TESTING AND MONITORING PLAN
LAC 43:XVII.3625

Magnolia Sequestration Project

1.0 Facility Information

Facility name:	Magnolia Sequestration Project (Magnolia Hub) Magnolia CCS 1, Magnolia CCS 2, Magnolia CCS 3, and Magnolia CCS 4 Wells
Facility contact:	Kelly Watson, Project Manager 5 Greenway Plaza Houston, TX 77046 713-552-8613 kelly_watson@oxy.com
Well location:	Allen Parish, Louisiana Magnolia CCS 1 30° 40' 56.2474" N, 092° 50' 1.2244" W (NAD 27) 30° 40' 56.9387" N, 092° 50' 1.7707" W (NAD 83) Magnolia CCS 2 30° 41' 40.1623"N, 092° 50' 23.1767"W (NAD 27) 30° 41' 40.8527" N, 092° 50' 23.7241" W (NAD 83) Magnolia CCS 3 30° 41' 6.1794" N, 092° 50' 24.1145" W (NAD 27) 30° 41' 6.8705" N, 092° 50' 24.6617" W (NAD 83) Magnolia CCS 4 30° 41' 38.4597" N, 092° 50' 23.1814" W (NAD 27) 30° 40' 39.1501" N, 092° 50' 23.7288" W (NAD 83)

This Testing and Monitoring Plan describes how Magnolia Sequestration Hub, LLC, will monitor the Magnolia Sequestration Project (the Project) site pursuant to LAC 43:XVII.3625. In addition to demonstrating that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs, the monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO_2 within the storage zone to support Area of Review (AoR) reevaluations and a non-endangerment demonstration.

2.0 Overall Strategy and Approach for Testing and Monitoring

The monitoring well network is designed to detect unforeseen CO_2 and/or brine leakage out of the injection zone that could endanger the USDW, migrate to a different stratum, or create a risk to human health or the environment. There are several components that integrate the master monitoring plan for the Magnolia Sequestration Hub, which are classified in the following categories:

1. Operational Testing and Monitoring During Injection
2. Mechanical Integrity Testing
3. Ground Water Quality and Geochemical Monitoring
4. Carbon Dioxide Plume and Pressure Front Tracking
5. Near surface and Surface monitoring
6. Induced Seismicity

Table TM-1 shows a summary of the different methods proposed to monitor the proposed AoR, tailored based on the qualitative risk assessment that was also used to inform the Emergency and Remedial Response Plan. The Testing and Monitoring plan is designed to monitor the CO_2 plume and pressure front from the four CO_2 injector wells proposed at the Magnolia Sequestration Hub, Magnolia CCS 1, Magnolia CCS 2, Magnolia CCS 3, and Magnolia CCS 4.

Table TM-1—Summary Table for Magnolia CCS 1, 2, 3, & 4 Testing and Monitoring Plan

Ct	Description	Method	Location	Pre	Injection Period	Requirement
1	Operational testing and monitoring during injection.	Carbon Dioxide Stream Analysis.	Sampling point upstream CO_2 Injector wells		Quarterly	LAC 43:XVII.3625(A)(1)
		Measurement of injection pressure and temperature on surface - surface transducers	Flow line of CO_2 Injector wells		Continuously	LAC 43:XVII.3621(A)(6)(a) through (A)(6)(a)(iv) LAC 43:XVII.3625(A)(2) LAC 43:XVII.3627(A)(2) through (A)(2)(b)
		Measurement of casing-tubing annular pressure in surface- surface transducers	Wellhead of CO_2 Injector wells		Continuously	LAC 43:XVII.3621(A)(6)(a) through (A)(6)(a)(iv) LAC 43:XVII.3625(A)(2) LAC 43:XVII.3627(A)(2) through (A)(2)(b)
		Measurement of rate and injection volume in surface - Coriolis flow meter	Flow Line CO_2 Injector wells		Continuously	LAC 43:XVII.3621(A)(6)(a) through (A)(6)(a)(iv) LAC 43:XVII.3625(A)(2) LAC 43:XVII.3627(A)(2) through (A)(2)(b)
		Measurement of casing-tubing annular pressure above packer- downhole gauges	Downhole CO_2 Injector wells		Continuously	LAC 43:XVII.3627(A)(2) through (A)(2)(b)
		Measurement of pressure and temperature at top of the perforations - downhole gauges	Downhole CO_2 Injector Wells		Continuously	LAC 43:XVII.3621(A)(6)(a) through (A)(6)(a)(iv) LAC 43:XVII.3621(A)(1)
		Automatic surface shut off devices.	Flow Line CO_2 Injector Wells		Continuously	LAC 43:XVII.3621(A)(7)(a)(i)
		Corrosion coupons analysis.	Upstream CO_2 Injector Wells		Quarterly	LAC 43:XVII.3625(A)(3)(a)
		Pressure Fall Off test	CO_2 Injector Well	x	Every 5 years	LAC 43:XVII.3625(A)(6)
		Measurements of tubing pressure and temperature on surface- Surface transducers	Wellhead of MLR and ACZ wells		Continuously	
		Measurement of casing-annular pressure on surface - Surface transducers	Wellhead MLR and ACZ wells		Continuously	
		Visual inspections and handheld monitors (LEL, H_2S, CO_2)	General facilities	x	Weekly	
		Leak detection and repair (LDAR) program using Optical Gas Imaging cameras , handheld during inspections	General facilities		Quarterly	

Notes:

1) "X" in the Pre column indicates that a baseline study is to be conducted in the pre-injection phase of the project.
2) MLR (Multi-Layer Reservoir) and ACZ (Above Confining Zone) are types of project monitoring wells included in the testing and monitoring plan

Table TM-1— Summary Table for Magnolia CCS 1 and Magnolia CCS 2 Testing and Monitoring Plan (continued)

Ct	Description	Method	Location	Pre	Injection Period	Requirement
2	Mechanical Integrity testing.	Ultrasonic cement evaluation , CBL, VDL	CO2 injector wells	x		LAC 43XVII.3617.(B)(1)(b)(ii) LAC 43XVII.3617.(B)(1)(c)(ii)
		Ultrasonic cement evaluation , CBL, VDL	MLR well	x		
		Ultrasonic casing inspection log	CO2 injector wells	x	During workover or well maintenance	LAC 43XVII.3627(A)(3)
		Pulse neutron log	CO2 injector wells	x	Annually	LAC 43XVII.3625(A)(5)
		Pulse neutron log	MLR well	x	Annually in IZM wells.	LAC 43XVII.3625(A)(7)(a)
		DTS fiber alongside the casing to the top of the perforations	CO2 injector wells	x	Continuously	LAC 43XVII.3627(A)(3) LAC 43XVII.3625(A)(5)
		Pulse neutron, temperature log, or electromagnetic log	MLR well	x	Yearly if fiber optic fails or not available	
		Annular pressure test	CO2 injector wells	x	After every WO; At least Yearly	LAC 43:XVII.3627(A)(2) through (A)(2)(b)
		Annular pressure test	MLR well	x	Annually	
3	Ground water quality and geochemical monitoring	Water sampling and testing in existing shallow fresh aquifer water wells.	Legacy water wells	Quarterly samples from selected wells for minimum 1 year before injection.	Quarterly first 3 years of injection. As needed based on other monitoring tools.	LAC 43XVII.3625(A)(4)
		Water sampling and testing in Above confining zone well (ACZ) and USDW monitoring well	ACZ and USDW wells	Initial sample before injection .	Quarterly	LAC 43XVII.3625(A)(4)
		Measurement of pressure and temperature downhole in Above Confining Zone monitoring wells (ACZ) - Downhole Gauges	ACZ Monitoring wells	x	Continuously	LAC 43XVII.3625(A)(7)(a)
		Isotopic fingerprinting of water in shallow aquifers, overburden, and injection targets	MLR, ACZ, USDW or CO2 injector wells	Initial sample during well construction .		LAC 43XVII.3625(A)(4) LAC 43XVII.3625(A)(8)

Notes:

1) "X" in the Pre column indicates that a baseline study is to be conducted in the pre-injection phase of the project.
2) MLR (Multi-Layer Reservoir) and ACZ (Above Confining Zone) are types of project monitoring wells included in the testing and monitoring plan

Table TM-1— Summary Table for Magnolia CCS 1 and Magnolia CCS 2 Testing and Monitoring Plan (continued)

Ct	Description	Method	Location	Pre	Injection Period	Requirement
4	Carbon Dioxide Plume and Pressure Front Tracking	Measurement of pressure and temperature in the reservoir - Downhole gauges	MLR well		Continuously	LAC 43XVII.3625(A)(7)(a)
		2D surface seismic survey	AOR	x	As required based on other monitoring techniques.	
		Gravity	AOR	x	Every 5 years	LAC 43XVII.3625(A)(7)(a)
		3D time lapsed surface seismic survey	AOR	x	As required based on other monitoring techniques.	
		Vertical Seismic Profile (VSP)	AOR	x	Annually in CO2 injectors.	
5	Near Surface & Surface	Airborne electromagnetic survey	AOR	x		
		Process-based soil gas approach	AOR	Minimum (1) year characterization	Quarterly	LAC 43XVII.3625(A)(8)
		Isotopic fingerprinting of the soil gas	AOR	Minimum(1) year characterization	If required to compliment other methods	LAC 43XVII.3625(A)(4) LAC 43XVII.3625(A)(8)
		Atmospheric CO2 sensors in wellhead.	CO2 injector wells		Continuously	LAC 43XVII.3625(A)(8)
		Atmospheric CO2 sensors in wellhead.	MLR, ACZ and USDW wells		Continuously	LAC 43XVII.3625(A)(8)
6	Induced Seismicity	Surface seismometers network	AOR	Minimum (1) year baseline	Continuously	

Notes:

1) "X" in the Pre column indicates that a baseline study is to be conducted in the pre-injection phase of the project.
2) MLR (Multi-Layer Reservoir) and ACZ (Above Confining Zone) are types of project monitoring wells included in the testing and monitoring plan

2.1 Well Network Design

Magnolia Sequestration Hub, LLC, will drill four CO_2 injection wells, Magnolia CCS 1, Magnolia CCS 2, Magnolia CCS 3, and Magnolia CCS 4, as part of the field development plan for the Magnolia Sequestration Hub. The monitoring program proposed was designed based on the projected CO_2 plume extension and propagation of the pressure front for all wells injecting simultaneously according to the AOR delineation process.

The proposed integrated monitoring plan includes a layout of four (4) In Zone (reservoir) monitoring wells (MLR), two (2) Above Confining Zone monitoring well (ACZ), and two (2) Underground Source of Drinking Water Aquifer monitoring wells (USDW). Details of the well construction and proposed schematics of the monitoring wells are included in the Well Construction Plan.

The monitoring well distribution was defined based on the evaluation of the AOR. The location of YAMS MLR 004 (stratigraphic test well converted to MLR) allow the project to have measurement of the CO_2 plume in early injection period (between 10 and 15 years of injection) and allow the project to monitor the behavior of the pressure front and CO_2 plume during the post injection period to the west and the south of the AOR.

The location of Magnolia MLR 1 and Magnolia MLR 2 will allow the Project to detect any deviation from the projected CO_2 Plume migration pattern if the VSP surveys conducted in the injection wells indicate a need to reassess the AOR prior to year 10. The project proposes to drill these wells in year 5, if necessary.

The location of Magnolia MLR 3 will allow the Project to match the rate of migration during the first 17 years of the post injection period with the use of pulse neutron logs and direct measurement of pressure and temperature in the reservoir. The Project proposes that the requirement to drill the Magnolia MLR 3 be assessed prior to initiation of the Post Injection Site Care (PISC) and be drilled prior to PISC initiation, if necessary. The proposed location may be adjusted to meet current surface and subsurface conditions at the time of drilling.

Magnolia ACZ 1, Magnolia ACZ 2, Magnolia USDW 1 and Magnolia USDW 2 locations were selected to cover most of the AOR projected by the model for monitoring the quality of the water above the upper confining zone. USDW 1 was drilled in 2024 and completed in 2025. ACZ 2 is proposed to be drilled in the same drilling campaign as the first Injection wells. USDW 2 and ACZ 1 drilling timeline will be assessed in year 5.

This network is complemented with baseline 3D and 2D surface seismic along with VSP and timelapse gravity for indirect plume detection. Additionally, existing water wells in the area will be used to establish the composition of the shallow aquifers and provide characterization of the waters.

This integrated approach will optimize the surveillance operations of the site with the goal of tracking the CO_2 plume extension and rate of migration, the development of the pressure front, and changes in the composition of deep and shallow aquifers as part of the holistic approach to demonstrate to stakeholders and regulators that the site is operating safely and efficiently, and that the CO_2 is permanently stored in the subsurface while limiting new artificial penetrations within the AOR

Figures TM-1 and TM-2 show the location and spatial distribution of the monitoring wells.

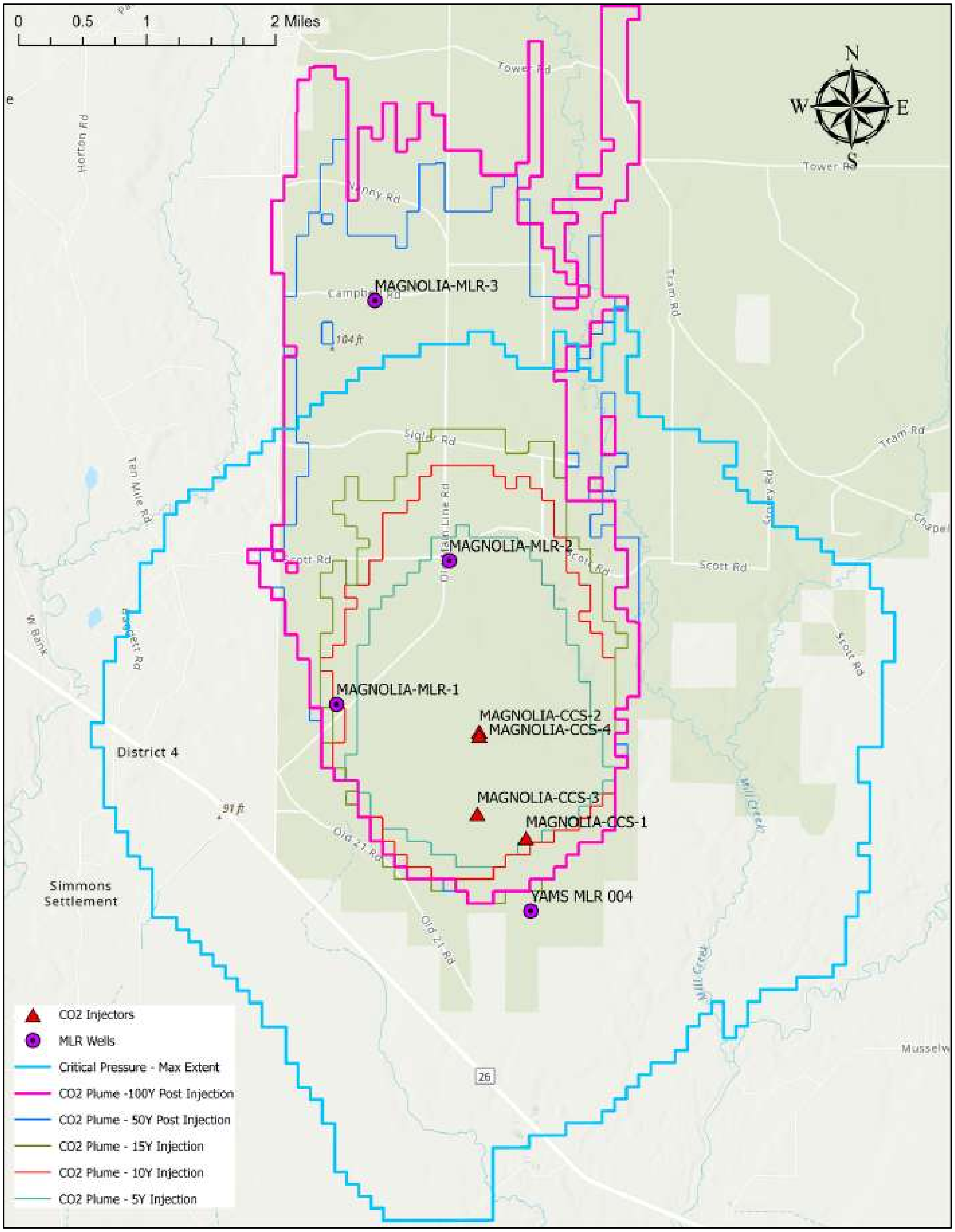

Figure TM-1—Location and layout of In Zone (MLR) monitoring wells relative to the injector wells and the CO_2 plume and pressure front development.

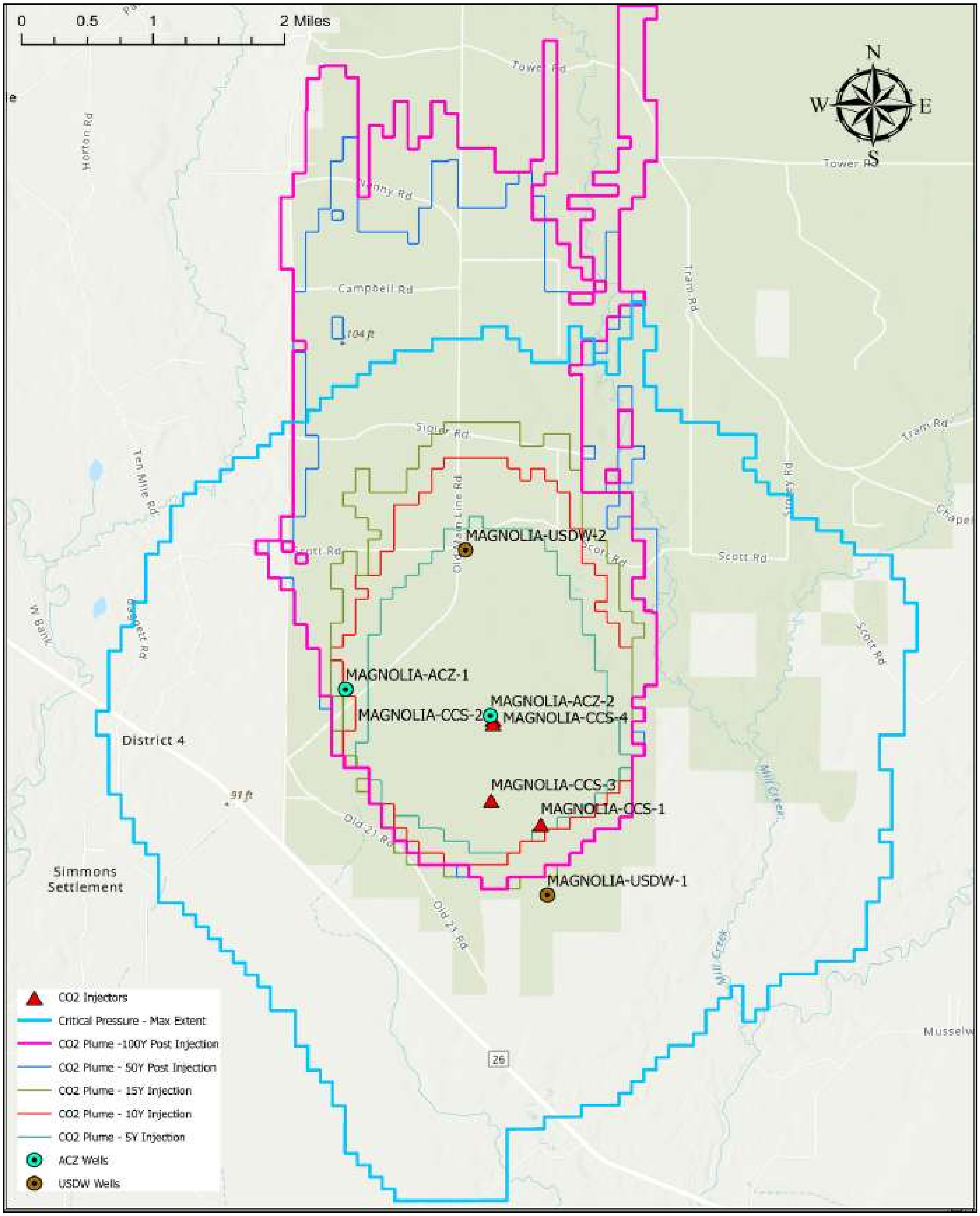

Figure TM-2—Location and layout of Above Confining Zone (ACZ) and USDW monitoring wells relative to the injector wells and the CO_2 plume and pressure front development.

The proposed Testing and Monitoring Plan will collect sufficient geospatial and monitoring data to validate the numerical simulation model, confirm the history match, and adjust the injection operating parameters as needed to operate the site as designed, efficiently and safely. The monitoring program results will allow the Project to re-evaluate the AOR and show that there is no endangerment to the USDW.

Each of these methods and their application in the proposed monitoring plan is discussed in the following sections. Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan (ERRP).

The proposed Testing and Monitoring Plan will be reviewed and updated at a minimum every 5 years during AOR reevaluation or sooner, if needed.

2.2 Quality assurance procedures

A Quality Assurance and Surveillance Plan (QASP) for testing and monitoring activities, required pursuant to LAC 43:XVII.3625(A)(11) is provided as a separate document. Detailed procedures and technical specification for the tools proposed in the Testing and Monitoring Plan are included in the QASP.

2.3 Reporting procedures

Magnolia Sequestration Hub, LLC, will report the results of all testing and monitoring activities to Louisiana Department of Conservation and Energy (C&E) in compliance with all rules and regulations, including LAC 43:XVII.3625.

3.0 Operational Testing and Monitoring During Injection

3.*1 Carbon Dioxide Stream Analysis*

Magnolia Sequestration Hub, LLC, will analyze the CO_2 stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of LAC 43:XVII.3625(A)(1).

3.1.1 Sampling location and frequency

CO_2 stream sampling will occur quarterly during operations upstream of the custody transfer flowmeter that measures the flow rate of the injectant at the site.

Multiple samples will be acquired during the startup period of the project (first injection) to validate the CO_2 stream complies with quality specifications. After the start up period, a sample will be taken 3 months after the start of injection. A sample will then be taken each calendar quarter until injection ceases in the well. The sampling period could be increased and shifted in time, depending on operations such as when there are known changes to CO_2 stream composition of sources.

The project has developed a standard CO_2 specification, defining the maximum variation in the impurities and delivery conditions at the site, as shown in Table TM-2. The project will install a gas analyzer at the custody transfer meter located in the sequestration site, to monitor CO_2 quality continuously before it is distributed to each well. The project could require additional components to be limited and analyzed based on final contractual terms with the CO_2 source facilities.

Table TM-2—CO_2 Stream Specification

Component	Specification
CO_2 (% mol)	>95
Water (lbs/MMCF)	<30
Nitrogen (% mol)	<4
Oxygen (ppm by wt)	<10
Hydrogen (% mol)	<1
SOx (ppm by wt)	<1
NOx (ppm by wt)	<1
Hydrogen Sulfide (ppm by vol)	<20
Hydrocarbons (%mol)	<5
Carbon Monoxide (ppm by wt)	<4250
Glycol (gal/MMSCF)	<0.3
Argon (%mol)	<1
Sulfur (ppm by wt)	<35
Particulates (ppm by wt)	<1
Mercury (nanograms/liter)	<0.005
Amines (ppm by wt)	<1

The CO_2 composition will be monitored continuously and/or routinely sampled at each receipt point into the pipeline network along with at the delivery point to the sequestration site.

If the inline analyzers or sample results indicate a deviation from the CO_2 specification, additional samples will be collected until sampling results show the CO_2 is within specifications. At that time, sampling will return to a normal frequency.

If the CO_2 delivered to a receipt point does not meet CO_2 specifications, the project will notify the CO_2 source facility and either shut-in the source facility or increase the sample frequency, depending on the possible effects of the out-of-spec CO_2 on the project components.

If the CO_2 source facility is shut-in, offtake will only resume from that facility once it has demonstrated the resumption of an in-spec product for an agreed period between 12 and 48 hours.

3.1.2 Analytical parameters

Magnolia Sequestration Hub, LLC, will test the quarterly CO_2 samples (or "as needed" samples) for the constituents identified in Table TM-3. Additional constituents may also be tested if necessary.

Table TM-3—CO_2 Stream Analysis

Component	Frequency	Analytical Method
CO_2 (% mol)	Quarterly	Gas chromatography
Water (lbs/MMCF)	Quarterly	Gas chromatography
Nitrogen (% mol)	Quarterly	Gas chromatography
Oxygen (% mol)	Quarterly	Gas chromatography
Hydrogen (% mol)	Quarterly	Gas chromatography
SOx (ppm by vol)	Quarterly	Colorimetry
NOx (ppm by vol)	Quarterly	Gas chromatography
Hydrogen Sulfide (ppm by vol)	Quarterly	Gas chromatography
Hydrocarbons (% mol)	Quarterly	Gas chromatography
Carbon Monoxide (ppm by vol)	Quarterly	Gas chromatography
Glycol (gal/MMSCF)	Quarterly	Gas chromatography
Argon (%mol)	Quarterly	Gas chromatography
Sulfur (ppm by wgt)	Quarterly	Gas chromatography
δ13C of CO_2	During Characterization	Chromatographic separation with combustion and dual-inlet isotope ratio mass spectrometry (IRMS) or compound-specific analysis (GC-C-IRMS)
14C of CO_2	During Characterization	Accelerator mass spectrometry (AMS)

The project may deem it necessary to test additional elements to ensure the CO_2 delivered to the Magnolia Sequestration Hub complies with the contractual specifications. Isotopes will be analyzed during the first year of operation and after any major change of CO_2 source composition to fingerprint the stream.

3.1.3 Sampling methods

- A sampling station will be installed with the ability to purge and collect samples into a container that will be sealed and sent to a third-party authorized laboratory.
- Sampling procedures will follow protocols to ensure the sample is representative of the injectant and samples will be processed, packaged, and shipped to the contracted laboratory, following standard sample handling and chain-of-custody guidance. Sampling methods are described in the QASP.

3.1.4 Laboratory to be used/chain of custody and analysis procedures

The samples will be analyzed by a third-party laboratory using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. Analytic methods and chain of custody procedures are described in the QASP.

3.2 Monitoring and Recording of Operating Parameters in Injector Wells

Magnolia Sequestration Hub LLC will install and use continuous recording devices to monitor injection pressure, rate, and volume; the pressure and volume of the annulus between the tubing and long string casing; and the temperature of the CO_2 stream, as required at LAC 43:XVII.3621(A)(6), 3627(A)(2) through (A)(2)(b), and 3625(A). Injection rates and pressures will be set by permit.

To monitor annular volumes between the tubing and casing, the project proposes to install downhole gauges above the packer that would measure the downhole pressures and temperatures in the tubing and annulus. This would be in addition to the surface gauges installed in the wellhead. Data from these gauges, will allow project operations to detect potential mechanical integrity issues.

The Project will add water to the casing-tubing annulus with a pump truck. The volumes of water added will be recorded.

Injection operations will be continuously monitored and controlled by the operations staff, utilizing the process control system. The system will continuously monitor, control, record, and alarm for pressure, temperature, and flow rate.

The process control system will limit maximum flow to 7,700 tonnes per day (MT/day), or approximately 140 million standard cubic feet per day (MMscfd), and limit the wellhead pressure to 2,300 psig. The system will alert if the specified control parameters of flow or pressure deviate outside of operating range thresholds and will trigger the remote shutdown process [including closure of Emergency Shutdown (ESD) valves] for excursions above the operating limit. Trend analysis will help evaluate the performance (e.g., drift) of the instruments and may be used for scheduling maintenance or calibration. The system will also allow for elective remote shutdown under situations such as adverse weather conditions that pose risk to the project.

During periods of approved workovers by the commissioner, continuous monitoring is not required [LAC 43:XVII.3625(A)(2) and (5)].

3.2.1 Monitoring location and frequency

Real time monitoring activities will begin during the start-up of the wells for first injection. The injection pressure and temperature will be continuously measured at the surface via real-time pressure and temperature (P/T) instruments installed in the CO_2 injection line near the interface with the wellhead. The pressure will be measured by electronic pressure transducer with analog output mounted on the CO_2 line associated with the injection well. The temperature will be measured by an electronic temperature transducer mounted in the CO_2 line at a location near the pressure transducer, and both will be located near the wellhead.

The flow rate of CO_2 injected into the well will be measured by flow meter skids with a Coriolis-type flow meter in the CO_2 injection line near the interface with the wellhead. The flow transmitter will be connected to a remote terminal unit (RTU) on the flow meter skid.

A pressure and temperature (P/T) gauge will be installed downhole as part of the upper completion and will be ported into the tubing to continuously measure CO_2 injection pressure and temperature at reservoir. The downhole sensor will be the point of compliance for maintaining injection pressure below 90% of formation fracture pressure gradient, as well as to evaluate the reservoir performance and history match the operation with the projection of the model. Operating surface and downhole gauge pressure maximum value calculations are included in the Summary of Operations Conditions (OP) documents.

If the downhole gauge stops working between maintenance events, then the surface pressure limitation approved for this permit (see Summary of Operating Conditions (OP) documents) will be used as a backup until the downhole gauge is repaired or replaced. For calibration purposes, in lieu of removing the injection tubing, the accuracy of the downhole gauges will be demonstrated by using a second pressure gauge with current certified calibration lowered into the well at the same depth as the permanent downhole gauge.

Electronic pressure and temperature transducers will be used to continuously monitor the pressure and temperature of the annulus between the tubing and long string casing at the surface. Gauges and sensors will be connected to the automation system to provide continuous data analysis as well as alarms for malfunctioning events if values deviate from the intended operating range.

A minimum of 100 psi differential will be maintained across the packer and the addition of volume or changes in pressure will be noted by the operator in the field and recorded in the project well databases daily. A pressure gauge and temperature sensor will be installed downhole as part of the upper completion and will be ported into the annular above the packer to continuously measure pressure in the annular space and identify any potential loss of mechanical integrity. If the pressure observed in the annular gauges (surface/downhole), departs from the normal operating trend line, or equalizes with the tubing pressure, then the field operator will proceed to troubleshoot the well.

A fiber optic cable will be attached along the side of the casing and a Distributed Temperature Sensing (DTS) interrogator will be installed on the surface, which will provide a Distributed Temperature Profile while injecting. This system will continuously record temperature to assist in monitoring the CO_2 behavior and any unforeseen mechanical integrity issue in the well.

Automated shut off devices will be installed at each exit of the flow lines in the wellhead and will be connected to the control system. If the operation parameters (flow rates, or other parameters designated by the Commissioner) deviate from the program operational limits, the system will send an alarm to the operators to evaluate and correct the situation. If the operation parameters exceed the maximum permitted limits (2300 psig or 7,700 MT/day), automatic shutdown will initiate. [LAC 43:XVII.3621(A)(7)(a) through (c)].

Magnolia Sequestration Hub, LLC, will perform the activities identified in Table TM-4 to monitor operational parameters. All monitoring will take place at the locations and frequencies shown in the table.

Table TM-4—Monitoring Devices, Locations, and Frequencies for Continuous Monitoring During Injection Operations in the CO_2 Injector Wells

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection Pressure	Pressure Transducer	Flow line close to the wellhead.	1 sec	15 sec
Injection Rate	Coriolis Meter	Flow line into the wellhead	1 min	1 hr
Injection Volume	Coriolis Meter	Flow line into the wellhead	15 sec	15 sec
Injection Temperature	Temperature transducer	Flow line close to the wellhead.	1 sec	15 sec
Surface Annular Pressure	Pressure Transducer	Wellhead Injector	1 sec	15 sec
Annulus Volume	Calibrates surface tank	Wellhead	Daily	Daily
Downhole Annular Pressure and temperature	Pressure Gauges, Temperature sensor	Deployed in tubing ported to annular above packer	15 sec	15 sec
Distributed temperature profile	Fiber Optic + DTS Interrogator	Alongside long string	10 min	30 min
Downhole injection Pressure and temperature	Pressure Gauges, Temperature sensor	Deployed in tubing ported to tubing above packer	15 sec	15 sec
Automatic surface shut off devices	Electric actuated valve	Each exit of the flow line in the wellhead	n/a	n/a

3.2.2 Monitoring devices description and technical specifications

Technical specifications for the tools to use for real time data acquisition, monitoring and shut down are described in the QASP. Results of the monitoring activities will be reported semi-annually according to LAC 43:XVII.3629(A)(1).

3.3 Corrosion Monitoring

To meet the requirements of LAC 43:XVII.3625(A)(3) Magnolia Sequestration Hub, LLC, will monitor well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to verify that the well components meet the minimum standards for material strength and performance.

Magnolia Sequestration Hub, LLC, will monitor corrosion using corrosion coupons and collect samples according to the description below. The project will complement the corrosion coupons with casing inspection logs, visual inspection of the facilities, a robust leak detection and repair program, the use of optical gas imaging cameras (OGI), and the data collected in real-time from the fiber optic installed in the injector wells.

During well material selection, Magnolia Sequestration Hub, LLC, simulated the chemical reactions of the selected material, the formation waters, and the proposed CO_2 stream at downhole conditions. The Project proceeded to test the selected materials to the maximum limits of the specifications and operating parameters to validate the correct selection for downhole materials that will be exposed to the injection stream and formation waters. The results of material testing are in progress and will be available for the Commissioner to review.

Final coupon samples will be representative of the well construction materials (well casing, tubing and any other well parts in contact with carbon dioxide such as the packer and wellhead).

3.3.1 Monitoring location and frequency

Table TM-5—Monitoring Location and Frequency of Corrosion Coupons

Tool	Location	Pre-Injection	Injection
Corrosion coupons	Flow Line CO_2 stream	n/a	Quarterly

3.3.2 Corrosion Coupons analysis description

Samples of selected materials in the wells and facilities (coupons) will be continuously exposed to the injected CO_2 stream at injection conditions and monitored for signs of corrosion to verify that the selected materials meet the minimum standards for material strength and performance and to identify well maintenance needs [(LAC 43:XVII.3625(A)(3)]. Coupons shall be collected and sent quarterly to a third-party company for analysis conducted in accordance with NACE Standard SP-0775-2018-SG to determine and document corrosion wear rates based on mass loss. The project will start corrosion coupon monitoring after the start of injection and will continue quarterly until the end of injection period.

Table TM-6—Summary of methods to evaluate Corrosion Coupons

Parameters	Analytical Method	Resolution Instruments	Precisions/Std Dev
Mass	NACE SP0775-2018-SC	0.05 mg	2%
Thickness	NACE SP0775-2018-SC	0.01 mm	± 0.05 mm

NACE SP0775-2018-SC: Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations

Table TM-7—List of Equipment with Materials of Construction

Equipment Coupon	Material of Construction
Pipeline	Carbon Steel
Long String Casing - CO_2 Injector well (above injection zone)	Carbon Steel. L80
Long String Casing - CO_2 Injector well (injection zone)	2507 110 ksi
Tubing – CO_2 Injector well (above Packer)	Carbon Steel. L80.
Tubing – CO_2 Injector well (below Packer)	2507 110 Ksi
Wellhead – CO_2 Injector Well (no CO_2 wetted areas)	Carbon Steel DD specification
Injection Tree and Tubing Hanger – CO_2 Injector Well	Sour Service - HH specifications
Packers – CO_2 Injector Well & In Zone Monitoring Wells	Nickel Plated
Long String Casing – In Zone and Above Confining Zone monitoring wells	Carbon Steel. L80
Tubing - In Zone and Above Confining Zone monitoring wells	Carbon Steel. L80
Wellhead and Tree – In Zone and Above Confining Zone monitoring wells	Carbon Steel DD specification

3.4 Pressure Fall-Off Testing in CO2 Injector (CCS)

Magnolia Sequestration Hub LLC will perform pressure fall-off tests in the CO_2 injector wells during the injection phase as described below to meet the requirements of LAC 43:XVII.3625(A)(6).

3.4.1 Testing location and frequency

Pressure fall-off testing will be conducted in the CO_2 injection wells to characterize reservoir hydrogeologic properties, aquifer response model characteristics, and changes in near-well/reservoir conditions that may affect operational CO_2 injection behavior.

Pressure fall-off testing will be conducted in the CO_2 injector before starting first injection, and at least once every five (5) years until the wells are plugged. The objective of the periodic pressure fall-off testing is to determine whether any significant changes in the near-wellbore conditions have occurred that may adversely affect the well or reservoir performance.

3.4.2 Testing details

Detailed procedure and analytics proposed for the fall-off test are described in the QASP.

3.5 Tracking and Recording Surface Pressure and Temperature in In Zone and Above Confining Zone Monitoring Wells

Magnolia Sequestration Hub, LLC, will continuously measure pressure and temperature in the In Zone (MLR) and Above Confining Zone (ACZ) monitoring wells at the surface via real-time pressure and temperature (P/T) instruments installed in the wellhead.

A pressure and temperature (P/T) gauge will be installed downhole in both the In Zone (MLR) and Above Confining Zone (ACZ) monitoring wells as part of the upper completion and will be ported into the tubing to continuously measure pressure and temperature in the reservoir. These measurements will allow the project team to calibrate and verify the model, improve predictive capability for confirming CO_2 containment, and evaluate the development of the pressure front.

Since the changes in reservoir pressure precede the movement of the CO_2 plume, in-zone monitoring wells will provide data to history-match the model and calibrate the response expected from the reservoir regarding the development of pressure front and CO_2 plume migration.

Detailed diagrams and construction schematics for the MLR and ACZ monitoring wells are provided in the Injection Well Construction Plan (CON) document Appendix G.

3.5.1 Monitoring location and frequency

Table TM-8—Monitoring Location and Frequency of Pressure and Temperature Testing in In Zone monitoring wells

Tool	Location	Pre-Injection	Injection	Min. Sampling Frequency	Min. Recording Frequency
Surface P/T transducers	MLR, ACZ monitoring wells	n/a	Continuously	1 sec	15 sec
Downhole P/T gauges	MLR, ACZ monitoring wells	n/a	Continuously	15 sec	30 min

In the event the downhole sensor fails before a planned well maintenance operation, the project will continue monitoring the pressure with the surface transducers and might implement measurement of fluid levels in the well to calculate the bottomhole pressure while the equipment is replaced and repaired. The project team might install temporary pressure gauges in the well and limit the collection of data to one sample per day.

3.6 Visual Inspection and Leak Detection and Repair (LDAR) **Program Using** *Optical Gas Imaging Camera (OGI)*

The project will perform visual inspection of the facilities and wells as part of the maintenance and mechanical integrity program. Inspection will start from the commissioning date and will continue weekly after the site is injecting steadily. LDAR field inspections will be performed quarterly after the start of injection and continue until injection ceases and will use OGI cameras.

During periodic visual inspections, the field operator will be provided with handheld devices to measure explosive gases, H_2S, and CO_2 as part of the safety requirements of the site.

Table TM-9—Monitoring Location and Frequency of Visual Inspections and LDAR Program

Tool	Location	Pre-Injection	Injection
Leak detection and repair (LDAR) program using Optical Gas Imaging cameras, handheld during inspections	Surface facilities and wellheads	n/a	Quarterly
Visual inspections and handheld monitors (LEL, H2S, CO_2)	Surface facilities and wellheads	Before start of injection	Weekly

Notes:

1. Multiple inspections using OGI cameras will be performed during the startup of the well (first injection) after authorization to inject is received and will continue quarterly as minimum frequency during the injection period

4.0 Mechanical Integrity Testing

4.1 External Mechanical Integrity Testing [LAC 43:XVII.3627(A)(3), LAC 43:XVII.3625(A)(5), LAC 43:XVII.3617(B)(1)(b)(ii), and LAC 43:XVII.3617(B)(1)(c)(ii)]

Magnolia Sequestration Hub, LLC, will perform a cement logging evaluation, with one or more of the following tools, to validate zonal isolation between the injection zone, confining zones, and overburden formations after installation of the long string casing during construction of the CO_2 injector and the In Zone (MLR) wells [LAC 43:XVII.3617(B)(1)(b)(ii) and LAC 43:XVII.3617(B)(1)(c)(ii)]]:

a. Cement Bond Logging
b. Ultrasonic cement evaluation tool
c. Variable density log (VDL)

Magnolia Sequestration Hub, LLC, will run a pulse neutron log (PNL) in the CO_2 injection wells after initial installation of the completion equipment, and at least once a year to evaluate external mechanical integrity (LAC 43:XVII.3627(A)(3) and LAC 43:XVII.3625(A)(5)).

The project team will run a PNL in the in-zone monitoring wells after initial installation of the completion equipment to set the baseline for mechanical integrity evaluation as well as for CO_2 plume tracking in the reservoir.

In the future, Magnolia Sequestration Hub, LLC, may use a different test method for mechanical integrity testing by giving notice to the Director.

Additionally, an ultrasonic casing inspection tool will be run during well maintenance operations or workovers for the CO_2 injector well to evaluate casing thickness and conditions.

Magnolia Sequestration Hub, LLC, will install a fiber optic cable alongside the long-string casing in the CO2 injection wells with the capability of continuously monitoring temperature changes from the top of the perforations to the surface, exceeding the requirements in LAC 43:XVII.3627(A)(3) and LAC 43:XVII.3525(A)(5).

Magnolia Sequestration Hub, LLC, will also install fiber optic alongside the casing in the monitoring wells, Magnolia MLR 1, Magnolia MLR 2 and Magnolia MLR 3 that will allow tracking of mechanical integrity in real time.

If the fiber optic cable fails in the In Zone Monitoring wells or its not available (as in YAMS MLR 4), Magnolia Sequestration Hub, LLC, will run one of the following tools at least every 5 years or during well maintenance operations or workovers to evaluate external mechanical integrity:

a. Pulse neutron through tubing
b. Electromagnetic casing inspection log
c. Temperature log

4.1.1 Testing location and frequency

Table TM-10 below provides a summary of the external mechanical integrity tools.

Table TM-10—Corrosion Monitoring and Surface Leak Detection Tools

Tool	Location	Pre-Injection	Injection
CBL-VDL or USIT	CO_2 injector wells MLR monitoring wells	After long string installation during completion operations	If required by future operations
Ultrasonic Casing Inspection tool	CO_2 injector wells	After long string installation during completion operations	During planned well maintenance operations
Pulse neutron log	CO_2 injector well	Before injection as baseline	Once a year
Pulse neutron log	MLR monitoring wells	Before injection as baseline	Annually in MLR well(s) to detect CO_2.
DTS survey	CO_2 injector well	Before injection as baseline	Continuously
DTS survey	MLR monitoring wells, except YAMS MLR 4		Continuously, after well completion operations
Pulse neutron, Temperature log, or Electromagnetic Log	MLR monitoring wells	After well completion operations as baseline	Yearly for mechanical integrity purposes if the DTS fails or not available.

4.1.2 Testing details

The logging industry has made an impressive advance in tools that provide images of and data identifying the quality of the cement bond behind the casing after cementing jobs are complete. The casing inspection tool and multi-finger calipers can provide information about ovality, collapse, or damage in the casing, as well as estimations of wall thickness to evaluate wearing and corrosion effects.

The most advanced tools can evaluate up to five concentric tubulars to measure changes in thickness that could be related to corrosion or wearing effects.

The tools described below are readily available technologies on the market and the basis of the project's master monitoring program for mechanical integrity. No specific provider has been selected. In the future, new technologies or tools may be proposed to the Director.

4.1.2.1 Cement bond logging, variable density log and ultrasonic cement evaluation

Cement Bond Log (CBL) is a basic method to evaluate cement quality in the annulus. It is an acoustic wave measurement. The tool usually includes a transmitter and receiver, separated by three (3) ft. The acoustic wave is emitted by the transmitter, propagated down and across the annulus, and recorded by the receiver. The attenuation of the wave is analyzed to interpret the bonding behind the pipe. Signal coming from a properly cemented casing will be more attenuated than the signal coming from a poorly cemented one.

The arriving signal recorded by the receiver is a mixed signal coming from casing, cement, mud, and formations. Each signal has its own pathway because they travel at different velocities through each medium. The signal through the casing is the fastest, as sound travels the quickest through steel. As a result, it is the first signal detected on the receiver. The second signal that is most likely to arrive is the signal through the formation and the last one is the drilling fluid signal because sound travels slower in a liquid.

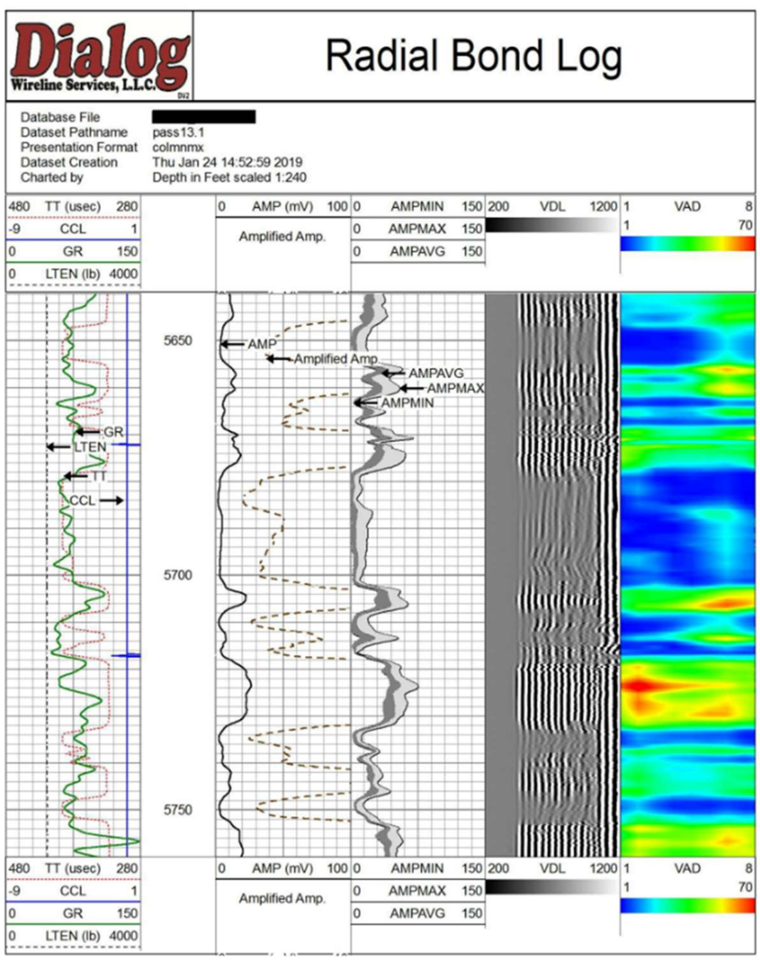

Figure TM-3—CBL and VDL Example from Dialog Wireline Services Web Page

Variable Density Log (VDL) is commonly used as an adjunct to the cement bond log and offers better insights with its interpretation. In most cases, micro-annulus and fast-formation-arrival effects can be identified using this additional display.

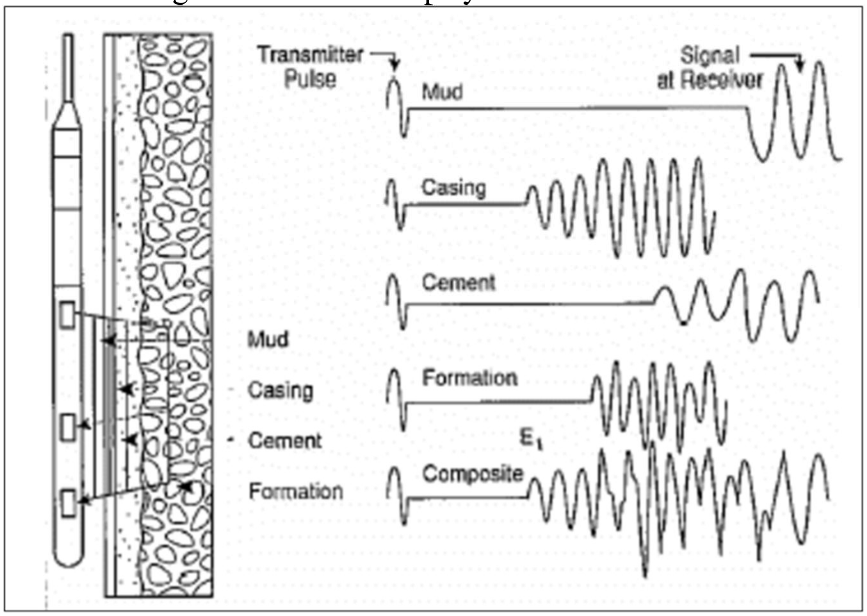

Figure TM-4—Signal Received by CBL-VDL

4.1.2.2 Ultrasonic cement and casing evaluation tools

USIT (Schlumberger Technology) is an example ultrasonic imager that delivers an accurate, comprehensive, and high-resolution confirmation of the pipe-to-cement bond quality and downhole pipe condition in real time. Casing inspection and monitoring applications include corrosion detection, identification of internal and external damage or deformation, and casing thickness analysis for collapse and burst pressure calculations.

The rate of decay of the waveforms received indicates the quality of the cement bond at the cement-casing interface, and the resonant frequency of the casing provides the casing wall thickness required for pipe inspection. The resulting 360° data coverage enables evaluation of the quality of the cement bond and determination of both the internal and external conditions of the casing.

Isolation Scanner (Schlumberger Technology) is a combination of independent measurements that fully characterizes the annular environment, differentiating low-density solids from liquids to distinguish lightweight and contaminated cements from liquids. Its azimuthal coverage provides results around the entire circumference of the casing, pinpointing any channels in the cement and confirming the effectiveness of the annular barrier for zonal isolation.

The Isolation Scanner tool also identifies corrosion or drilling-induced wear through measurement of the inside diameter and thickness of the casing. The flexural wave measurement produces entirely new information from the third-interface echoes (TIEs) between the annulus and borehole or outer casing. The TIEs image the borehole shape, define the position of the casing within the borehole or outer casing, and image the outer string to reveal corrosion and damage.

4.1.2.3 Distributed temperature sensing (DTS)

Distributed Temperature Sensing (DTS) technology uses fiber optic sensor cables, typically several kilometers in length, that function as linear temperature sensors. The result is a continuous temperature profile along the entire length of the sensor cable. DTS utilizes the Raman effect to measure temperature. An optical laser pulse sent through the fiber results in some scattered light reflecting to the transmitting end, where the information is analyzed. The intensity of the Raman scattering is a measure of the temperature along the fiber. The Raman anti-Stokes signal changes its amplitude significantly with changing temperature, while the Raman Stokes signal is relatively stable. The position of the temperature reading is determined by measuring the arrival timing of the returning light pulse like a radar echo.

The fiber optic cable is run alongside the casing as an umbilical and it is protected with clamps and centralizers to avoid any damage while deploying it into the well. The fiber is connected on the surface to an interrogator to convert the signal to temperature values and data is transmitted to the monitoring platform in real time for surveillance purposes.

The maintenance and calibration of the equipment will be performed according to the manufacturer's manuals and will be the responsibility of the technology provider. Technical specifications are available in the QASP.

4.1.2.4 Electromagnetic casing inspection tool

Electromagnetic casing inspection log Pipe Xaminer (Halliburton Technology) is an example of proprietary electromagnetic tool. The operating principle of the tool is to induce a High-Definition Frequency (HDF) electromagnetic energy into the surrounding pipe, which propagates through the concentric well strings with no wellbore fluid influences. The interaction with the metal of the pipe returns a signal to the tool, yielding information on the metal loss present in the tubulars. The magnitude and location of corrosion-induced defects are identified using HDF variance algorithms of the returning electromagnetic waves. This information leads to a quick total thickness calculation determining the overall condition of the pipe structure. This technology enables one to examine the whole well in one trip and up to five concentric strings of pipe.

4.1.2.5 Temperature log

Temperature logs are used to locate gas entries, detect casing leaks, and evaluate fluid movement behind casing. They are also used to detect lost-circulation zones and cement placement. Temperature logs are used as a basic diagnostic tool and are usually paired with other tools like acoustics or multi arms calipers, if more in depth analysis is required.

Temperature instruments used today are based on elements with resistances that vary with temperature. The variable resistance element is connected with bridge circuitry or constant current circuit, so that a voltage response proportional to temperature is obtained. The voltage signal from temperature device is then usually converted to a frequency signal transmitted to the surface, where it is converted back to a voltage signal and recorded. The absolute accuracy of temperature logging instruments is not high (in the order of +- 5°F), but the resolution is good (0.05°F or better), although this accuracy can be compromised by present day digitalization of the signal on the surface. The temperature instrument usually can be included in the string with other tools, such as radioactive tracer tools or spinners flowmeters. Temperature logs are run continuously, typically at cable speeds of 20 to 30 ft/min. (A.Daniel Hill).

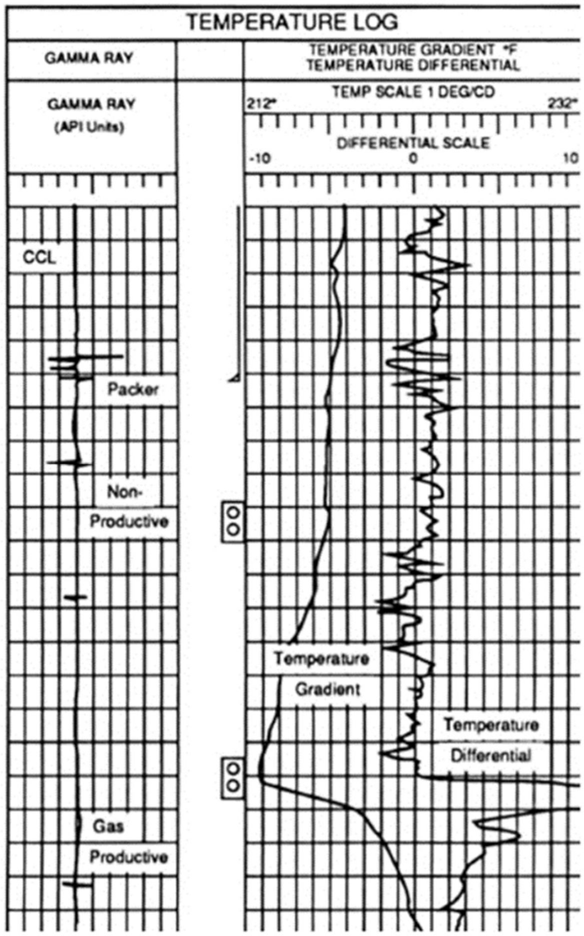

Figure TM-5—Example of temperature log output

4.1.2.6 Pulse neutron log

Pulse neutron log (PNL) provides formation evaluation and reservoir monitoring in cased holes. PNL is deployed as a wireline logging tool with an electronic pulsed neutron source and one or more detectors that typically measure neutrons or gamma rays. High-speed digital signal electronics process the gamma ray response and its time of arrival relative to the start of the neutron pulse. Spectral analysis algorithms translate the gamma ray energy and time relationship into concentrations of elements. Each logging company has its own proprietary designs and improvements on the tool.

Schlumberger's Pulsar Multifunction Spectroscopy Service (PNX) pairs multiple detectors with a high output pulsed neutron generator in a slim tool with an outer diameter (OD) of 1.72 inches for through-tubing access in cased hole environments. The housing is corrosion-resistant, allowing deployment in wellbore environments such as CO_2. The tool's integration of the high neutron output and fast detection of gamma rays with proprietary pulse processing electronics, allows to differentiate and quantify gas-filled porosity from liquid-filled and tight zones. The tool can accurately determine saturation in any formation water salinity across a wide range of well conditions, mineralogy, lithology, and fluid contents profile at any inclination. Detection limits for CO_2 saturation for the PNX tool vary with the logging speed as well as the formation porosity. Detailed measurement and mechanical specifications for the PNX tool are provided in the QASP document. The wireline operator will provide QA/QC procedures and tool calibration for their equipment.

Haliburton's RMT-D reservoir monitor tool, the Halliburton Reservoir Monitor Tool 3-Detector™ (RMT-3D™) pulsed-neutron tool, solves for water, oil, and gas saturations within reservoirs using three independent measurements (Sigma, C/O, and SATG). This provides the ability to uniquely solve simple or complex saturation profiles in reservoirs, while eliminating phase-saturation interdependency. The RMT-#D provides gas phase analysis to identify natural gases, nitrogen, CO_2, steam, and air. The tool has a 2.125 inch OD that allows it to be run through tubing.

4.1.3 Description and technical specifications of the tools for external mechanical integrity evaluation

Detailed information and technical references of these tools are provided in the QASP.

4.2 Internal Mechanical Integrity Testing [LAC 43:XVII.3627(A)(2) through (A)(2)(b)]

Magnolia Sequestration Hub, LLC, will perform an annular pressure test in the CO_2 injector as well as in MLR and ACZ monitoring wells to demonstrate internal mechanical integrity of the system according to LAC 43:XVII.3627(A)(2) through (A)(2)(b).

Annular pressure testing is used to validate mechanical integrity in the system. Tests will be performed according to the frequency presented in table TM–11.

Table TM-11—Annular Pressure Testing Frequency

Tool	Location	Pre-Injection	Injection
Annular Pressure Test	CO_2 injector wells	After long string installation before completion	After every well maintenance operation or at least once every 12 months in accordance with LAC 43:XVII.3627 (A)(2)(a)(ii)
Annular Pressure Test	MLR monitoring wells	After long string installation before completion	Annually

If the additional monitoring systems indicate a potential mechanical integrity issue, Magnolia Sequestration Hub, LLC, will perform trouble shouting and perform an annular pressure test as part of the protocol, if needed.

An example overview of the procedure is as follows (actual procedures may vary based upon operating conditions at the well and other safety or technical considerations):

- First, shut-in the well to stabilize the pressures in the injectors and validate static conditions in the monitoring wells.

- Connect the testing equipment to the annular valves and test surface lines to 1,500 psi above the testing pressure.

- Verify that there are no surface leaks from the pumping unit to the wellhead valve. Bleed any air in the system. If needed, fill the annular space with packer fluid and corrosion inhibitor (if so, it should require only a minimal amount). Record the initial tubing and casing pressure.

- The well will be tested to 500 psi in the annular space for the CO_2 Injector wells and In Zone monitoring wells. The pressure should not decrease more than 5% in 30 minutes.

- Monitor continuously the tubing and casing pressures. Record the final tubing and casing pressure, then bleed the pressure and volume. If the pressure decreases more than 5%, bleed the pressure, test the surface connection, and repeat the test.

- If there is an indication of mechanical failure, the operator will prepare a plan to repair the well and discuss it with the Director.

- Surface gauges should be calibrated according to manufacturer recommendations. There should be a pressure range that will allow the test pressure to be near the mid-range of the gauge. Additionally, the gauge must be of sufficient accuracy and scale to allow an accurate reading of 5% change to be read.

- The test results will be documented and stored in the centralized database of the project for reporting and documentation.

5.0 Ground Water Quality and Geochemical Monitoring [LAC 43:XVII.3625(A)(3)]

Magnolia Sequestration Hub, LLC, will monitor groundwater quality and geochemical changes above the confining zone during the operation period to meet the requirements of LAC 43:XVII.3625(A)(3).

Groundwater monitoring locations were selected based on original assessment of the AOR for existing legacy wells, numerical simulation results for CO_2 plume and pressure front, and risk assessment performed by the project (Figure TM-6). The location, techniques, and frequency were optimized, taking into consideration the complementary techniques proposed in this monitoring plan for direct and indirect measurements, such as 2D seismic surveys, pulse activated neutron logs, soil gas analyses, and other techniques described in this document.

Examples of associated above confining zone and USDW monitoring include installation of DTS fiber optics along injector wells will be utilized to monitor for potential vertical fluid movement above confining zones and the USDW. Magnolia Sequestration Hub also plans to recomplete stratigraphic test well YAMS MLR 004 (SN 975950) as an In Zone monitoring well and construct three (3) additional In Zone Monitoring wells. In Zone monitoring wells also act as above confining zone and USDW monitoring wells when conducting pulse activated neutron logging and indirect methods such as 2D time lapsed surface seismic surveys.

Table TM-12 and TM-13 show planned locations and frequencies for sampling shallow freshwater wells, respectively (LAC 43:XVII.3625(A)(4)(a) and (b)). Magnolia Sequestration Hub, LLC, selected thirteen (13) legacy water supply wells distributed around the AOR to sample and characterize local groundwater resources. Candidates wells for water sampling are completed in the Chicot Aquifer, and water use varies from agricultural, domestic, and municipal.

The Magnolia Sequestration project will drill and complete two ACZ monitoring wells and two USDW monitoring wells targeting the lower section of the USDW. Monitoring of the USDW at the Magnolia Sequestration Project will be conducted in the first permeable zone above the upper confining zone. Fluid samples will be collected from all monitoring wells to characterize and monitor pre- and post-injection fluid geochemistry above the upper confining zone.

5.1 Freshwater shallow aquifer water sampling and testing

Groundwater production for agricultural, municipal, and domestic use in Allen Parish is primarily sourced from shallow wells completed in the Chicot Aquifer. Therefore, proposed locations for sampling and testing the shallow freshwater (< 1,000 mg/l TDS) aquifer utilize existing wells completed in the Chicot Aquifer (Table TM-12).

Candidate wells for sampling and testing were selected to cover an extensive area inside and around the defined AOR. Candidate wells were evaluated using publicly available data for installation age, use, depth, and relative location to the AOR and other monitoring wells. Field evaluations are planned for each proposed candidate well to assess mechanical integrity and accessibility. Selected wells will be identified and reported upon completion of field evaluations and access confirmation.

Shallow freshwater aquifer sampling and characterization is planned to commence a minimum of one year prior to the start of injection (Table TM-13). Detailed analytical suite for water samples is shown in Table TM-18, which includes characterization of physical and chemical compositions as well as analysis of dissolved gases and major isotope systems.

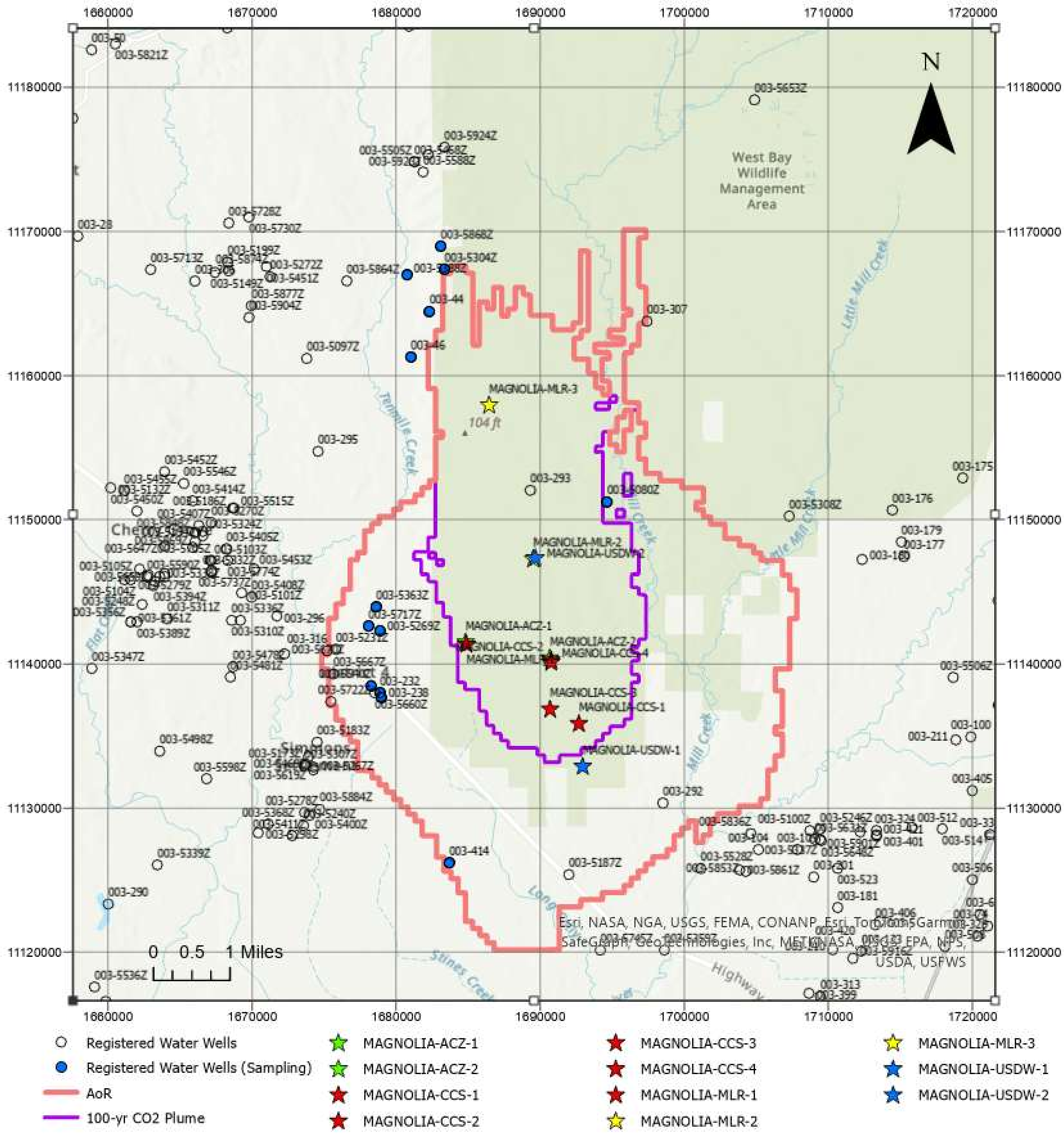

Figure TM-6—Location of potential sampling wells for legacy water wells, Above Confining Zone and USDW monitoring wells.

Table TM-12—Existing Shallow Freshwater Wells Potential Sampling Locations.

Well Number	Latitude	Longitude	Depth (ft)	Aquifer	Use	Well Status
003-5080Z	30.724722	-92.827500	133	Chicot	Rig Supply	Active
003-414	30.655833	-92.862500	195	Chicot	Irrigation	Active
003-46	30.752500	-92.870833	27	Chicot	Livestock	Active
003-44	30.761111	-92.866667	21	Chicot	Domestic	Active
003-5304Z	30.769167	-92.863333	130	Chicot	Domestic	Active
003-5868Z	30.773611	-92.864167	135	Chicot	Irrigation	Active
003-5388Z	30.768056	-92.871667	103	Chicot	Domestic	Active
003-5363Z	30.704722	-92.878611	95	Chicot	Domestic	Active
003-5717Z	30.701111	-92.880278	110	Chicot	Domestic	Active
003-5269Z	30.700278	-92.877778	82	Chicot	Domestic	Active
003-5540Z	30.689722	-92.879722	100	Chicot	Domestic	Active
003-232	30.688333	-92.877778	225	Chicot	Irrigation	Active
003-238	30.687500	-92.877500	171	Chicot	Industrial	Active

Table TM-13—Existing Shallow Freshwater Wells Sampling Frequency

Monitoring Location(s)	Monitoring Activity	Target Formation	Pre-Injection	Injection Period
Shallow water wells distributed in the AOR. Figure TM-6	Fresh water sampling and analysis.	Chicot	Baseline minimum (1) year before injection, (1) sample every quarter.	First sample 3 months after start of injection and quarterly after that for year 1 to year 3.

5.2 USDW Monitoring wells sampling and testing.

Tables TM-1**Error! Reference source not found.**4 and TM-15 show the location, monitored formation, and sampling frequency for USDW monitoring wells Magnolia USDW 1 and Magnolia USDW 2 (LAC 43:XVII.3625(A)(4)(a) and (b)).

Two (2) USDW monitoring wells will be drilled to the base of the Jasper Aquifer (Table TM-14). Specific completion intervals at each USDW well will be determined using onsite drilling and logging data and interpreted base USDW from offset logs. Site-specific base USDW will be confirmed from field investigations conducted during drilling and completion of USDW wells, including fluid sampling and analysis for gravimetric TDS.

Magnolia USDW 1 will be sampled prior to injection to establish geochemical baselines, and during the injection period for water quality monitoring (Table TM-15). USDW sampling will follow USGS methods and utilize an ESP. Detailed analytical suite for water samples collected from USDW monitoring wells is shown in Table TM-18 and is identical to the analytical suite used for the existing shallow freshwater wells. Pressure transducers will be deployed in USDW monitoring wells for high frequency monitoring of fluid levels and temperature during injection required by LAC 43:XVII.3625(A)(4).

Table TM-14—USDW Monitoring Wells Planned Locations.

Well Name	Latitude	Longitude	Elevation (ft)	Status	Measured Depth (ft)	Target Aquifer
Magnolia USDW 1	30.67435	-92.83282	86	Drilled	2,900-3,200	Jasper
Magnolia USDW 2	30.74335	-92.85380	101	Planned Future	2,900-3,200	Jasper

Table TM-15—USDW Monitoring Wells Sampling Frequency.

Monitoring Location(s)	Monitoring Activity	Pre-Injection	Injection Period
Magnolia USDW 1	Water Sampling	Baseline sample acquired after the well is drilled and completed.	One sample 3 months after the start of injection and quarterly after that.
Magnolia USDW 2	Water Sampling	Baseline sample acquired after the well is drilled and completed.	Quarterly.

5.3 Above Confining Zone Well water sampling and testing

Tables TM-16 and TM-17 show the location, interval, formation, and sampling frequency for ACZ monitoring wells Magnolia ACZ 1 and Magnolia ACZ 2 (LAC 43:XVII.3625(A)(4)(a) and (b)).

Two (2) ACZ monitoring wells will be drilled and completed in the first permeable sands above the upper confining zone (Table TM-16). Specific completion intervals at each ACZ monitoring well will be determined using onsite drilling and logging data and interpreted offset logs.

Pressure transducers will be deployed in ACZ monitoring wells for high frequency monitoring of fluid levels and temperature during injection required by LAC 43:XVII.3625(A). Dependent upon timing of scheduled maintenance, permanent downhole gauge failures may result in setting temporary downhole gauges with wireline.

ACZ monitoring wells will be sampled prior to injection to establish geochemical baselines, and during the injection period for water quality monitoring (Table TM-15). ACZ monitoring wells will be equipped with a U-Tube sampling system to facilitate collection of fluid samples, described in further detail in the QASP. Alternatively, in the case that a U-Tube line is not functional, ACZ monitoring wells will be sampling with downhole PVT sampling canisters. Detailed analytical suite for water samples collected from ACZ monitoring wells is shown in Table TM-18 and is identical to the analytical suite used for the USDW monitoring wells.

Table TM-16—Location of Magnolia ACZ 1 and Magnolia ACZ 2

Well Name	Latitude	Longitude	Elevation (ft)	Status	Measured Depth (ft)	Target Formation
Magnolia ACZ 1	30.69791	-92.85861	92	Planned	3,344-3,618	Lower Miocene
Magnolia ACZ 2	30.69485	-92.84011	91	Planned	3,337-3,611	Lower Miocene

Table TM-17—Location and Frequency of Water Sampling and Testing in Above Confining Zone wells

Monitoring Locations	Monitoring Activity	Target Formation	Pre-injection	Injection Period
Magnolia ACZ 1 Magnolia ACZ 2	Pressure and temperature measurement with downhole gauges	Lower Miocene	Baseline. Data acquired during installation of the completion	Continuously
Magnolia ACZ 1 Magnolia ACZ 2	Water sampling and testing	Lower Miocene	Baseline. Data acquired during installation of the completion	First samples 3 months after start of injection and quarterly after that

5.4 Analytical parameters for water testing in groundwater and above confining zone samples

Magnolia Sequestration Hub, LLC has proposed an extensive water quality characterization program using natural tracers and unique fluid chemical characteristics to define reservoirs within the storage complex (in-zone reservoir, ACZ, USDW, and freshwater aquifers). The sampling and analysis protocol will be used to establish baseline geochemical characteristics and differentiate changes in water quality between natural and anthropogenic influences.

Pre-injection baseline analytical will include detailed characterization of chemical composition and major isotope systems (Table TM-18). Following baseline characterization, a reduced analytical suite will be developed from baseline characterization results to focus on primary indicators of potential leakage. Isotopic compositions will likely not be routinely conducted during injection unless required for source attribution. Proposed changes to the analytical suite will be discussed with the UIC Director after the baseline data is collected and routine testing protocol is finalized. Table TM-18 outlines the analytical suite for water quality samples collected from existing shallow freshwater, USDW, and ACZ monitoring wells.

Field sampling methods and chain of custody procedures for water quality sampling are described in the QASP. All field and laboratory analytical test will be performed by third-party certified laboratories and follow applicable EPA or industry standard methods.

Table TM-18— Measured parameters and analytical methods summary for existing shallow freshwater, USDW, and ACZ monitoring wells.

Parameter	Analytical Method
Cations: Al, Ba, B, Cd, Ca, Cu, Cr, Fe, Pb, Li, Mg, Mn, Ni,P, K, Si, Na Sr, Zn	ICP-OES, EPA Method 6010d , ICP-MS Method 200.8 or equivalent
Other Metals: As, U, Co, Se, Pb, Mo, V	ICP-MS Method 200.8 or equivalent
Mercury	EPA 245.7 CVAA, or equivalent
Anions: Cl^-, Br^-, F^-, SO_4^{2-}, PO_4^{3-}, NO_3^-, $NO2^-$	Ion Chromatography, EPA Method 300.1 or similar
Carbonate, bicarbonate and hydroxide	Titration, ASTM D3875.
Gravimetric Total Dissolved Solids (TDS)	Gravimetric Method Standard Methods 2540C, ASTM D5907, EPA 160.1 or equivalent
Water Density	ASTM D5057, ASTM D4052 or equivalent
Stable Carbon Isotopes $^{13/12}C$ (^{113}C) of DIC in Water	Gas Bench and CF-IRMS for $^{13/12}C$
Radiocarbon ^{14}C of DIC in Water	AMS for ^{14}C
Hydrogen and Oxygen Isotopes $^{2/1}H$ (δ) and $^{18/16}O$ (^{118}O) of Water	CRDS H_2O
Carbon and Hydrogen Isotopes (^{14}C, $^{13/12}C$, $^{2/1}H$) of Dissolved Methane in Water	Offline Prep & Dual Inlet IRMS for ^{13}C; AMS for ^{14}C
Compositional Analysis of Dissolved Gas in Water (including N_2, CO_2, O_2, Ar, H_2, He, CH_4, C_2H_6, C_3H_8, iC_4H10, nC_4H_{10}, iC_5H_{12}, nC_5H_{12}, and C_{6+})	GC, ASTM 1945D, RSK 175 or equivalent
pH	ASTM D1293, EPA 150.23 or equivalent
Temperature	ASTM 2550
Conductivity	ASTM D1125
Conductivity (field)	EPA 120.1
ICP-OES = inductively coupled plasma optic emission spectrometry; ICP-MS = inductively coupled plasma mass spectrometry; GC/MS = gas chromatography–mass spectrometry; ; AMS = accelerator mass spectrometry; CRDS = cavity ring down spectrometry; IRMS = isotope ratio mass spectrometry; CVAA: Cold Vapor Atomic Absorption;	

5.5 Sampling methods for groundwater

Fluid sampling will be performed by qualified field personnel with oversight from licensed geologists or engineers. Appropriate fluid sampling procedures (e.g., USGS, USEPA) or industry best practices will be applied to ensure sample integrity and chain of custody are maintained. Sampling procedures and technical specification of tools are provided in the QASP. Operators may audit procedures and results of selected laboratories with a third party to improve quality control.

5.6 Laboratory to be used/chain of custody procedures

Fluid samples will be analyzed by third-party certified laboratories using applicable laboratory analytical methods (e.g., USEPA, ASTM) and best industry practices for gas chromatography, mass spectrometry, detector tubes, and photo ionization. Quality inspections will be periodically conducted based on adherence to appropriate applicable laboratory analytical methods outlined in the analytical suite. Sampling methods and chain of custody procedures are further described in the QASP.

6.0 *Carbon Dioxide Plume and Pressure Front Tracking [LAC 43:XVII.3625(A)(7)]*

Magnolia Sequestration Hub, LLC, will employ direct and indirect methods to track the extent of the carbon dioxide plume and presence or absence of elevated pressure during the operation period to meet the requirements of LAC 43:XVII.3625(A)(7).

6.1 Methods for CO_2 plume extension and pressure front monitoring

Table TM-19 and Table TM-20 present methods that Magnolia Sequestration Hub, LLC, will use to monitor the position of the CO_2 plume, including the activities, locations, and frequencies for the Magnolia Sequestration Hub.

Table TM-21 presents the surface location of the In Zone monitoring wells planned by the Project.

Table TM-19—Summary of methods for monitoring of CO_2 plume extension and Pressure Front

Monitoring Locations	Method	Monitoring Activity	Target Formation	Pre-injection	Injection Period
AOR	Indirect	Gravity survey	Reservoir, seal, and overburden	Baseline acquisition before injection	Every 5 years until injection ceases
AOR	Indirect	2D surface seismic survey	Reservoir, seal, and overburden	Baseline acquisition before injection	As required, based on other methods results.
AOR	Indirect	3D surface seismic survey	Reservoir, seal, and overburden	Baseline acquisition before injection	As required, based on other methods results.
Injection wells	Indirect	3D VSP time lapsed survey	Reservoir, seal, and overburden	Baseline once the wells are completed	Annually in CO_2 injectors until plume extends beyond radius of detection.
Injection & In Zone Monitoring wells (MLR)	Indirect	Pulse Neutron	Reservoir, seal, and overburden	Baseline once the wells are completed	Annually
Injection & In Zone Monitoring wells (MLR)	Direct	Downhole gauges; pressure and temperature.	Reservoir	Initial completion	Continuously

Table TM-20—Summary of Location and Sampling Frequency for Pressure Front Monitoring with the In Zone monitoring wells.

Location	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
In Zone Monitoring wells (MLR)	Pressure and temperature gauges	Downhole deployment on tubing	10 sec	5 min

6.1.1 Methods for CO2 Plume extension and pressure front monitoring details

A multi-scale approach will be employed for plume migration, CO_2 saturation monitoring, and potential leak detection with multiple seismic methods.

A baseline acquisition program consisting of surface gravity, 2D seismic, surface 3D seismic, and 3D Vertical Seismic Profile (VSP) surveys will be acquired prior to injection and is designed to calibrate the in-situ seismic response across multiple scales of investigation and model the predicted seismic response resulting from injection (Figure TM-7).

During the injection period, gravity will be acquired and analyzed every five years to monitor plume movement and saturation on an AOR-wide scale. 3D VSP timelapse surveys will also be acquired during the injection period to calibrate the early development of the plume. If any aspect of the monitoring system indicates plume movement outside the intended pore space at any point during the injection and post injection periods, a 2D and/or 3D timelapse surface seismic survey may be acquired and compared to the reference surface seismic baseline surveys.

6.1.1.1 3D surface seismic baseline survey

A 3D surface seismic baseline survey will be acquired covering the AOR prior to injection. Notional acquisition parameters for the survey are designed specifically to provide full fold coverage of the storage complex and strata above. The 3D surface seismic baseline survey will be acquired primarily with Vibroseis as the energy source; however, dynamite may be used in some areas due to surface conditions. The survey will utilize a high density of sources and receivers designed to increase the definition of shallow horizons above the confining zone. The 3D surface seismic baseline survey has a large surface footprint sometimes extending more than 1 mile beyond the AOR in all directions and is designed to image from surface to basement on a broad frequency band. The processing sequence will include onshore pre-processing and depth imaging (pre-stack depth migration and velocity model building), followed by complete post-migration processing. Survey results will be used to update the structure, faulting (if any), and stratigraphy for input into an updated static model prior to injection.

Survey results will also be integrated with rock-physics studies to determine the expected timelapse seismic response given predicted CO_2 saturation values. Extensive testing of the modelled seismic response will be performed prior to injection to interrogate the predicted amplitude response for a multitude of CO_2 saturation scenarios as determined by the dynamic simulation.

Additional 3D surface seismic surveys may be acquired at any time in the event that the greater monitor system indicates unexpected migration of CO_2 that warrants further characterization.

6.1.1.2 2D surface seismic baseline survey

2D surface seismic will be acquired prior to injection to establish a baseline. The 2D surface seismic baseline survey is designed to cover the extent of the AOR. The 2D surface seismic baseline survey will be acquired primarily with Vibroseis as the energy source; however, dynamite may be used in some areas due to surface conditions. The survey will utilize a high density of sources and receivers designed to increase the definition of shallow horizons above the confining zone. The 2D surface seismic baseline survey data will be processed with 2D pre-processing and pre-stack migration workflows, followed by complete post-migration processing.

Additional 2D surface seismic surveys may be acquired at any time in the event that the greater monitor system indicates unexpected migration of CO_2 that warrants further characterization. The 2D seismic timelapse data will be processed with joint parallel 2D time-lapse pre-processing workflows of the baseline, current, and previous monitor surveys, followed by pre-stack time migration and complete post-migration processing. Seismic amplitude changes observed between the current and previous surveys will be evaluated against the rock physics model to infer changes in CO_2 saturations. These results will be checked against and integrated into the predictive models.

6.1.1.3 Gravity baseline and time-lapse surveys

Surface time-lapse microgravity monitoring is a passive geophysical technique used to detect subsurface mass redistribution resulting from CO_2 injection. The method relies on precise measurements of gravity acceleration changes over time, which correlate with density variations in the reservoir due to CO_2 replacing brine. For the Magnolia Sequestration Project, located in Allen Parish, Louisiana, this technique is being implemented as part of an integrated monitoring strategy to track the extent and shape of the CO_2 plume.

Gravity methods are directly sensitive to changes in bulk density. The 3D gravity simulations for Magnolia show that density changes due to CO_2 injection become detectable within five years of injection, with modeled gravity responses exceeding instrument noise levels of 0.002–0.005 mGal. This makes gravity particularly effective for long-term monitoring of mass redistribution, especially as for the Magnolia project in high porosity deep saline formations.

Magnolia Sequestration Hub, LLC. developed an in-house advanced 3D gravity feasibility workflow, utilizing density differences derived from reservoir simulations. The modeling results have confirmed that surface microgravity surveys are effective for monitoring CO_2 plume propagation at the Magnolia site. These simulations, which track temporal changes in subsurface density distributions resulting from CO_2 injection, demonstrate that gravity anomalies will be detectable well above instrument noise thresholds (Figure TM-7).

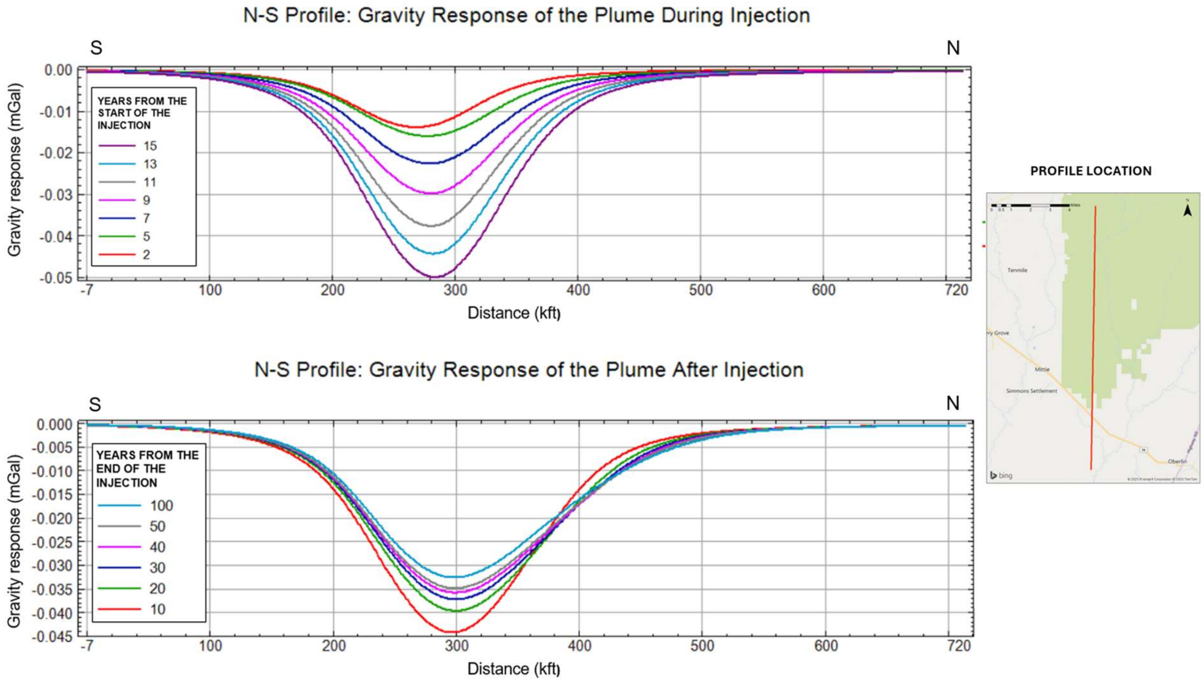

Figure TM-7—Profile of time-lapse gravity differences due to CO_2 plume propagation.

To facilitate optimal monitoring of CO_2 plume migration at Magnolia, a strategically distributed network of gravity stations will be established. High-resolution gravity data will be acquired through an integrated approach employing both relative and absolute gravity measurements, ensuring optimal spatial coverage and data fidelity. Potential noise sources, such as water table fluctuations and surface deformation, will be systematically monitored and rigorously accounted for during data processing following well established procedures (Kennedy et al., 2021; Gettings, 2009).

For the quantitative recovery of subsurface density and CO2 saturation changes and caused by CO_2 injection, a constrained 3D gravity inversion workflow will be applied to characterize plume dynamics.

6.1.1.4 3D VSP baseline and time-lapse surveys

The 3D baseline VSP surveys will be acquired at the injection wells using permanent DAS fiber optic cables installed in the wellbores with conventional Vibroseis vehicles and/or SOV (surface orbital vibroseis) as the surface source. All VSP surveys will use state-of-the-art VSP pre-processing and depth imaging (pre-stack depth migration), followed by post-migration processing. The imaging radius for the 3D VSP survey is assumed to be 0.5 miles. Within this radius, high resolution seismic imaging (exceeding that of surface seismic) is expected, along with accurate time-depth control. Structure and stratigraphy from the 3D baseline VSP surveys will be evaluated and integrated into the Geomodel. Survey results will be integrated with rock-physics studies to determine the expected timelapse VSP seismic response given predicted CO_2 saturation values.

Repeat timelapse VSP surveys will be acquired during early injection (using the same acquisition parameters as the VSP baseline surveys) until a time when the plume is determined to have moved beyond the imaging radius for a particular location. The timelapse surveys will be processed using state-of-the-art joint parallel VSP time-lapse pre-processing of baseline, current, and previous monitor surveys, followed by pre-stack depth migration and complete post migration processing. Seismic amplitude changes observed between the current and previous surveys will be evaluated against the rock physics model to infer changes in CO_2 saturations. The high-imaging-resolution, and acquisition of repeat VSP surveys is intended to provide detailed information on the early evolution of the CO_2 plume, including (but not limited to) the response to heterogeneity within the injection reservoir, the integrity of the seals, the rate of CO_2 movement, and the fidelity of the subsurface Geomodel and resulting simulation.

Additional timelapse VSP surveys may be acquired in the event that unexpected CO_2 movement is detected at the injection wellbores. The ability to collect high-resolution VSP data at the wellbores will allow for rapid evaluation and characterization of and response to unexpected CO_2 migration in such an event.

6.2 Location selection for the In Zone Monitoring wells

Table TM-21—Location of In Zone Monitoring wells

Well Name	Latitude	Longitude	Elevation (ft) GL + KB	Status	Target monitoring interval MD (ft)	Target monitoring interval TVDSS (ft)	Target Formations
Magnolia MLR 1	30.69798	-92.867289	120	Planned Future	4840-6800	4719-6679	Frio1-Frio7
Magnolia MLR 2	30.72029	-92.832252	118	Planned Future	4715-6644	4597-6526	Frio1-Frio7
Magnolia MLR 3	30.74336	-92.853492	128	Planned Future	4529-6402	4400-6273	Frio1-Frio7
YAMS MLR 004	30.67429	-92.832989	112	Drilled, TA	5109-7106	4996-6994	Frio1-Frio7

7.0 Surface and Near Surface Monitoring [LAC 43:XVII.3625(A)(8)]

7.1 Soil Gas Monitoring and Isotopic Fingerprinting

Magnolia Sequestration Hub, LLC will install soil gas sample stations and collect soil gas samples using the Gulf Coast Carbon Center (GCCC) methodology (Figure TM-8; Table TM-22). Samples will be analyzed by a certified laboratory to determine bulk gas and gas isotopic compositions. Analytical results will be used to develop a Process Based Soil Gas Monitoring approach for evaluation and attribution of potential geochemical and ecological changes overtime at the site.

Soil gas geochemical modeling in concert with subsurface geochemical data from monitoring wells will be used to define diagnostic parameters soil gas source attribution.

Soil gas well sampling will occur quarterly and commence a minimum of one year prior to injection to establish baseline geochemical characterization and site variability. Soil gas will be analyzed quarterly for CO_2, O_2, N_2, CH_4, C1-C5 hydrocarbons, $\delta^{13}C$ and ^{14}C of CO_2, and CH_4 and δD of CH_4 (Table TM-23). Baseline geochemical characterization will be used to develop site-specific protocols for evaluating soil gas geochemical data such as soil gas source differentiation of potential vertical upward CO_2 migration. Following baseline characterization, sampling frequency for gas isotopic compositions may be reduced unless required for source attribution.

7.1.1 Soil Gas Well Installation and Sampling

Permanent soil gas wells will be installed by a licensed driller who is qualified to drill and install permanent soil gas wells using drilling equipment and methods that are appropriate for site conditions and will not introduce contaminants into the borehole or casing. Anticipated depths for soil gas wells range from 3 to 6 feet below ground surface. Four protective bollards and a cement pad will be installed at each soil gas well location. Soil gas wells will be completed at the surface with stickup, protective steel cover, locking cap, and scribed well ID or tags.

Soil gas probes will be installed using Geoprobe® dual tube sampling system to advance each boring to target depth, resulting in a minimum amount of soil disturbance around the borehole annulus. The dual-tube sampling system typically involves advancing a 2 1/2-inch diameter inner sampling probe followed by advancing a 3 1/2-inch diameter outer casing. Drill cuttings will be continuously screened for VOCs and logged using USGS methodology during drilling activities and recorded on a field boring log along with any applicable observations. Soil gas wells will be constructed with solid casing, 6-inch to 12-inch long prefabricated screen intervals, and 1/4-inch stainless steel tubing for the gas sampling probe. Soil gas well installation activities will involve setting casing and screen in borehole followed by appropriate clean sand pack material, bentonite seal, and neat-cement grout. Soil gas probes will be fitted with airtight stainless steel compression fittings (e.g., Swagelok®) with valves to allow for an airtight connection to soil gas sampling equipment. Following soil gas well installation, vacuum and Helium leak tests will be conducted on each soil gas probe to confirm isolation of screened interval. Soil gas well installation and sampling will be performed with the understanding that field conditions are variable and can result in changes to drilling, sampling, and installation strategies.

Sampling will be performed by qualified field personnel with oversight from licensed professional geologist or engineer. Appropriate sampling procedures (e.g., USGS, USEPA) or industry best practices will be applied to ensure sample integrity and chain of custody are maintained. Sampling procedures and technical specification of tools are provided in the QASP.

Fluid samples will be analyzed by third-party certified laboratories using appropriate laboratory analytical methods (e.g., USEPA, ASTM) and best industry practices for gas chromatography, mass spectrometry, detector tubes, and photo ionization. Quality inspections will be periodically conducted based on adherence to appropriate applicable laboratory analytical methods outlined in the analytical suite. Sampling methods and chain of custody procedures are further described in the QASP.

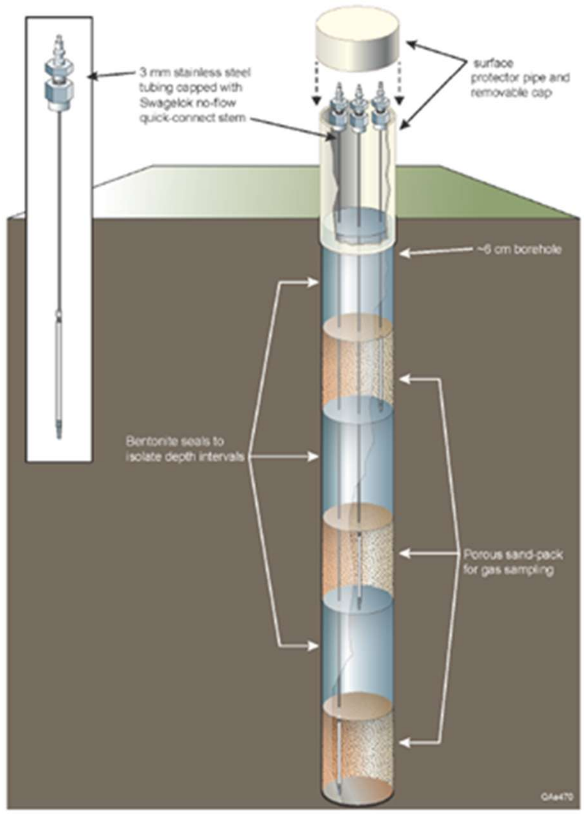

Figure 1. Schematic of gas sampling station construction showing individual gas wells set at different levels. Not to scale.

Figure TM-8—Schematic of Gas Sampling Station

Table TM-22—Gas Sampling Locations, Frequencies, and Methods

Monitoring Locations	Monitoring Activity	Target Formation	Pre-injection	Injection Period
Soil gas stations	Soil gas sampling and compositional gas analysis	Vadose zone	Minimum 1 years of characterization, 1 sample per station per quarter	Quarterly starting 3 months after injection is approved, 1 sample per station
Soil gas stations	Isotopic compositions of CH_4 and CO_2	Vadose zone	Minimum 1 year of characterization, 1 sample per station per quarter	As required
AOR	Electromagnetic airborne survey	Surface	1 year before injection	As required based on other monitoring techniques responses

Table TM-23—Soil Gas Analysis Parameters

Soil Gas Parameter	Analysis method
CO_2, N_2, O_2,	Gas Chromatography (GC)
CH_4, C_2-C_4	Gas Chromatography (GC)
C_5-C_6	Gas Chromatography (GC)
$\delta^{13}C$ of CO_2	Gas chromatography with combustion isotope ratio mass spectrometry (GC/C/IRMS)
$\delta^{13}C$ of CH_4	Gas chromatography with combustion isotope ratio mass spectrometry (GC/C/IRMS)
δD of CH_4	Gas chromatography combustion isotope ratio mass spectrometry (GC/C/IRMS)
^{14}C of CO_2	Accelerated mass spectrometry (AMS).
^{14}C CH_4	Accelerated mass spectrometry (AMS).

7.2 Electromagnetic and Magnetic Surveys

An airborne electromagnetic (EM) survey will be conducted over the site to establish a baseline of surface and near-surface electrical resistivity distribution due to fluctuations of the water table and groundwater salinity. EM data can used to identify and delineate near-surface saline sources that may be required for understanding soil gas and groundwater geochemical baselines and changes at the site.

EM surveys will be performed with aircraft mounted source and receivers to cover extensive areas of investigation at an approximate ground clearance of 115 ft. The data acquisition system will be equipped with Geographic Positioning System (GPS) electronic navigation system, laser and radar altimeters to ensure accurate positioning of the data, a magnetometer, and airborne video. For the baseline survey, a 1D data inversion will be used.

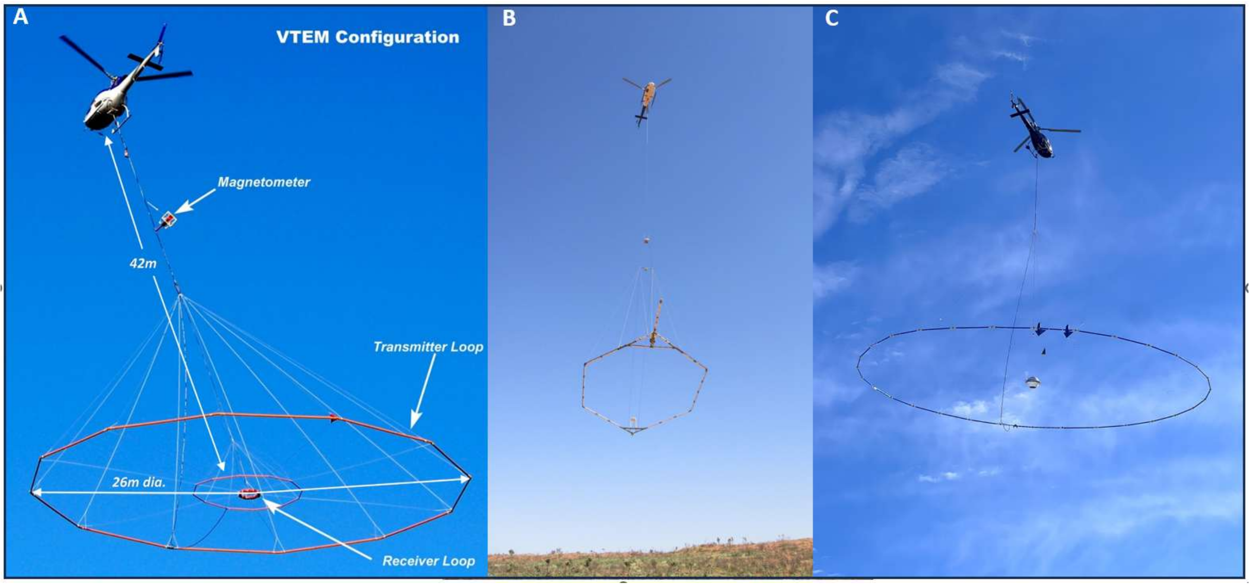

Figure TM-9—Varying configurations of airborne time-domain electromagnetic system. A) Geotech VTEM system, courtesy of Geotech (*https://geotech.ca/papers/helicopter-electromagnetic-vtem-ztem-applications-gold-exploration)*; B) SkyTEM system, courtesy of SkyTEM; and C) HeliTEM system, courtesy of Xcalibur Multiphysics

An airborne magnetic survey will be conducted over the site prior to initial injection for detection of near surface steel-cased wellbores and wellheads. Magnetic data can be used to confirm location of existing artificial penetrations (APs) with the AOR.

The magnetic survey will detect magnetic anomalies (steel casing or wellheads) using an airborne acquisition system and a magnetometer heigh of approximately 80 ft above ground level and magnetic data line spacing of approximately 65 ft. The data acquisition system will be heliborne and equipped with Geographic Positioning System (GPS) electronic navigation system, laser and radar altimeters to ensure accurate positioning of the data, a magnetometer, and airborne video.

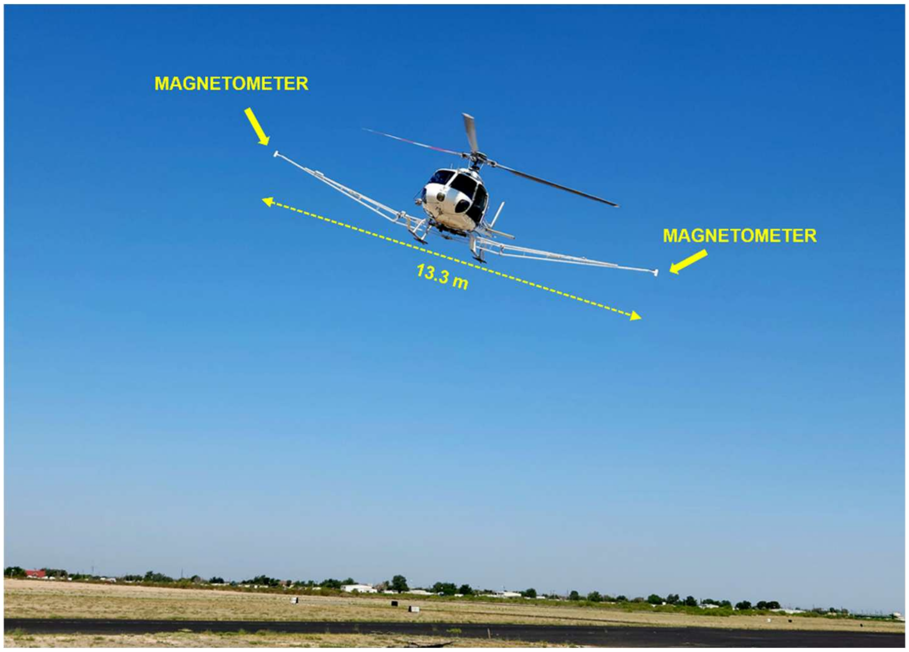

Figure TM-10—Example of heliborne magnetic data acquisition system (MIDAS by Xcalibur, Inc.)

7.3 CO_2 sensors in injector and monitoring wellheads

Magnolia Sequestration Hub, LLC, will install infrared gas detectors close to the wellheads of the injector and monitoring wells. These sensors will interface with the surveillance system to set alarms and identify on potential leaks at the surface. The final selection of the technology will consider the integration of all the sensors and transducers in a unique surveillance system. Calibration and maintenance protocols will be based on the manufacturer specifications and performed by specialized professionals. Technical specifications for the CO_2 leak detector are provided in the QASP Plan.

Table TM-24—Atmospheric CO_2 Sensor in wellhead

Tool	Pre-Injection	Injection
Atmospheric CO_2 sensor in wellhead – CO2 injector well	n/a	Continuously
Atmospheric CO_2 sensor in wellhead – Monitoring wells	n/a	Continuously

<u>8.0 Induced seismicity monitoring</u>

While induced seismicity is not anticipated, Magnolia Sequestration Hub LLC will deploy a seismometer monitoring network to determine the locations, magnitudes, and focal mechanisms of any seismic events observed near the injection site. This information may be used to address public concerns and identify other features that may help to evaluate the plume and pressure front behavior.

8.1 Monitoring location and frequency for seismicity measurement

Table TM-25—Seismicity Monitoring Tools

Tool	Pre-Injection	Injection
Seismometer network on surface to measure potential induced seismicity events.	Minimum (1) year baseline before injection	Continuously

8.2 Traffic light system

The operator intends to maintain a surface array for the duration of the project. This seismic monitoring will be conducted with a surface array deployed to ensure detection of events above ML 2.0 with epicentral locations within 5.6 miles of the injection well covering an area of 100 square miles. This areal coverage was determined by referencing the Texas Railroad Commission's historic designation of Seismic Response Areas (SRA). SRAs are areas determined by RRC seismologists for which consistent identification and seismic response approach will be implemented after the occurrence of seismic events with a magnitude of 3.5 or greater (TRRC, January 2022). For example, after a magnitude 5.4 earthquake occurred on December 19, 2022, the RRC designated SRA with a radial area of 100 square miles (TRRC, December 2022). Out of an abundance of caution, the seismic monitoring area for this project is designed to preemptively cover an area equivalent to the RRC's post-event SRA coverage.

If an event is recorded by either the local private array or public national array is determined to have occurred within 5.6 miles of the injection well, the operator will implement its response plan as further defined below:

1. For events above M_L 2.0 within 5.6 miles of the injection well, the operator will closely monitor seismic activity and may implement a pause to operations or continue operations at a reduced rate, should analysis strongly indicate a direct causal relationship between injection operations and detected seismicity.
2. For events above M_L 3.5 within 5.6 miles of the injection well, the operator will initiate contact with relevant regulatory and/or government entities. Operator will begin a technical review within 24 hours of the event to determine if a causal relationship exists. Should a causal relationship be determined, a revised injection plan would be developed to reduce or eliminate operationally related seismicity. Such plans are dependent on the pressures and seismicity observed and may include, but not be limited to:
    - Reducing CO_2 injection pressures until reservoir pressures fall below a critical limit.
    - Increasing water production rates until reservoir pressures fall below a critical limit
    - Continuing operations at a reduced rate and/or below a revised maximum operation pressure.

- o Operator will obtain approval from the relevant regulatory and/or government entities to implement revised plan
- o If the event is not related to the storage facility operation, the operator will resume normal injection rates.

3. For events above M_L 4.5 within 5.6 miles of the injection well, the operator will stop injection as soon as safely practical. The operator will inform the regulator of seismic activity and inform them that operations have stopped pending a technical analysis. The operator will initiate an inspection of surface infrastructure for damage from the earthquake. A detailed analysis will be conducted to determine if a causal relationship exists between injection operations and observed seismic activity. Should a causal relationship be determined, a revised injection plan will be developed to reduce or eliminate operationally related seismicity before resuming injection operations. Such plans are dependent on the pressures and seismicity observed and may include, but not be limited to:
    - Reducing injection pressures until reservoir pressures fall below a critical limit.
    - Increasing water production rates until reservoir pressures fall below a critical limit
    - Continuing operations at a reduced rate and/or below a revised maximum operation pressure.

- o Operator will obtain approval from the relevant regulatory and/or government entities to implement revised plan
- o If the event is not related to the storage facility operation, and with previous approval from the regulators, the operator will adjust injection and/or production rates to previous rates in steps, while increasing the surveillance.

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