



ATTACHMENT D

Testing & Monitoring Plan

Gulf Coast Sequestration, LLC (G1037)

Project Minerva, Cameron Parish

Minerva South CCS Well Nos. 001 & 002

EPA Project Id: R06-LA-0002

LDCE Appl Nos: 45031 & 45032

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Revision 1: January 2026

Revision 2: May 2026

Revision 3: May 2026



CERTIFICATION

Per LAC 43:VII §3603.H.1, the geoscientific aspects of the Testing and Monitoring Plan have been prepared by or under the supervision of a licensed Professional Geologist authorized to practice by and in good standing with the Louisiana Board of Professional Geoscientists.

Kaycee M. Garrett

LA License No. 1325

I, Kaycee M. Garrett, certify that I have personally examined and am familiar with the information submitted in this document and the attached documents, and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the submitted information is true, accurate, and complete.



TESTING AND MONITORING SECTIONS

(Including applicable Tables, Figures, and Appendices)

Section 1 Introduction

Section 2 Testing and Monitoring Requirements

Section 3 Carbon Dioxide Stream Analysis

Section 6 Above Confining Zone Monitoring

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FACILITY INFORMATION

Facility Name:	Minerva Facility
Injection Wells:	Minerva South CCS Well No. 001 (MS CCS 1) Minerva South CCS Well No. 002 (MS CCS 2)
Facility Contact:	David Cook, CEO 5599 San Felipe St., Ste. 1450, Houston, Texas 77056 (713) 419-6808; dcook@gcscarbon.com
Well Locations:	Sec 3, T12S, R13W, Cameron Parish, Louisiana MS CCS 1 (NAD 1927) Surface: 30° 02' 34.10" N, 93° 40' 20.63" W Bottom-Hole: 30° 02' 34.10" N, 93° 40' 20.63" W MS CCS 2 (NAD 1927) Surface: 30° 02' 33.84" N, 93° 40' 20.48" W Bottom-Hole: 30° 02' 13.74" N, 93° 40' 42.07" W

1 INTRODUCTION

This Testing and Monitoring Plan describes how Gulf Coast Sequestration, LLC (GCS) will monitor Project Minerva pursuant to Louisiana Administrative Code (LAC), Title 43, Chapter XVII, Section 3625.A (LAC 43:XVII §3625.A) of the Class VI UIC Regulations. In addition to demonstrating that the proposed wells are operating as planned, the carbon dioxide (CO₂) plume and pressure front are moving as predicted, and that there is no endangerment to underground sources of drinking water (USDWs), the monitoring data will be used to validate and adjust the geological models used to predict the distribution of CO₂ within the Injection Zone, to support Area of Review (AoR) revaluations, and to establish a non-endangerment demonstration.

The scope of the Testing and Monitoring Plan is limited to the 30-year operational life of Project Minerva. Testing and monitoring activities conducted during the post injection surveillance period are discussed in the Post Injection Site Care (PISC) and Closure Plan (Attachment F). Plugging and abandonment activities for the injection wells are defined in the Injection Well Plugging Plan (Attachment E) and for the monitoring wells in the PISC and Closure Plan (Attachment F). Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan (Attachment G).

2 TESTING AND MONITORING REQUIREMENTS

Testing and monitoring will be conducted throughout all phases of the project for acquisition of baseline measurements and to ensure the CO₂ remains in compliance with the permitted specifications, the storage complex and injection wells are performing as expected, the CO₂ is contained and confined, and surrounding resources and USDWs are free from endangerment.



At this time, GCS does not propose to conduct soil gas or air quality monitoring as part of the testing and monitoring plan. However, if data collected in the pre-operational phase indicates that the subsurface has been significantly mischaracterized, GCS will reconsider incorporating surface air and/or soil gas monitoring into the testing and monitoring plan.

The testing and monitoring plan will be reevaluated once every 5 years after the date injection commences and modified as necessary to ensure the plan is meeting expectations. If revisions to the plan are deemed necessary, supporting documentation and an amendment will be provided to the Louisiana Department of Conservation and Energy (C&E) Secretary (C&E Secretary) for approval.

A summary of the testing and monitoring plan is provided in Table D.2-1. The monitoring network is shown in Figure D.2-1 with the proposed AoR, the proposed injection wells, and the adjacent existing artificial penetrations. A magnetometer survey was performed over the area defined by the red dashed line in Figure D.2-1. The main objective was to identify any potential undocumented artificial penetrations that could provide pathways for vertical fluid migration within the modeled AoR, and to ensure that the proposed monitoring network was designed to monitor all potential risks. The results of the survey can be found in Appendix VIII-2 of the Project Minerva Narrative.

2.1 QUALITY ASSURANCE PROCEDURES

A Quality Assurance and Surveillance Plan (QASP) for all testing and monitoring activities, required pursuant to LAC 43: XVII §3625.A.11, is provided in Appendix D-I to this Testing and Monitoring Plan.

2.2 REPORTING PROCEDURES

GCS will report the results of all testing and monitoring activities to C&E in compliance with the requirements under LAC 43: XVII §3629.A. This includes quarterly reporting regarding characteristics of the carbon dioxide stream and related data per House Bill 571. Table D.2.2-2 summarizes the monitoring activities presented in this plan and provides the monitoring frequency and reporting timeline for each activity.

2.3 COMPLIANCE AND REEVALUATION

Per LAC 43:XVII §3625.A.10, GCS will periodically review the testing and monitoring plan to incorporate monitoring data collected under LAC 43:XVII §3625, operational data collected under LAC 43:XVII §3621, and the most recent AoR reevaluation performed under LAC 43:XVII §3615.C.2. GCS will review the testing and monitoring plan no less often than once every five years and will submit an amended testing and monitoring plan to C&E or demonstrate to the C&E Secretary that no amendment to the testing and monitoring plan is needed.

If an amendment to the testing and monitoring plan is required, it will be submitted to C&E for review. Upon approval by the C&E Secretary, it will be incorporated into the permit and will be subject to the permit modification requirements of LAC 43:XVII §3613, as appropriate. Amended plans or demonstrations will be submitted to the C&E Secretary



within 12 months of the AoR revaluation; following any significant changes to the facility, such as the addition of monitoring wells or newly permitted injection wells within the AoR, on a schedule determined by the C&E Secretary; or when required by the C&E Secretary.

3 CARBON DIOXIDE STREAM ANALYSIS

GCS will sample and analyze the chemical and physical characteristics of the CO₂ stream during the operational period to yield representative data of the stream.

The anthropogenic CO₂ will be sourced from undisclosed strategic partners in the Lake Charles Industrial Corridor.

GCS has developed minimum specifications for constituents allowed in the CO₂ stream received from sources. The specifications are presented in Table D.3-1 and emitters will be required to provide evidence of compliance with the specification prior to transmission to the Minerva Facility. GCS will confirm compliance with the specifications by sampling the CO₂ steam according to the protocols provided in the following section.

3.1 SAMPLING LOCATION AND FREQUENCY

Prior to the commencement of injection, a representative sample of the CO₂ stream will be taken and test results will be submitted to C&E. After injection starts, CO₂ stream samples will be collected and analyzed quarterly. Sampling will begin on the first month of the quarter (March, June, September, December) following commencement of injection. When a proposed source is added and/or changes are made to the existing emitters CO₂ stream, GCS will conduct additional sampling outside of the sampling schedule to confirm compliance.

As demonstrated on the Process Flow Diagram for the Minerva Facility, Figure D.3.1-1, CO₂ stream sampling will be conducted at a sample port along the comingled inlet pipework prior to reaching the Minerva Facility.

3.2 ANALYTICAL PARAMETERS

According to the requirements of LAC 43:XVII §3625, analysis of the CO₂ stream is required with sufficient frequency to provide data representative of its chemical and physical characteristics. The list of parameters identified for analysis of the CO₂ stream along with analytical methods are outlined in Table D.3.2-2. An equivalent method may be utilized with the prior approval of the C&E Secretary.

3.3 SAMPLING METHODS

Grab samples of the CO₂ stream will be obtained for analysis of gases (Table D.3.2-2). Samples will be collected by the emitter at their outlet and by GCS at the comingled inlet pipework. These grab samples will be obtained using laboratory approved sampling cylinders to collect and transport the samples. Stainless steel tubing or equivalent pressure hoses will be connected to a designated sampling port, with a regulator to control the pressure. The pressure of the CO₂ will be reduced ensuring the CO₂ is collected in the gaseous state as required by the Federal transportation regulations for shipment of



compressed gases (CFR 173.301.a.8). Sample cylinders will be purged during sample collection to remove laboratory-added helium gas and ensure a representative sample. Sample containers will have a chain of custody form and will be labeled appropriately (See QASP, Appendix D-1).

3.4 LABORATORY SELECTION AND CHAIN OF CUSTODY PROCEDURES

Samples will be sent to and analyzed by a Louisiana Environmental Laboratory Accreditation Program (LELAP) accredited laboratory.

The LELAP lab will have all the necessary equipment, experience and certifications to complete the analysis.

The lab will have chain of custody procedures that includes at a minimum the following:

- Sample date
- Sample description
- Sample type
- Relinquished/received by signature
- Sampler Name

3.5 LOCATION INFORMATION

For each CO₂ analysis, field personnel will document the time of each sample collection, a summary of all CO₂ stream analyses (including any quality assurance/quality control samples), interpret the results, note any identified changes, and explain any data gaps.

3.6 REPORTING

GCS will report any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data (LAC 43:XVII §3629.A.1.a.i). If a change to the CO₂ stream is detected in the quarterly sampling, the results of the sample will be reported to C&E and EPA in the quarterly report (LAC 43:XVII §3629.A.1.a).

4 CONTINUOUS RECORDING OF OPERATIONAL PARAMETERS

GCS will install and use continuous recording devices to monitor injection pressure, temperature, rate, and volume; the pressure on the annulus between the tubing and the long-string casing; and the annular volume added as required by LAC 43:XVII §3621.A.6.a.i-iv.

4.1 MONITORING EQUIPMENT, LOCATION, AND FREQUENCY

GCS will perform the activities identified in Table D.4.1-1 to monitor operational parameters and verify mechanical integrity of injection wells. Monitoring will take place at the locations and frequencies shown in the table. The general location of the devices within the injection well system is depicted on the Process Flow Diagram, Figure D.3.1-1.

Instrument specification sheets for the proposed continuous recording devices are provided in Appendix D-II. The appendix will be updated with the final technology selection



upon completion of detailed design.

Except where indicated, monitoring data will be transmitted to a computerized control system that records, monitors, and controls injection processes. The system has not been selected at this time, but examples include: Programmable Logic Controller (PLC), Supervisory Control and Data Acquisition (SCADA), or Distributed Control System (DCS).
Monitoring Details

4.1.1 Injection Temperature, Pressure, Rate, and Volume/Mass

Injection temperature, pressure, rate, and volume will be measured at each injection well by volumetric flow meter(s). Each well will be equipped with primary and secondary meters. The volumetric flow meters will also be equipped with electronic pressure and temperature gauges with transmitters to continuously monitor pressure and temperature of the injection stream (Figure D.3.1-1). The data from the meter station will be collected and recorded in the computerized control system.

The computerized control system will record the volume of CO₂ and calculate the mass of CO₂ injected. The flow rate, a volumetric measurement of million standard cubic feet per day (MMscfd), will be used to determine mass over a given injection time. The metered pressure and temperature data will be used to calculate the injectate density, which will be divided into the flow rate and multiplied by injection time to determine the mass injected.

The meter will be calibrated annually for the expected flow rate range using accepted standards and will be accurate to within manufacturer's tolerances. Injection rate and pressure limitations will be implemented to ensure adherence to the maximum allowable bottomhole injection pressure. Pressure and temperature gauges will be calibrated annually.

Each wellhead will also be equipped with downhole electronic temperature and pressure gauges with transmitters to monitor both annular and injection readings.

4.1.2 Tubing-Casing Annulus Pressure Monitoring

The tubing-casing annulus pressure will be monitored continuously to ensure integrity of the downhole packer, tubing, and casing. GCS will monitor the tubing-casing pressure continuously (every 10 seconds) using a downhole electronic pressure and temperature gauge with a transmitter at the wellhead. The annulus will be filled 9.3 ppg CaCl₂ inhibited brine with corrosion control (98% MgO, magnesium oxide).

The annular pressure for injection wells will be maintained with a pressure that exceeds the operating injection pressure, as stated in the injection well's Operating Plan (Project Minerva Narrative, Appendix XII). Significant changes in annular pressure may indicate potential internal or external mechanical integrity failures, as long as thermal effects (like material contraction from cooling) and pressure effects (such as ballooning from increased tubing pressure) during normal operations are accurately identified as acceptable deviations.

An initial threshold of 5% change in annular pressure, that cannot be explained by changing operational conditions (e.g., injection rate, pressure, or temperature), will be utilized as an



indication of mechanical integrity loss. GCS will notify C&E if the annular pressure exceeds the threshold and cannot be maintained or stabilized after three attempts. After operation commences, GCS will conduct frequent evaluation of the pressure records to determine if the threshold is appropriate considering the external factors that may impact operations (e.g., liquid property changes, atmospheric pressure, or pressure in the formation). Any proposed changes to the threshold will be implemented with the approval of the C&E Secretary.

4.1.3 Annular Fluid Volume Monitoring

When injection commences, an annulus stabilization system will be connected to the injection wells. The annulus stabilization system will be equipped with a non-corrosive brine reservoir fluid tank, a positive displacement style pump, and a reservoir fluid level gauge. The annulus stabilization system will be used to manually stabilize the annular pressure, by adding or removing annular fluid until the annular pressure normalizes. The change in volume from the annular fluid reservoir, as fluid is added or removed from the annulus, will be measured by the reservoir fluid level gauge and will be recorded by GCS.

Once normal injection operations are achieved and the annular pressure is stable, GCS will remove the annulus stabilization system and will monitor the annular pressure using the annular pressure and temperature gauge. Any future additions or removal of annular fluid to stabilize the annular pressure will be also conducted manually through the use of the portable annulus stabilization system.

4.2 NOTIFICATION

In the event that monitoring results indicate possible endangerment of the USDW, GCS will notify C&E and EPA within 24 hours of discovery of the compliance issue (LAC 43:XII §3629.A.3.a-e).

4.3 REPORTING

Per LAC 43:XVII §3629.A.1, GCS will report the following values in the quarterly report submitted to C&E and EPA:

- monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and a description of any event that exceeds operating parameters for injection pressure specified in the permit;
- the monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume injected cumulatively over the life of the project;
- monthly average, maximum, and minimum values for the tubing-casing annular pressure, and a description of any event that exceeds operating parameters for the tubing-casing annulus pressure specified in the permit;
- monthly annulus fluid volume added; and
- a description of any event which triggers a shut-off device required by LAC 43:XVII §3621 and the response taken.



5 CORROSION MONITORING

To meet the requirements of LAC 43.XVII §3625.A.3, 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.

5.1 SURFACE MONITORING DETAILS

GCS will monitor corrosion by analyzing corrosion coupons made from well construction materials exposed to the carbon dioxide stream. These materials include 25Cr corrosion resistant alloy (CRA), consistent with the material installed across the Injection Zone (9 5/8" long string casing and 4 1/2" tubing), as well as the CRA representative of the packer material, which is pending final selection. Final material selection will be completed after detailed engineering.

5.1.1 Monitoring Location and Frequency

The corrosion coupons will be installed in a pipe parallel with the surface facilities pipeline that feeds CO₂ injectate to the injection wells. A process flow diagram depicting the location is shown in Figure D.3.1-1. Material inspections will be performed by approved third-party contractors on a quarterly calendar basis starting during the first month of the quarter (March, June, September, December) following commencement of injection.

5.1.2 Material Inspection

When coupon inspection is conducted, they will be assessed using the American Society for Testing and Materials (ASTM) G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (or equivalent industry standard) by an approved 3rd party laboratory. This ASTM process includes visually inspecting the coupons for evidence of corrosion (e.g., discoloration, pitting), measuring the weight and size (thickness, width, length) of the coupons, and calculating the corrosion rate based on weight loss during the exposure period divided by the duration (i.e., weight loss method).

5.2 DOWNHOLE MONITORING DETAILS

Downhole logging data will be performed on MS CCS 1 and MS CCS 2 prior to commencing injection operations. These logs will provide a baseline casing thickness measurement to which future logs will be compared. A casing inspection logging tool will be used (which include ultrasonic imaging, magnetic flux leakage, and electromagnetic imaging) as it is proven and widely accepted within the industry for their accuracy in determining casing thickness and identifying casing corrosion.

If required, subsequent logs using the same technology will be run at a frequency specified by the C&E Secretary (LAC 43.XVII §3627.A.4). Results will be compared to the initial baseline log (LAC 43.XVII §3617.B.1.d.iv). Thickness measurements showing a reduction in thickness greater than 20 percent of API published nominal thickness will warrant further investigation. 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 C&E Secretary. To obtain approval for alternative testing, GCS will submit a written request to the C&E Secretary, setting forth the proposed test and all technical data supporting its use.

5.3 NOTIFICATION

Per LAC 43.XVII §3617.B.6, GCS will notify C&E at least 72 hours prior to conducting wireline logs used to monitor downhole corrosion.

In the event that monitoring results indicate possible endangerment of the USDW, GCS will notify C&E and EPA within 24 hours of discovery of the compliance issue (LAC 43:XII §3629.A.3.a-e).

5.4 REPORTING

GCS will submit the results of the wireline logs to C&E and EPA within 30 days (or as specified by permit) (LAC 43:XVII §3629.A.1.b) and will include the results in the quarterly report (LAC 43:XVII §3629.A.1.a).

GCS will submit the quarterly results of the corrosion monitoring conducted at the surface to C&E and EPA in the quarterly report (LAC 43:XVII §3629.A.1.a).

6 ABOVE CONFINING ZONE (ACZ) MONITORING

The goal of Above Confining Zone (ACZ) monitoring is to ensure non-endangerment of the USDW and to detect either brine or CO₂ leakage from the Injection Zone. GCS will achieve this goal by implementing monitoring methods to detect potential vertical fluid movement from the Injection Zone.

The only potential pathways for vertical fluid movement within the delineated AoR for Project Minerva are along the proposed injection wells and faults. GCS proposes to strategically install groundwater monitoring wells adjacent to these pathways to track geochemical changes that could impact the USDW in accordance with LAC 43.XVII §3625.A.4. Additionally, GCS will conduct direct monitoring of the interval above the Confining Zone using Distributed Temperature Sensing (DTS) fiber optic cables installed along MS CCS 1 and MS CCS 2 to monitor for changes in temperature as indicators of potential upward fluid migration from the Injection Zone. A summary of the ACZ monitoring strategy is provided in Table D.6-1.

6.1 ABOVE CONFINING ZONE MONITORING WELL CONSTRUCTION

Two new ACZ monitoring wells, Minerva South USDW Well No. 001 (MS USDW 1) and Minerva South USDW Well No. 002 (MS USDW 2), will be drilled after the injection wells are constructed but before injection begins. A third well, Minerva South USDW Well No. 003 (MS USDW 3), will be drilled within the AoR after injection commences, following data collection indicating the plume and pressure front directions.



The drilling and logging procedures for MS USDW 1 and MS USDW 2 are detailed in Appendix D-III. GCS will submit Form UIC-25 (or its successor), Class V Well Applications, to C&E for approval to drill MS USDW 1 and MS USDW 2 after receiving the Approval to Construct for MS CCS 1 and MS CCS 2. The application for MS USDW 3 will be submitted as appropriate.

Appendix D-III will be updated to include the permit, conversion procedures, and as-drilled schematics following the completion of each ACZ monitoring well.

6.1.1 Well Placement

Figure D.6.1-1 illustrates the locations of the planned monitoring wells to be drilled before injection:

- MS USDW 1 will be located at the Minerva South Well Pad, monitoring the known potential pathway for vertical fluid migration within the AoR.
- MS USDW 2 will be at the site of Stream 34 Well No. 001 (SN 224951, Map Id 1). GCS will convert this existing wellbore, located approximately 0.75 miles north of the Minerva South Well Pad, into Minerva South In-Zone Well No. 001 (MS IZ 1).

Figure D.6.1-2 identifies the optimal location for installing MS USDW 3, which is situated within the AoR towards the projected plume and pressure front south of the injection well pad. The figure illustrates the leading edge of the plume and pressure front at 2 and 5 years after injection commences, indicating that there will be adequate time to confirm the final location of MS USDW 3 before the 5-year reevaluation period (LAC 43:XVII §3625.A.10).

As data is collected through both direct and indirect monitoring (see Sections 9.2 and 9.3) and the model is history-matched, GCS will collaborate with C&E to finalize the timing, location, and installation of MS USDW 3. The testing and monitoring plan will be updated accordingly at that time.

6.1.2 Monitoring Interval

MS USDW 1 and MS USDW 2 will be completed in the first confined sand unit below the base of the USDW. This interval corresponds to the upper sands of the Evangeline Aquifer. The monitoring interval of MS USDW 3 will be finalized once the timing and location for the monitoring well is determined in coordination with C&E.

6.1.3 Installation

The proposed drilling and logging procedures for MS USDW 1 and MS USDW 2 are provided as Appendix D-III. GCS will amend the testing and monitoring plan to include the drilling and logging procedures for MS USDW 3 once the timing and location for the monitoring well is determined in coordination with C&E.

6.1.4 Operation

GCS will operate ACZ monitoring wells in accordance with the applicable testing and integrity requirements applicable to Class V monitoring wells.



6.2 GROUNDWATER QUALITY MONITORING

6.2.1 Methods and Frequency

Table D.6-1 shows the planned monitoring methods, locations, and frequencies for groundwater quality and geochemical monitoring above the confining zone.

To meet the requirements at LAC 43.XVII §3607.C.2.e, GCS will establish a baseline geochemical dataset of groundwater quality prior to injection. After the ACZ monitoring wells are drilled, baseline monitoring will be conducted on a quarterly basis until the start of injection.

Once injection commences, groundwater samples will be collected quarterly through the operational life of the project.

6.2.2 Analytical Parameters

Table D.6.2-1 identifies the parameters that will be analyzed during groundwater monitoring and the analytical methods GCS will use.

The list of parameters may be reduced over the operational period, should it be determined during baseline sampling and/or the operational period that parameters listed in Table D.6.2-1 are no longer constituents of concern.

6.2.3 Sampling Methods

Samples will be collected using the following procedures:

- Water Level depth and elevation measurements will be taken.
- Wells will be purged such that existing water in the well is removed and fresh formation water is sampled.
- Downhole measurements of static fluid level, temperature, pH, conductance, dissolved oxygen, and pressure will be collected.
- Samples will be collected by lowering clean equipment downhole.
- Field measurements taken for density, pH, conductance, temperature, and dissolved oxygen will be collected from the samples at the surface.
- Samples will be preserved and sent to lab as per chain-of-custody procedure.

Groundwater samples will be collected following the procedures outlined in the project's QASP (Appendix D-I) during the operational and post-operational periods.

6.2.4 Accredited Laboratory/Chain of Custody and Analysis Procedures

Final laboratory selection has not been made at this time. The laboratory selected will be LELAP accredited and will meet all requirements set forth in the Testing and Monitoring Plan and the QASP (Appendix D-I). The Chain-of-Custody procedures will follow the requirements of the QASP.

The selected LELAP accredited laboratory will have all the necessary equipment, experience, and certifications to complete the analysis. Once selected, the LELAP accredited laboratory will have a chain of custody procedures that will be similar to the



following:

- Sample date
- Sample description
- Sample type
- Relinquished by and received by signature
- Sampler name
- Location information

6.3 TEMPERATURE MONITORING

In addition to the required groundwater quality monitoring above the Confining Zone, GCS proposes to monitor the temperature of the intervals immediately above the Confining Zone to identify any potential upward migration of fluids from the approved Injection Zone.

A Distributed Temperature Sensing (DTS) fiber optic cable will be installed within the long-string/borehole annulus of MS CCS 1 and MS CCS 2 from surface to total depth to continuously monitor temperature. Upon completion of the injection wells, GCS will begin continuous temperature monitoring to collect baseline data prior to injection.

After injection commences, GCS will continue collecting continuous DTS data through the operational life of Project Minerva.

6.4 NOTIFICATION

In the event that monitoring results indicate possible endangerment of the USDW, GCS will notify C&E and EPA within 24 hours of discovery of the compliance issue (LAC 43:XII §3629.A.3.a-e).

6.5 REPORTING

GCS will submit the results of the groundwater sampling to C&E and EPA in the quarterly report (LAC 43:XVII §3629.A.1.a). Analytical results will be submitted in the quarterly report of the period in which the testing took place.

7 INJECTION WELL INTEGRITY TESTING

Per LAC 43.XVII §3627.A.2.a, §3627.A.3, and §3625.A.5, GCS will perform mechanical integrity tests (MIT) on the proposed injection wells at least once every 12 months to demonstrate internal and external integrity, using an approved method until the injection well is permanently plugged and abandoned. The primary and alternative test descriptions, the mechanical integrity demonstration, technology and frequency are summarized in Table D.7-1. The specifications for the technologies proposed to collect formation evaluation and mechanical integrity data are provided in Appendix D-IV. The appendix will be updated with the final technology selection upon selection of the vendor.

7.1 INTERNAL INTEGRITY TESTING

Although LAC 43.XVII §3625.A.5 does not prescribe demonstration of internal mechanical



integrity, GCS will perform a Standard Annular Pressure Test (SAPT) test witnessed by an agent of C&E on the proposed injection wells at least once every 12 months (LAC 43.XVII §3627.A.2.a).

GCS will also perform a SAPT after initial well construction as part of the Pre-Operational Testing Program (Attachment C) and after performing any well remedial work that involves unseating the tubing or packer (LAC 43.XVII §3627.A.2.a.i-iii).

The SAPT is the most common means used to demonstrate mechanical integrity. This test is based on the principle that pressure applied to fluids filling a sealed vessel will persist. A well's annulus system, though closed to transfer of matter, is not closed to energy transfer because it is not isolated from transfer of heat from its surroundings, therefore an allowance for small pressure changes is necessary. The test provides an immediate demonstration of whether or not leaks, detectable by these means, exist. A discussion of the procedures for the SAPT are outlined in Appendix D-V.

7.2 EXTERNAL INTEGRITY TESTING

The approved methods to demonstrate external mechanical integrity described in LAC 43.XVII §3627.A.3.a-b include a tracer-type survey – such as a radioactive tracer, oxygen-activation log, or similar tool – or a temperature or noise log.

In accordance with LAC 43.XVII §3627.A.5.a, the C&E Secretary may allow the use of an alternative demonstration of mechanical integrity other than those described above. The following sections outline GCS' request to use an alternative demonstration of external mechanical integrity, the technical data supporting its use, and the alternative and supplemental test technologies available should a contingent method be required.

The specifications for the technologies proposed to collect formation evaluation and mechanical integrity data are provided in Appendix D-IV. Additional information about the external mechanical integrity testing performed prior to operations can be found in the Pre-Operational Testing Program (Attachment C).

7.2.1 Primary – Temperature Logging

GCS will perform a temperature log annually to demonstrate external integrity of the injection wells (LAC 43:XVII §3627.A.3.a-b).

Temperature logging is a critical method employed to demonstrate the external mechanical integrity of injection wells. This technique involves monitoring temperature profiles over time to detect any anomalies or changes that may indicate potential issues such as leaks, casing failures, or mechanical disruptions. Notable variations in temperature can reveal fluid movement outside the wellbore, raising concerns about the well's integrity and its impact on the surrounding environment.

Implementation

A baseline temperature survey will be acquired in MS CCS1 and MS CCS2 as part of the Preoperational Testing Program (Attachment C – Table C.2.2-1 and Table C.2.2-3). This profile represents the state of external integrity before injection commences.



Once injection commences, temperature logging will be conducted annually and compared to the baseline.

Procedure

Background information and procedures for temperature logging is provided in Appendix D-V.

Interpretation

By establishing initial baseline temperature conditions and systematically comparing subsequent readings, the well's performance can be effectively assessed, ensuring adherence to safety regulations. Significant deviations from the baseline temperature, such as unexpected spikes or drops, can signal fluid movement outside the wellbore and will be investigated further.

7.2.2 Alternative – DTS

In addition to the regulatory approved methods, GCS will conduct an alternative demonstration using Distributed Temperature Sensing (DTS) to corroborate the temperature logs. Once a sufficient validation of the data is made, GCS will submit a request to the C&E Secretary to utilize the alternative method for external MIT demonstration.

GCS will perform a DTS MIT at least once every 12 months to corroborate the data acquired from the Temperature log described in Section 7.2.1. DTS fiber optic cables will be installed along the long-strings of MS CCS 1 and MS CCS 2 to provide continuous external mechanical integrity monitoring of the wellbores. The DTS system monitors and records the well's temperature profiles at a pre-set frequency in real time.

DTS will detect temperature changes along the wellbore if external mechanical integrity is compromised. The DTS fiber will monitor temperature throughout and above the Confining Zone, and the configuration of DTS fiber as described above, from surface to total depth, is sufficient to monitor injection wells for external mechanical integrity above the Injection Zone. A continuous two-point calibration, using downhole pressure/temperature (P/T) gauges and wellhead temperature, will allow ongoing verification of DTS temperature measurements.

Implementation

Upon completion of MS CCS 1 and MS CCS 2 and prior to injection, a baseline temperature profile will be established. This profile represents the natural temperature gradient for each stratigraphic zone.

During the annual defined shut-in periods, the temperature profile along the length of the long-string will be compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile.

Procedure

The procedure for using the DTS for well mechanical integrity is as follows:



1. During injection operation, record the temperature profile for 6 hours prior to shutting in well.
2. Stop injection and record temperature profile for 6 hours.
3. Evaluate data to determine if additional cooling time is needed for interpretation.
4. Start injection and record temperature profile for 6 hours.
5. Interpret Data.

Interpretation

Once the in-situ temperature is determined along the wellbores of MS CCS 1 and MS CCS 2, temporal changes will be analyzed by comparing the new data to previously collected data. GCS will produce and interpret time-series graphs for each well, taking into consideration the injection rate and well location.

7.2.3 Supplemental

Per LAC 43:XVII §3627.A.4 and §3627.A.7, the C&E Secretary can request a casing inspection log and/or other supplemental alternative test to demonstrate external mechanical integrity.

7.2.3.1 Casing Inspection Log

A casing inspection log is a record of casing thickness and integrity. This log is used to determine whether or not the casing has undergone damage. The casing inspection log identifies and quantifies corrosion damage. It identifies scale, wax, solids accumulation, and location of mechanical damage. The procedures for running the logs and presentation of the results are set by the logging company. Because the standards adopted by the logging companies are appropriate, no additional information is provided for running casing inspection logs.

7.2.3.2 Cement Bond Log

A cement bond log provides an assessment of the cement quality radially as part of well integrity and for zonal isolation, particularly the radial distribution of cement behind the casing, the casing to cement bond (traditionally known as cement bond index) and cement to formation bond in the form a variable density log (VDL). Modern cement evaluation tools provide an assessment of the cement distribution behind the casing to properly evaluate the cement quality around the circumference of the casing.

7.2.3.3 Casing Collar Locator Log

A casing collar locator log is used to precisely determine the depth of casing collars, which acts as a key reference point for correlating other logging data (like pressure or temperature) to specific locations within the wellbore. When used with other logging technologies, it ensures accurate location of potential anomalies that are identified.



7.3 FREQUENCY

GCS will perform a demonstration of external mechanical integrity on each well using a method approved by the C&E Secretary at least once every 12 months until the injection wells are permanently plugged and abandoned.

7.4 NOTIFICATION

Per LAC 43.XVII §3617.B.6, GCS will notify C&E at least 72 hours prior to conducting wireline logs or integrity tests.

In the event that monitoring results indicate possible endangerment of the USDW, GCS will notify C&E and EPA within 24 hours of discovery of the compliance issue (LAC 43:XII §3629.A.3.a-e).

If there are any temperature anomalies that indicate a failure of well integrity (i.e. tubing leak or movement of fluid behind the casing), GCS will submit a Form UIC-17 Work Permit within 30 days of identification and propose to run a test approved by the C&E Secretary (Table D.7-1).

7.5 REPORTING

GCS will submit the results of the wireline logs and integrity tests to C&E and EPA within 30 days (or as specified by permit) (LAC 43:XVII §3629.A.1.b) and will include the results in the quarterly report for the period in which the testing took place per (LAC 43:XVII §3629.A.1.g).

8 RESERVOIR TESTING

Per LAC 43.XVII §3625.A.6, GCS will conduct reservoir testing by performing a pressure fall-off test throughout the operational life the injection wells.

Pressure fall-off tests help evaluate the integrity of the reservoir by monitoring how pressure decreases after the injection of CO₂ or other fluids. These tests provide valuable data on formation characteristics, such as permeability, porosity, and compressibility.

Additionally, the findings from pressure fall-off tests can be corroborated with other data sources, such as seismic surveys, to better understand the geometry and properties of the fault system. The use of the pressure fall-off result to characterize faults is presented in Section 10.1 (Fault Characterization).

8.1 TESTING LOCATION AND FREQUENCY

As described in the Pre-Operational Testing Plan (Attachment C), GCS will perform a pressure fall-off test followed by a step rate injectivity test in MS CCS 1 and MS CCS 2 prior to operation of as required by LAC 43.XVII §3617.B.5.

After injection commences, a pressure fall-off test will be conducted within ±45 days of the 5-year operational anniversary. Thereafter, a pressure fall-off test will be performed at least once every 5 years during the operational period to meet the requirements of LAC 43.XVII §3625.A.6.



8.2 TESTING DETAILS

Testing procedures will follow the methodology detailed in EPA Region 6 UIC Pressure Fall-off Testing Guideline-Third Revision (August 8, 2002) provided in Appendix D-VI.

8.3 NOTIFICATION

Per LAC 43.XVII §3617.B.6, GCS will notify C&E at least 72 hours prior to conducting reservoir testing.

In the event that testing results indicate possible endangerment of the USDW, GCS will notify C&E and EPA within 24 hours of discovery of the compliance issue (LAC 43:XII §3629.A.3.a-e).

8.4 REPORTING

Per LAC 43:XVII §3629.A.1.a, GCS will submit the results of the pressure fall-off test to C&E and EPA in the quarterly report for the period in which the testing took place.

9 INJECTION ZONE CARBON DIOXIDE PLUME AND PRESSURE EXTENT TRACKING

GCS will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of LAC 43.XVII §3625.A.7.

Table D.9-1 presents the direct and indirect monitoring methods GCS will employ and includes the target interval, technology, locations, objectives, and frequencies for each method.

The monitoring strategy will be implemented prior to commencement of injection and will be executed throughout the life of the project. GCS will assess new technologies as they are developed and reevaluate the plan to ensure that the best site-specific methods are employed.

9.1 IN-ZONE MONITORING WELL

In-Zone monitoring wells serve as a monitoring source for tracking the presence or absence of elevated pressure and/or CO₂ saturation within AoR. Since there are no artificial penetration within the AoR, therefore no potential pathways for fluid migration from the Injection Zone, GCS maintains that sufficient in-zone monitoring can be achieved without creating a potential pathway within the uncompromised AoR. The following section outlines how GCS proposes to conduct in-zone monitoring and the strategy for implementing it.

9.1.1 Well Location

GCS has identified Stream 34 Well No. 001 (SN 224951), an existing plugged and abandoned wellbore, as a viable candidate for conversion to an in-zone monitoring well. The bottomhole location is located outside of the AoR and approximately 0.75 miles north of the



Minerva South well pad (Figure D.6.1-1).

9.1.2 Conversion

As demonstrated in the conversion plan provided in Appendix D-VII, GCS proposes to convert Stream 34 Well No. 001 into Minerva South In-Zone Well No. 001 (MS IZ 1) and utilize it to track the presence or absence of CO₂ saturation within the Injection Zone and conduct microseismic monitoring of the adjacent faults.

GCS will convert MS IZ 1 to ensure external isolation of the Injection Zone and USDW and will run pre-operational cement bond and temperature logs to demonstrate integrity. The well will not be perforated, which will allow for streamlined monitoring operations and improve data acquisition of CO₂ plume monitoring (See Section 9.3.1.4, Pulsed Neutron Logging).

GCS will submit Form UIC-25 (or its replacement), Class V Well Application, to C&E to convert Stream 34 Well No. 001 to MS IZ 1. A detailed conversion plan along with the other required documents will be submitted for approval with the Class V application. Appendix D-VII will be updated with the permit, conversion procedure, and as-drilled schematic upon approval and completion.

GCS will phase the conversion on the in-zone monitoring well no later than one year after injection commences into MS CCS 1 and MS CCS 2.

9.1.3 Monitoring Activities

MS IZ 1 will be utilized to conduct monitoring of CO₂ saturation, microseismic events, and wellbore integrity, as outlined in Table D.9-2. Section 9.3.1.4 (Pulse Neutron Logging) provides details on the plume monitoring activities that will be performed utilizing MS IZ 1, and Section 10.2.1 (Microseismic Monitoring) describes the activities in place to monitor for microseismic events associated with injection-induced pressure.

Since MS IZ 1 is located outside of the delineated AoR, the external integrity of the wellbore should not be impacted by the effects of the CO₂ plume and pressure front. However, GCS will conduct cement bond and temperature logging to demonstrate this assumption. The logging schedule will follow the pulse neutron logging schedule, which is annually for the first four years, and every 2 years thereafter.

9.1.4 Operation

GCS will operate MS IZ 1 in accordance with the applicable testing and integrity requirements applicable to Class V monitoring wells.

9.2 DIRECT MONITORING

9.2.1 In Situ Fluid Pressure Monitoring

GCS will track the pressure influence within the Injection Zone using the injection wells themselves.



9.2.1.1 Implementation and Duration

GCS will complete the injection wells, MS CCS 1 and MS CCS 2, with downhole pressure and temperature gauges connected by an electric line to a transmitter at the surface. The gauge will continuously collect pressure readings (every 10 seconds) that can be read on the transmitter at the surface. Then the pressure data will be transmitted to a computerized control system that records, monitors, and controls injection processes.

Baseline reservoir pressure data will be collected prior to injection. Injection will commence in MS CCS 1 and MS CCS 2 in succession, allowing GCS to collect pressure monitoring data from the inactive or shut-in well. As the wells are both in operation, GCS will alternately shut-in the wells annually for mechanical integrity testing. During that time, GCS will collect pressure monitoring data from the shut-in well as the active well continues injection. This will allow GCS to history-match modeled near-well pressure influence within the Injection Zone through the operational life of the injection wells.

The baseline in-situ reservoir pressure within the Injection Zone will be established after the completion of MS CCS 1 and MS CCS 2. Once operation commences, reservoir pressure data will be collected from MS CCS 1 and MS CCS 2 during scheduled shut-ins and compared to the modeled predictions. If pressure increases greater than predicted by the current AoR model, or increases at a greater rate, it may indicate that the AoR model needs to be revised. In this case, GCS will consult with the C&E Secretary to determine whether an AoR reevaluation is necessary.

9.2.1.2 Frequency and Reporting

Pressure data collected from MS CCS 1 and MS CCS 2 during scheduled annual shut-ins will be reported in the quarterly report, along with a time-series graph depicting the annual trend over the life of the well.

9.3 INDIRECT MONITORING

Indirect monitoring methods are geophysical techniques used to infer and interpret changes in subsurface properties without direct access to a monitored reservoir. Unlike direct monitoring methods, indirect methods rely on detecting changes in physical properties such as seismic velocities, acoustic impedance, or electromagnetic characteristics. These changes often result from variations in fluid composition, pressure, temperature, or other factors within the subsurface. Indirect monitoring is particularly valuable in projects involving subsurface CO₂ storage, as it provides continuous and comprehensive monitoring capabilities over large areas and at various depths simultaneously.

The specifications for the proposed technologies used to conduct indirect plume monitoring are provided in Appendix D-VIII. The appendix will be updated with the final instrument selection should a different vendor be selected for construction.

9.3.1 Plume Monitoring Methods

Four indirect monitoring methods will be used to define the extent of the modeled plume for Project Minerva:



- Walk-Away Vertical Seismic Profile (WA VSP)
 - Surface sources arranged in lines intersecting MS CCS 1; wellbore fiber optic cable receiver (distributed acoustic sensing, DAS) in MS CCS 1
- 3D Distributed Acoustic Sensing Vertical Seismic Profile (3D DAS VSP)
 - Surface sources arranged in a grid array with wellbore fiber optic cable receiver (distributed acoustic sensing, DAS) in MS CCS 1
- 2D Seismic Survey
 - Surface sources and surface receivers arranged in lines intersecting MS CCS 1
- Wireline logging in MS IZ 1
 - Pulsed neutron (PN) logging

A seismic baseline will be acquired before injection begins using WA VSP, 3D DAS VSP, and 2D seismic surveys simultaneously. Once injection commences, WA VSP will serve as the primary plume monitoring method for at least 10 years (or until its coverage is surpassed by the leading edge of the plume) and will be supplemented, as necessary, with 3D DAS VSP and/or 2D seismic surveys. Rock physics and VSP feasibility studies were completed to confirm that indirect seismic monitoring of injected CO₂ will be effective at Project Minerva (Appendix D-IX and Appendix D-X).

The following sections provide details of each monitoring method and the rationale for the integrated monitoring program.

9.3.1.1 Walk Away Vertical Seismic Profile (WA VSP)

WA VSP is a seismic survey technique in which seismic receivers are placed inside a well, and a seismic source is progressively moved farther away from the well (“walked away”) in a linear or specific pattern (Figure D.9.3-1). GCS plans to utilize distributed acoustic sensing (DAS) technology to receive seismic signals (Appendix D-VIII), rather than discrete geophones. GCS will install the DAS fiber optic cable along the long-string of MS CCS 1. Vertical well design and DAS fiber optic cable was selected for MS CCS 1 to:

- Optimize the receiver-sensor signal
- Maximize vertical seismic resolution
- Maximize lateral seismic monitoring coverage

WA VSPs are particularly useful for monitoring CO₂ plumes in CCS projects because they provide high-resolution imaging, enabling detection of subtle changes in the subsurface over time. When a CO₂ plume migrates, it changes the rock’s properties, such as density and velocity. Repeated capture of WA VSPs over the life of the project allows the detection of these changes. This process is called time-lapse (4D) seismic monitoring and is a cost-efficient and effective tool.

The advantages that WA VSPs offer are the following:



- High sensitivity to changes near the wellbore – optimum method for tracking CO₂ plume fronts over time, in multiple completion intervals
- Ability to monitor complex geological structures like faults or stratigraphic traps
- Flexibility in implementation over time; acquisition layout, timing and frequency can easily be adapted to effectively track CO₂ in the subsurface
- Allows for focused monitoring, with the flexibility to adapt and decide whether a larger-scale 3D DAS VSP is necessary, optimizing both cost and data acquisition frequency
- Can be combined with 2D seismic lines – signals from the sources used in 2D seismic surveys can also be recorded by the DAS cable to capture a WA VSP

Acquisition Layout

When GCS conducts the baseline 3D DAS VSP survey (described in Section 9.2.1.2), it will provide a full 3D seismic snapshot of the subsurface at the time before CO₂ injection starts. This initial survey serves as a reference point for all subsequent WA VSPs.

GCS proposes to perform WA VSP surveys by placing the seismic sources along six seismic lines intersecting MS CCS 1 at 30-degree angles from each other (Figure D.9.3-2). This layout will detect CO₂ plume migration in multiple azimuthal directions, across all injection intervals within the Injection Zone.

Seismic sources will be progressively “walked away” (the lines will be extended) with each successive seismic shoot, as necessary, to ensure that the CO₂ plume is fully monitored. This will occur up to the coverage limit of the WA VSP. A VSP feasibility study indicates that fully coverage is possible up to at least the modeled 10-year CO₂ plume but may continue up to the 20-year modeled plume. Preoperational field testing will further refine the feasibility study outputs. Operational data will be critical in optimizing WA VSP acquisition layout.

Implementation

A DAS fiber optic cable will be cemented behind casing, down to the base of the long-string, and will act as the seismic receiver. A seismic source (typically a vibrator truck, an air-gun, or dynamite) will be moved/placed along surface locations on the six seismic lines surrounding the well. Signals will be received by the DAS fiber optic cable and processed into a WA VSP outputs for each seismic line.

GCS will optimize the implementation of WA VSPs throughout the life of the project as seismic data is collected, analyzed and used to improve the reservoir simulation model. Optimizations may include shortening or lengthening seismic lines in certain orientations, adding additional seismic lines or modifying the frequency of WA VSPs.

Processing

The WA VSP processing sequence can be summarized in key grouped steps as follows:

- **Data QC and Geometry Setup:** First, data quality is verified by ensuring proper signal



recording and geometry setup. Receiver and source locations are linked to well trajectories, ensuring accurate spatial information for processing.

- **Amplitude and Wavefield Processing:** An amplitude recovery function is normally applied to separate upgoing and down-going wavefields to focus on primary reflections. Furthermore, techniques like f-k filtering and deconvolution are used to isolate the key signals from noise and multiples.
- **First-Break Picking, Velocity Model, and Static corrections:** The first arrivals are picked to apply static corrections, which adjust for near-surface variations. These picks are also used to refine the velocity model, critical for time-to-depth conversion and further seismic imaging.
- **Migration and Stacking:** Once static corrections are applied, the data is migrated using techniques like Kirchhoff or Reverse Time Migration (RTM) to position reflectors accurately in the subsurface. RTM is a prestack two-way wave-equation migration for accurate imaging in and below areas with both great structural and velocity complexities. The method is based on directly solving the wave equation in the time domain (rather than the frequency domain). RTM can accurately handle any variation in subsurface material properties and has no limit in imaging steep dips. RTM is not based on ray tracing and hence can be performed in situations where Kirchhoff ray-based migration breaks down (Figure D.9.3-3). RTM has a proven track record for generating final images and is increasingly used for refining structural boundaries during velocity model building.
- **Final Imaging and Interpretation:** The final seismic image is generated and interpreted. Since the objective is for CO₂ monitoring, time-lapse comparisons may be made with baseline surveys to track changes in the subsurface, like the movement of the CO₂ plume based on amplitude changes (AVO/AVA).

This sequence ensures accurate subsurface imaging in depth and is particularly useful in dynamic monitoring situations like CO₂ sequestration.

Frequency

A WA VSP baseline will be recorded along the full length of all lines defined in Figure D.9.3-2, before injection begins.

The frequency of the WA VSP monitoring is planned as follows:

- **Year 0 through 5:** WA VSPs will be repeated at least 4 times along all seismic lines. The number of sources and length of the seismic lines will be designed to ensure full CO₂ plume coverage during this period. The 4th WA VSP will occur at year 4.5, to provide 6 months for acquisition, processing and integration prior to the required 5 year AoR reevaluation. If necessary, more frequent WA VSP monitoring may be carried out, or a 3D DAS VSP may be shot to provide more detailed coverage.
- **Year 5 through 10:** WA VSPs will be repeated at least once along all seismic lines. The number of sources and length of the seismic lines will be designed to ensure full



CO₂ plume coverage during this period. The WA VSP will occur at year 9.5, to provide 6 months for acquisition, processing and integration into the required 10 year AoR reevaluation. If necessary, more frequent WA VSP monitoring may be carried out, or a 3D DAS VSP may be shot to provide more detailed coverage.

- **Year 10 through Year 30:** WA VSPs will be repeated at least every 5 years, initiating 6 months before each subsequent 5-year reevaluation (to provide sufficient lead time for acquisition, processing and integration), until coverage is determined to be insufficient to monitor CO₂ migration across the full Injection Zone (currently estimated at between 10 and 20 years). After this, WA VSPs will be acquired concurrently with 2D seismic surveys every 5 years until the end of operations (~year 30). 2D seismic will extend coverage and WA VSPs will continue to provide high resolution CO₂ monitoring within the VSP coverage area.

Duration

Based on the reservoir simulation model prediction and the VSP feasibility study (Appendix D-IX), the WA VSP coverage is anticipated to be effective for an area consistent with at least the 10-year plume and potentially up to 20 years (Figure D.9.3-2). Beyond this period, the plume's dispersion and attenuation of seismic signals may reduce the effectiveness of VSP, necessitating complementary monitoring techniques or additional surveys. GCS anticipates using WA VSP as the primary monitoring method through year 10 of the project, and possibly longer, depending on the movement of the CO₂ within the proposed AoR.

Once the CO₂ plume has moved outside of the VSP coverage area, GCS will layer the WA VSP with a 2D seismic survey. While lower in resolution compared to the VSPs, the 2D seismic survey will provide broader coverage and will be essential in understanding the long-term migration of the CO₂ plume over a larger area. Repeating the 2D seismic lines will help detect any far-field plume migration that could potentially intersect faults or other structural features, providing an additional layer of assurance in containment. Once 2D seismic surveys are implemented along with WA VSPs as the primary plume monitoring method, they will be acquired every five years prior to the re-evaluation period through the operational life of the project.

Contingency

When significant anomalies or deviations from the expected CO₂ migration path are observed in the WA VSPs, it signals that a supplemental, more detailed monitoring survey may be needed. In such cases, GCS will perform a 3D DAS VSP survey which will provide a higher-resolution, full-volume view of the CO₂ plume, allowing for a precise re-evaluation of the plume's extent and behavior.

9.3.1.2 3D DAS VSP

A 3D DAS VSP is an advance borehole seismic survey technique used to create a three-dimensional high-resolution image of the subsurface around the well with higher vertical resolution than conventional 3D seismic data. In a traditional 3D VSP, seismic sources are positioned at various locations on the surface surrounding the well, and the seismic waves



generated by these sources are recorded by receivers placed inside the well at multiple depths (Figure D.9.3-4). In the 3D DAS VSP, the DAS fiber optic cable will be used as a dense array of acoustic receivers to capture the seismic data along the wellbore (Figure D.9.3-2). Acquiring a 3D DAS VSP for Project Minerva will result in enhanced spatial resolution, data coverage, and operational efficiency, enabling real-time, cost-effective, and comprehensive subsurface imaging.

MS CCS 1 will be equipped with DAS fiber optic cables along the length of the long-string casing. A VSP feasibility study was conducted for Project Minerva, which included ray-trace modelling (seismic technique used to simulate how seismic waves propagate through the subsurface). The study concluded that a VSP operated via MS CCS 1 will offer the highest quality and longest-range seismic coverage and that installing DAS along MS CCS 2 does not add any extra benefit to the monitoring program.

A technical report was prepared by Ikon Science detailing the technical workflow followed to understand the elastic changes in the surface that can be expected during sequestration, specifically focused on monitoring the CO₂ plume (Appendix D-X). The workflow details the rock physics model (including fluid substitution, forward modelling, and seismic feasibility studies), petro-elastic model, and a comprehensive breakdown for the baseline survey design, acquisition, processing and interpretation/analysis.

Acquisition Layout

The chosen seismic acquisition company will provide sources to cover an approximate area of 11.4 km² (~2,817 acres). Provisionally, the sources are planned to be placed on a 500 feet by 500 feet grid, totaling approximately 1,350 source points, each placed at 100 feet deep (Figure D.9.3-2). These parameters will result in a high spec 3D DAS VSP that can account for repeatability and is fit for 4D monitoring. Optimization and finalization of all parameters are subject to field testing to be carried out once MS CCS 1 has been constructed. The key steps in the acquisition layout are as follows:

- **Well Preparation and DAS Fiber Deployment:** The DAS fiber-optic cable will be installed the wellbore of MS CCS 1 from surface to a predetermined total depth (TD). This cable is permanently installed to ensure continuous seismic recording along the wellbore during the project's lifecycle.
- **Seismic Source Deployment:** Seismic sources will be deployed at carefully selected locations to ensure comprehensive coverage of the subsurface around the well, allowing for 3D imaging (Figure D.9.3-5).
- **Seismic Data Acquisition:** Once the seismic source is activated, the resulting seismic waves travel through the subsurface, reflecting off various geological layers before being recorded by the DAS system. The fiber-optic cable in the wellbore captures these reflected waves, providing a continuous and highly detailed seismic record along the well. DAS technology enables the recording of data at fine spatial intervals, typically every meter or less, along the wellbore.
- **3D Coverage and Azimuthal Sampling:** The strategic placement of seismic sources



around the well ensures that the subsurface is illuminated from multiple angles and azimuths. This multi-azimuthal coverage is crucial for creating a comprehensive 3D image of the subsurface, capturing variations in geological structures and fluid distributions that may not be visible with a single azimuth.

Implementation

The implementation begins with the deployment of the DAS optic fiber cable, which will be integrated with the well completion equipment for MS CCS 1. Once the cable is placed, a seismic source will be moved/placed in multiple surface locations in a grid pattern surrounding the well. Source type will be specified during field testing, after MS CCS 1 has been constructed. Sources will be selected to optimize seismic imaging and minimize surface impact.

The seismic signals generated by the source will be recorded by the DAS system as they travel through the subsurface and reflect off geological formations, including the CO₂ plume. The fiber optic cable will capture the strain induced by the passing of seismic waves, which will then be converted into seismic data. The recorded data provides a detailed 3D image of the subsurface, allowing for the monitoring of the CO₂ plume's size, shape, and migration over time.

GCS will optimize the implementation of the 3D VSP once a preoperational field study is completed and throughout the life of the project as seismic data is collected, analyzed and used to improve the reservoir simulation model. Optimizations may include modifications to the number, layout and type of source.

Processing

Once the 3D DAS VSP data is acquired, it will undergo a series of processing steps to convert the raw seismic recordings into usable subsurface images. The processing workflow typically includes the following steps:

- **Data Pre-processing:** The initial step involves quality control and pre-processing of the raw DAS data. Noise reduction techniques are applied to remove unwanted signals, such as ambient noise and instrument-related artifacts. Deconvolution is then performed to eliminate the source signature, enhancing the resolution of the seismic data.
- **Wavefield Separation:** The DAS VSP data includes both upgoing and down-going seismic waves. Wavefield separation is performed to isolate the upgoing waves, which are used for subsurface imaging. This step also involves the removal of multiples and other types of coherent noise that could interfere with the interpretation of the seismic signal.
- **Velocity Model Building:** Accurate imaging of the subsurface requires a detailed velocity model, which is derived from the direct arrivals (down-going waves) recorded by the DAS system. This velocity model is essential for time-to-depth conversion and ensures that the seismic reflections are accurately positioned within the subsurface.



- **Imaging and Migration:** The processed DAS VSP data will be migrated to create a 3D image of the subsurface. Migration algorithms correct for the effects of dipping layers and complex geological structures, relocating seismic events to their true spatial positions. This process results in a higher-resolution 3D images that accurately reflect the subsurface geology.
- **Amplitude Preservation and AVO/AVA Analysis:** Throughout the processing workflow, care is taken to preserve the true amplitude of the seismic reflections. This is particularly important for AVO/AVA analysis, where changes in reflection amplitude with offset or angle provide insights into the rock properties and fluid content within the reservoir.
- **Final Data Interpretation:** The processed 3D DAS VSP data is then ready for interpretation. 3D images undergo a full geophysical analysis to identify geological features, monitor fluid movements, and assess the effectiveness of reservoir management strategies. The high resolution and azimuthal coverage of 3D DAS VSP data make it a powerful tool for detailed subsurface characterization and monitoring.

This comprehensive workflow ensures that the 3D DAS VSP data is accurately processed and interpreted, providing valuable insights into the subsurface for applications such as CO₂ storage monitoring, reservoir characterization, and enhanced oil recovery.

Frequency

The initial 3D DAS VSP baseline survey will be conducted before CO₂ injection begins, establishing a reference state of the subsurface. Subsequent 3D DAS VSP surveys will be implemented if the other indirect monitoring techniques (WA VSP and 2D seismic) do not offer the information needed to track the plume. Any necessary surveys will be acquired at least 6 months prior to re-evaluation deadlines (year 5 and 10).

Duration

Based on the reservoir simulation model prediction and the VSP feasibility study (Appendix D-IX), the 3D DAS VSP coverage is anticipated to be effective for up to at least 10 years after injection commences, and possibly up to 20 years (Figure D.9.3-2). Beyond this period, the plume's dispersion and attenuation of seismic signals may reduce the effectiveness of the 3D DAS VSP, necessitating complementary monitoring techniques or additional surveys.

Contingency

When significant anomalies or deviations from the expected CO₂ migration path are observed outside of the coverage area of the 3D DAS VSPs, a 2D seismic survey will be initiated to track the plume beyond the extent of coverage.

9.3.1.3 2D Seismic Survey

Surveys along six conventional 2D seismic lines will be acquired at various times throughout the injection period of Project Minerva. These lines are designed in a star pattern, radiating outward from MS CCS 1, with each line spaced 30 degrees apart (Figure D.9.3-2). This configuration ensures comprehensive 360-degree coverage, allowing for thorough



monitoring of the CO₂ plume's migration and distribution across the AoR. The length of the lines varies based on the shape of the modeled plume and may be optimized over the life of the project, as necessary.

2D seismic monitoring has been selected as it has a relatively low impact on the surface, as compared to 3D seismic surveys, or VSP networks requiring additional wells in wetland areas.

In the context of monitoring the CO₂ plume for the Project Minerva, especially when combined with a central VSP, acquiring 2D seismic lines can offer significant advantages. While the VSPs around the well will provide detailed imaging around the wellbore, the 2D seismic lines will complement this data by offering focused insights along specific azimuths. The following points outline some of the key reasons why GCS decided to acquire conventional 2D seismic data as part of the integrated CO₂ monitoring program:

- **Complementary coverage and enhanced imaging:** Seismic lines arranged in a star pattern intersecting at MS CCS 1, provide focused imaging along specific azimuths and will complement any VSP survey acquired by offering insight along key directions.
- **Cost-effectiveness:** 2D seismic has a lower acquisition cost compared to other remote sensing techniques; however, it also brings advantages such as less time and resources for acquisition, lower long-term cost, especially for ongoing monitoring programs where multiple surveys might be needed over time.
- **Flexibility and rapid deployment:** 2D seismic surveys can be more quickly designed, acquired, and processed compared to other seismic surveys such as 3Ds. This allows GCS to have the capacity for rapid responses to unexpected changes in the CO₂ plume or other subsurface conditions.
- **Simpler data processing and interpretation:** Processing 2D seismic data is generally less complex and less computationally demanding than 3D seismic data. This can lead to faster turnaround times for interpretation and decision-making. Furthermore, the simplicity of 2D seismic lines allows for a straightforward interpretation of specific geological features.
- **Lower surface impact:** Protection of wetland environments is a key priority.

Acquisition Layout

The six 2D seismic lines will be designed in a star-shaped arrangement, radiating outward, from MS CCS 1 with approximately 3,000 source points, each one at a depth of 100 feet. The appropriate number and layout of surface receivers will be determined in field testing. Each line will be spaced 30 degrees apart, covering the full 360-degrees around the well. This symmetrical distribution ensures complete azimuthal coverage, allowing for detailed imaging of the subsurface across multiple directions. This layout is particularly important for capturing potential anisotropies in the reservoir and detecting any lateral variations in the CO₂ plume. The acquisition layout consists of the following main steps:



- **Layout design:** The survey consists of six 2D seismic lines arranged in a star pattern, radiating outward from MS CCS 1 and spaced 30 degrees apart (Figure D.9.3-2). This configuration provides comprehensive 360-degree coverage around the well, ensuring thorough subsurface imaging. The lines vary in length between 4 and 6 miles based on the shape of the modeled plume and any potential risk areas.
- **Source and receiver positioning:** Detailed planning was undertaken to determine the optimal placement of seismic sources and receivers along each line. The length of the lines and the spacing of the sources/receivers are carefully designed to achieve the desired subsurface resolution and coverage. However, field tests are needed to fine tune the final acquisition parameters.
- **Deployment of seismic sources:** Mobilize seismic source equipment such as vibrators, dynamite, or air-guns, depending on the specific requirements of the survey area and environmental considerations. For Project Minerva, vibrators won't be an option due to surface conditions (wetlands), therefore, different type of sources will be tested in the field following the state's regulations.
- **Seismic data acquisition:** Seismic sources along the 6 lines are activated either sequentially or simultaneously, depending on the acquisition strategy defined in the field. The generated seismic waves travel through the subsurface and reflect off geological layers. As the seismic waves are reflected back to the surface, they are recorded by the receivers positioned along the 2D seismic lines. This process is repeated along all six lines to gather comprehensive data on the subsurface structures.
- **Quality control and monitoring:** Conduct real-time quality control to ensure that the recorded data meets the required standards. This involves monitoring signal strength, noise levels, and other key parameters.
- **Demobilization:** Once data acquisition is complete, retrieve all seismic sources and receivers from the field. Conduct site restoration to minimize any environmental impact from the survey activities, returning the area to its pre-survey condition.

Implementation

GCS will implement the survey with precise positioning of seismic sources along each of the six 2D seismic lines. The sources will sequentially activated/detonated at multiple predetermined points along each line. The seismic waves generated by the sources travel through the subsurface, reflecting off geological layers, and are captured by the surface receivers placed along the conceptual lines. The data acquisition process is carefully synchronized to ensure that each source activation and subsequent data recording are accurately time-stamped, facilitating high-quality data processing.

GCS will optimize the implementation of 2D seismic throughout the life of the project as seismic data is collected, analyzed and used to improve the reservoir simulation model. Optimizations may include shortening or lengthening seismic lines in certain orientations, adding additional seismic lines or modifying the frequency of 2D seismic acquisition.



Processing

The processing of data acquired from the six 2D lines around MS CCS 1 is a crucial step in transforming raw seismic data into actionable insights. This process aims to generate high-resolution images of the subsurface, enabling detailed monitoring of the CO₂ plume's migration and distribution within the reservoir. A standard processing sequence involves the following steps:

- **Data pre-processing:** Perform initial quality control checks and apply noise reduction techniques to clean up the raw seismic data. This step is crucial for enhancing the clarity of the recorded signals. Apply deconvolution to remove the source signature and improve the resolution of the seismic data. This helps in distinguishing between different subsurface features.
- **Velocity analysis and model building:** Use recorded seismic data to build an accurate velocity model of the subsurface. This model is essential for converting seismic travel times to depth, which is crucial for accurate subsurface imaging. Use the velocity model to convert the seismic data from the time domain to the depth domain, aligning the seismic reflections with their true subsurface positions.
- **Imaging and stacking:** Sort the seismic data into common midpoint gathers, where traces that share the same subsurface reflection point are aligned. This process enhances signal quality by improving the coherence of reflections. Follow by stacking the sorted data to enhance signal strength and suppress noise. This step is crucial for generating a clearer and more reliable image of the subsurface structures. Finish by applying migration algorithms to correct for the effects of dipping layers and other complex subsurface structures. Migration relocates seismic events to their true spatial positions, resulting in a more accurate subsurface image.
- **Amplitude preservation and analysis:** Ensure that true seismic amplitudes are preserved throughout the processing steps. This is particularly important for AVO/AVA analysis, which relies on accurate amplitude information to interpret changes in subsurface rock properties and fluid content.
- **Final imaging and interpretation:** Generate final seismic images from the processed data. These images will be used for detailed interpretation of the subsurface, including the identification of geological features and monitoring changes in the reservoir.

Frequency

The initial 2D surveys will be conducted as part of the baseline data collection before CO₂ injection begins but after the injector well has been drilled. This baseline serves as a reference for subsequent monitoring surveys.

2D seismic surveys will be implemented once CO₂ migration moves outside of the VSP coverage. Once this occurs, surveys will be shot at least every 5 years during the testing and monitoring period. The surveys will be acquired at least 6 months prior to re-evaluation deadlines.



Duration

After the CO₂ plume leaves the VSP coverage area, 2D seismic surveys will be used as the primary monitoring method. GCS anticipates this will begin 10 to 20 years after injection commences and will continue through the operational life of the project.

As discussed in Section 9.2.2 (Integrated Plume Monitoring Program), the implementation plan has been designed to be flexible, allowing for adjustments in survey frequency and scope based on real-time data and evolving site conditions.

Contingency

If there are significant anomalies or deviations of the CO₂ migration path that cannot be resolved using 2D seismic surveys, GCS will explore alternate technologies to track the plume.

9.3.1.4 Pulsed Neutron Logging

GCS will utilize Pulsed Neutron (PN) logging to monitor CO₂ saturation changes in subsurface reservoirs. A down-hole tool is used to produce PN logs, whose primary output is the “Sigma” curve. The tool distinguishes fluids based on neutron capture rates. CO₂-rich zones exhibit distinct behavior due to their large Sigma contrast with saline formation waters. The specifications for the PN logging tool is provided in Appendix D-VIII.

In addition to the Sigma curve, PN logs provide a secondary measurement—the hydrogen index ratio (Ratio) obtained from gamma-ray counts (Kennedy, Dance, Hawkes, Lenuik, & Nickel, 2018). The Ratio can be used to determine the suitability of the Sigma curve for monitoring CO₂ movement. The Ratio shows slightly better repeatability than the Sigma curve and will be used to monitor CO₂ saturation changes (Kennedy, Dance, Hawkes, Lenuik, & Nickel, 2018).

The neutron response from the PN log is more representative of the in-situ conditions when the wellbore is unperforated, which is crucial for assessing the saturation and porosity of the formation where CO₂ is stored. As described in Section 9.1 (In-Zone Monitoring Well), MS IZ 1 will remain unperforated to enhance the accuracy and reliability of data.

Implementation

GSC will conduct time-lapsed PN logging at MS IZ 1 to monitor for CO₂ saturation throughout the Injection Zone. Since MS IZ 1 is located outside of the modeled stabilized CO₂ plume, GCS will be able to monitor the gas saturation outside of the AoR and validate model assumptions.

Interpretation

As measured CO₂ saturation data is collected at MS IZ 1, it will be compared to the predicted data from the model. As appropriate, re-evaluation of the model, or further investigation of the downhole conditions will be performed to ensure that no major deviation from the expected behavior of the plume front is experienced.



Frequency and During

PN logging of MS IZ 1 will be conducted annually for the first four years, and every two years thereafter through the operational life of Project Minerva.

9.3.2 Integrated Plume Monitoring Program

The proposed monitoring program aims to combine WA VSP, 3D DAS VSP, and 2D seismic surveys to track CO₂ plume movement over the life of Project Minerva. The three seismic techniques chosen, complemented by advanced analytical approaches such as AVO/AVA and seismic inversions, will provide a comprehensive framework for understanding the plume's behavior in real-time and ensuring containment within the storage formation.

Initial Baseline Survey Integration

WA VSP, 3D DAS VSP, and 2D seismic surveys will be acquired simultaneously as part of the baseline before injection begins. This baseline dataset will serve as a crucial reference for detecting changes in the subsurface over time.

WA VSPs, recorded in the same direction as the 2D seismic survey lines, will provide mid-range imaging that bridges the gap between the near-well and regional coverage. By taking advantage of the DAS fiber in MS CCS 1, these VSPs can deliver time-lapse imaging in specific directions of interest at a relatively low cost.

The 3D DAS VSP will provide high-resolution, near-wellbore imaging, allowing for detailed characterization of geological features close to the injection well. This method will capture the initial geometry of key structural elements such as faults and stratigraphic layers, setting a reliable benchmark for subsequent monitoring.

2D seismic survey acquired along lines in a star pattern will provide regional coverage away from the well, offering insights into the broader subsurface structure, in particular after VSP coverage is no longer sufficient.

Role of AVO/AVA and Inversions in Integration

AVO/AVA analysis will be used to extract amplitude variations with offset and/or angle, which are highly sensitive to changes in fluid content, porosity, and lithology. AVO attributes can help distinguish between the CO₂ plume and the surrounding brine-saturated rock, making them a critical tool for monitoring the plume's evolution. This technique can be applied to both WA VSPs and 2D seismic surveys to detect fluid movement away from the wellbore.

Inversion techniques will be employed to convert seismic data into physical property models, such as acoustic impedance and shear impedance. Inversions will be particularly valuable in identifying subtle changes in reservoir properties caused by CO₂ injection. By applying inversion to both the 3D DAS VSP and 2D seismic data, the results will help track changes in the reservoir and identify zones of potential leakage or migration pathways, particularly around faults.

Elastic and rock physics inversions will also be key in interpreting WA VSPs, which will likely be shot more frequently due to their cost-effectiveness. These inversions can help quantify



changes in the elastic properties of the subsurface over time, providing critical information on how the CO₂ is behaving Appendix D-X.

Temporal Monitoring and Walk-Away VSP as the Primary Tool

After the baseline acquisition, the WA VSPs will be the primary monitoring method. At the 5-year re-evaluation period, GCS will reassess the frequency of WA VSP acquisition and as the plume migrates towards the extent of the usable coverage area.

The WA VSPs will provide time-lapse data, which will be compared against the baseline to track changes in the plume and assess containment.

Reshooting the 3D VSP: Decision-Making Based on Walk-Away VSP Results

If the WA VSPs indicate unexpected CO₂ migration or potential leakage pathways GCS may decide to reshoot the 3D VSP for higher-resolution imaging. A 3D VSP reshoot would provide a more detailed update on the near-wellbore region and clarify areas of concern.

Post Year 10 Monitoring with Walk-Away VSPs and 2D Seismic Surveys

The VSP coverage area is anticipated to be effective through at least year 10 of the project. Currently, the 3D DAS VSP coverage area is consistent with the modeled plume at year 10 (Figure D.9.3-2). Outside of this coverage area, the VSP will no longer be as effective due to its limited repeatability and capacity. At this point, the WA VSP layered with a 2D seismic survey will become the primary monitoring tools for tracking the plume. While lower in resolution compared to the 3D DAS VSPs, the 2D lines will provide broader coverage and will be essential in understanding the long-term migration of the CO₂ plume over a larger area. Repeating the 2D seismic lines will help detect any far-field plume migration that could potentially intersect faults or other structural features, providing an additional layer of assurance in containment. Once 2D seismic surveys are implemented along with WA VSPs as the primary plume monitoring methods, they will be acquired every five years prior to the re-evaluation period through the operational life of the project.

Complementary Value of Each Method

The 3D DAS VSP offers high-resolution imaging around the well, capturing fine details of the reservoir and faults. The 2D seismic lines offer broader regional coverage, making them valuable for detecting long-range plume migration. The WA VSPs combine mid-range resolution and cost-efficiency, allowing for frequent monitoring in key directions.

By integrating these methods and applying advanced interpretation techniques, the monitoring program will ensure effective tracking of the CO₂ plume, with flexibility in decision-making based on real-time data.

9.4 NOTIFICATION

Per LAC 43.XVII §3617.B.6, GCS will notify C&E at least 72 hours prior to conducting the PN logging in MS IZ 1.



In the event that monitoring results indicate possible endangerment of the USDW, GCS will notify C&E and EPA within 24 hours of discovery of the compliance issue (LAC 43:XII §3629.A.3.a-e).

9.5 REPORTING

Per LAC 43:XVII §3629.A.1.a, GCS will report the results of the proposed direct and indirect monitoring events in the quarterly report submitted to C&E and EPA. Direct results will be submitted in the quarterly report for the period in which the monitoring took place. Due to the post-processing time associated with the proposed indirect methods, results will be submitted in the quarterly report following the period in which the monitoring took place.



10 FAULT CHARACTERIZATION AND SURVEILLANCE

In order to further characterize and survey the nearest fault in the proximity of Project Minerva's injection wells, GCS has developed a methodology using reservoir testing and seismic monitoring. Table D.10-1 presents the testing and monitoring methods GCS will employ and includes the testing, instrumentation, locations, frequencies, and objectives for each method.

10.1 FAULT CHARACTERIZATION

As discussed in Section 8 (Reservoir Testing), GCS will conduct reservoir testing prior to injection and during the operational life of the injection wells. Along with helping to understand the characteristics of the injection reservoir, the results of these tests will be used to help characterize the faults adjacent to the proposed injection wells.

Description

Pressure fall-off tests monitor how pressure declines over time after injection stops. The rate and pattern of pressure decline can indicate reservoir boundaries, barriers, or connectivity. Along with monitoring the operational health of the injection interval, the test can determine if fluid is escaping through a fault, or if the fault is acting as a seal, trapping pressure within the Injection Zone. The test will also indicate if the fault behaves as a no-flow boundary or a transmissive feature.

Frequency

After injection commences, a pressure fall-off test will be performed at least once every 5 years during the operational period as required by LAC 43.XVII §3625.A.6.

Procedure

Testing procedures will follow the methodology detailed in EPA Region 6 UIC Pressure Fall-off Testing Guideline-Third Revision (August 8, 2002) provided in Appendix D-VI.

Reporting

Per LAC 43:XVII §3629.A.1.a, GCS will submit the results of the pressure fall-off test to C&E and EPA in the quarterly report for the period in which the testing took place.

10.2 SEISMIC SURVEILLANCE

GCS will implement a seismic surveillance program utilizing microseismic and seismic technologies to monitor any seismic responses that may be related to injection activities. This integrated approach aims to provide crucial insights into subsurface conditions and fault dynamics in the project's vicinity, ensuring the effective containment of the CO₂ plume.



10.2.1 Microseismic Monitoring

GCS will utilize DAS technology combined with downhole geophones or accelerometers to gather valuable insights into subsurface conditions and fault activity adjacent to Project Minerva.

Components of the Monitoring System

Integrating both DAS and Geophone/Accelerometer as a monitoring strategy allows for high sensitivity and spatial resolution, comprehensive monitoring, and enhanced safety and risk management. DAS provides fine spatial resolution over long distances, while downhole geophones/accelerometers offer high sensitivity to local seismic events. The integration of these technologies allows for both regional and localized monitoring of fault activity, providing a more robust assessment of the geological setting. Continuous monitoring can help identify potential hazards early, ensuring the integrity of the CCS project and the safety of surrounding communities.

Distributed Acoustic Sensing (DAS)

GCS proposes utilizing DAS fiber-optic cable installed along MS CCS 1, located south of the nearest fault, to detect and measure acoustic signals. It converts the backscattered light from the fiber into high-resolution data on vibration and strain, allowing for the continuous monitoring of subsurface activities. The DAS system can cover long distances, making it an effective tool for large-scale monitoring of faults and geological formations.

During CO₂ injection, the DAS system will continuously record acoustic signals from the injection well. These signals can indicate changes in pressure, fluid flow, and microseismic events associated with the injection process. Changes in the acoustic response of the surrounding rocks can reveal stress changes caused by CO₂ injection, as well as any induced seismicity or fault activation.

By analyzing the acoustic data captured by DAS, it is possible to identify anomalies or changes in the patterns of seismic waves, indicating the potential movement or slippage along faults.

Downhole Geophones and Accelerometers

Downhole geophones and accelerometers will be installed in MS IZ 1, located north of the nearest fault. Geophones convert ground motion into electrical signals, while accelerometers measure the acceleration of the ground. The placement of these sensors allows for localized monitoring of seismic activity and fault movement in the surrounding geological formations.

The downhole geophones and accelerometers provide supplementary data by capturing local seismic events and ground motion that may not be detected by DAS alone. This information helps to establish a more comprehensive understanding of fault dynamics.

GCS has not selected the technology that will be installed in MS IZ 1; however, the specification sheet of an example technology is provided in Appendix D-VIII. When GCS is prepared to convert Stream 34 Well No. 001 to MS IZ 1, a detailed conversion plan along with



the other required documents will be submitted for approval with the Class V application. This will include the proposed technology that will be installed in MS IZ 1 to monitor microseismic activity.

Monitoring Process

Pre-Injection Baseline Survey

For the baseline data collection, data will be collected continuously for a minimum duration of 48 to 72 hours, or longer if geological conditions necessitate.

The sampling frequency will be set according to the expected range of microseismic events, typically between 100 and 1000 Hz. During this collection period, it is crucial to ensure that all sensors are functioning correctly. Real-time monitoring of the data will be implemented to identify and rectify any potential sensor faults or environmental noise, with periodic calibrations performed to maintain accuracy.

Following the data collection, the gathered baseline data will be analyzed to establish a reference for background noise levels and microseismic activity. Comprehensive baseline reports will be generated, detailing the characteristics of recorded seismic events, noise levels, and the performance of the sensors, providing essential insights for future operations.

Operational Monitoring

During the injection process, continuous collection of microseismic data will be conducted while maintaining the same sampling rate established during the baseline survey. To enhance data quality, appropriate filtering and noise cancellation techniques will be employed. Real-time monitoring of the data will be critical for identifying significant seismic events or anomalies that may indicate changes in stress distribution or unexpected fluid migration.

Regular data quality checks will be implemented at intervals to address any potential sensor malfunctions or environmental noise. Furthermore, thresholds for event triggering will be established based on the baseline data, allowing for immediate analysis of any detected microseismic events.

Data Processing

The recorded data will be processed and analyzed to filter out noise and identify significant seismic events. Techniques such as time-frequency analysis and spectral analysis may be applied to extract meaningful information. By comparing the spatial and temporal characteristics of the recorded signals, the geological features and potential fault lines are mapped to give a clearer picture of the subsurface environment. Advanced data processing and interpretation techniques, such as machine learning and statistical analysis, will be applied to assess the relationship between CO₂ injection and fault movements, as well as to predict future fault behavior.

10.2.2 Seismic Monitoring

As described in Section 9.3 (Indirect Monitoring), GCS will employ seismic technologies,



such as Vertical Seismic Profiling (VSP), Walk Away VSP, and 2D seismic surveys, to monitor plume movement throughout the Injection Zone. In addition to monitoring the extent of plume movement within the Injection Zone, these seismic technologies can provide additional clarity on the structure of the faults and identify any potential pathways for fluid migration. Collecting surveys before and after CCS activities allow for the assessment of any alterations or deformations in the fault structure, ensuring proactive management of potential risks.

3D DAS VSP and 2D seismic surveys will be performed as a baseline examination to acquire high-resolution images of the subsurface structures, including faults. This data will be used to validate the dip and strike angles interpreted from existing 3D seismic data. This detailed imaging allows for the identification and characterization of fault lines and potential pathways for vertical fluid migration from the Injection Zone.

Walk-Away VSP and 2D seismic surveys will be performed during the injection phase. By creating a profile of the subsurface using seismic wave data collected along a linear survey line, GCS will gather valuable insights into the broader geological framework, including regional fault systems and sedimentary structures afield from the injection site. By assessing seismic reflection data before and after CO₂ injection commences, changes in the seismic response can indicate whether CO₂ is migrating outside the intended Injection Zone along faults.

The seismic monitoring frequency is described in Table D.9-1 and the notification and reporting protocol is described in Sections 9.4 and 9.5, respectively.

10.2.3 Notification

The monitoring system will be configured for real-time analysis, allowing for immediate detection of any significant seismic activity related to fault movements. In case of detected anomalies, alerts will be generated to notify GCS, enabling timely interventions to mitigate risks associated with fault slip or unexpected seismic events.

In the event that monitoring results indicate possible endangerment of the USDW, GCS will notify C&E and EPA within 24 hours of discovery of the compliance issue (LAC 43:XII §3629.A.3.a-e).

10.2.4 Reporting

Per LAC 43:XVII §3629.A.1.a, GCS will submit the results of seismic surveillance to C&E and EPA in the quarterly report for the period in which the seismic monitoring event took place (see Section 9.5).



11 REFERENCES

Kennedy, M., Dance, T., Hawkes, C., Lenuik, A., & Nickel, E. (2018). Interpreting CO₂ Saturation Changes from Pulsed Neutron Logs at the Aquistore Site. *GHGT-14*. Melbourne, Australia.