0508_Aqueous_Sat_Cap_Press_YAMS.pdf

Aqueous Trapped Gas Modeled: Yes

Hysteresis other than non-wetting fluid trapping: No

Aqueous Relative Permeability: Table

Tabular Format File for Aqueous Relative Permeability: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0509_Aqueous_Relative_Perm_YAMS.pdf

Hysteresis other than non-wetting fluid trapping: No

Gas Relative Permeability: Table

Tabular Format File for Gas Relative Permeability: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0510_Gas_Relative_Perm_YAMS.pdf

Hysteresis other than non-wetting fluid trapping: No

Porosity and Permeability Reduction Due to Salt Precipitation

Boundary Conditions

Attach Boundary Conditions Description File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0601_Boundary_Conditions_Description_YAMS.pdf

Initial Conditions

Initial Phases in Domain: Aqueous

Initial Aqueous Pressure: Varying with Depth, Temperature, and Salinity

Initial Aqueous Pressure: -999 MPa at Reference Elevation: -999 m

Initial Temperature: Varying with Depth

Initial Temperature: -999 C at Reference Elevation: -999 m Gradient: -999 deg C/m

Initial Salinity: Spatially Constant

Initial Salinity: -999 mg/L

Initial Condition Comments: The initial conditions can be found in the AoR and Corrective Action Plan in the confidential business information.

Operational Information

Number of Injection Wells: -999

Number of Production/Withdrawal Wells: -999

Model Output/Results

Provide file name and corresponding spatial location for each file: See Confidential Business Information file for Time Series information.

Time-Series File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0901_Time_Series_File_YAMS.pdf

Provide file name and corresponding variable and time stamp for each file: See Confidential Business Information file for snapshot data information.

Snapshot File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0902_Snapshot_File_YAMS.pdf

Provide file name and corresponding description of surface for each file: This is not applicable.

Surface Flux File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0903_Surface_Flux_File_YAMS.pdf

Sensitivity Analysis Description/Results: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/0904_Sensitivity_Analysis_YAMS.pdf

AoR Pressure Front Delineation

Lowermost USDW:

Name of Lowermost USDW: -999

Water Density: -999 kg/m^3 at Elevation: -999 m

Location of Measurement for Density: -999

Temperature: -999 C at Elevation: -999 m

Location of Measurement: -999

Pressure: -999 MPa at Elevation: -999 m

Location of Measurement: -999

Salinity: -999 mg/L at Elevation: -999 m

Location of Measurement: -999

Elevation of bottom of USDW: -999 m

Injection Zone:

Name of Injection Zone: -999

Water Density: -999 kg/m^3 at Elevation: -999 m

Location of Measurement: -999

Temperature: -999 C at Elevation: -999 m

Location of Measurement: -999

Pressure: -999 MPa at Elevation: -999 m

Location of Measurement: -999

Salinity: -999 mg/L at Elevation: -999 m

Location of Measurement: -999

Elevation of top of Injection Zone: -999 m

Method of Estimating Critical Pressure: Static Mass Balance

Assumptions: linear density gradient

File Describing Critical Pressure Estimation: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/1001_Critical_Pressure_Estimation_YAMS.pdf

Estimated Critical Pressure: 32 MPa

Delineated AoR:

Shapefile or KML File Showing Delineated AoR: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/1002_Shape_Delineated_AOR_YAMS.pdf

Corrective Action

File with Location of All Penetrations within AoR: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/1101_Location_Penetrations_AOR_YAMS.pdf

File with Location of Wells Requiring Corrective Action: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/1102_Location_Corrective_Action_YAMS.pdf

Supporting Documentation: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/1103_Supporting_Documentation_YAMS.pdf

Area of Review and Corrective Action Plan [40 CFR 146.82(a)(13) and 146.84(b) or applicable state requirements]

Are you making an Area of Review and Corrective Action Plan submission at this time?: Yes

Reason for Project Plan Submission: Permit application submission

Project Plan Upload

Attach the Area of Review and Corrective Action Plan: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/AOR_CA_YAMS_CCS_1g.pdf

Appendices and Supporting Materials Upload

Attach Any Supporting Documentation for the AoR and Corrective Action Plan: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/AoRModeling-07-20-2021-1055/1202_Appendices_Supporting_Materials_YAMS.pdf

Area of Review Reevaluation [40 CFR 146.84(e) or applicable state requirements]

Minimum fixed frequency of AoR reevaluation: 5 Years

Are you making an Area of Review reevaluation submission at this time?: No

Reevaluation Background

Reevaluation Materials

Please upload your amended AoR and Corrective Action Plan on the previous tab.

Complete Submission

Authorized submission made by: Kelly Watson

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

December 16, 2020

On October 12, 2020, Gulf Coats Sequestration (GCS) submitted to EPA information related to Area of Review and Corrective Action for project R06-LA-0002. This submission contains Confidential Business Information (CBI) and is, therefore, being stored in a secure electronic location by EPA Region 6. The GSDT lacks the security requirements necessary to receive and store CBI data.

For additional information, please contact the EPA Region 6 Permit Writer/Project Manager(s) assigned to the GCS Class VI project account R06-LA-0002 or the GSDT system manager(s) at EPA headquarters (GSDataTool@epa.gov).

Class VI UIC Financial Responsibility Demonstration

This submission is for:

Project ID: R06-LA-0004

Project Name: YAMS CO2 Sequestration Project

Current Project Phase: Pre-Injection Prior to Construction

Cost Estimates

Company providing estimates: Oxy Low Carbon Ventures, LLC

Cost of each phase: Date of Third-Party Estimate:

Corrective Action on Deficient Wells: $0.00 6/1/2021

Plugging Injection Well: $0.00 6/1/2021

Post-Injection Site Care and Site Closure: $0.00 6/1/2021

Emergency and Remedial Response: $0.00 6/1/2021

Total Cost Estimate: $.00

Year of Dollars: 2021

Cost Estimate File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/FinancialResp-07-20-2021-1056/FRD_Cost_Est_060121.pdf

Additional Cost Information: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/FinancialResp-07-20-2021-1056/FRD_Cost_Est_060121a.pdf

Description of Information Submitted: The Financial Assurance Demonstration Plan is included in the project Confidential Business Information file location and describes the financial instruments intended to be executed prior to commencement of injection. The cost estimate is included in the project Confidential Business Information file location and includes a summary of cost for each phase, covering corrective actions, injection well plugging, post-injection site care, site closure, and emergency and remedial response.

Trust Fund

Surety Bond

Letter of Credit

Third Party Insurance

Escrow Account

Self Insurance

Is Self Insurance Used as a Financial Instrument: No

Other Instrument

Notifications

Complete Submission

Authorized submission made by: Kelly Watson

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

YAMS CO2 Sequestration Project
Financial Assurance Estimate Summary

Date of Estimate: 06/01/2021
Company Providing Estimate: Oxy Low Carbon Ventures, LLC

		Phase			
Activity	**Cost**	As Needed	During Operation	At Site Closure	PISC
Performing Corrective Action on Wells in AOR					
Plugging Injection Wells					
Post Injection Site Care					
Site Closure					
Emergency and Remedial Response Actions					
Endangerment of USDWs					
Total $					

YAMS CO2 Sequestration Project
Additional Cost Information

Date of Estimate: 06/01/2021
Company Providing Estimate: Oxy Low Carbon Ventures, LLC

This does not apply as no state has primacy in the project area as of submittal.

CLASS VI PERMIT APPLICATION NARRATIVE

40 CFR 146.82(a)

GULF COAST SEQUESTRATION
PROJECT MINERVA

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1.0 PROJECT BACKGROUND

1.1 Project goals

Gulf Coast Sequestration (GCS) seeks to build and operate the United States premier saline sequestration asset, Project Minerva, in the Louisiana Gulf Coast. Once completed, the GCS "hub" is expected to be the largest geologic carbon capture sequestration project in the United States and one of the largest in the world, designed to permanently store more than 80 million tons of carbon in a saline aquifer. With the capacity to sequester 2,700,000 tons of CO2 annually, Project Minerva will have the same carbon offset impact as more than 600 utility-scale solar facilities or some half a million-household rooftop solar panels.

Project Minerva envisions sourcing CO_2 volumes from industrial producers of CO_2 in the Eastern Texas and Southwestern Louisiana industrial corridors. Project Minerva desires to enable the United States manufacturing and industrial base in the Texas and Louisiana Gulf Coast to continue to provide jobs and economic opportunity while minimizing the amount of CO_2 which would have been emitted into the earth's atmosphere. GCS maintains that both economic and environmental stewardship can advance in unison with an asset such as Project Minerva. GCS intends to see this vision become a reality.

1.2 Ownership

GCS is a wholly owned subsidiary of the Stream family, a multi-generational single-family office, based in Lake Charles, Louisiana. In addition to other investments, the Stream family are long-term landowners in Southwestern Louisiana, owning and operating land assets for well over a century in and near Lake Charles. The Stream family have protected and restored tens of thousands of acres of wetlands and sustainably managed thousands of acres of timber assets. The GCS sequestration "hub" is a natural fit for the Stream family.

1.3 Proposed injection mass/volume and CO_2 source

Project Minerva is designed for four wells which are spread into two project areas – 'Perry Ridge' located in southwestern Calcasieu Parish and 'South Island' located in northwestern Cameron Parish. Each of Perry Ride and South Island project areas will contain four injection wells emanating from a single surface location per project area. Four injection wells were selected to maximize access to the available pore volume of the Oligocene Frio Formation and to disperse and maximize the flow of CO_2 from the project areas. Project Minerva is designed to operate for thirty years at a nameplate capacity per annum of 2.7 million metric tons of CO_2 across all four injection wells.

CO_2 is anticipated to be sourced from industrial facilities in Southwestern Louisiana and Southeastern Texas, primarily from the Lake Charles and Beaumont industrial corridors. According to Environmental Protection Agency (EPA) Facility Level Information on GreenHouse gases Tool (FLIGHT) the total CO_2 emissions from the four counties/parishes which abut Project Minerva emitted nearly 57 million metric tons of CO_2 in 2018 (EPA FLIGHT database at https://ghgdata.epa.gov/ghgp/). The two counties in Texas are Jefferson and Orange and the two parishes in Louisiana are Cameron and Calcasieu. Project Minerva does not have a dedicated

source of CO_2 under contract but is in advanced stage discussion on offtake arrangements for CO_2 with a number of counterparties with assets in the four county/parish area discussed above.

2.0 REGIONAL GEOLOGICAL DESCRIPTION

2.1 Regional Geological Background

2.1.1 Gulf of Mexico regional geologic setting

The Gulf of Mexico is a relatively small ocean basin covering an area of more than 579,000 mi^2 (1.5 million km^2) (Ocean Exploration and Research Website, 2018). Since ~135 million years ago, the basin has been a stable geologic province characterized by the persistent subsidence of its central part, and the massive influx of clastic sediments off the North American Continent, forming thick prograding clastic wedges along its northwestern and northern margins. Sediment input has been particularly voluminous since the start of the Paleogene and is responsible extensive deformation of underlying salt and the resulting abundance of prolific hydrocarbon systems along the Gulf Coast of Louisiana and Texas (Figure 2.1 and Figure 2.2) (Foote et al., 1984). The Project Minerva interval of interest comprises >8,000 ft of dominantly clastic strata.

2.1.2 Gulf of Mexico Basin origin and early evolution

Around 200 million years ago, the super continent Pangea split into two separate and smaller supercontinents, Laurasia (which would later become North America, Europe, and Asia) and Gondwana (which would later become South America, Africa, Antarctica, and Australia). As Pangea rifted apart, a section of the fracture between the future North American and South American continental plates expanded and the resulting stretching as well as thinning of the Earth's crust created a large depression that would become the Gulf of Mexico basin (Ocean Exploration and Research Website, 2018).

2.1.3 Deposition of thick Mid Jurassic salt deposits

As spreading of new oceanic crust expanded and deepened the young Gulf of Mexico basin, between 160 and 140 million years ago (mid to late Jurassic), it was intermittently filled by seawater from the Pacific and early Atlantic, creating shallow bodies of water with restricted flow conditions. Repeated cycles of seawater flooding and evaporation resulted in the formation of extensive salt accumulations that locally attained thicknesses of 10,000 to 15,000 ft thick before flowage into the numerous pillows, massifs, and diapiric stocks that today dominate the structural fabric of much of the Gulf basin (Foote et al., 1984).

2.1.4 Dominantly carbonate deposition from late Jurassic until the late Cretaceous

Following the last major cycle of evaporitic deposition early in Late Jurassic time, the Gulf of Mexico region was flooded by open seas. Depositional environments quickly changed from evaporitic and continental to shallow and, perhaps locally, deep marine. Terrigenous sands and muds initially were deposited across the basin, and eventually they were overlain by predominantly carbonate accumulations as subsidence slowed and the supply of terrigenous clastic material waned. A carbonate depositional regime prevailed into the Early Cretaceous, during which time, broad carbonate banks composed of limestones, dolomites, and interbedded anhydrites were

constructed around the periphery of the basin. Carbonate muds accumulated in the deeper water areas between these broad banks. As reef construction and sedimentation kept pace with regional subsidence, the banks were continually built upward as their foundations sank (Foote et al., 1984).

2.1.5 Voluminous clastic sediments dominate during late Cretaceous

General uplift of the North American continent during latest Cretaceous and early Tertiary times was related to the tectonic formation of the Rocky Mountains in the western United States; this general uplift produced voluminous amounts of clastic sediment throughout the Tertiary period. Large volumes of land-derived sands and muds were deposited in successively younger wedges of off-lapping strata as the basin subsided relatively rapidly. Alternate periods of load-induced subsidence and up-building of sediments followed by less subsidence and out-building of sediments produced the multiple transgressions and regressions of depositional environments that are characteristic of the Tertiary sequence along the Louisiana and Texas Gulf Coast. Sediment supplies during Cenozoic time overwhelmed the general rate of subsidence, causing the margins to be prograded as much as 240 mi (384 km) from the edges of Cretaceous carbonate banks to the present position of the continental slopes off Texas and Louisiana (Foote et al., 1984).

Cenozoic and Mesozoic shales and dense limestones demonstrably serve as seals in producing oil and gas fields regionally. Cenozoic sedimentary units of clastic origin deposited across the Gulf Coast, such as those of interest at Project Minerva, appear as dominantly well-layered alternating sands and shales, based upon their seismic characteristics, the widely accepted depositional model and data collected from drilled wells (Foote et al., 1984).

2.1.6 Pleistocene glacial sedimentation forms dominant USDW interval

The voluminous infilling of the Gulf basin during Tertiary time was followed by sediment influx of similar proportions due to the profound effects of continental Pleistocene glaciation. Sea levels rose and fell in concert with climatic conditions that controlled the retreats and advances of glacial sheets. Pleistocene sediments accumulated along the outer shelf and upper slope regions of the northern gulf margin, blanketing the Project Minerva area (Foote et al., 1984). The main underground source of drinking water (USDW) at Project Minerva, the Chicot reservoir, was deposited at this time.

2.1.7 Regional structural framework

Tectonism caused by sediment loading and gravity has played a major role in contemporaneous and post-depositional deformation of Tertiary strata, however the continental margins and deep ocean basin regions of the Gulf of Mexico, are relatively stable areas (Foote et al., 1984).

During the Tertiary, large quantities of sand and mud were deposited along the margins of the Gulf of Mexico and these sediments accumulated in a series of wedges that thicken and dip gulfward. Large growth fault systems formed near the downdip edge of each sediment wedge within the area of maximum deposition; these faults developed as a result of rapid sediment loading (Swanson and Karlsen, 2009) which caused the plastic flowage of underlying Jurassic salt deposits and masses of under-consolidated Cenozoic shale (Figure 2.3). Mobilization of salt resulted in the formation ridges and troughs and extensive salt diapirism, many of which have pierced many thousands of feet of overlying strata. Regional faulting typically occurred parallel to successive shelf edges during Tertiary and Quaternary times, down-thrown towards the gulf (Foote et al., 1984). Radial faulting is common around major salt diapirs (eg. Vinton Dome).

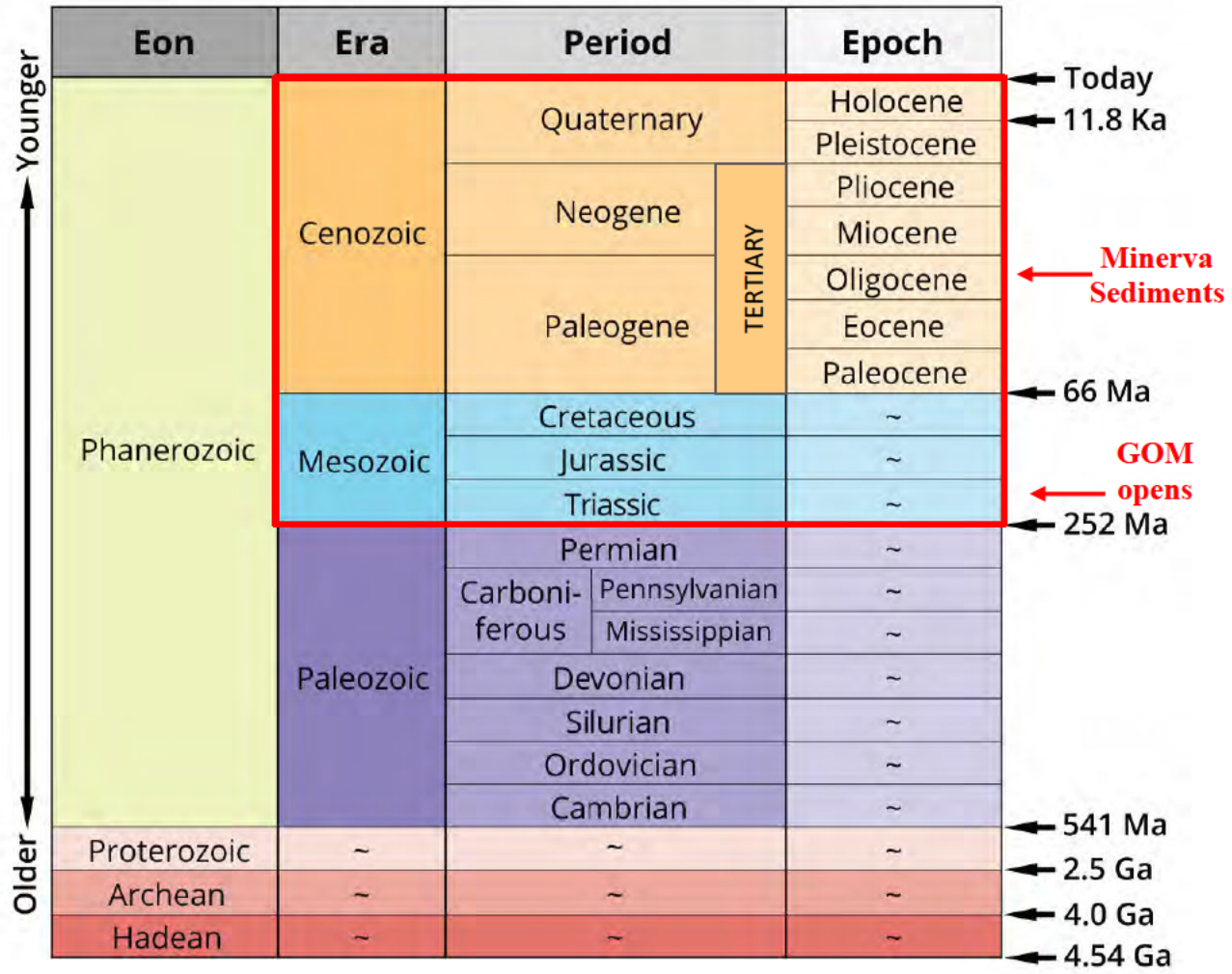
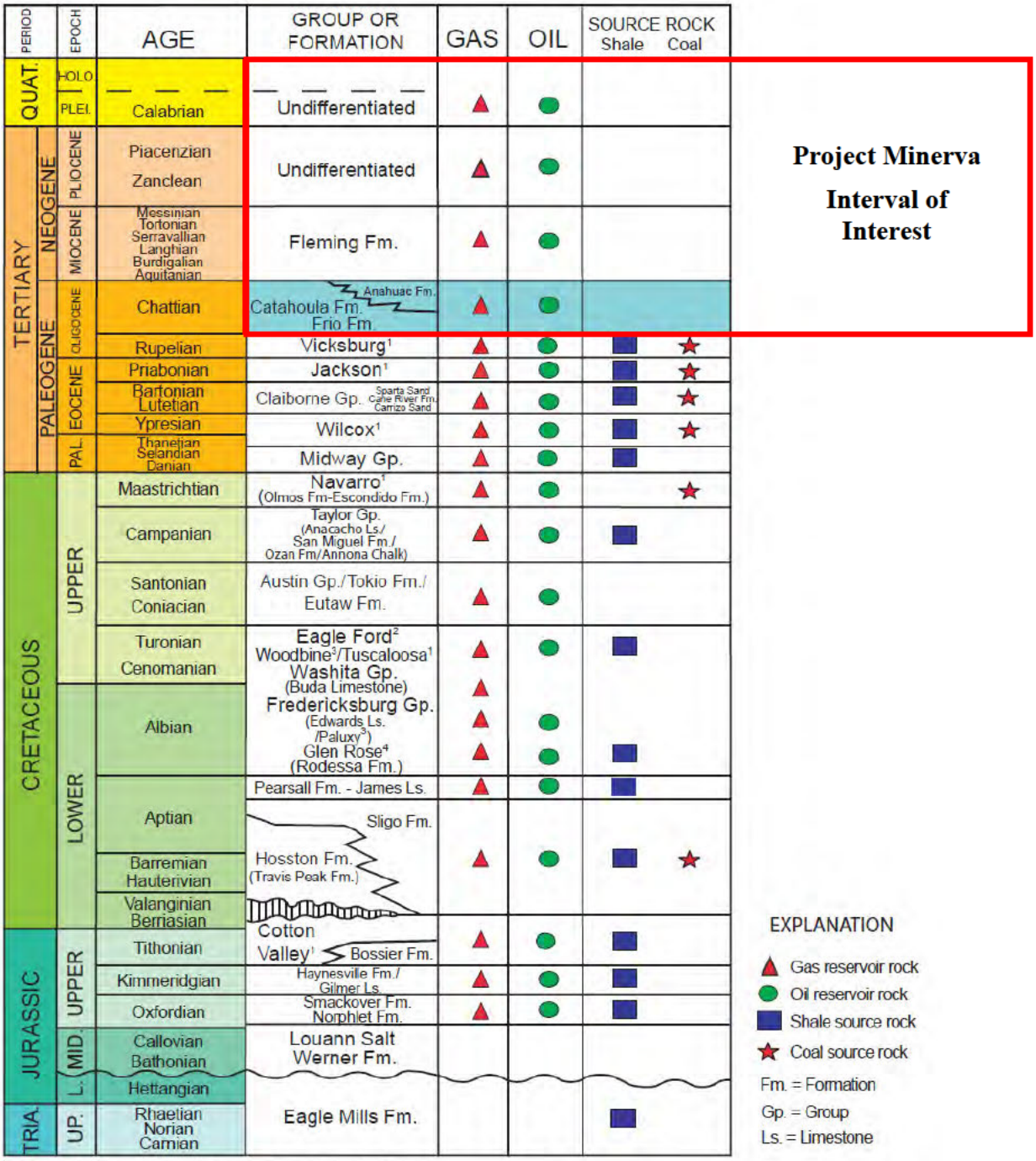


Figure 2.1 Geological time scale. Red box indicates the time interval in which the Gulf of Mexico (GOM) has existed (modified from Jonathan R. Hendricks)



[1] Indicates classification of Group or Formation, depending on locality use.

[2] Indicates classification of Group, Formation, Clay or Shale, depending on locality use.

[3] Indicates classification of Formation or Sand, depending on locality use.

Figure 2.2 Generalized regional stratigraphic section of the northern Gulf of Mexico coastal plain, with the Frio Formation (equivalent to the Catahoula Formation in up-dip areas) and Anahuac Formation highlighted in blue. Abbreviations and symbols: Mid., Middle; Pal., Paleocene; Plei., Pleistocene; Holo., Holocene; Quat., Quaternary; wavy line, missing section; jagged line, interfingering; dashed line, uncertain. Modified from Swanson & Karlsen, 2013.

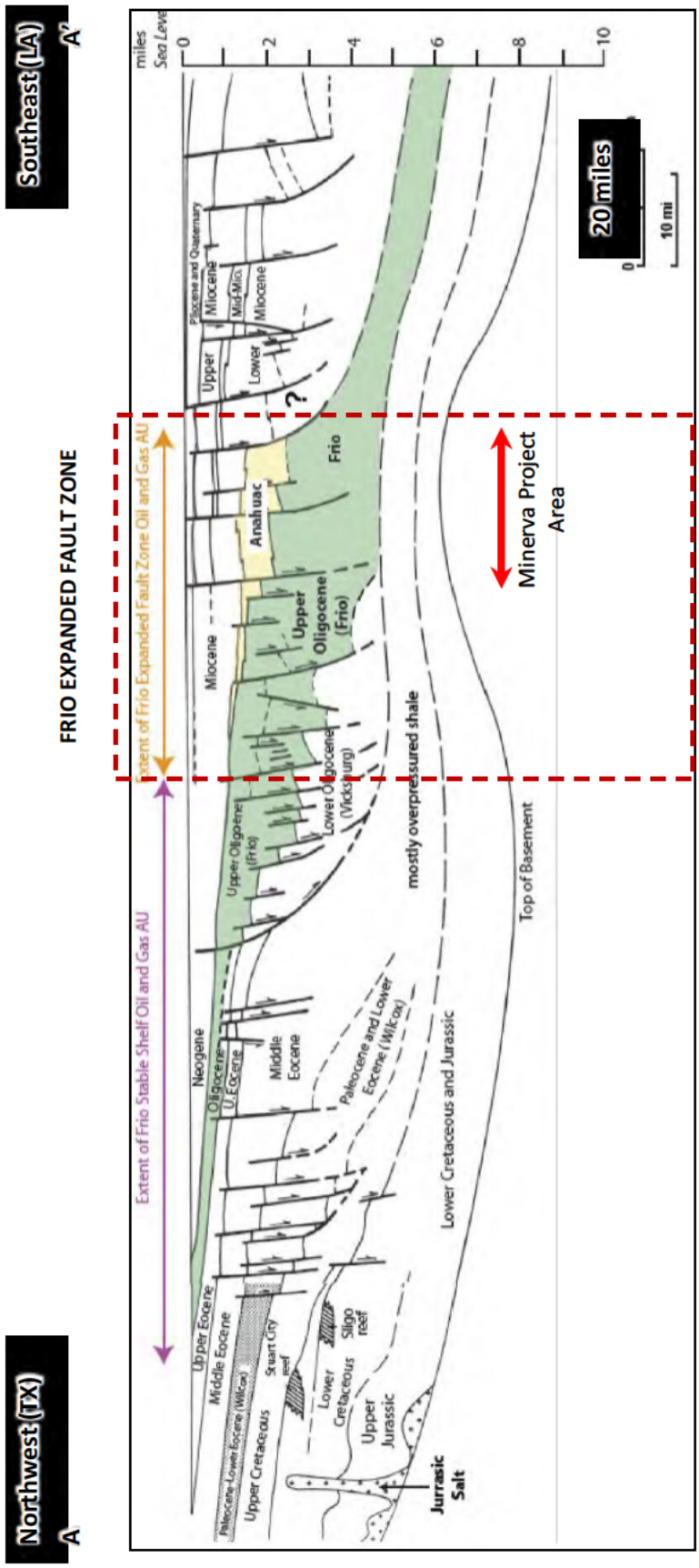


Figure 2.3 Cross section (A-A' Figure 2.4) through eastern Texas and southern Louisiana showing a schematic view of the typical structural regime stepping from the north down to the Guld of Mexico in the south. Frio and Anahuac Formations shown in yellow and green, respectively. Red Box: represents the "Frio Expanded Fault Zone", where faulting and salt dome development created significant accommodation space for thick Frio sandstones and overlying Anahuac Shale. Blue Arrows: Project Minerva sits in the southern extent of the zone, where the thickest Frio and Anahuac accumulated. Modified Swanson & Karlsen, 2013.

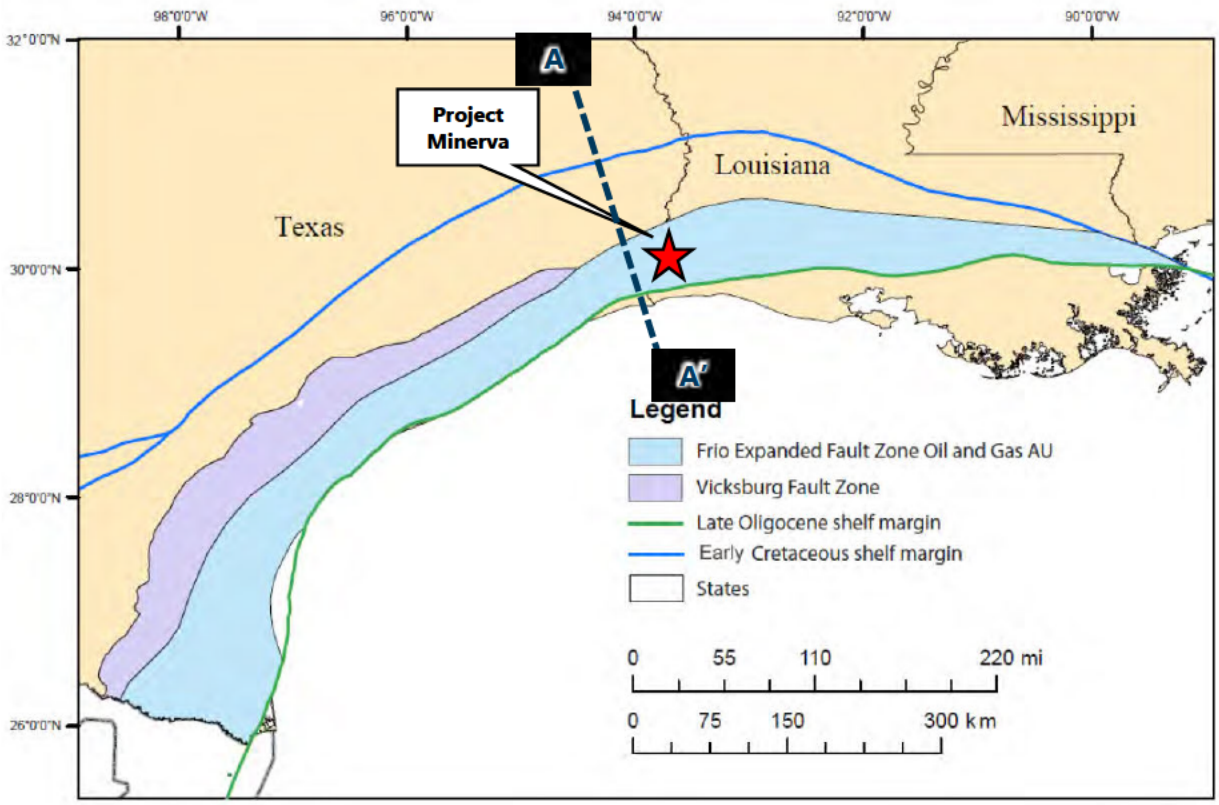


Figure 2.4 Frio Expanded Fault Zone. Modified from Swanson and Karlsen (2009)

2.2 Geological background of the Oligocene and Miocene (Interval of Interest)

2.2.1 Interval of interest overview

Project Minerva is primarily interested in the Late Oligocene Frio Formation (sandstone-rich Injection Zone) and Anahuac Formation (shale-rich Confining Zone). Attention has also been paid to the Miocene interval (clastic-/shale-rich Secondary Confining Zone) and the Quaternary interval (glacial sediments and regional potable water aquifers) (Figure 2.2 and Figure 2.5).

2.2.2 Regional geological setting of Project Minerva

Project Minerva lies within the "Frio Expanded Fault Zone", where large-scale regional fault movement generated accommodation space for thick, clastic Frio reservoir sandstones, and a subsequent transgressive sealing shale (Anahuac Formation) (Figure 2.2 and Figure 2.3). Regional structure dips to the south and is dominated by deep-seated "fault zones" (bands / complexes of closely aligned faults) generally dipping towards the Gulf, driven by gravity sliding along underlying salt and shales. Simplified fault zones are shown on regional maps where 3D seismic is not available for detailed analysis. Salt dome features are visible as structural highs typically surrounded by radial faulting (Figure 2.6).

2.2.3 Oligocene Deposition

During the Oligocene four sediment-dispersal axes dominated the Gulf margin (Figure 2.7). The Houston, and central Mississippi deltas, provided a source of coarse-grained sediment at Project Minerva (Swanson & Karlsen, 2009). Oligocene sediments were deposited along the Gulf Coast basin as cyclic depositional units, which represent transgressive and regressive stages of deposition. These depositional cycles were caused by variations in sediment supply and subsidence. Oligocene deposits are subdivided according to depositional cycles (Figure 2.5) (Foote et al., 1984).

1. Lower Oligocene (Vicksburg) represents a transgressive phase (mainly shale and some sandstone lenses) and underlies our interval of interest
2. Middle Oligocene (Frio) represents a regressive phase (sandstones interbedded with marine shales)
3. Upper Oligocene (Anahuac) represents transgression (marine shales and thin sandstones)

2.2.4 Frio Formation

The Middle Oligocene Frio Formation is a very thick sequence of regressive sediments that were deposited rapidly in alluvial, lagoonal and inner-neritic environments, forming a major progradational wedge along the Gulf. Non-marine sands were deposited in constantly shifting deltas and are interbedded with marine shales that were deposited during periods of local transgression. The massive/stacked Frio sands seen at Project Minerva are likely related to thick accumulations in shorezone of strand plain and deltaic environments. Locally, lenses of Frio sandstone may shale-out along strike into the Frio shales (Foote et al., 1984). Regionally, the extent of the Frio Sandstone trend is defined to the north (southern Beauregard Parish) by transition into fine-grained, mix-load dominated fluvial sediments, and to the south (offshore Gulf of

Mexico) by large-scale fault-related juxtaposition against thick, fine-grained formations in the overlying Neogene. (Swanson et al., 2013).

2.2.5 Hackberry Trend

A transgressive, deep water shale and sandstone unit referred to as the "Hackberry" occurs in the middle to lower part of the Frio Formation. Oligocene turbidite sands were deposited in nearshore and deep marine environments, in a relatively confined area of southern Louisiana and Texas where deltas prograded directly into deeper waters (Figure 2.7 and Figure 2.10) (Foote et al., 1984). The Hackberry interval appears in the middle to lower Frio Formation and is characterized by thick shales punctuated by incised submarine channel sandstones.

2.2.6 Anahuac Formation

The Frio Formation is regionally overlain by late Oligocene, the Anahuac Formation, a transgressive marine shale containing sandstone, carbonate bank, and carbonate reef deposits. The Anahuac Formation occurs in the subsurface of Texas, Louisiana, and southwestern Mississippi (Figure 2.12). Three depositional systems have been proposed in south-central and southwestern Louisiana: proximal deltaic, distal deltaic, and slope environments (Swanson et al., 2013).

The Anahuac Formation strata of southwestern Louisiana and Texas typically consist of light- to dark-greenish-gray calcareous shale that is interbedded with thin beds of locally calcareous sandstone and limestones. In western and central parts of Louisiana (Project Minerva area) the interval mostly comprises shales with lesser sandstones, while limestones and calcareous clastics dominate in Anahuac eastern Louisiana and the eastern Gulf of Mexico, where clastic influx was minimal (Swanson et al., 2013).

2.2.7 Miocene Deposition

At the end of Oligocene time, the depocenters shifted northeastward into southern Louisiana where the ancestral Mississippi River began to supply large quantities of sand, silt, and mud. In each Miocene depocenter, sediments were deposited on deltas and further distributed gulfward and laterally across broad shelf areas by marine currents Progradation of coastal depositional environments dominated throughout Upper Miocene and Pliocene times and represent persistent and laterally uniform sedimentary environments. In southern Louisiana depocenters, Miocene deposits exceed 20,000 ft in thickness and comprise prolific source beds, reservoir rocks, structural-stratigraphic traps, and reservoir seals (Foote et al., 1984).

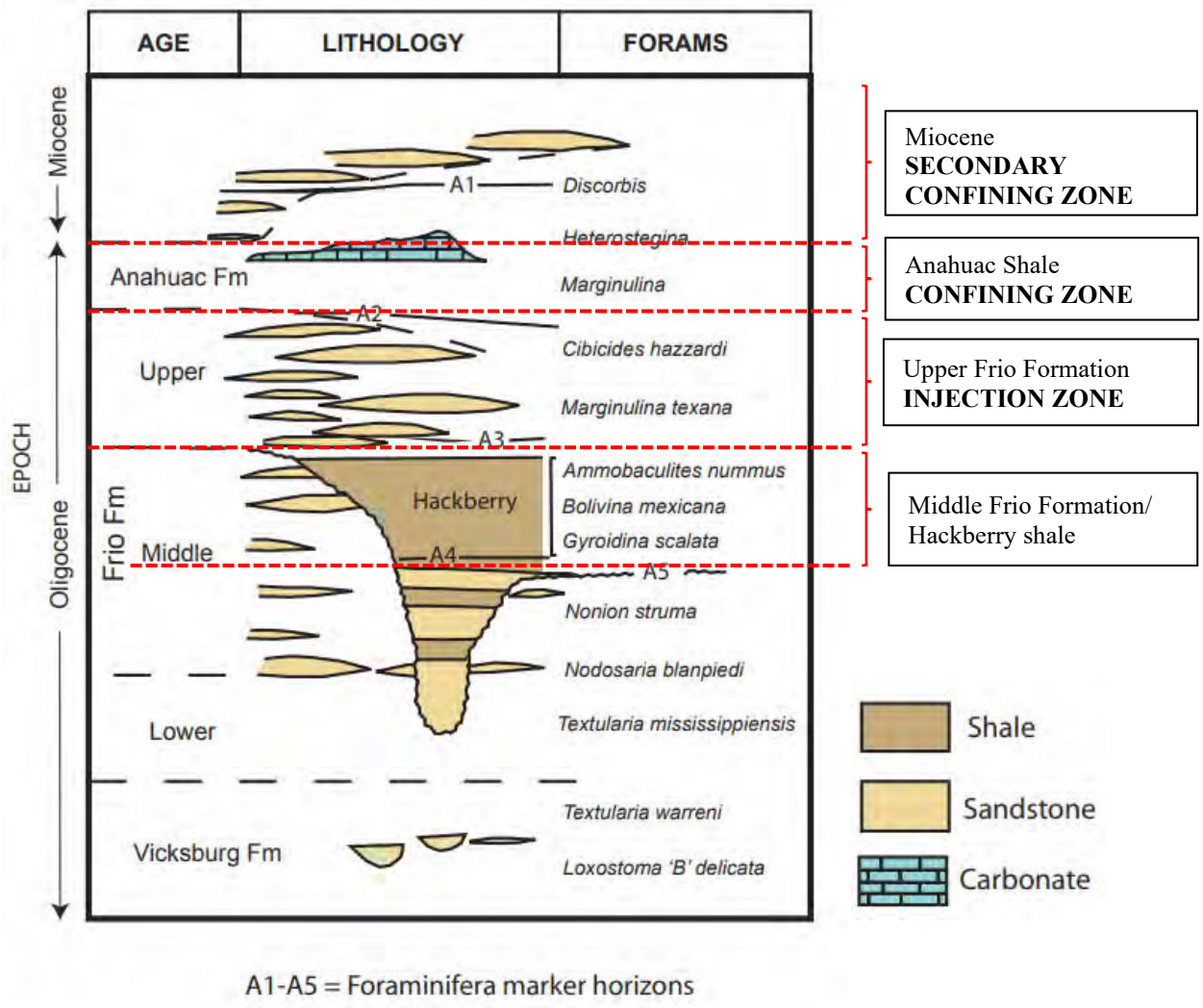


Figure 2.5 Schematic stratigraphic column illustrating the relative position of the Confining and Injection Zones.

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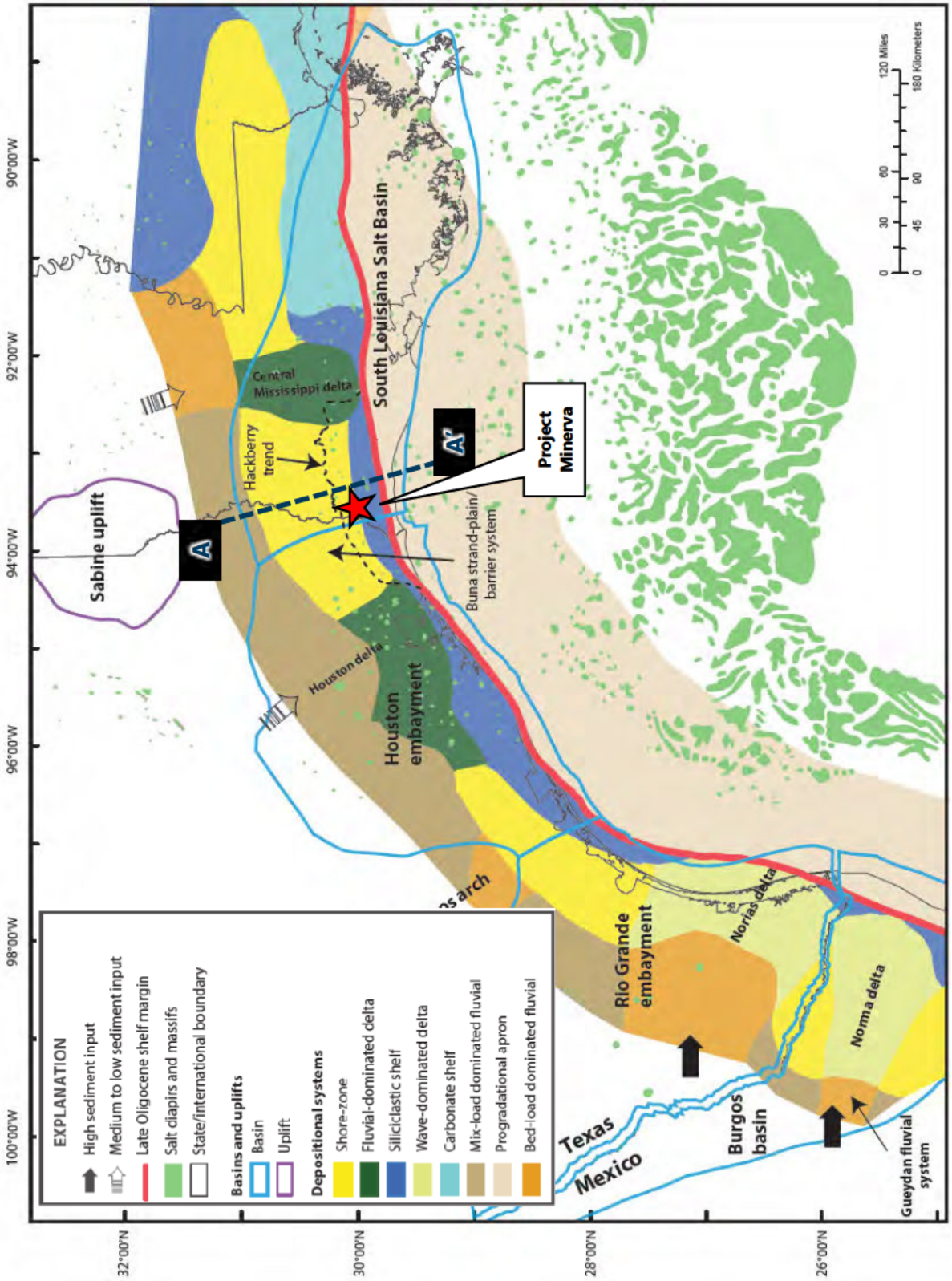
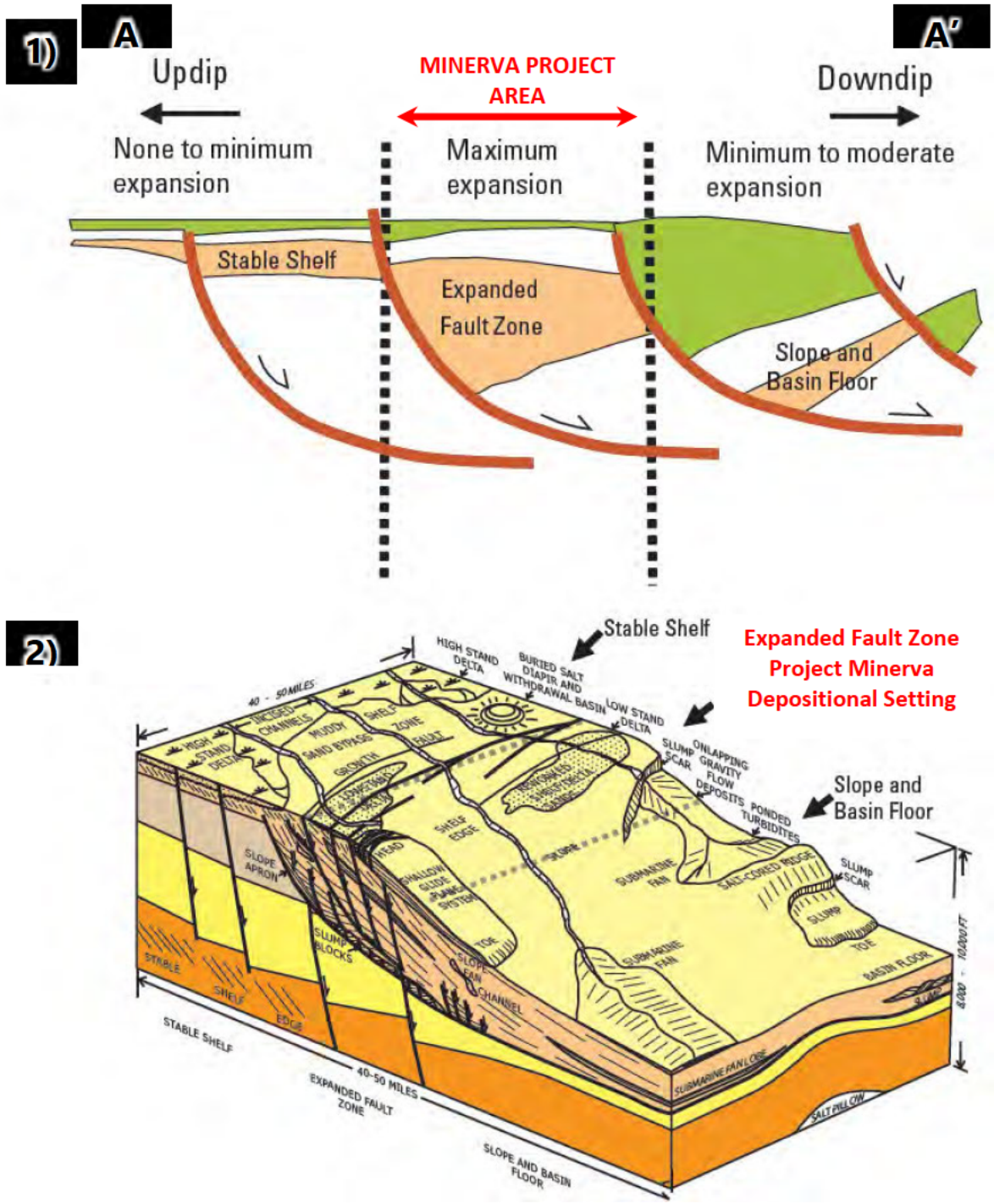


Figure 2.7 Regional depositional model for the late Oligocene Frio Formation (Project Minerva Site highlighted with red star). Principal sediment sources, basins and uplift, and depositional systems shown. Cross section line refers to Figure 2.8. Modified from Swanson & Karlsen, 2013.



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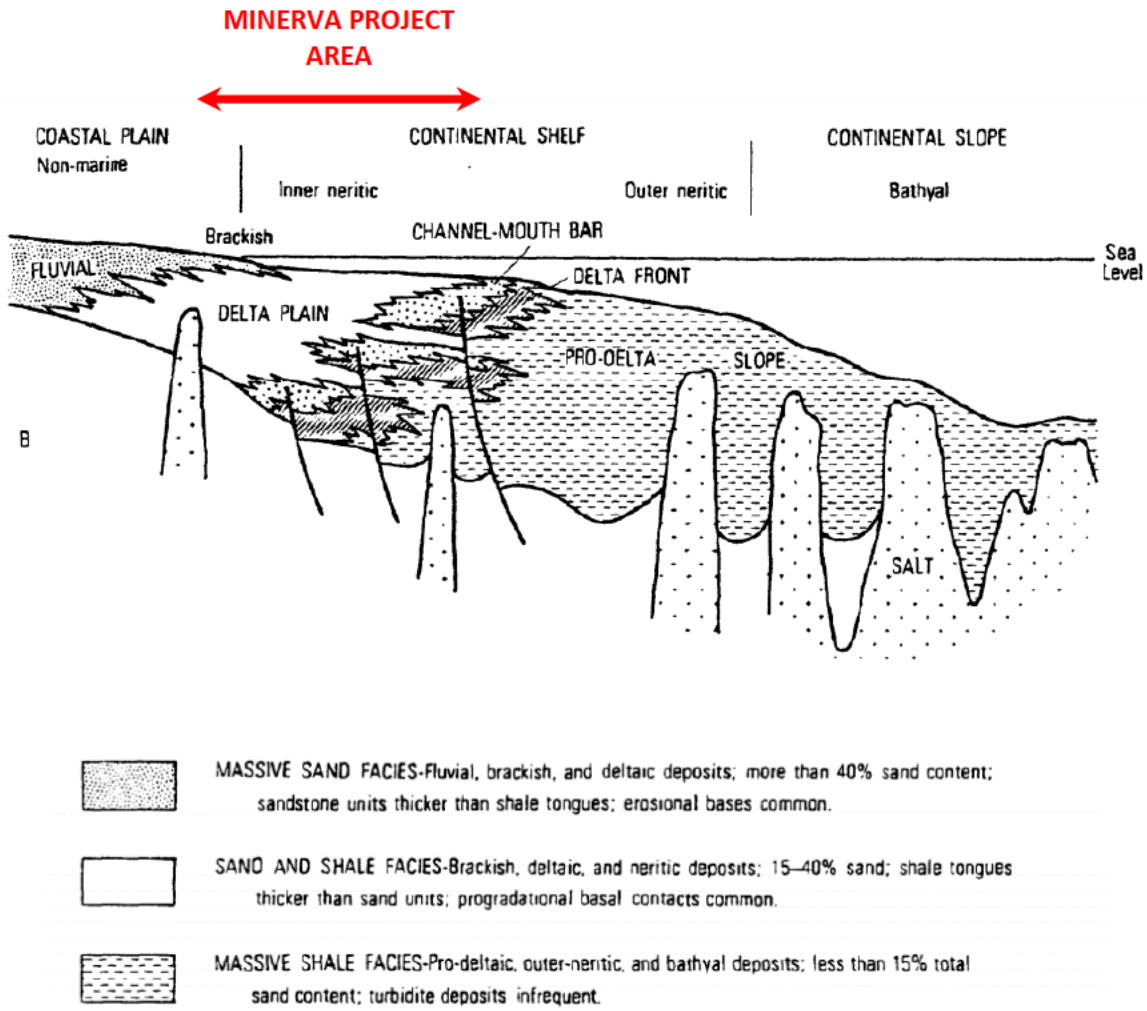

Figure 2.9 Schematic cross section of depositional facies during the Oligocene along the Gulf Coast

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4.0 PROJECT AREA SPECIFIC DESCRIPTION OF THE GEOLOGY OF THE AOR

4.1.1 Project Minerva Geological System Overview

Project Minerva benefits from an ideal geological system involving the late Oligocene Frio Formation reservoir sealed by the overlying Anahuac shale interval, in a broad syncline structure created by the interplay of regional fault zones and salt diapirs. Secondary sealing is provided by a shale-rich Miocene (Figure 4.1). Significant separation exists between the top of the Frio Formation and the deepest mapped USDW. See Figure 4.2 for a schematic cross section of the system.

4.1.1.1 Injection Zone – High Net-to-Gross Upper Frio Formation

The Frio Formation comprises a thick series of stacked, laterally extensive, high net-to-gross deltaic and marginal-marine sandstones. It is a proven high quality reservoir interval (>8% porosity) and is one of the largest hydrocarbon producers from the Paleogene in the Gulf of Mexico.

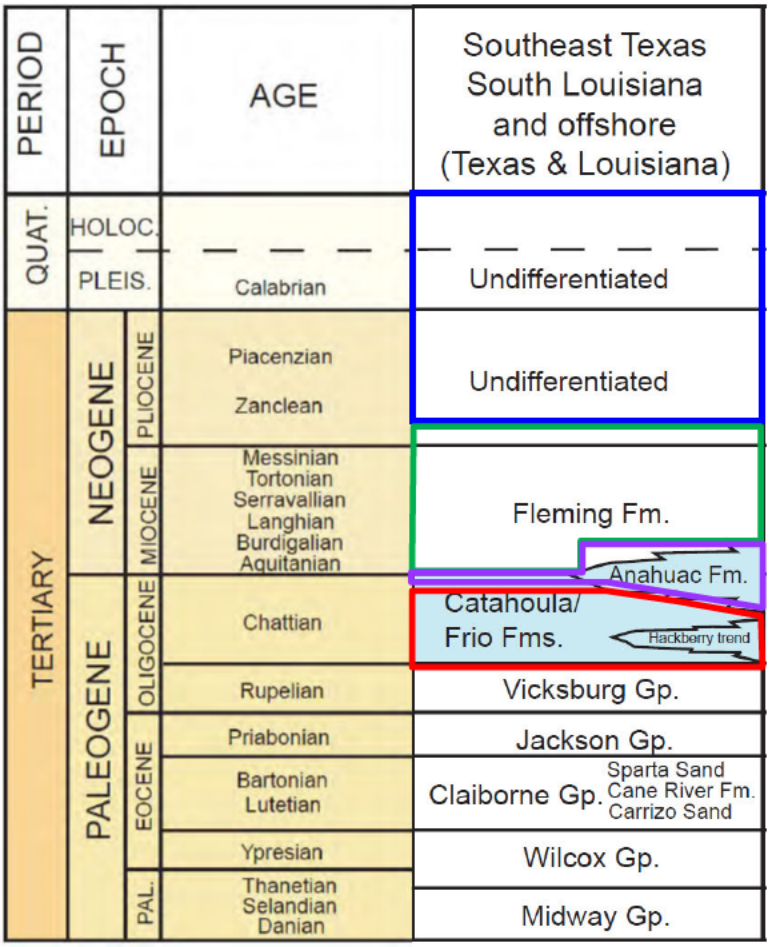
At Project Minerva, the Frio Formation comprises three distinct zones – Upper, Middle and Lower – clearly visible in geophysical log data (Figure 4.3). The Upper and Middle zones contain the highest quality and most prolific reservoir sandstone intervals. Both the Upper and Middle Frio intervals have been extensively developed in in southwest Louisiana, however, at Project Minerva, the Upper Frio is sparsely drilled and water-wet.

4.1.1.2 Confining Zone – Low Permeability Anahuac Shale

Progradation of shore-zone (Frio Formation) depositional systems across Project Minerva in the early Oligocene was followed by sustained systems tract retreat during the late Oligocene. The shale-rich retrogradational systems tract (Confining Zone) that overlies and seals the Injection Zone is known regionally as the Anahuac Formation. It typically comprises thick (average 750ft), low vertical permeability (~10^{-6} mD), fine-grained, open-marine deposits, light- to dark-greenish-gray calcareous shale that is interbedded with thin beds of locally calcareous sandstone and limestones. Regionally extensive deposition occurred in proximal deltaic, distal deltaic, and slope environments and completely covers the Project Minerva area (Swanson et al., 2013).

4.1.1.3 Secondary Confining Zone and USDW– Miocene Overburden

The Miocene in the Louisiana coast is one of the thickest wedges of terrigenous clastic sediments fed by a complex river system in the northern Gulf of Mexico. In the Early Miocene, active salt tectonics restricted deposition to the shelf with the salt reinforcing the prograding slope, thereby trapping sediments on the shelf (Coker, 2006). This resulted in more than 7,000ft of Miocene strata (>1,100 feet net impermeable shale) being deposited across the Project Minerva site. Extensive shales within this interval act as secondary confinement of the Frio reservoir and the interval provides significant vertical separation of the USDW (Figure 4.2)



Approx. USDW
Pliocene and younger formations

Secondary Confining Zone
Fleming Formation: thick interbedded shales, siltstones and sandstones. >7,000ft vertical separation from Frio Formation in project area

Confining Zone
Anahuac Shale >750ft

Injection Zone
Upper Frio Formation; Catahoula Formation represents up-dip equivalent to the Frio (north of project area); Hackberry channel trend (Middle Frio) variably present across project area.

Figure 4.1 Figure 4.1 Stratigraphic section of the Tertiary and younger strata in the Northern Gulf of Mexico coastal plain. Modified from Sharon & Karlsen, 2013)

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Date/Time	Latitude	Longitude	Depth (km)	Magnitude	Event ID	Place/Location
2020-03-23T06:52:42.892Z	31.94070	-94.44260	5	2.5	us70008ee1	6km NW of Timpson, Texas
2019-07-27T04:01:03.081Z	31.84680	-94.42260	5	2.6	us60004y6h	6km SSW of Timpson, Texas
2019-01-20T11:32:03.040Z	31.47030	-94.13540	5	3.3	us2000j6m0	7km SSW of San Augustine, Texas
2018-09-12T04:35:06.180Z	31.89210	-94.38740	5	2.5	us2000hd8u	1km SSE of Timpson, Texas
2018-09-04T15:06:46.490Z	31.96130	-94.43430	5	3.5	us2000h85v	7km NNW of Timpson, Texas
2014-10-03T04:52:32.650Z	31.67610	-94.05540	5	3.1	usb000sie0	16km NNE of San Augustine, Texas
2013-09-02T23:51:15.460Z	31.90950	-94.42790	4.69	4.3	usb000jfgm	3km WNW of Timpson, Texas
2013-09-02T21:52:38.940Z	31.96560	-94.52610	4.75	4.2	usb000jfey	14km WNW of Timpson, Texas
2013-05-31T10:01:17.070Z	31.86000	-94.33200	5	2.9	usp000k11q	eastern Texas
2013-03-11T15:22:37.220Z	27.87500	-92.04300	10	2.9	us2013mqa8	212km SW of Dulac, Louisiana
2013-01-31T21:20:33.480Z	31.93900	-94.46600	5	2.8	usc000ezjq	13km WNW of Timpson, Texas
2013-01-29T12:31:33.140Z	31.86600	-94.38900	5	2.8	usc000exeh	3km S of Timpson, Texas
2013-01-25T07:01:19.840Z	31.84400	-94.30000	5	4.1	usc000ev85	11km SE of Timpson, Texas
2012-12-22T17:55:12.990Z	31.90500	-94.41400	5	2.6	usp000jx9c	eastern Texas
2012-12-07T19:38:37.790Z	31.87300	-94.40100	5	2.8	usp000jwmu	eastern Texas
2012-05-26T05:58:27.220Z	31.87800	-94.39400	5	2.5	usp000jkxz	eastern Texas
2012-05-20T18:28:34.620Z	31.90400	-94.45800	5	2.7	usp000jkpw	eastern Texas
2012-05-17T08:12:00.990Z	31.92600	-94.36900	5	4.8	usp000jkhb	eastern Texas
2012-05-10T15:15:38.840Z	31.96400	-94.46500	7	3.9	usp000jk92	eastern Texas
2010-08-02T04:34:29.350Z	30.81500	-90.85400	0.4	3	usp000hhbw	14km E of Clinton, Louisiana
2005-12-20T00:52:20.510Z	30.25800	-90.70800	5	3	usp000e6fr	Louisiana
1983-10-16T19:40:50.830Z	30.24300	-93.39300	5	3.8	usp0001z1h	Louisiana-Texas border region
1981-11-06T12:36:40.460Z	32.02100	-95.26200	5	3.2	usp0001gu9	northern Texas
1981-06-09T01:46:33.120Z	32.14200	-94.39900	5	3	usp0001e27	northern Texas
1930-10-19T12:17:00.000Z	30.00000	-91.00000		4.2	ushis853	Louisiana
1891-01-08T06:00:00.000Z	31.70000	-95.20000		3.8	ushis291	eastern Texas

Table 4.1 List of earthquakes within 300 km of Project Minerva. Note event closest to Project Minerva is event ID 'usp0001gu9 at a depth of 5 km, which is at basement level rather than fault reactivation in shallower stratigraphy.

4.2.4.2 Seismic Risk - Texas

In Texas, the regions at greatest risk for seismicity are in West Texas, where earthquakes of magnitude of about 6 occurred in 1931 and 1995, and in the Panhandle area, where at least six earthquakes with magnitude above 4 have occurred since 1900. Earthquakes of similar magnitude may occur again in these areas. Geologically, some features of the Panhandle are similar to the Missouri-Tennessee area, however, large continental quakes are extraordinarily rare (occurring less often than once per 500 years in any particular place). Within the twentieth century there have been more than 100 earthquakes large enough to be felt in Texas; their epicenters occur in 40 of Texas's 257 counties. Four of these earthquakes have had magnitudes between 5 and 6, making them large enough to be felt over a wide area and produce significant damage near their epicenters.

In four regions within Texas there have been historical earthquakes that indicate potential earthquake hazard. Two of the regions, near El Paso and in the Panhandle, have had earthquakes with magnitudes of about 5.5-6.0 occurring every 50-100 years, with even larger earthquakes possible. In northeastern Texas the greatest hazard is from very large earthquakes (magnitude 7 or above), which might occur outside of Texas, particularly in Oklahoma or Missouri-Tennessee. In south-central Texas and along the Gulf Coast the hazard is generally low, however, small

earthquakes can occur there, including some that are triggered by oil or gas production. Elsewhere in Texas, earthquakes are exceedingly rare. However, the hazard level is not zero anywhere in Texas; small earthquakes remain possible.

A series of moderate earthquakes in the Texas - Louisiana border region near Hemphill started on April 23, 1964. Epicenters were determined on April 23, 24, 27, and 28. There were numerous additional shocks reported felt at Pineland, Hemphill, and Milam. The only damage reported was from the magnitude 4.4 earthquake on April 28 - wallpaper and plaster cracked at Hemphill. The magnitude of the other epicenters changed from 3.4 to 3.7. Shocks were also felt at Pineland on April 30 and May 7. On June 2, three more shocks were reported in the same area. The strongest was measured at magnitude 4.2; intensities did not exceed IV. Another moderate earthquake on August 16 awakened several people at Hemphill and there were some reports of cracked plaster. The shock was also felt at Bronson, Geneva, Milam, and Pineland.

Finally, there is some risk to Texas from earthquakes that may occur outside of the state. Large earthquakes similar to the 1811-1812 Missouri-Tennessee earthquakes would probably damage some structures in North Texas that aren't designed to withstand earthquakes. There is also potential hazard in the Panhandle area from earthquakes that may occur in Oklahoma.

In the Project Minerva area, the likelihood of an earthquake caused by natural forces or fluid injection is considered remote. Injection of carbon dioxide at Project Minerva is expected to be at comparatively low pressures and take place into deep, high porosity-high permeability formations that are extensive over a broad area that is not subject to natural earthquakes. Therefore, the probability of an earthquake of sufficient intensity to damage the injection system, injection well, or the confining layer is very low.

4.2.4.3 Induced Seismicity

Seismicity related to fluid injection normally results from activity involving high pressures and large volumes, such as those associated with high-pressure water flood projects for enhanced oil recovery. This seismicity is caused by increased pore pressure, which reduces frictional resistance and allows the rock to fail. Fluid withdrawal has caused land subsidence and earthquakes due to dewatering and differential compaction of the sediments. Earthquakes of magnitude 3.4 to 4.3 on the Richter scale appear to have been caused by fluid withdrawal near some oil fields in east Texas (Davis et al., 1987), such as Sour Lake, Mexia, and Wortham Fields.

Since 2010, the occurrence of earthquakes with a magnitude greater than 3.0 have increased from 20 events per a year (1967-2000) to over 100 events per a year (2010-2013) in the central and eastern US region (Ellsworth, 2013). The increased rate of occurrence in previously inactive seismic areas has been correlated with the increased use of injection wells located near faults. Fluid injection induced earthquakes are most likely caused by the increased pore pressure from injection operations which have reduced effective stress of faults leading to failure. This mechanism has been used to explain the best-known cases of injection-induced seismicity which was first studied in the Rocky Mountain Arsenal near Denver. New case studies have increased with the use of wastewater injection wells associated with hydraulic fracking. In many sites, smaller seismic occurrences have shown to be precursors to larger events. More data has become available since the Rocky Mountain study in the 1960’s, leading to a better understanding of factors and processes associated with induced-seismicity.

One of the most notable regional cases of induced seismicity associated with injection wells occurred in Youngstown, Ohio. In 2011, 12 low-magnitude seismic events occurred along a previously unknown fault line (Ohio Department of Natural Resources, 2012). These events occurred less than a mile from Class II injection well Northstar I. Previously, the area was seismically inactive, with earthquakes beginning a few months after the injection of wastewater. The injectable pressure at Northstar I was increased twice over 6 months (Ohio Department of Natural Resources, 2012) and may have reduced the effective stress on a fault. After the well was shut down by the Ohio Department of Natural Resources, the seismic activity declined. As a result of this case, seismic monitoring prior to injection and after injection has become common in Class II sites.

A case study in the Dallas-Fort Worth area tied small seismic events to a Class II injection well. 11 hypocenters have been observed at a focal depth of 4.4 km and 0.5 km from a deep saltwater disposal (SWD) well (Frohlich et al., 2010). Injection at this well began 8 weeks prior to the first recorded seismic event. A northeast trending fault is located approximately at the same location of the DFW focus (Frohlich et al., 2010). As a result of fluid injection into the disposal well, the stress upon the fault had been reduced and thus reactivated the fault (Frohlich et al., 2010). All of the seismic events associated with the DFW focus are small magnitude events (less than 3.3) and occurred very shortly after initial injection.

In Oklahoma, one of the largest earthquakes in the state's history may have been a result of wastewater injection at a Class II disposal site. In 2011, Prague, Oklahoma was the location of a 5.7 magnitude earthquake that was followed by thousands of smaller aftershocks. Wastewater had been pumped continuously into an old oil well for 17 years. As the pore spaces filled, the wellhead pressure was increased to continually inject the wastewater. This reduced the effective stress upon the Wilzetta fault located 650 meters from the well (Keranen et al., 2013). The fluid was injected into the same sedimentary strata at which 83% of the aftershocks originated (Keranen et al., 2013). In this case, the seismic event occurred years after the initial injection phase. Since the area was considered low risk seismically, there is no data on smaller earthquakes that may have proceeded the event in 2011.

In north-central Arkansas, multiple earthquakes have been triggered because of a Class II injection well. Since the operation of the disposal well in 2009, the site has experienced an increase from 2 events in 2008 to 157 events in 2011 (Horton, 2012). It was also tied to the discovery of a new vertical fault. 98% of earthquakes within this area occurred within 6 km of one of three waste disposal sites (Horton, 2012). The depth of the earthquake foci occurred between 6.7 and 7.6 km. Injection of fluid occurred at a depth of 2.6 km. At this disposal site, and E-W trending (Enders Fault) cut into the aquifer in which the fluid was injected and then acted as a conduit to the new fault at the depth of 6.7 to 7.6 km (Horton, 2012). The disposal wells were shut down in 2011 by the Arkansas Oil and Gas Commission. The rate and size of the earthquakes steadily decreased following the shutdown of the wells (Horton, 2012).

In Texas there are at least two known examples of previously seismically inactive areas becoming seismically active after major injection programs began. One site is located in the Central Basin Platform, near Kermit, and the other is in the Midland Basin near Snyder. In both cases, large scale, high pressure, oil field related, water flooding projects were under way, and earthquakes with a magnitude of over 4.0 on the Richter scale were recorded. Historically, induced earthquakes in Texas have not exceeded 4.6 magnitudes (Frohlich et al., 2010). Factors for an induced earthquake are limited to the distance a well is located from a fault, the stress state of the fault, and

a sufficient quantity of fluids from the injection well at a high enough pressure and enough time to cause movement along the fault (Ohio Department of Natural resources, 2012). A hydraulic conduit from the injection zone to a fault may also induce earthquakes (Ellsworth, 2013). The largest injection-induced events are associated with faulting that is deeper than the injection interval, suggesting that the increased pressure into the basement increases the potential for inducing earthquakes (Ellsworth, 2013). In all in cases, faults have been reactivated at or in close proximity of Class II injection sites. In some cases, previously unknown faults have been discovered. No induced earthquakes have been known or are postulated to have been caused by Class I injection operations (Davis et al., 1987).

The potential for induced seismicity at Project Minerva can be evaluated using the very conservative "zero-cohesion Mohr-Coulomb failure criterion," recommended by the U.S. Geological Survey (Wesson and Nicholson, 1987). This method is based on the following equation:

$$P_{crit} = \frac{S_v(3\alpha - 1)}{2} \qquad (1)$$

where:

P_{crit} = the critical injection zone fluid pressure required to initiate slippage along faults and fractures

S_V = the total overburden stress (which represents the maximum principal stress in the Gulf Coast region)

α = the ratio of the minimum principal stress (horizontal in the Gulf Coast region) to the maximum principal stress (overburden stress)

Inherent in Equation (1) are a number of conservative assumptions, guaranteed to produce a worst-case lower bound to the critical fluid pressure for inducing seismicity. These are:

1) It neglects the cohesive strength of the sediments

2) It assumes that a fault or fracture is oriented at the worst possible angle

3) It assumes a worst-case value of 0.6 for the coefficient of friction of the rock (see Figure 4 of Wesson and Nicholson, 1987)

For present purposes, Equation (1) can be expressed in a more convenient form by introducing the so-called matrix stress ratio (Ki) (Matthews and Kelly, 1967; Eaton, 1969), which is defined as the ratio of the minimum to the maximum "effective" principal stresses. Effective principal stress is equal to actual principal stress minus fluid pore pressure (p_o). Thus:

$$K_i = \frac{\alpha S_v - p_o}{S_v - p_o} \qquad (2)$$

Substituting Equation (2) into Equation (1) yields:

$$\Delta P_{crit} = \left(\frac{3K_i - 1}{2}\right)\left(S_v - p_o\right) \quad (3)$$

where ΔP_{crit} is the critical injection zone pressure build-up required to induce seismicity, with:

$$P_{crit} = p_o + \Delta P_{crit} \quad (4)$$

Equation (3) will be used to evaluate induced seismicity at Project Minerva.

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4.6.1 ***Water Wells and Data Sets***

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). Primary water well locations present within the AoR (red boundary) of the Project Minerva site are shown on Figure 4.36. All water wells within the AoR are located within Louisiana. A total of 9 water wells in the determined Area of Review are tabulated in Table 4.3. 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 (Figure 4.37). Five of these water wells are plugged and abandoned wells that supplied water from rigs, 2 are current active supply for rigs, and 2 are currently used for domestic purposes. Additionally, to be conservative, a 5-mile buffer around the AoR (larger blue boundary) was searched for additional water data. These tabulated data are

contained in **A.4.2 Project Narrative Appendices (Hydrogeology Report)**. To the west of the AoR (in Texas), there are 119 water wells contained within the 5-mile buffer from the Project Minerva site. These wells range in depth from 10 feet to 990 feet, with the average well depth of 627 feet. Primary use is for domestic and industrial purpose. All water is withdrawn from the Chicot aquifer, with the 500-Foot sand as the main supply. No water is withdrawn from the deeper Evangeline aquifer for public use.

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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 (see Figure 4.37):

- 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. The Chicot Aquifer System is the main regional aquifer system that provides the usable groundwater for southwestern Louisiana. The Chicot aquifer system is largely composed of one, major undifferentiated sand, that splits down dip. These Pleistocene-aged sands are predominately comprised of unconsolidated to loosely consolidated gravels and coarse graded sands.

A regional stratigraphic section (A-A') parallel to dip from Baker (1979) depicting the aquifers in the regional area of Southeast, Texas is contained in Figure 4.38.

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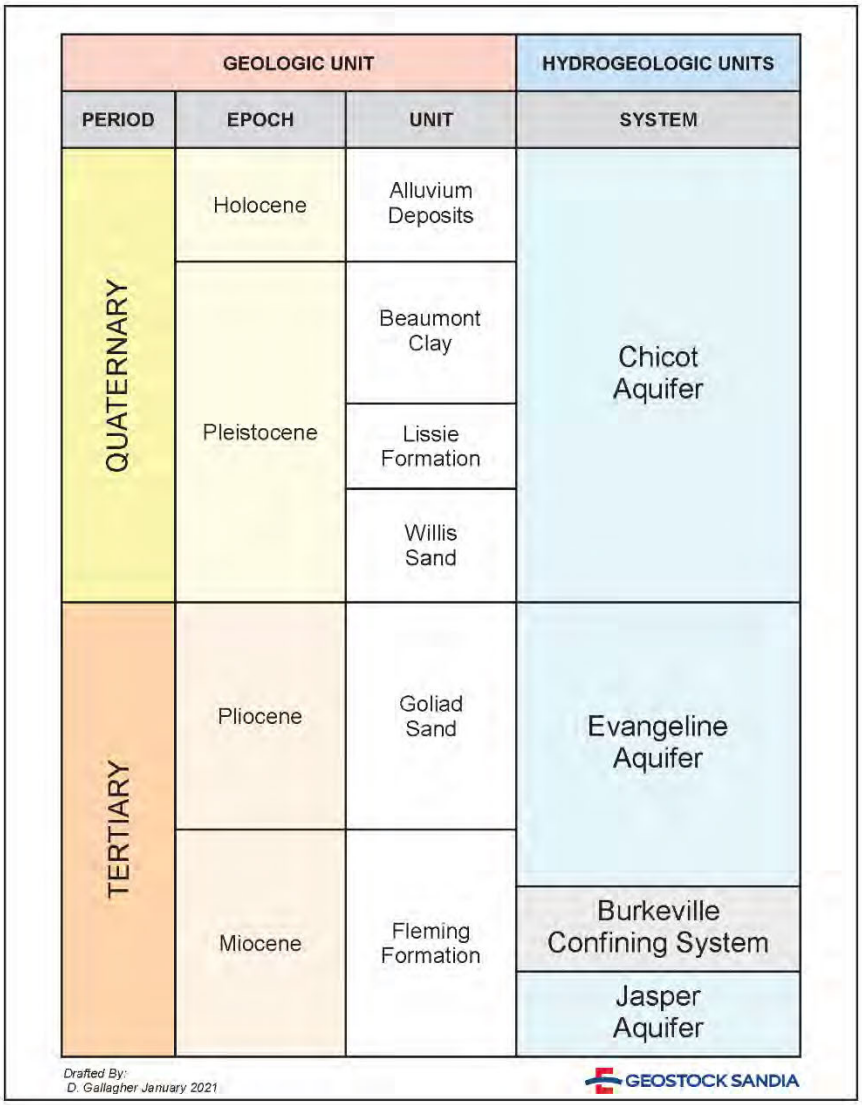

Figure 4.37 Regional hydrostratigraphic column for southeastern Texas and southwestern Louisiana.

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*4.6.3 **Regional Groundwater Flow***

Groundwater moves through aquifer systems from areas of high hydraulic head to areas of lower hydraulic head. Regional uses from industry and the public water systems have some impacts on diverting the direction of flow.

The Chicot regional flow is in the direction of development. Major development of groundwater occurs around the Lake Charles area. In Cameron Parish, due to aquifer development, the direction of groundwater flow is primarily north and northeast (Lovelace et al, 2004).

A map of the potentiometric surface for the Chicot aquifer (Figure 4.39) shows the direction of groundwater flow. Lovelace et al. (2004) indicated that the flow direction is towards major pumping areas such as Lake Charles in Calcasieu Parish and the northern part of Acadia Parish and south Evangeline Parish, where there is heavy pumping for industrial and irrigation uses. Control points and wells in the analysis are located on Table 4.3.9. The direction of flow of groundwater is downgradient at 90 degrees to the potentiometric contours at right angles. An additional issue from pumping and heavy groundwater usage is the upwards coning of saltwater that can occur as response to freshwater withdrawal. The result is higher salinity waters being pulled upwards as pumping increases in aquifers that are hydraulically connected. Along the coast in the southwestern and southern portion of Louisiana, saltwater is being gradually pulled inland (northwards) due to over pumping of groundwater aquifers for industry and agriculture, especially during the peak rice irrigation and aquaculture harvesting seasons. Two regional cross sections (Figure 4.40) extending across Calcasieu Parish show that the southern portion of the parish is impacted by saltwater encroachment in the Chicot aquifer (and by default the Evangeline) from the Gulf of Mexico. Increasing chloride concentrations between 1968 and 1984 indicated that a northwards or upward movement of the freshwater-saltwater interface in areas east and south of Lake Charles.

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4.6.4 Local Hydrogeology

The Project Minerva site is located [redacted]. Hydrostratigraphic units of importance range in age from Miocene to recent-aged strata and include in ascending order: (1) Lagarto, (2) Goliad, (3) Willis, (4) Lissie (which is subdivided into the Montgomery and Bentley formations), (5) Beaumont Formation, and (6) Holocene/Recent sediments (Figure 4.37). Within this stratigraphic section are the two main aquifers of local interest, which are the Chicot aquifer and the Evangeline aquifer. The base of the lowermost USDW is located approximately at the base of the Chicot aquifer 700-Foot Sand or at the top portion of the Evangeline aquifer.

Within the local project area, the Evangeline aquifer predominantly contains saline ground water (greater than 10,000 mg/l TDS). Upper and lower boundaries to the Chicot include the Goliad Formation and the upper part of the Lagarto Formation, respectively. The Evangeline and Chicot aquifers are usually separated by confining clay, however, when this clay is absent, the geologic boundary between the two aquifers is indistinguishable. In general, the Evangeline aquifer tends to have greater sand to clay ratio with individual sand beds up to several tens of feet thick. Because the Evangeline aquifer is mostly saline within the Project Minerva area, it is not considered a USDW and is not used for groundwater in Calcasieu Parish.

The shallower Chicot aquifer contains upper and lower members separated by clay beds. The upper member of the Chicot aquifer consists of a basal sand overlain by clay and is actually part of both the Lissie Formation and the Beaumont Formation. Elevated chloride content prevents the lowermost member of the Chicot aquifer from being a source of potable water the southern portion of Calcasieu Parish. The Chicot Aquifer System is the main local aquifer system for the Project Minerva area and is the target of the majority of water wells within the AoR and 5 mile AoR buffer.

4.7 Detailed description of Geochemistry

A data collection program will be designed and implemented to fully characterize mineralogy in the Injection and Confining Zones. Based on regional analogues (eg. BEG pilot injection program) no compatibility issues are predicted.

Geochemical modelling was confined to the dissolution of CO_2 into the formation fluids.

The principal chemical reaction we wish to model in Reveal was the dissolution of CO_2 into the formation brine and its dissociation into H^+ and CO_3^{2-}.

CO_2 (supercritical phase) <-> CO_2 (aqueous phase)

CO_2 (aqueous phase) + H_2O <-> H_2CO_3 (aqueous phase)

H_2CO_3 <-> $2H^+ + CO_3^{2-}$ (a weak acid)

Only a small fraction of the dissolved CO_2 exists as the acid H_2CO_3, the equilibrium constant being equal to 1.3E-3 typically. The time scale to form H_2CO_3 is of the order of seconds. Other possible geochemical reactions are not considered in the current study.

To specify this reaction, we defined the following species in the Reveal/PHREEQC model:

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6.0 DESCRIPTION OF AOR AND CORRECTIVE ACTION PLAN

6.1 Description of the files submitted for the AOR and the Corrective Action plan

The fully completed AoR and Corrective Action Plan Report has been submitted via the GSDT in 'Confidential Business Information' form. All Tabs that require input data within the module have also been completed and submitted via the GSDT.

The report covers in detail the computational modelling approach to the delineation of the Area of Review (AoR), the Corrective Action Plan relating to existing well penetrations within the AoR and the Reevaluation Schedule for AoR delineation once operations commence. A thorough review of the hydrogeology was also supplied as an appendix to the main report, along with a comprehensive bibliography of references utilized during the AoR modelling execution and reporting phase.

The AoR and Corrective Action Plan Report satisfies rule requirements *40 CFR 146.82(a)(13), 146.84(b) and 146.84(c).*

AoR and Corrective Action GSDT Submissions
GSDT Module: *AoR and Corrective Action* ***Tab(s):*** *All applicable tabs* *Please use the checkbox(es) to verify the following information was submitted to the GSDT:* ☒ *Tabulation of all wells within AoR that penetrate confining zone* ***[40 CFR 146.82(a)(4)]*** ☒ *AoR and Corrective Action Plan* ***[40 CFR 146.82(a)(13) and 146.84(b)]*** ☒ *Computational modeling details* ***[40 CFR 146.84(c)]***

7.0 DESCRIPTION OF FINANCIAL RESPONSIBILITY

7.1 Description of the files submitted for the financial responsibility.

The Financial Responsibility submission is currently being prepared and will be filed via the GSDT when it is complete.

The Financial Responsibility submission will satisfy rule requirements *40 CFR 146.82(a)(14) and 146.85).*

Financial Responsibility GSDT Submissions

GSDT Module: *Financial Responsibility Demonstration*
Tab(s): *Cost Estimate tab and all applicable financial instrument tabs*

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☐ *Demonstration of financial responsibility* ***[40 CFR 146.82(a)(14) and 146.85]***

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9.0 DESCRIPTION OF PRE-OPERATIONAL LOGGING AND TESTING PLAN

9.1 Description of the documents that are submitted to the GSDT

The Pre-Operational Logging and Testing Plan submission is currently being prepared and will be filled be filed via the GSDT when it is complete.

The Pre-Operational Logging and Testing Plan submission satisfies rule requirements. *40 CFR 146.82(a)(8) and 146.87*

Pre-Operational Logging and Testing GSDT Submissions
GSDT Module: *Pre-Operational Testing* ***Tab(s):*** *Welcome tab* *Please use the checkbox(es) to verify the following information was submitted to the GSDT:* ☐ *Proposed pre-operational testing program* ***[40 CFR 146.82(a)(8) and 146.87]***

10.0 DESCRIPTION OF WELL OPERATION PLAN

The Well Operation Plan submission will be submitted when the CO_2 streams have been identified for the nameplate capacity of Project Minerva.

10.1 Operational Procedures

The Operational Procedures [40 CFR 146.82(a)(10)] submission is currently being prepared and an update to this report will be filed via the GSDT when it is complete.

10.2 Description of the proposed Carbon Dioxide Stream

The Description of the proposed Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)] submission is currently being prepared and will be filed via the GSDT when it is complete.

11.0 DESCRIPTION OF TESTING AND MONITORING PLAN

11.1 Description of the documents that are submitted to the GSDT

The Testing and Monitoring Plan Report has been submitted via the GSDT in 'Confidential Business Information' form. All tabs that require input data within the module have also been completed and submitted via the GSDT. A 'Confidential Business Information' version has been submitted to Region VI of EPA as well.

The report covers in detail the overall strategy and approach for testing and monitoring, carbon dioxide stream analysis, continuous recording of operational parameters, corrosion monitoring, above confining zone monitoring, external mechanical integrity testing, pressure fall off testing, carbon dioxide plume and pressure front tracking, environmental monitoring at the surface, sampling/analytical procedures. A Class IV well Quality Assurance and Surveillance Plan (QASP) was submitted as an appendix along with additional information relation to project management, data generation and acquisition, assessment and oversight and data validation and usability.

The Testing and Monitoring Plan Report satisfies rule requirements 40 CFR 146.82(a)(15) and 146.90.

Testing and Monitoring GSDT Submissions
GSDT Module: *Project Plan Submissions* ***Tab(s):*** *Testing and Monitoring tab* *Please use the checkbox(es) to verify the following information was submitted to the GSDT:* ☒ *Testing and Monitoring Plan* ***[40 CFR 146.82(a)(15) and 146.90]***

12.0 DESCRIPTION OF INJECTION AND WELL PLUGGING PLAN

12.1 Description of the documents that are submitted to the GSDT

The Injection and Well Plugging Plan has been submitted via the GSDT in 'Confidential Business Information' form. All Tabs that require input data within the module have also been completed and submitted via the GSDT. A 'Confidential Business Information' version has been submitted to Region VI of EPA as well.

The report covers in detail the planned tests and measurements to determine the bottom hole reservoir pressure, Planned External Mechanical Integrity Test, Information on Plugs, methods used for volume calculations, notifications, permits and inspections required, plugging procedures and contingency procedures/measures.

The Injection and Well Plugging Plan satisfies rule requirements 40 CFR 146.82(a)(16) and 146.92(b).

Injection Well Plugging GSDT Submissions
GSDT Module: *Project Plan Submissions* ***Tab(s):*** *Injection Well Plugging tab* *Please use the checkbox(es) to verify the following information was submitted to the GSDT:* ☒ *Injection Well Plugging Plan* ***[40 CFR 146.82(a)(16) and 146.92(b)]***

13.0 DESCRIPTION OF POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

13.1 Description of the documents that are submitted to the GSDT

The Post Injection Site Care and Site Closure Plan (PISC) Plan has been submitted via the GSDT in 'Confidential Business Information' form. All Tabs that require input data within the module have also been completed and submitted via the GSDT. A 'Confidential Business Information' version has been submitted to Region VI of EPA as well.

The report covers in detail the pre and post injection pressure differential, post-injection monitoring plan, alternative post-injection site care timeframe, non-endangerment demonstration criteria, site closure plan and QASP.

An Alternative PISC timeframe has been proposed as part of the GSDT submission. GCS has indicated an alternative PISC timeframe of 10 years instead of the default 50 years.

The Post Injection Site Care and Site Closure Plan satisfies rule requirements 40 CFR 146.82(a)(17) and 146.93(a) and the Alternative PISC submission satisfies rule requirements 40 CFR 146.82(a)(18) and 146.93(c).

PISC and Site Closure GSDT Submissions
GSDT Module: *Project Plan Submissions* ***Tab(s):*** *PISC and Site Closure tab* *Please use the checkbox(es) to verify the following information was submitted to the GSDT:* ☒ *PISC and Site Closure Plan* ***[40 CFR 146.82(a)(17) and 146.93(a)]***
GSDT Module: *Alternative PISC Timeframe Demonstration* ***Tab(s):*** *All tabs (only if an alternative PISC timeframe is requested)* *Please use the checkbox(es) to verify the following information was submitted to the GSDT:* ☒ *Alternative PISC timeframe demonstration* ***[40 CFR 146.82(a)(18) and 146.93(c)]***

14.0 DESCRIPTION OF EMERGENCY AND REMEDIAL RESPONSE PLAN

14.1 Description of the documents that are submitted to the GSDT

The Emergency and Remedial Response Plan has been submitted via the GSDT in 'Confidential Business Information' form. All Tabs that require input data within the module have also been completed and submitted via the GSDT. A 'Confidential Business Information' version has been submitted to Region VI of EPA as well.

The report covers in detail the local resources and infrastructure, potential risk scenarios, response personnel and equipment, emergency communications plan, a plan review and staff training and exercise procedures.

The Emergency and Remedial Response Plan Report satisfies rule requirements 40 CFR 146.82(a)(19) and 146.94(a).

Emergency and Remedial Response GSDT Submissions
GSDT Module: *Project Plan Submissions* ***Tab(s):*** *Emergency and Remedial Response tab* *Please use the checkbox(es) to verify the following information was submitted to the GSDT:* ☒ *Emergency and Remedial Response Plan* ***[40 CFR 146.82(a)(19) and 146.94(a)]***

15.0 INJECTION DEPTH WAIVER AND ACQUIFER EXEPMTION EXPANSION

Not applicable as GCS is not seeking a waiver or exemption.

16.0 DESCRIPTION OF ANY ADDITIONAL INFORMATION REQUESED

16.1 Description of the documents that has been requested by the UIC Program Director

No documents have been requested by the UIC Program Director.

[redacted]

[redacted]

[redacted]

Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

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).

2 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).

2.1 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 2.1). From the formation water resistivity and the formation temperature, the salinity of the formation water can be calculated (Figure 2.2).

2.2 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) with the exception of 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.

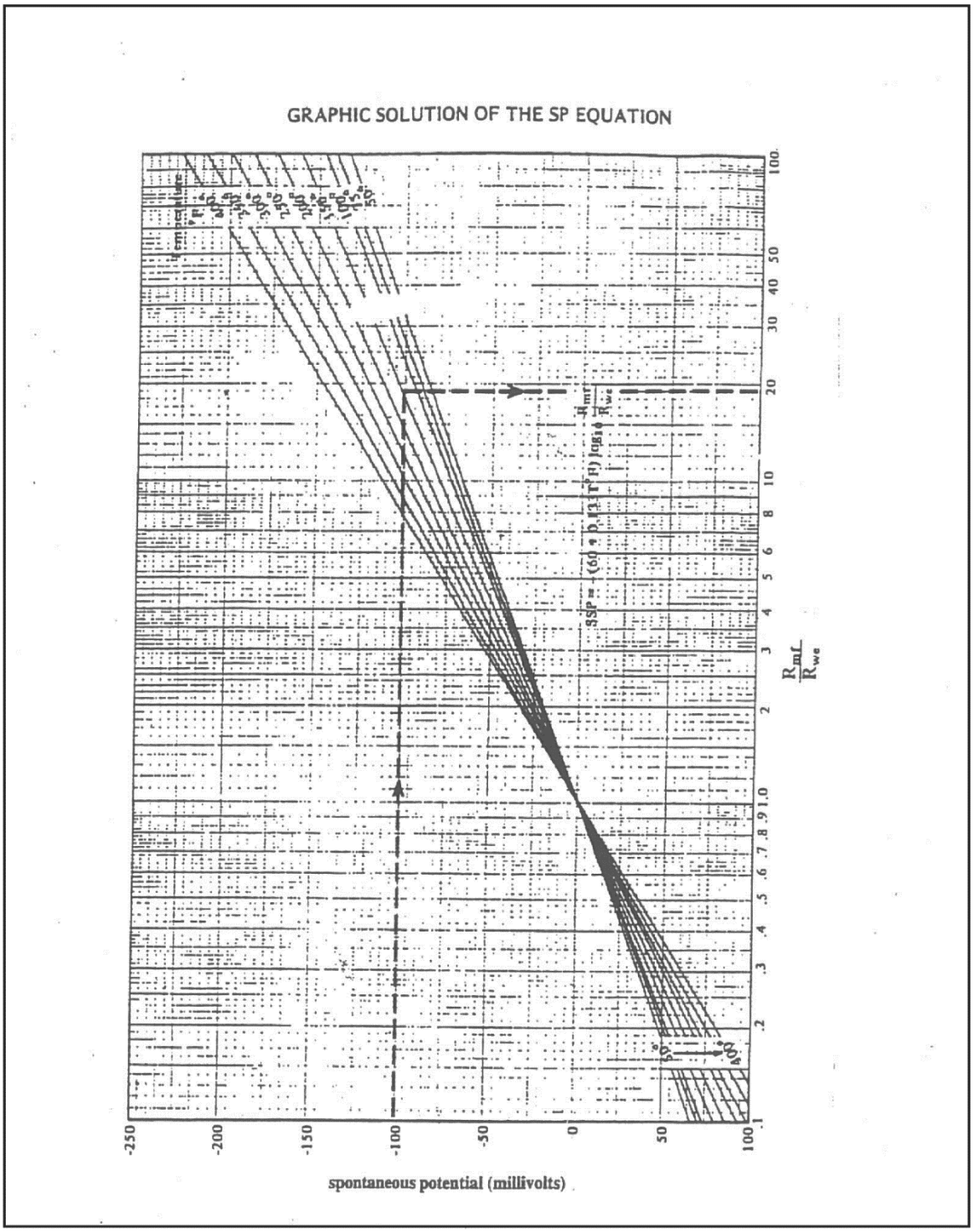

Figure 2.1 Graphic solution of the Spontaneous Potential Equation (Schlumberger, 1987)

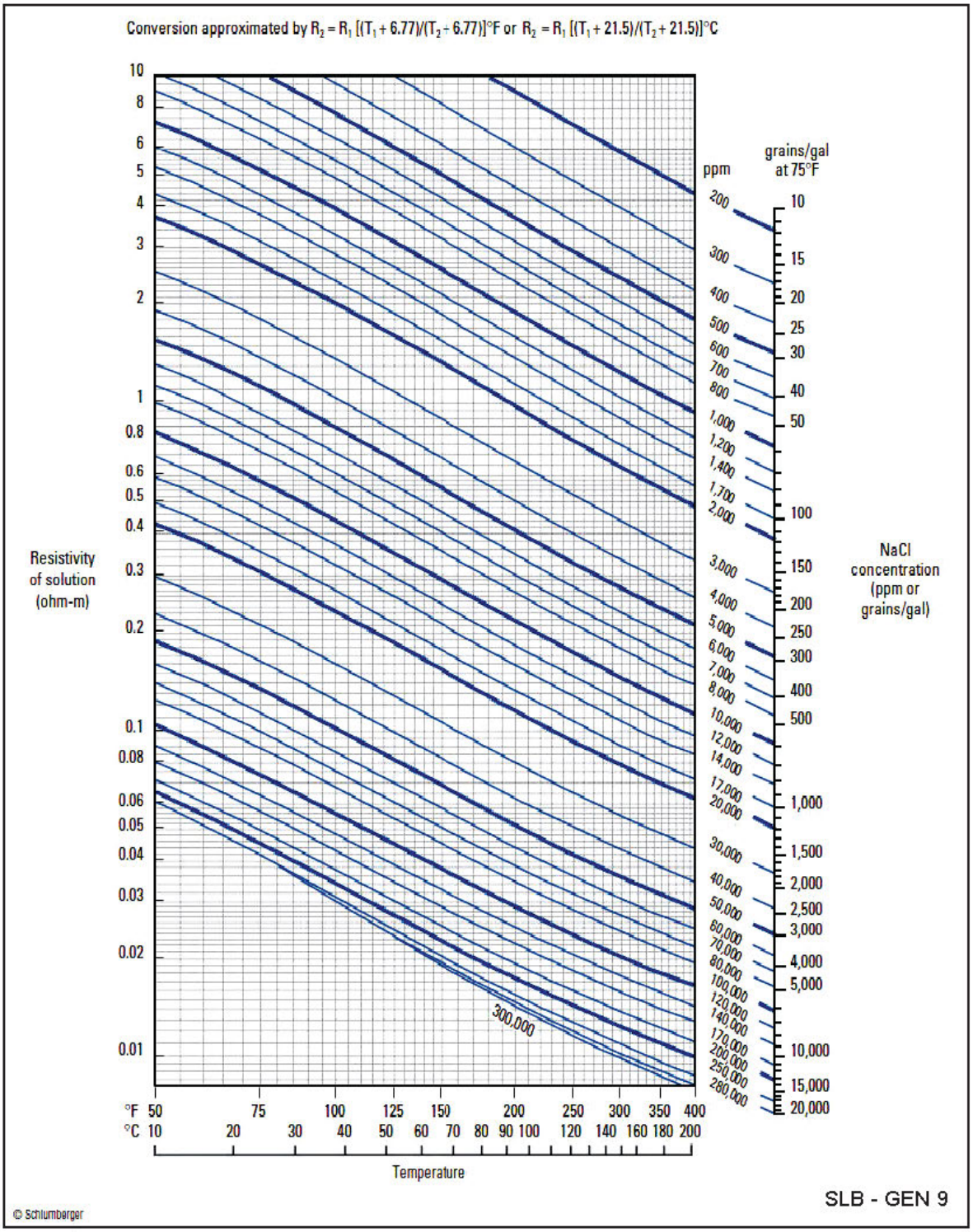

Figure 2.2 Resistivity nomograph for NaCl solutions (Schlumberger, 1979)

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:

$$F = \frac{R_t}{R_w} \qquad (3)$$

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:

$$F = \frac{a}{\phi^m} \qquad (4)$$

Where:

ϕ = 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):

$$F = \frac{0.81}{\phi^2} \qquad (5)$$

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:

$$R_t = \frac{R_{we}\ x\ 0.81}{\phi^2} \qquad (6)$$

3 Methodology

To determine the formation water resistivity in a particular zone, the resistivity of the drilling mud filtrate (obtained from the log header) at the depth of the zone must first be determined. Resistivities of saline solutions vary as a function of NaCl concentration and temperature. The relationship between temperature, NaCl concentration, and resistivity are typically shown in the form of a nomograph for computational ease (Figure 2). From Figure 1, the resistivity of the drilling mud filtrate can be corrected to the temperature of the zone of interest. A shale baseline is next established on the spontaneous potential curve and the deflection away from the shale baseline measured. A chart containing the graphic solution of the spontaneous potential Equation (1) (Figure 1) gives the solution for the ratio between the resistivity of the mud filtrate and the formation water (R_{mf}/R_{we}) based on the measured spontaneous potential curve deflection. The resistivity of the formation water at formation temperature can be determined from the R_{mf}/R_{we} ratio and converted to the equivalent NaCl concentration from Figure 2. Once the base of the lowermost USDW is established, a formation resistivity (R_t) cut off on the deep induction log can be established using Equation (6). This formation resistivity cut-off is used to establish the base of the lowermost USDW at the Minerva Site.

By manipulating Figures 1 and 2, a formation water resistivity of 0.35 ohm-m corresponds to a salinity of 10,000 mg/l TDS. At a temperature of approximately 90 °F, a formation water resistivity value of 0.45 ohm-m corresponds to a salinity of 10,000 mg/l TDS. Deeper intervals with higher temperatures will have a higher resistivity cut off for analysis.

From this water resistivity value and an estimate of formation porosity, a formation resistivity (R_t) cut-off can be calculated. For the Project Minerva site, the USDW is project to be relatively shallow, thus a formation water resistivity of 0.35 ohm-m is used. Using an assumed formation porosity of 34 percent (shallow unconsolidated sands) and solving for the total formation resistivity, gives the following result:

From Equation (6), a formation resistivity (R_t) cut-off can be calculated if the approximate formation porosity is known. Therefore, solving Equation (6) gives the following result:

$$R_t = \frac{0.35\ ohm - m\ x\ 0.81}{0.34^2} = 2.45\ ohm - m$$

Therefore, it is conservatively calculated that the sands with a formation resistivity of greater than 2 ohm-m were considered to be USDWs. This site-specific calculation is in agreement with the Louisiana Department of Natural Resources (LaDNR) guidance located at *http://www.dnr.louisiana.gov/assets/OC/im_div/uic_workshop/2_USDW.pdf*, which indicates that the USDW should fall between:

Ground surface to 1,000 feet: 3 ohms or greater is considered USDW;

1,000 feet to 2,000 feet: 2 ½ ohms or greater is considered USDW; and

2,000 feet and deeper: 2 ohms or greater is considered USDW.

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5 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:

- the Jasper aquifer;
- the Burkeville confining system;
- the Evangeline aquifer;
- and the 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 5.1. The following sections provide details on the regional expanse and parameters pertaining the hydrostratigraphy for the defined systems from deepest to shallowest intervals. A regional stratigraphic section (A-A') parallel to dip from Baker (1979) depicting the aquifers in the regional area of Southeast, Texas is contained in Figure 5.2.

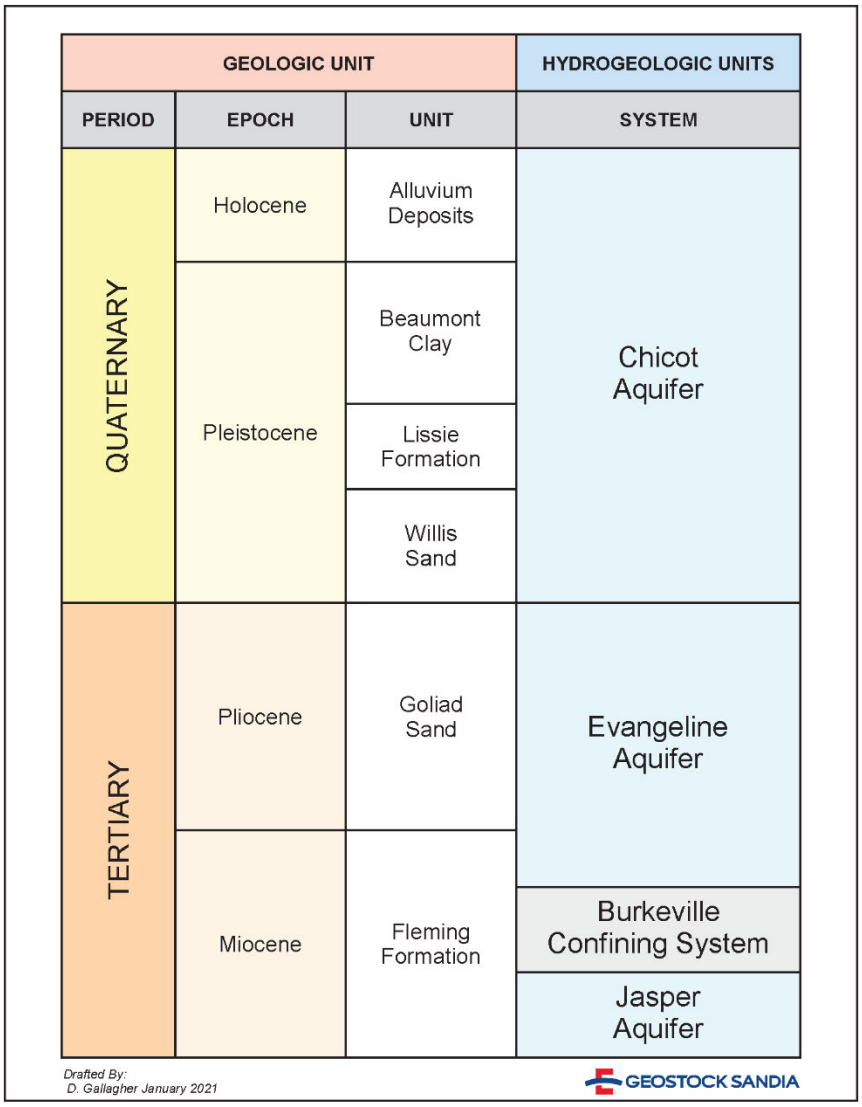

Figure 5.1 Regional hydrostratigraphic column for southeastern Texas and southwestern Louisiana.

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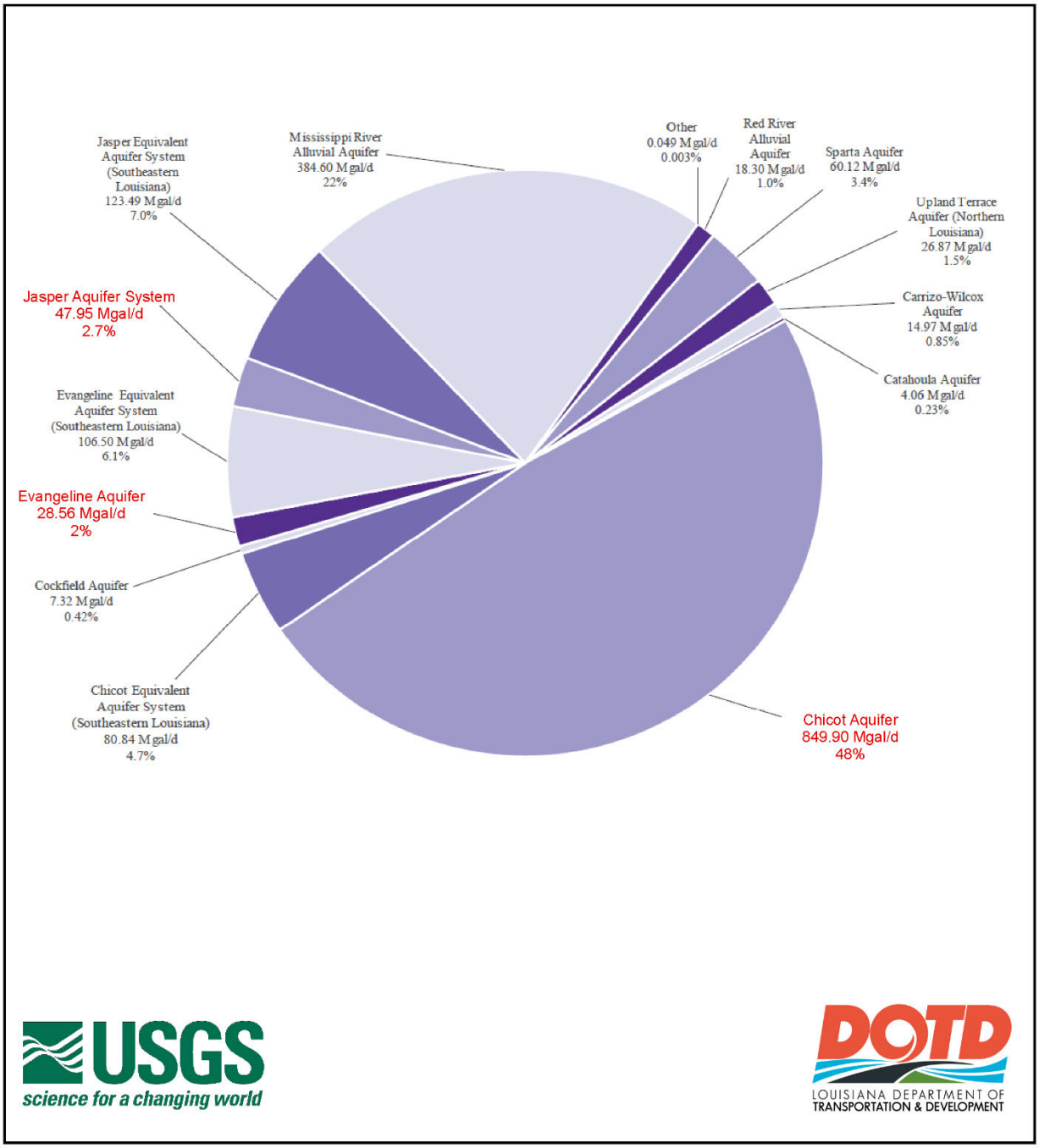

Figure 7.1 Groundwater withdrawals in Louisiana by aquifer system, 2015 (from Water Use in Louisiana, 2015, Water Resources Report No. 18)

[redacted]

[redacted]

[redacted]

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 have an effect on either the safety of the injection site (non-endangerment of USDWs) or injection operations. The target Frio Injection Interval at Project Minerva is separated by over 4,000 feet of geologic section (>1,100 feet net impermeable shale) from the shallow USDWs (<10,000 mg/L TDS) (Figure 7.1). 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. Regional aquifer data on the characteristic for the systems is contained in the in the table below (from Wesselmann and Arrow, 1971) for the aquifers in the Beaumont and Orange, Texas. These data are regional and applicable across the Sabine River into southwestern Louisiana.

Aquifer	Transmissivity (gpd)	Storativity	Permeability (cm/sec)
Chicot Aquifer Upper Unit	19,500	4.5×10^{-4}	3.1×10^{-4}
Chicot Aquifer Lower Unit	69,200	1.5×10^{-3}	2.5×10^{-2}
Evangeline Aquifer	34,000	3.0×10^{-5}	1.4×10^{-2}

[redacted]

8 Regional Groundwater Flow

Groundwater moves through aquifer systems from areas of high hydraulic head to areas of lower hydraulic head. Regional uses from industry and the public water systems have some impacts on diverting the direction of flow.

The Chicot regional flow is in the direction of development. Major development of groundwater occurs around the Lake Charles area. In Cameron Parish, due to aquifer development, the direction of groundwater flow is primarily north and northeast (Lovelace et al, 2004).

A map of the potentiometric surface for the Chicot aquifer (Figure 8.1) shows the direction of groundwater flow. Lovelace et al. (2004) indicated that the flow direction is towards major pumping areas such as Lake Charles in Calcasieu Parish and the northern part of Acadia Parish and south Evangeline Parish, where there is heavy pumping for industrial and irrigation uses. Control points and wells in the analysis are located on Figure 8.1. The direction of flow of groundwater is downgradient at 90 degrees to the potentiometric contours at right angles. An additional issue from pumping and heavy groundwater usage is the upwards coning of saltwater that can occur as response to freshwater withdrawal. The result is higher salinity waters being pulled upwards as pumping increases in aquifers that are hydraulically connected. Along the coast in the southwestern and southern portion of Louisiana, saltwater is being slowly pulled inland (northwards) due to over pumping of groundwater aquifers for industry and agriculture, especially during the peak rice irrigation and aquaculture harvesting seasons. Two regional cross sections (Figure 8.2) extending across Calcasieu Parish show that the southern portion of the parish is impacted by saltwater encroachment in the Chicot aquifer (and by default the Evangeline) from the Gulf of Mexico. Increasing chloride concentrations between 1968 and 1984 indicated that a northwards or upward movement of the freshwater-saltwater interface in areas east and south of Lake Charles.

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Class VI UIC Project Information Tracking

This submission is for:

Project ID: R06-LA-0002

Project Name: Project Minerva

Current Project Phase: Pre-Injection Prior to Construction

General Information

Number of proposed Class VI wells: 4

Brief description of the project: Project Minerva comprises of 4 injection wells

Facility and Owner/ Operator Information

Facility name: Minerva

Facility mailing address: 2417 Shell Beach Drive, Lake Charles, Louisiana 70601

Facility location: Latitude: -999 Longitude: -999

Up to four Standard Industrial Classification (SIC) codes for the products/services provided by the facility: CO2 sequestration

Facility located on Indian lands: No

Facility contact information

Contact person: Benajmin Heard

Contact's business phone number: 713 - 320 - 2497

Contact's business email: bheard@gcscarbon.com

Operator's name: Gulf Coast Sequestration

Operator's business address: 2417 Shell Beach Drive, Lake Charles, Louisiana 70601

Operator's business phone number: 713 - 320 - 2497

Operator's status: Private

Ownership status: Owner

Initial Permit Application

Permit Application Narrative: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/ProjInfo-03-26-2021-2120/A.4.1--Class--VI--Permit--Application--Narrative--GSDT.pdf

Proposed project plans, submitted with the Project Plan Submission module:

Other Required Information: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0002/Phase1-PreConstruction/ProjInfo-03-26-2021-2120/A.4.2--Class--VI--Permit--Application--Narrative--Appendices--GSDT.zip

Updated Information

Complete Submission

Authorized submission made by: Benjamin Heard

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

CLASS VI PERMIT APPLICATION NARRATIVE SUMMARY
40 CFR 146.82(a)

YAMS CO_2 Sequestration Project

1.0 Project Background and Contact Information 1
2.0 Site Characterization 2
3.0 AoR and Corrective Action 2
4.0 Financial Responsibility 3
5.0 Injection Well Construction 3
6.0 Pre-Operational Logging and Testing 3
7.0 Well Operation 4
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10.0 Post-Injection Site Care (PISC) and Site Closure 5
11.0 Emergency and Remedial Response 6
12.0 Injection Depth Waiver and Aquifer Exemption Expansion 6

1.0 Project Background and Contact Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

The YAMS CCS 1 well in the YAMS CO2 Sequestration Project is part of the Oxy Low Carbon Ventures, LLC (OLCV), objective to demonstrate technical feasibility of Carbon Capture and Storage (CCS), utilizing CO2 from industrial emitters along the Louisiana Gulf Coast. The advancement of CCS technology is critically important in addressing CO2 emissions and global climate change concerns. The YAMS CO2 Sequestration Project is designed to demonstrate utility-scale integration of transport and permanent storage of captured CO2 into a deep geologic formation (i.e., geologic sequestration). A commercial-scale CCS system will be designed, built, and operated with the capability of storing CO2 gas.

The YAMS CO2 Sequestration Project will display that the geologic sequestration process can be done safely, ensuring that the injected CO2 will be retained within the intended storage reservoir.

GSDT Submission - Project Background and Contact Information
GSDT Module: Project Information Tracking ***Tab(s):*** General Information tab; Facility Information and Owner/Operator Information tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Required project and facility details ***[40 CFR 146.82(a)(1)]***

2.0 Site Characterization

The Area of Review (AoR) is defined as the larger of the maximum extent of the a) free-phase CO_2 plume or b) pressure boundary within which brines from the injection zone can migrate into overlying USDW via leaky wells, faults, or breaches of the confining zone. Both AoRs are determined using a multiphase CO_2-brine transport model, which is constructed from a sophisticated geologic model that accounts for site-specific hydrogeology.

3.0 AoR and Corrective Action

The Area of Review and Corrective Action Plan document meets the requirements of Environmental Protection Agency (EPA) document 40 CFR Subpart H - Criteria and Standards Applicable to Class VI Wells. The key challenges are detailed characterization of the injection and confining zones, delineating all underground sources of drinking water, and implementing corrective action on existing wells within the Area of Review. The attachment describes the subsurface characterization, computational modeling, current AoR delineation, corrective action plan and schedule, wells requiring corrective action, and future AoR re-evaluation plan and schedule.

At a fixed frequency specified in the Area of Review and Corrective Action Plan, or more frequently when monitoring and operational conditions warrant, Oxy Low Carbon Ventures, LLC, must reevaluate the AoR and perform corrective action in the manner specified in 40 CFR 146.84. Oxy Low Carbon Ventures, LLC, must also update the Area of Review and Corrective Action Plan or demonstrate to the Director that no update is needed.

Following each Area of Review and Corrective Action Plan reevaluation or demonstration showing that no new evaluation is needed, Oxy Low Carbon Ventures, LLC, shall submit the resultant information in an electronic format to the Director for review and approval of the results. Once approved by the Director, the revised Area of Review and Corrective Action Plan will become an enforceable condition of this permit.

AoR and Corrective Action GSDT Submissions
GSDT Module: AoR and Corrective Action ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Tabulation of all wells within AoR that penetrate confining zone ***[40 CFR 146.82(a)(4)]*** ☒ AoR and Corrective Action Plan ***[40 CFR 146.82(a)(13) and 146.84(b)]*** ☒ Computational modeling details ***[40 CFR 146.84(c)]***

4.0 Financial Responsibility

Oxy Low Carbon Ventures, LLC, shall maintain financial responsibility and resources to meet the requirements of 40 CFR 146.85 and conditions of this permit. Financial responsibility shall be maintained through all phases of the project. The approved financial assurance mechanisms are found in the Financial Assurance Plan document of this permit. The financial instrument(s) must be sufficient to cover the cost of:

- Corrective action (meeting the requirements of 40 CFR 146.84);
- Injection well plugging (meeting the requirements of 40 CFR 146.92);
- Post-injection site care and site closure (meeting the requirements of 40 CFR 146.93);
- Emergency and remedial response (meeting the requirements of 40 CFR 146.94).

Financial Responsibility GSDT Submissions
GSDT Module: Financial Responsibility Demonstration ***Tab(s):*** Cost Estimate tab and all applicable financial instrument tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Demonstration of financial responsibility ***[40 CFR 146.82(a)(14) and 146.85]***

5.0 Injection Well Construction

The YAMS CCS 1 injection well is designed with the highest standards and best practices for drilling and well construction. Operational parameters and material selection are aimed to ensure mechanical integrity in the system and to optimize the operation during the life of the project.

6.0 Pre-Operational Logging and Testing

The YAMS CCS 1 well testing program aims to obtain chemical and physical characteristics of the injection and confining zone(s). The program includes logging, sidewall coring, formation hydrogeologic testing, and other activities performed during the drilling and construction of the CO_2 injection well, monitoring well(s), and any stratigraphic characterization well(s).

The pre-operational testing program will determine or verify the depth, thickness, mineralogy, lithology, porosity, permeability, and geomechanical information of the injection zone, overlying confining zone, and other relevant geologic formations. In addition, formation fluid characteristics are to be obtained from the injection zone to establish baseline data against which future measurements may be compared after the start of injection operations.

Pre-Operational Logging and Testing GSDT Submissions
GSDT Module: Pre-Operational Testing ***Tab(s):*** Welcome tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Proposed pre-operational testing program ***[40 CFR 146.82(a)(8) and 146.87]***

7.0 Well Operation

The well was designed to maximize the rate of injection as well as reduce the surface pressure and friction alongside the tubing, while maintaining the bottomhole pressure below the frac gradient. The selected design provides enough clearance to deploy the pressure and temperature gauges on tubing and to ensure continuous surveillance of external integrity and conformance through the external fiber optic cable.

No injectate other than that identified in this permit shall be injected into the well except fluids used for stimulation, rework, and well tests as approved by the Director.

Electronic reports, submittals, notifications, and records made and maintained by Oxy Low Carbon Ventures, LLC, under this permit must be in an electronic format approved by EPA. The permittee shall electronically submit all required reports to the Director.

8.0 Testing and Monitoring

This Testing and Monitoring Plan describes how Oxy Low Carbon Ventures, LLC, will monitor the YAMS CO_2 Sequestration Project 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.

Other than during periods of well workover or maintenance approved by the Director, in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the injection well must have and maintain mechanical integrity consistent with 40 CFR 146.89.

Testing and Monitoring GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Testing and Monitoring tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Testing and Monitoring Plan ***[40 CFR 146.82(a)(15) and 146.90]***

9.0 Injection Well Plugging

Upon end of life for YAMS CCS 1, the injection well will be plugged and abandoned relevant to the requirements of Environmental Protection Agency (EPA) document 40 CFR Subpart H – Criteria and Standards Applicable to Class VI Wells. The plugging procedure and materials will be designed to prevent unwanted fluid movement, resist the corrosive aspects of carbon dioxide (CO2) with water mixtures, and protect any underground sources of drinking water (USDWs).

Injection Well Plugging GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Injection Well Plugging tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Injection Well Plugging Plan ***[40 CFR 146.82(a)(16) and 146.92(b)]***

10.0 Post-Injection Site Care (PISC) and Site Closure

The Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Oxy Low Carbon Ventures, LLC, will perform to meet the requirements of 40 CFR 146.93. Oxy Low Carbon Ventures, LLC, will monitor ground water quality and track the position of the carbon dioxide plume and pressure front until site closure. Oxy Low Carbon Ventures, LLC, may not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, Oxy Low Carbon Ventures, LLC, will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

PISC and Site Closure GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** PISC and Site Closure tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ PISC and Site Closure Plan ***[40 CFR 146.82(a)(17) and 146.93(a)]***

PISC and Site Closure GSDT Submissions
GSDT Module: Alternative PISC Timeframe Demonstration ***Tab(s):*** All tabs (only if an alternative PISC timeframe is requested) Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Alternative PISC timeframe demonstration ***[40 CFR 146.82(a)(18) and 146.93(c)]***

11.0 Emergency and Remedial Response

This Emergency and Remedial Response Plan (ERRP) describes actions Oxy Low Carbon Ventures, LLC, 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.

Emergency and Remedial Response GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Emergency and Remedial Response tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Emergency and Remedial Response Plan ***[40 CFR 146.82(a)(19) and 146.94(a)]***

12.0 Injection Depth Waiver and Aquifer Exemption Expansion

Injection depth waivers are not requested in this permit application.

Injection Depth Waiver and Aquifer Exemption Expansion GSDT Submissions
GSDT Module: Injection Depth Waivers and Aquifer Exemption Expansions ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Injection Depth Waiver supplemental report ***[40 CFR 146.82(d) and 146.95(a)]*** ☐ Aquifer exemption expansion request and data ***[40 CFR 146.4(d) and 144.7(d)]***

Class VI UIC Project Information Tracking

This submission is for:

Project ID: R06-LA-0004

Project Name: YAMS CO2 Sequestration Project

Current Project Phase: Pre-Injection Prior to Construction

General Information

Number of proposed Class VI wells: 2

Brief description of the project: The YAMS CO2 Sequestration Project includes two proposed Class VI injection wells in Louisiana.

Facility and Owner/ Operator Information

Facility name: YAMS CO2 Sequestration Project

Facility mailing address: -999

Facility location: Latitude: -999 Longitude: -999

Up to four Standard Industrial Classification (SIC) codes for the products/services provided by the facility: 28130100

Facility located on Indian lands: No

Facility contact information

Contact person: Kelly Watson

Contact's business phone number: 713 - 552 - 8613

Contact's business email: kelly_watson@oxy.com

Operator's name: Oxy Low Carbon Ventures, LLC

Operator's business address: 5 Greenway Plaza Houston, TX 77046

Operator's business phone number: 713 - 215 - 7000

Operator's status: Private

Ownership status: Owner

Initial Permit Application

Permit Application Narrative: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R06-LA-0004/Phase1-PreConstruction/ProjInfo-07-20-2021-1054/Narrative_YAMS_CCS_1g.pdf

Proposed project plans, submitted with the Project Plan Submission module:

An Area of Review (AoR) and Corrective Action Plan

A Testing and Monitoring Plan

A Well Plugging Plan

A Post-Injection Site Care (PISC) and Site Closure Plan

An Emergency and Remedial Response Plan

Computational modeling information, submitted with the Area of Review Computational Modeling module

A financial responsibility demonstration, submitted with the Financial Responsibility Demonstration module

Updated Information

Complete Submission

Authorized submission made by: Kelly Watson

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

Plan revision number: v1
Plan revision date: 3/12/2021

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

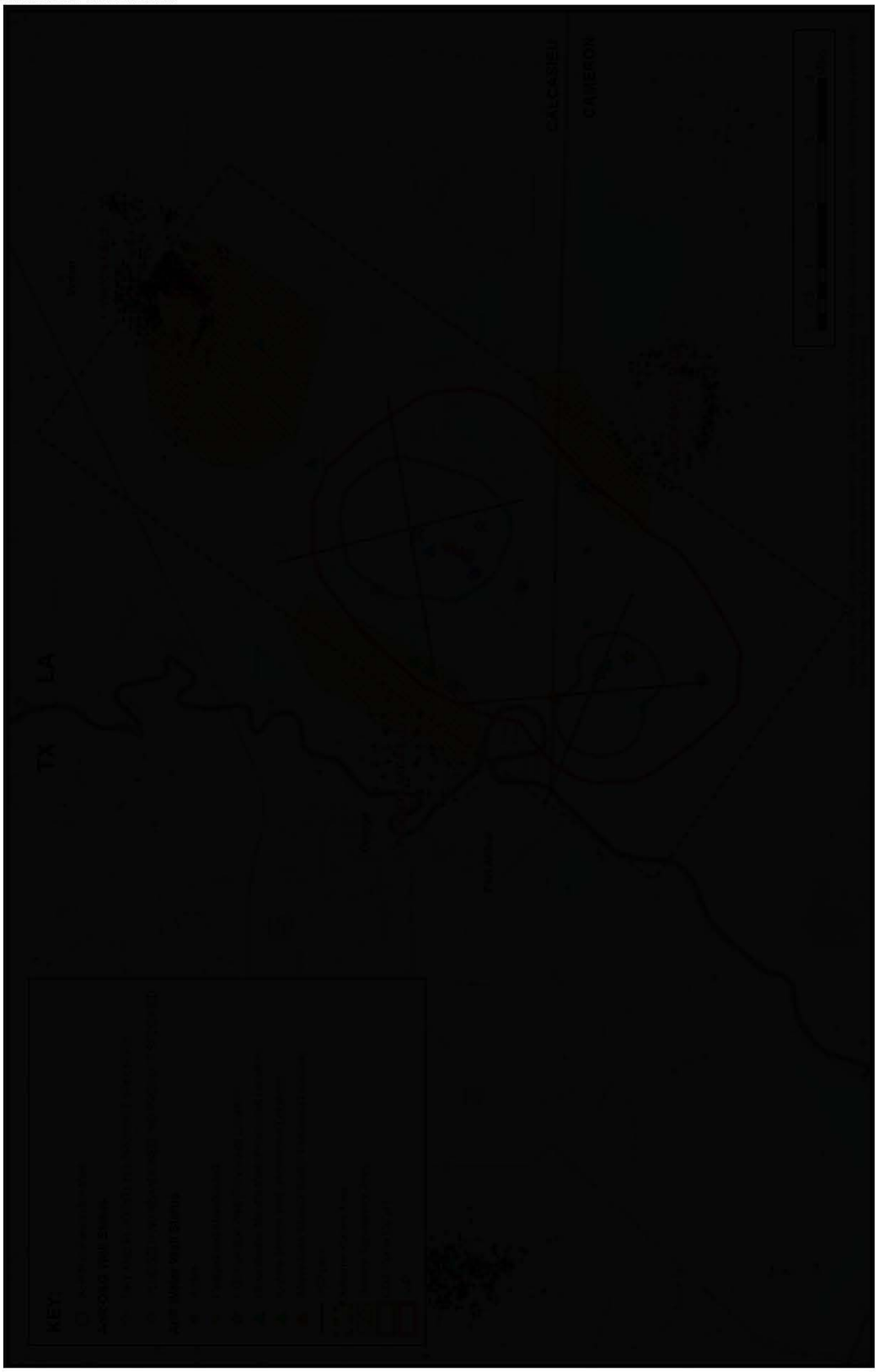

Figure 2.1 Testing and monitoring plan overview

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 ALI method SAM 4.1 subtraction method (GC/DID) 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 δC^{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	
δC^{13} CO_2	Gas Chromatography with dual inlet isotope ratio mass spectrometer	+/- 0.1 ‰.
δC^{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 Resolution	0 – 10,000 psi/200 °C +/-0.02 psi/0.005 °C
	Accuracy	+/-0.024% of full scale (+/-2.4 psi/+/-0.25 °C)
	Manufacturer's Recommended Calibration Frequency	Minimum Annual
Memory Pressure Gauge	Range Resolution	0 – 10,000 psi/200 °C +/-0.02 psi/0.005 °C
	Accuracy	+/-0.024% of full scale (+/-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 δD 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 δD 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 ‰.
δD 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 ‰.
δD 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.

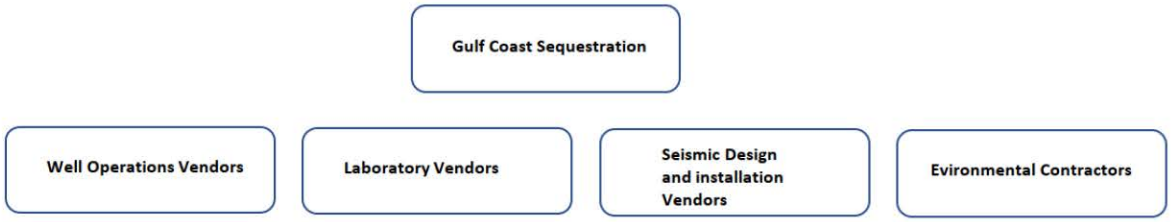

Figure 12.1 GCS Organization

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) 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) GC/TCD	Note 2	Note 2	Note 2
Nitrogen (N_2)	ISBT 4.0(GC/DID) 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 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: [List specific cations]				
Anions: [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: [List specific cations]				
Anions: [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: [List specific cations]				
Anions: [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: [List specific cations]				
Anions: [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: [List specific cations]			
Anions: [List specific anions]			
Dissolved CO_2			
Isotopes: [List specific isotopes]			
Alkalinity			
Field Confirmation: [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.

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

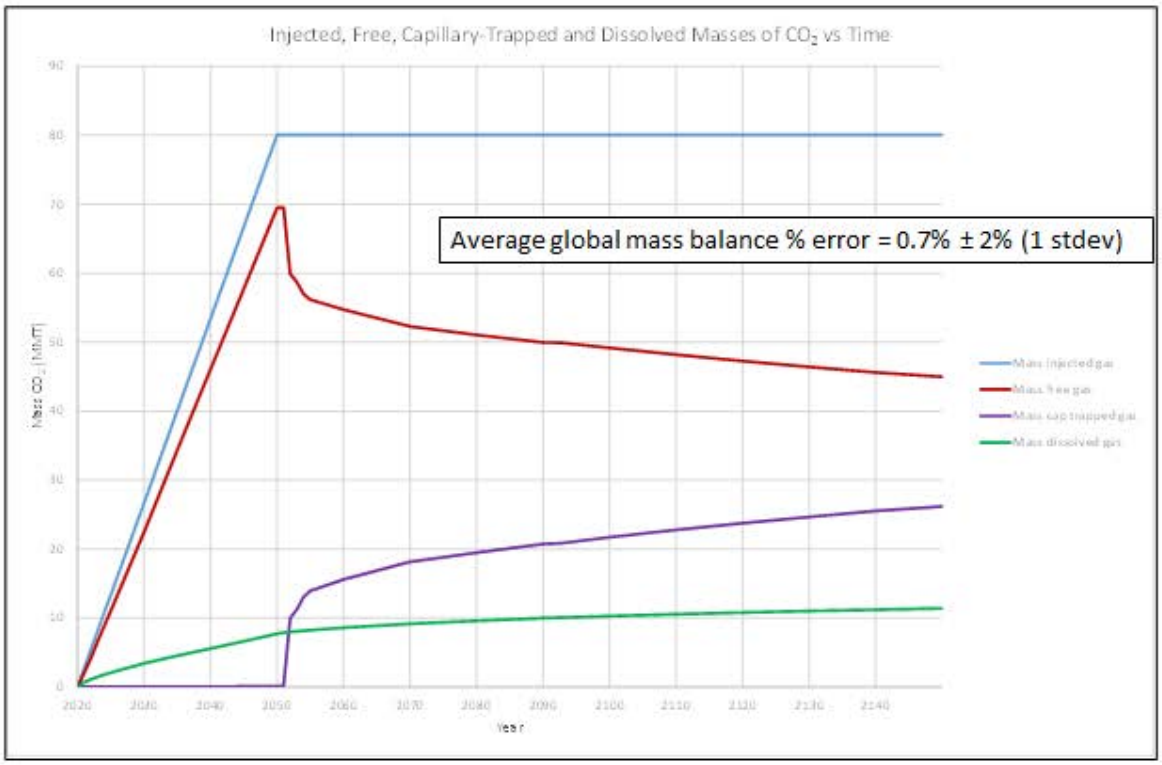

Figure 4.46 CO_2 mass balance and cumulative trapping

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.

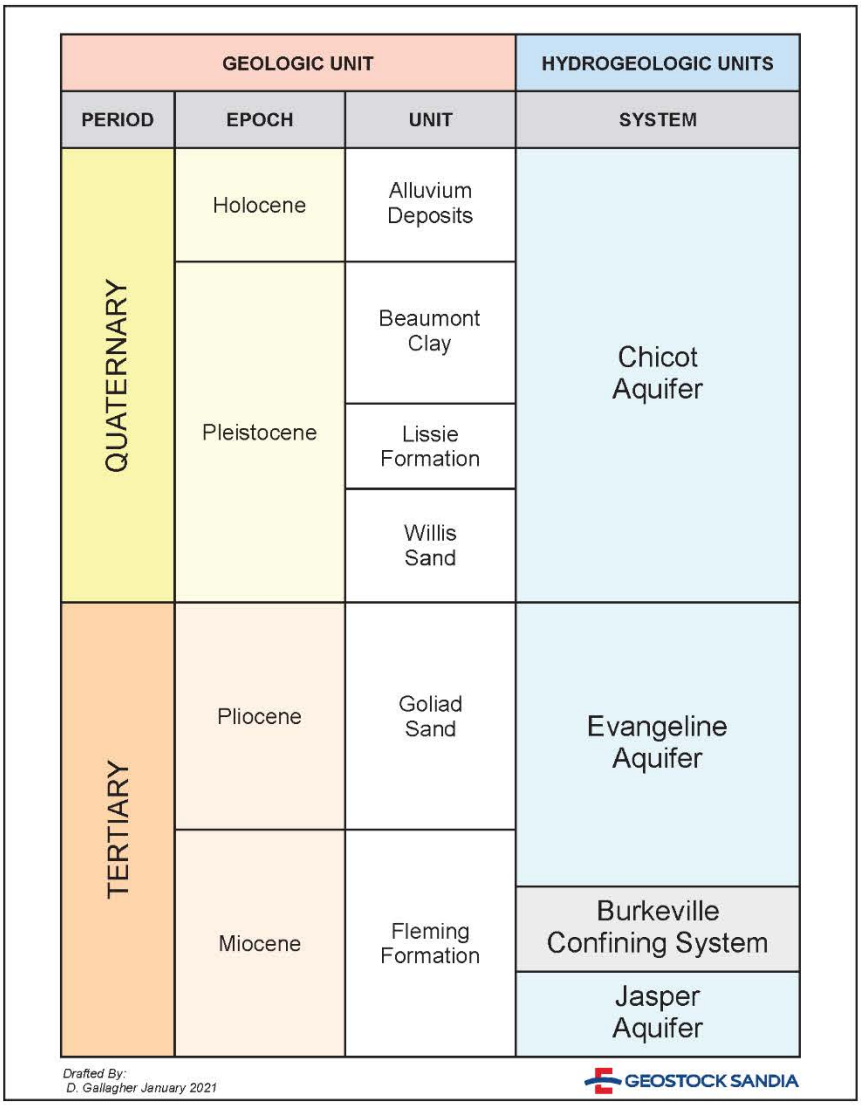

Figure 4.53 Regional hydrostratigraphic column for southeastern Texas and southwestern Louisiana.

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:

ϕ = 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:

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

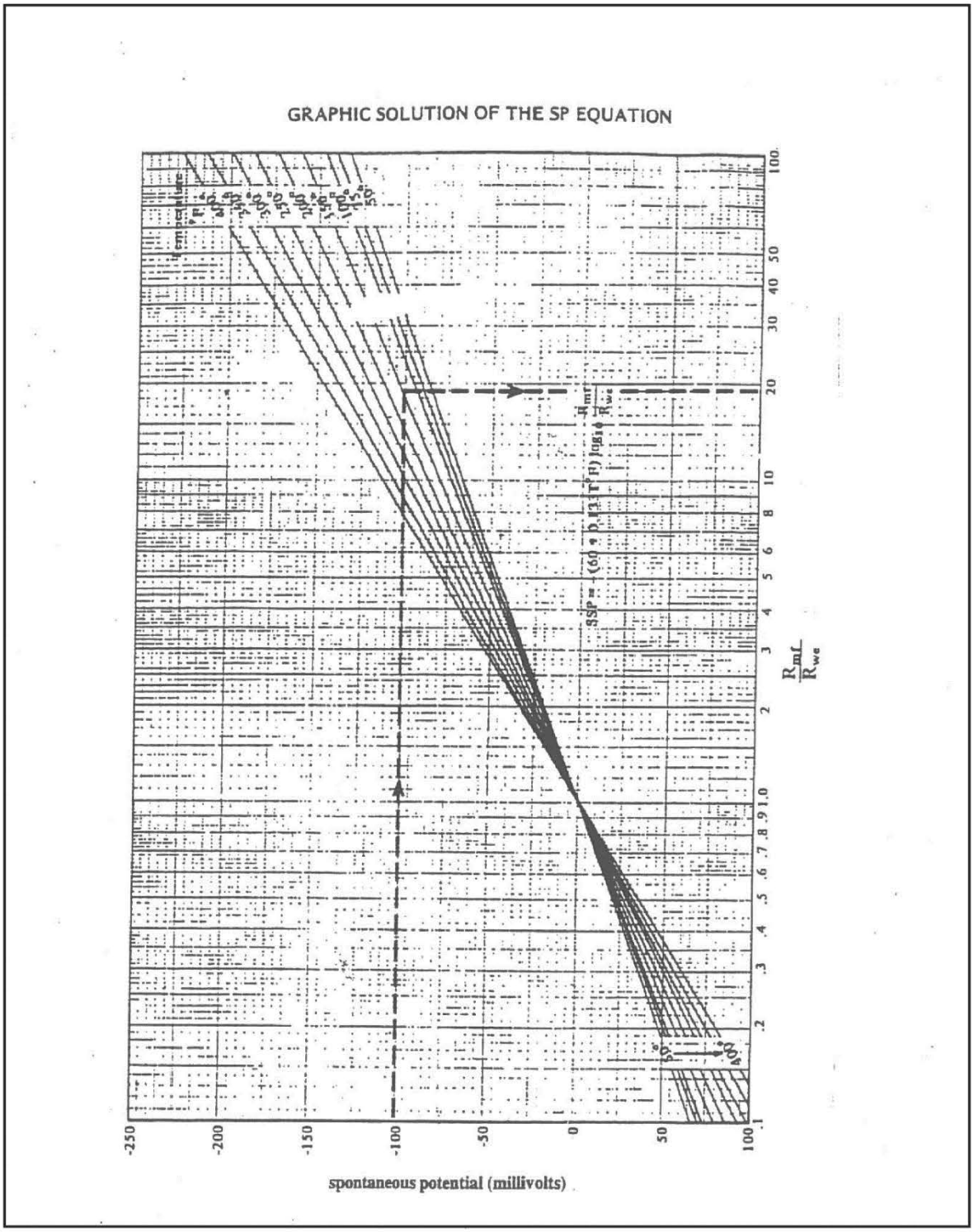

Figure 4.54 Graphic solution of the Spontaneous Potential Equation (Schlumberger, 1987)

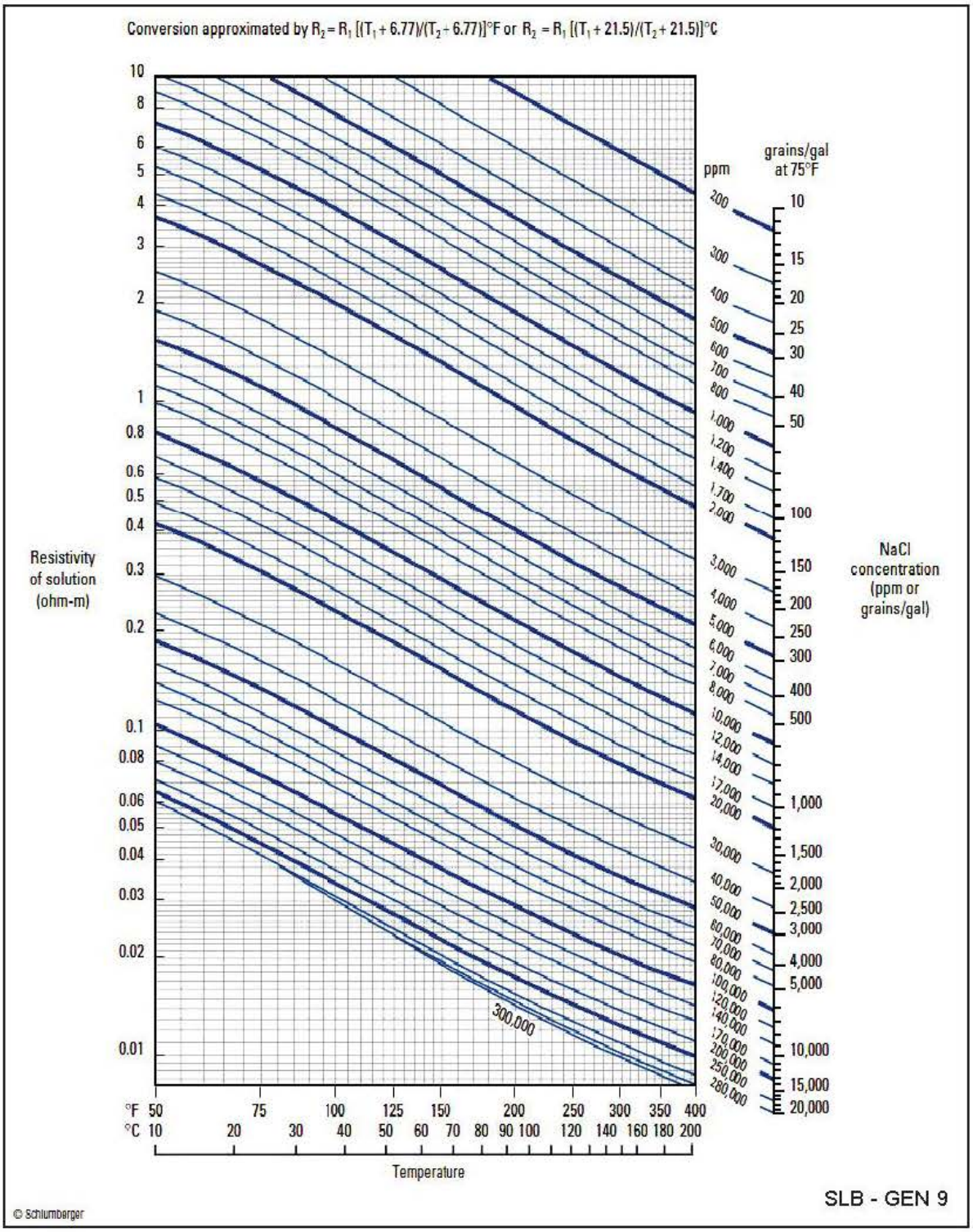

Figure 4.55 Resistivity nomograph for NaCl solutions (Schlumberger, 1979)

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 Wells 1-4
Facility contact:	Benjamin Heard, Principal 2417 Shell Beach Drive, Lake Charles, Louisiana 70601 (713) 320-2497, bheard@gcscarbon.com
Well location:	Calcasieu/Cameron Parish, Louisiana Well No 1: [redacted] Well No 2: Well No 3: 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. 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 Seismic event greater than M2.0 and no felt report	1. Continue normal operation within permitted levels. 2. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 3. Review seismic and operational data. 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. 2. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 3. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 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). 5. Determine if leaks to ground water or surface water occurred. 6. If USDW contamination is detected: a. Notify the UIC Program Director within 24 hours of the determination. 7. Review seismic and operational data. 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. 2. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well. 3. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 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). 5. Determine if leaks to ground water or surface water occurred. 6. If USDW contamination is detected: a. Notify the UIC Program Director within 24 hours of the determination. 7. Review seismic and operational data. 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-03-12-2021-2303/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: No

Project Plan Upload

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-03-12-2021-2303/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

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Authorized submission made by: Benjamin Heard

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Plan revision number: v1
Plan revision date: 3/12/2021

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

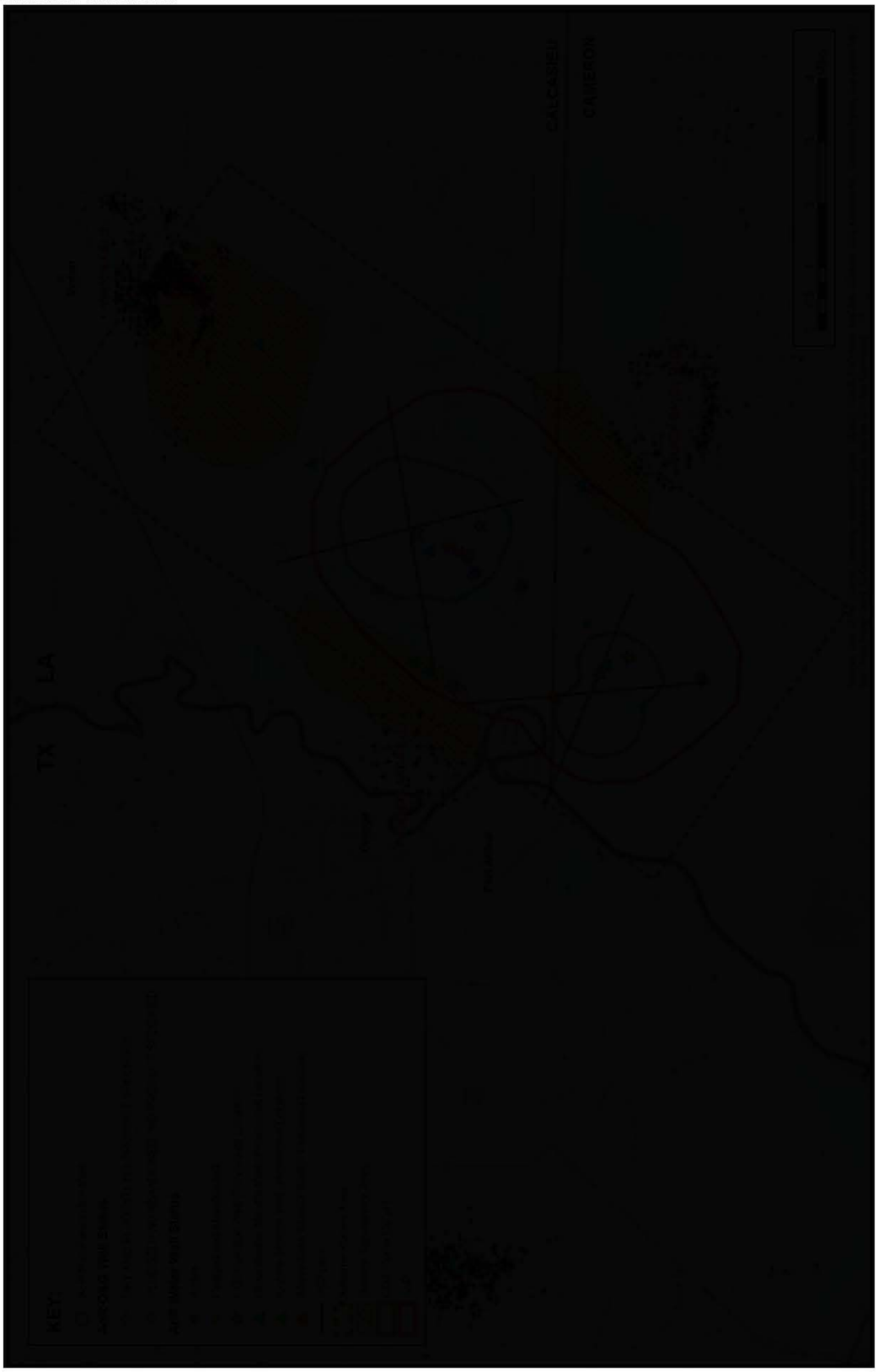

Figure 2.1 Testing and monitoring plan overview

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 ALI method SAM 4.1 subtraction method (GC/DID) 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 δC^{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	
δC^{13} CO_2	Gas Chromatography with dual inlet isotope ratio mass spectrometer	+/- 0.1 ‰.
δC^{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 Resolution	0 – 10,000 psi/200 °C +/-0.02 psi/0.005 °C
	Accuracy	+/-0.024% of full scale (+/-2.4 psi/+/-0.25 °C)
	Manufacturer's Recommended Calibration Frequency	Minimum Annual
Memory Pressure Gauge	Range Resolution	0 – 10,000 psi/200 °C +/-0.02 psi/0.005 °C
	Accuracy	+/-0.024% of full scale (+/-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 δD 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 δD 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 ‰.
δD 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 ‰.
δD 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.

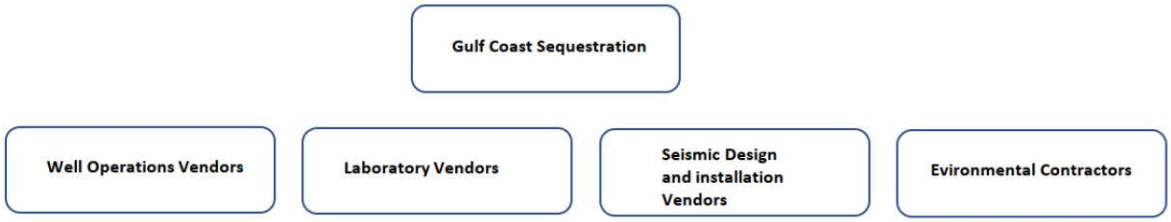

Figure 12.1 GCS Organization

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) 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) GC/TCD	Note 2	Note 2	Note 2
Nitrogen (N_2)	ISBT 4.0(GC/DID) 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 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: [List specific cations]				
Anions: [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: [List specific cations]				
Anions: [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: [List specific cations]				
Anions: [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: [List specific cations]				
Anions: [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: [List specific cations]			
Anions: [List specific anions]			
Dissolved CO_2			
Isotopes: [List specific isotopes]			
Alkalinity			
Field Confirmation: [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) (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 (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 (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 (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 Wells 1-4
Facility contact	Benjamin Heard, Principal 2417 Shell Beach Drive, Lake Charles, Louisiana 70601 (713) 320.2497; bheard@gcscarbon.com
Well location:	Calcasieu/Cameron Parish, Louisiana Well No 1: [redacted] Well No 2: Well No 3: 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 (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.

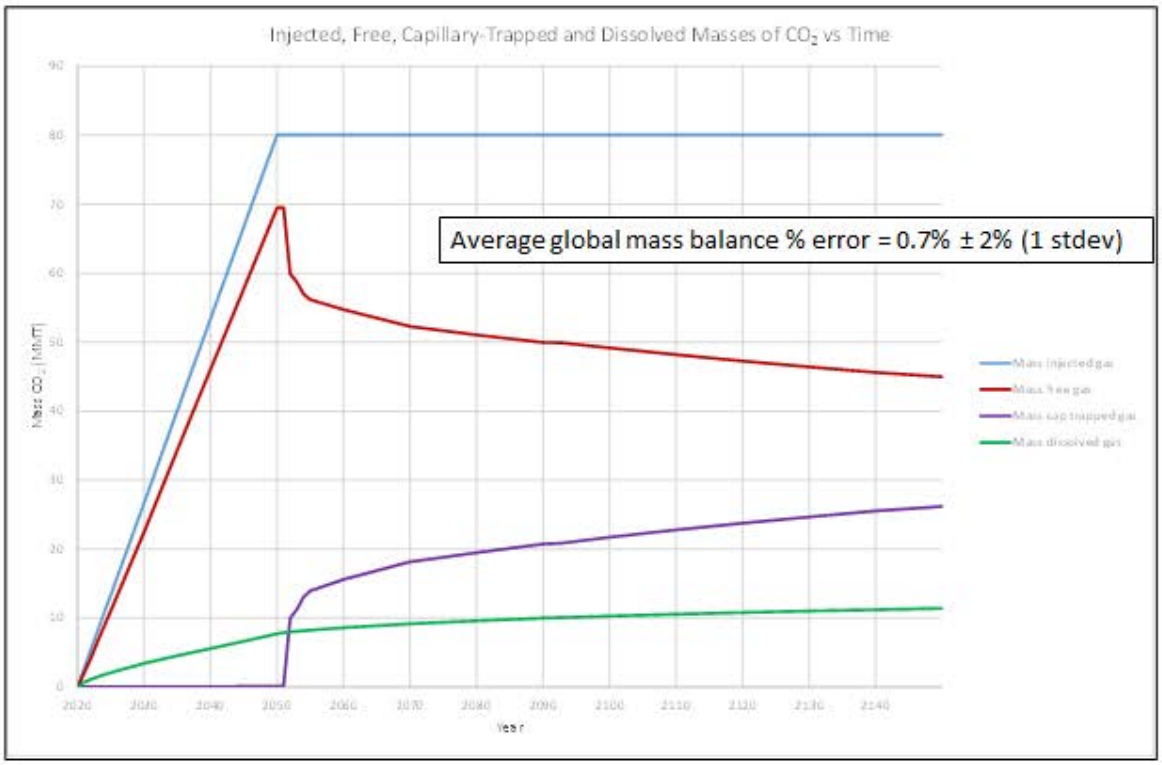

Figure 4.46 CO_2 mass balance and cumulative trapping

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.

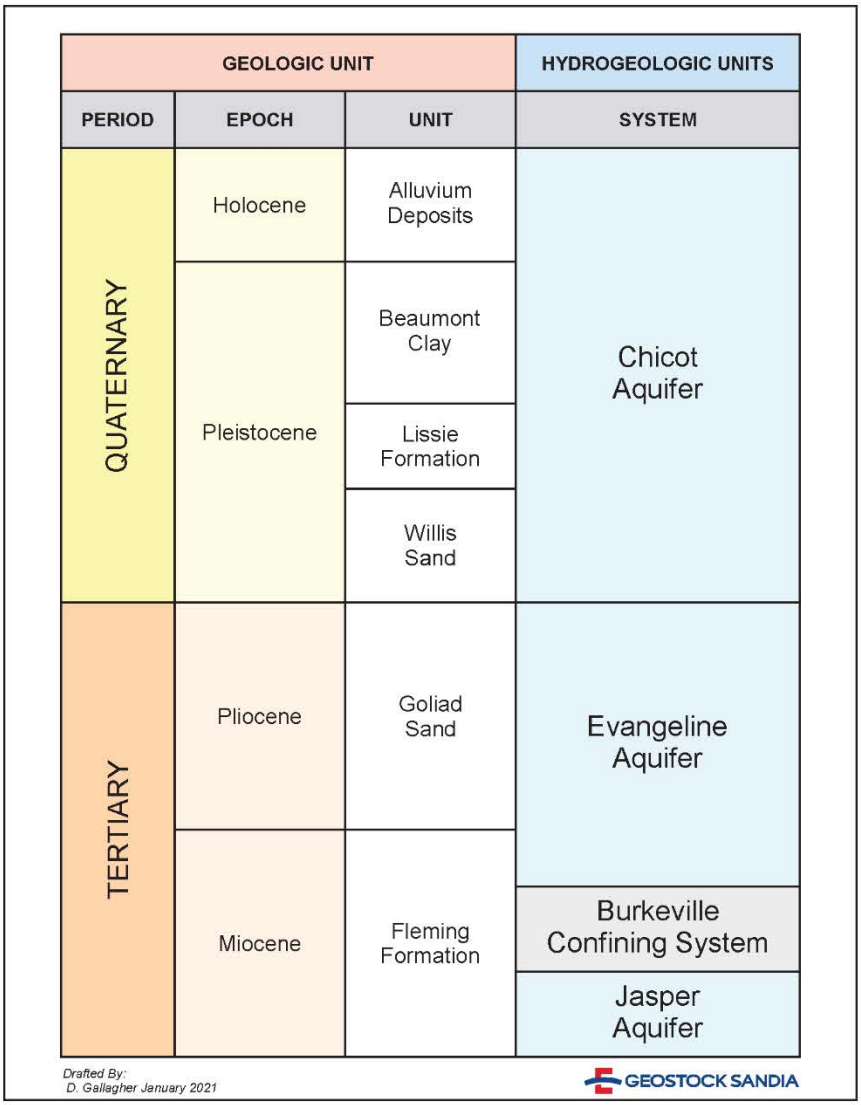

Figure 4.53 Regional hydrostratigraphic column for southeastern Texas and southwestern Louisiana.

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:

ϕ = 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:

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

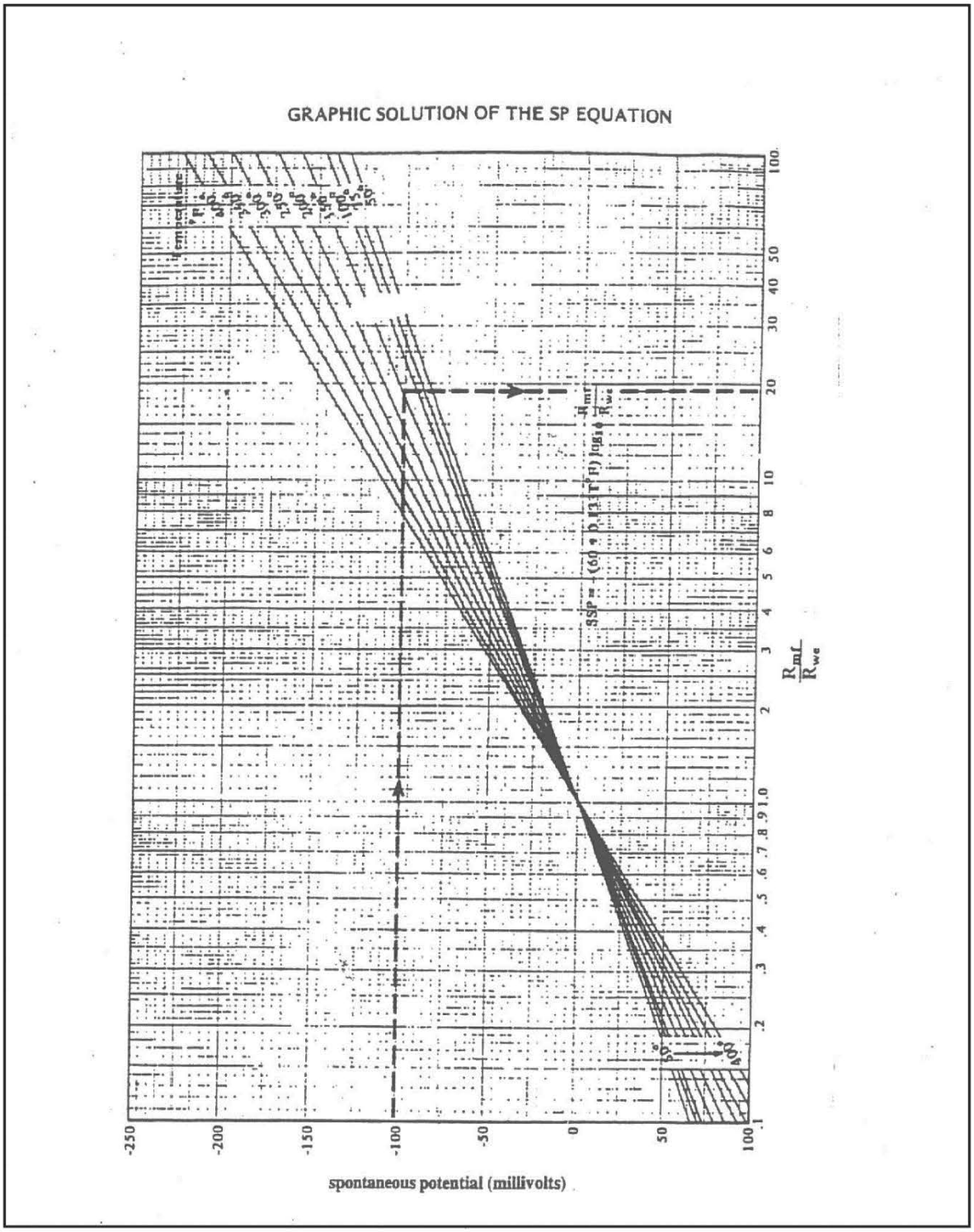

Figure 4.54 Graphic solution of the Spontaneous Potential Equation (Schlumberger, 1987)

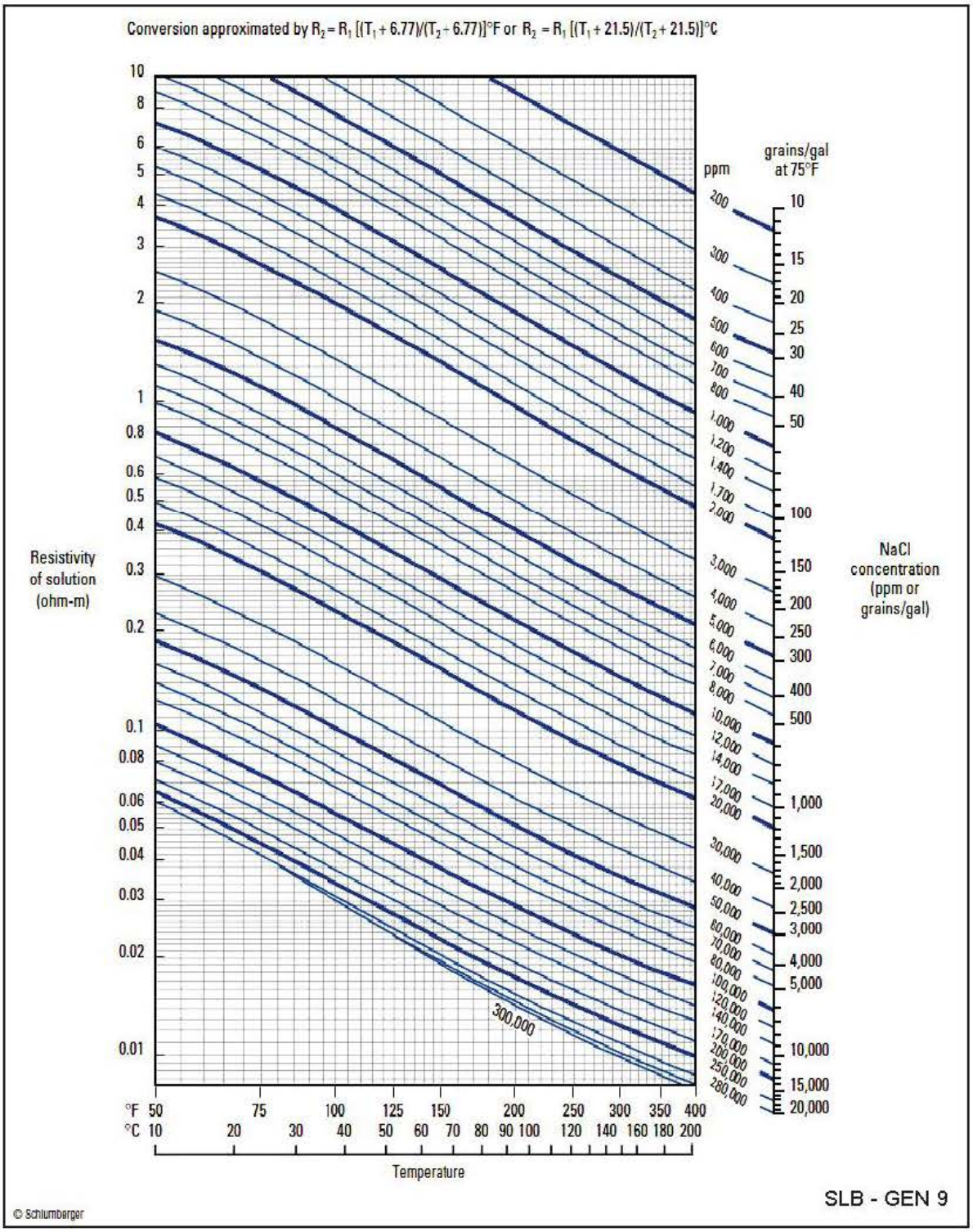

Figure 4.55 Resistivity nomograph for NaCl solutions (Schlumberger, 1979)

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 Wells 1-4
Facility contact:	Benjamin Heard, Principal 2417 Shell Beach Drive, Lake Charles, Louisiana 70601 (713) 320-2497, bheard@gcscarbon.com
Well location:	Calcasieu/Cameron Parish, Louisiana Well No 1: [redacted] Well No 2: Well No 3: 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. 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 Seismic event greater than M2.0 and no felt report	1. Continue normal operation within permitted levels. 2. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 3. Review seismic and operational data. 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. 2. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 3. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 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). 5. Determine if leaks to ground water or surface water occurred. 6. If USDW contamination is detected: a. Notify the UIC Program Director within 24 hours of the determination. 7. Review seismic and operational data. 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. 2. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well. 3. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 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). 5. Determine if leaks to ground water or surface water occurred. 6. If USDW contamination is detected: a. Notify the UIC Program Director within 24 hours of the determination. 7. Review seismic and operational data. 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

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

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Overall Strategy and Approach for Emergency and Remedial Response 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

The Emergency and Remedial Response Plan (ERRP) describes actions Oxy Low Carbon Ventures, LLC, 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 Oxy Low Carbon Ventures, LLC, obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, Oxy Low Carbon Ventures, LLC, 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.

2.0 Overall Strategy and Approach for Emergency and Remedial Response

Resources in the vicinity of the YAMS CO_2 Sequestration Project that may be affected as a result of an emergency event at the project site include USDWs, surface rivers and riverines, and nontidal, emergent wetlands. The Area of Review and Corrective Action Plan document addresses the USDWs within the project rea.

Infrastructure in the vicinity of the YAMS CO_2 Sequestration Project that that may be affected as a result of an emergency at the project site include local surface operations and an unincorporated community adjacent to the AoR.

The events related to the YAMS CO_2 Sequestrations Project that could potentially result in an emergency response are include over-pressured gas flow, movement of brine or CO2 outside the defined AoR, loss of mechanical integrity, monitoring equipment failure, seismic event, or natural disaster. Response actions will depend on the severity of the event(s) triggering an emergency response and are described in detail in the project Emergency and Remedial Response Plan document of the permit.

Monitoring, control, and routine maintenance of the injection operations will be the responsibility of the Injection Operations Staff. Site personnel, project personnel, and local authorities will be relied upon to implement the ERRP. A site-specific emergency contact list will be developed and maintained during the life of the project. 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, Oxy Low Carbon Ventures, LLC, shall be responsible for its procurement.

Oxy Low Carbon Ventures, LLC, will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether there are any environmental or safety implications.

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

YAMS CO_2 Sequestration Project

1.0 Facility Information 1

2.0 Overall Strategy and Approach for Post-Injection Site Care and Closure 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Oxy Low Carbon Ventures, LLC, will perform to meet the requirements of 40 CFR 146.93. Oxy Low Carbon Ventures, LLC, will monitor ground water quality and track the position of the carbon dioxide plume and pressure until site closure. Oxy Low Carbon Ventures, LLC, may not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, Oxy Low Carbon Ventures, LLC, will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

2.0 Overall Strategy and Approach for Post-Injection Site Care and Closure

The reservoir simulation indicates that, after injection ceases, the pressure front begins to dissipate, and the CO_2 plume remains within the injection zone and continues to expand.

After the injection ceases, the project will plug and abandon the injector wells according to the plugging procedure proposed in the Plugging Plan document. Additional monitoring wells will be drilled as proposed in the phased approach of the monitoring plan provided in the Testing and Monitoring Plan document.

Planned groundwater quality monitoring and plume and pressure front tracking during the post-injection phase will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection phase testing and monitoring will be submitted annually, within 60 days of the anniversary of the date that injection ceases. The post-injection monitoring program will focus on the tracking of the projected CO_2 plume migration.

During the PISC period, the monitoring reports will be prepared annually and submitted to the EPA Region 6 UIC Branch Office. These reports will summarize methods and results of ground water quality monitoring, CO_2 storage zone pressure tracking, and indirect geophysical monitoring for CO_2 plume tracking.

The PISC and Site Closure Plan will be reviewed every 5 years during the PISC period. Results of the plan review will be included in the PISC monitoring reports. The operational and monitoring results will be reviewed for adequacy in relation to the objectives of the PISC. The monitoring locations, methods, and schedule will be analyzed in relation to the size of the CO_2 storage zone, pressure front, and protection of USDWs. In case of changes to the PISC plan, a modified plan will be submitted to the EPA Region 6 UIC Branch Office at least 30 days before the planned initiation of the changes.

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

Oxy Low Carbon Ventures, LLC, will conduct site closure activities to meet the requirements of 40 CFR 146.93(e) as described below. Oxy Low Carbon Ventures, LLC, 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, Oxy Low Carbon Ventures, LLC, 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.

Upon conclusion of the post-injection site care period, all monitoring wells will be plugged and capped below grade in accordance with the approved Plugging and Abandonment Plans. Before the wells are plugged, the internal and external integrity of the wells will be confirmed. The results of this logging and testing will be reviewed and approved by the appropriate regulatory agencies prior to plugging the wells.

After the completion of the plugging activities, a plugging report will be submitted to the UIC Program Director describing the methods used and tests performed on the well during plugging. This report will be submitted to the UIC Program Director within 60 days of completing the plugging activities.

At the end of the PISC phase, Oxy Low Carbon Ventures, LLC, will ensure the site is reclaimed and returned to predevelopment condition to meet the requirements of 40 CFR 146.93(e).

INJECTION WELL PLUGGING PLAN SUMMARY
40 CFR 146.92(b)

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Overall Strategy and Approach for Injection Well Plugging and Abandonment 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

Oxy Low Carbon Ventures, LLC, will conduct injection well plugging and abandonment according to the procedures below.

Upon the end of life for YAMS CCS 1, this injection well will be plugged and abandoned relevant to the requirements of Environmental Protection Agency (EPA) document 40 CFR Subpart H – Criteria and Standards Applicable to Class VI Wells. The plugging procedure and materials will be designed to prevent any unwanted fluid movement, resist the corrosive aspects of carbon dioxide (CO_2) with water mixtures, and protect any underground sources of drinking water (USDWs).

2.0 Overall Strategy and Approach for Injection Well Plugging and Abandonment

After injection has ceased, the well will be flushed and pressure measurements taken. A log to ensure integrity inside and outside of the casing will be run prior to plugging. Any injection tubing and packer will be removed, and the well will be plugged.

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

The tools and techniques proposed to plug and abandon the injection well are included in the project Injection Well Plugging Plan document of the permit.

Class VI UIC Project Plan Submissions

This submission is for:

Project ID: R06-LA-0004

Project Name: YAMS CO2 Sequestration Project

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-0004/Phase1-PreConstruction/ProjPlan-07-20-2021-1057/TM_YAMS_CCS_1g.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-0004/Phase1-PreConstruction/ProjPlan-07-20-2021-1057/PLG_YAMS_CCS_1g.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-0004/Phase1-PreConstruction/ProjPlan-07-20-2021-1057/PISC_SC_YAMS_CCS_1g.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-0004/Phase1-PreConstruction/ProjPlan-07-20-2021-1057/ERR_YAMS_CCS_1g.pdf

Appendices and Supporting Materials Upload

Complete Submission

Authorized submission made by: Kelly Watson

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

TESTING AND MONITORING PLAN OVERVIEW
40 CFR 146.90

YAMS CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Overall Strategy and Approach for Testing and Monitoring 1

1.0 Facility Information

Facility name: YAMS CO_2 Sequestration Project
YAMS CCS 1 Well

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: [redacted], Louisiana

This Testing and Monitoring Plan describes how Oxy Low Carbon Ventures, LLC, will monitor the YAMS CO_2 Sequestration Project 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.

2.0 Overall Strategy and Approach for Testing and Monitoring

The monitoring network is designed to detect unforeseen CO_2 and/or brine leakage out of the injection zone that could endanger the USDW, migrate to a different stratus, or create a risk for the people or environment. The monitoring program is tailored to track the migration of the CO_2 plume and development of the pressure front to validate the simulation models and to be able to delineate the AoR effectively. There are several components that are integrated into the master plan for monitoring, which are classified in the following categories:

1. Carbon Dioxide Stream Analysis
2. Continuous Recording of Operational Parameters
3. Corrosion Monitoring and Leak Detection

4. Above Confining Zone Monitoring
5. External Mechanical Integrity Testing
6. Pressure Fall-Off Testing
7. Carbon Dioxide Plume and Pressure Front Tracking

The tools and techniques proposed to monitor the surface and downhole operating conditions of the wells along with the quality of the CO_2 being injected are included in the project Testing and Monitoring Plan document of the permit.

Class VI UIC Alternative PISC Timeframe Demonstration

This submission is for:

Project ID: R06-LA-0002

Project Name: Project Minerva

Current Project Phase: Pre-Injection Prior to Construction

Computational Modeling

Proposed Alternative PISC Timeframe: 10 years

Potential Conduits

Data Quality

Complete Submission

Authorized submission made by: Benjamin Heard

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