Riverside Energy Michigan, LLC Chester 21-29N-02W Storage Facility Subpart RR Monitoring, Reporting, and Verification Plan

February 6, 2025

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Abbreviations and Acronyms

°F	Degrees Fahrenheit
AMA	Active Monitoring Area
API	American Petroleum Institute
BBL	Barrel
Bcf	Billion cubic feet
BHL	Bottom hole location
cf	Cubic feet
CO_2	Carbon dioxide and other carbon oxides
EGLE	Environment, Great Lakes, and Energy
EOR	Enhanced oil recovery
EPA	United States Environmental Protection Agency
ft	Foot (feet)
GOR	Gas to oil ratio
GRMD	Geologic Resources Management Division
HMI	Human Machine Interface
IP	Initial production
KB	Kelly bushing
lbs	Pounds
Mcf	Thousand cubic feet
Mcfd	Thousand cubic feet per day
MD	Measured depth
md	Millidarcy
MIT	Mechanical integrity test
MMA	Maximum Monitoring Area
MMscf	Million standard cubic feet
MMscfd	Million standard cubic feet per day
MRV	Monitoring, Reporting, and Verification
NNPRT	Northern Niagaran Pinnacle Reef Trend
P&A	Plugged and abandoned
PBTD	Plugged back total depth
pH	Scale of acidity
psi	Pounds per square inch
SCADA	Supervisory Control and Data Acquisition
scf	Standard cubic feet
SHL	Surface hole location
SLB	Schlumberger
SWD	Salt water disposal
TD	Total depth
TDS	Total dissolved solids
TVD	True vertical depth
UIC	Underground Injection Control
USGS	United States Geologic Survey

1. STORAGE FACILITY INFORMATION

1.1 Project Overview

The Chester 21-29N-02W Storage Facility is a CO_2 acid gas disposal injection project being developed by Riverside Energy Michigan, LLC (Riverside) in Otsego County, Michigan. The purpose of the project is to securely store the CO_2 emissions captured from the processing of natural gas produced from the Antrim Shale biogenic gas play in the northern Michigan Basin. The captured CO_2 will be injected into a Niagaran Pinnacle Reef reservoir, the Chester 21-29N-02W Reef.

The Chester 21-29N-02W Reef was once a natural gas producing field but has since been depleted, plugged, and abandoned. The Niagaran reservoir at a depth of approximately 6,100 feet (ft) enables CO_2 to be stored efficiently in a critical gas phase. This Monitoring, Reporting, and Verification (MRV) plan is designed in accordance with 40 CFR 98.440-449, Subpart RR, to define and describe the Chester 21-29N-02W Storage Facility (Storage Facility).

The Chester 21-29N-02W Storage Facility spatially consists of the surface and subsurface areas contained within the active and maximum monitoring areas, defined in *Section 3*. In process terms, the Chester 21-29N-02W Storage Facility begins at the mass flow meter positioned on the CO_2 flowline immediately upstream of the injection wellhead and ends in the subsurface at the reservoir's lithofacies-controlled aerial limits. Figure 1 shows the location of the Chester 21-29N-02W Storage Facility, the separate Turtle Lake Capture Facility (Capture Facility) from where CO_2 is sourced, and the approximately 2 miles of CO_2 flowline that links the two.

The Devonian age Antrim Shale Formation, from which the CO_2 originates as a minor co-constitute of natural gas production, produces regionally from a subsurface depth of approximately 1,000 to 2,000 ft. In contrast, the Silurian age Niagaran reef reservoir that constitutes the Chester 21-29N-02W Storage Facility is approximately 6,000 to 7,000 ft deep and currently has neither unplugged wells nor hydrocarbon production associated with it. It is the explicit purpose and design of this project to sequester and dispose of CO2 and not to facilitate any additional production from the Storage Facility. As such, the Turtle Lake Capture Facility exists and operates separate from the Storage Facility and is not a part of the Storage Facility as defined in this MRV plan.

1.2 Reporter Number

Greenhouse Gas Reporting Program Identifier: 589821

Operator: Riverside Energy Michigan, LLC on behalf of Riverside Carbon Solutions, LLC

1.3 Storage Facility Location

The Storage Facility is located in Otsego County, Michigan, approximately 9 miles southeast of the town of Gaylord, Michigan.

Storage Facility location description in the Public Land Survey System:

Sections 21 and 22, T29N-R02W

Storage Facility coordinates in North American Datum of 1983 (NAD83):

Latitude: 44.896048°
Longitude: -84.547381°

1.4 Underground Injection Control Permit Class: Class II

The Michigan Department of Environment, Great Lakes, and Energy (Michigan-EGLE) Geologic Resources Management Division (GRMD) administers the Underground Injection Control (UIC) program in Michigan for all Class II injection wells, by the statutes and rules subject to Part 615, Supervisor of Wells, of the Michigan Natural Resources and Environmental Protection Act (NREPA), Public Act 451 of 1994, as amended. The CO_2 injection well (Smith 3-21) will be operated by Riverside Energy Michigan, LLC, permitted as a UIC Class II well, and regulated by Michigan-EGLE GRMD.

The UIC Class II permit for the proposed Smith 3-21 injection well was issued by Michigan-EGLE GRMD on 1/10/2025 (EGLE permit number 61818).

The unique identifer assigned to the well is API number 21-137-62019-00-00.

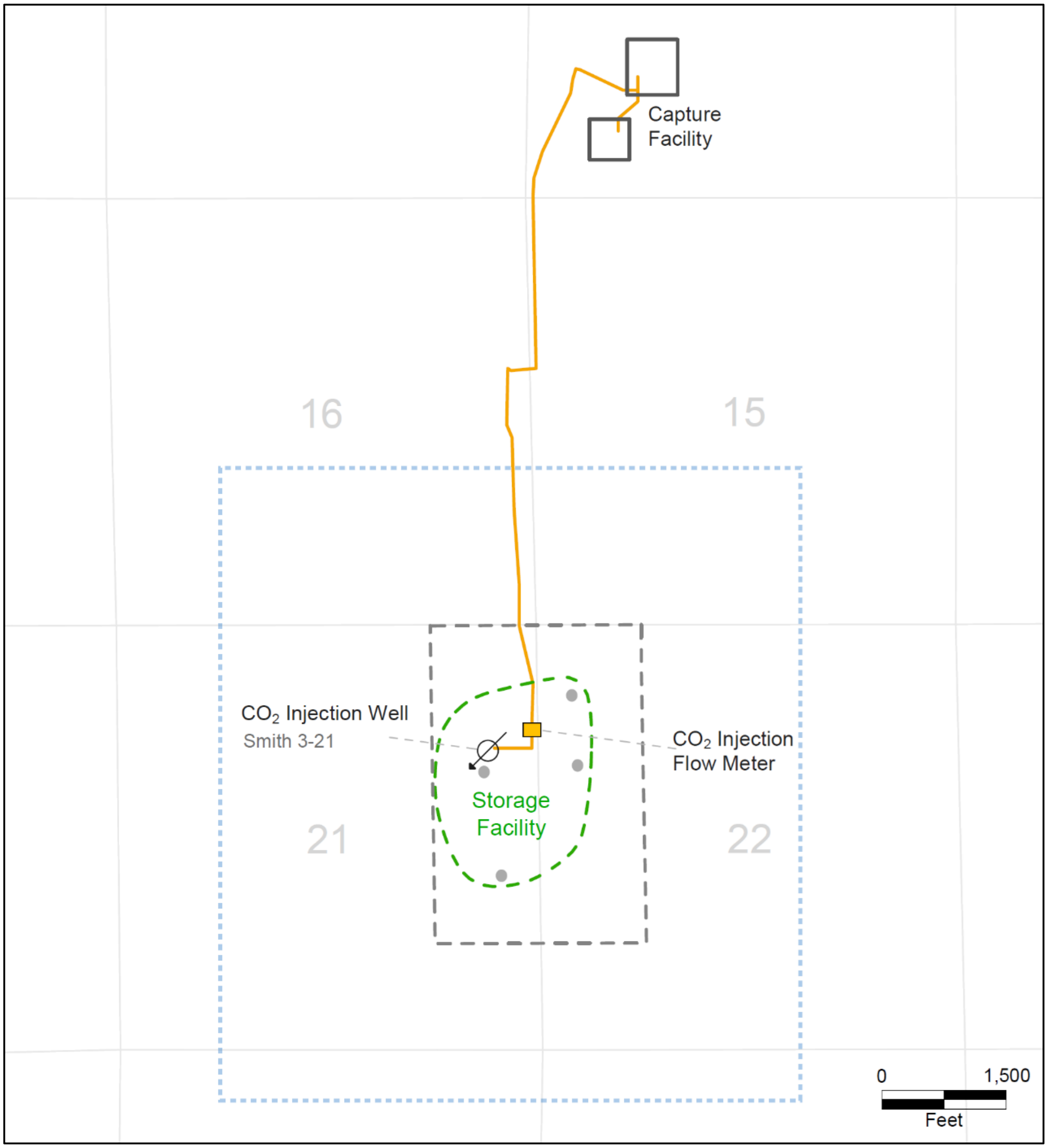

Figure 1. Map of the Chester 21-29N-02W Storage Facility (dashed green outline), showing the Capture Facility, CO_2 pipeline (orange) from the Capture Facility, Injection Unit (dashed gray rectangular outline) permitted with Michigan-EGLE, the Active and Maximum Monitoring Areas for the Storage Facility (dashed blue outline), the Smith 3-21 CO_2 Injection Well, and all plugged wells within the Storage Facility (gray circles). Section 3 and Figure 14 discuss the Active and Maximum Monitoring Areas in greater detail. The base map depicts the PLSS and shows all or portions of sections within T29N-R02W.

2. PROJECT DESCRIPTION

2.1 Regional Geology

The Northern Niagaran Pinnacle Reef Trend (NNPRT) in the Michigan Basin features several hundred highly compartmentalized pinnacle reefs found at an average dept of about 6,000 ft below the ground surface. These reefs are separated from one another by distances as little as hundreds of feet to as much as several miles. The NNPRT originated from coral reefs formed during the Silurian Period 420 to 440 million years ago in tropical sea environments (Figure 2).

The reefs were subsequently buried by sediments deposited around and above the reefs encasing them within mostly impermeable layers of evaporitic and carbonate rocks. These impermeable evaporitic and carbonate rocks are responsible for trapping and sealing prolific quantities of oil and gas within these reefs.

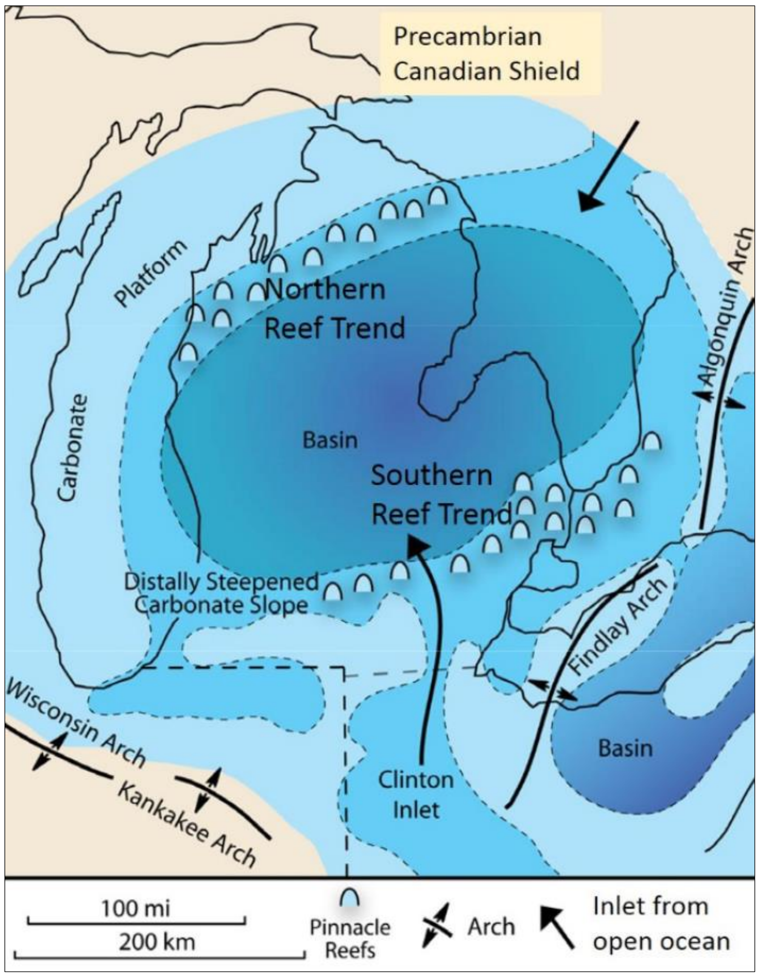

Figure 2. Map of the Michigan Basin and interpreted paleogeography during the Silurian Period, depicting the Northern Niagaran Reef Trend amongst regional environments. Ritter (2008) modified after Briggs and Briggs (1974).

The NNPRT forms a part of a broader shallow shelf carbonate depositional system that partially encircles the Michigan Basin. The NNPRT is positioned along the margin of the system's carbonate platform. Individual reefs typically range in area from 50 to 500 acres and have vertical heights between 100 to 700 ft in the subsurface.

The reservoir facies primarily consist of porous and permeable dolomite and limestone. Some reefs are completely dolomitized, while others are essentially all limestones. Dolomitization of the reefs, which helps enhance porosity, increases as the reefs become shallower. Salt and anhydrite plugging of porosity occurs in the deeper reefs (Gill 1979). Reef porosity values can be as high as 35%, but typically average 3 to 12%. Net pay intervals can total from only a few feet to several hundred feet. The most productive reef reservoirs are characterized by dolomitized reef facies with well-developed inter-crystalline and vuggy porosity. Secondary porosity is present and can enhance permeability, which typically averages 3 to 10 millidarcies.

The Niagara and A1 Carbonate Formations of the early Silurian Niagara Group contain the main reservoir units within the reefs, shown in the stratigraphic column in Figure 3. The base of the Niagara Formation, referred to as the "Lockport" or "White Niagaran" is typically a partially dolomitized to dolomitized crinoidal wackestone, (Charbonneau, 1990). Overlying the Lockport, the Guelph Formation is comprised of units commonly referred to as the "Gray" and "Brown" Niagaran. The Gray Niagaran and Lockport are typically characterized by very low porosity. The Brown Niagaran comprises the core of the reef reservoir and pinnacle reef buildup. It is characterized by dolomite and limestone skeletal wackestones and boundstones, (Huh, 1973).

The A1 Carbonate overlies the Brown Niagaran at the reef crest and is sometimes referred to as the "Ruff" Formation. The A1 Carbonate is considered a reservoir unit in the crest of some reefs but grades into tight, low porosity dolomitic mudstone near the reef flanks, (Huh, 1973).

The A1 Carbonate and Brown Niagaran Formations are encased by a sequence of evaporites and salt-plugged carbonates, comprising the seal for the reefs. The A1 Evaporite is typically thin or not present at the crest of the reef but forms a seal of the Brown Niagaran at reef flanks. Overlying the A1 Carbonate and providing the primary seal for the Storage Facility is the A2-Evaporite, Figure 3. The A2 Evaporite is characterized by non-porous and impermeable anhydrite at the reef crest. It transitions to halite dominated facies off the structure of the reef. Further overlying the A2 Evaporite are hundreds of feet of non-porous evaporite and low porosity carbonate and shale sequences that comprise the Salina Group.

The lithostratigraphy and internal reef structure are visualized in Figure 4. Reef formation began surrounding a carbonate bioherm in warm, shallow waters, (Rine, 2017). The reef core grew upwards as sea level in the Michigan Basin rose. When sea level fell, the reefs became exposed and evaporite deposition encased the reefs.

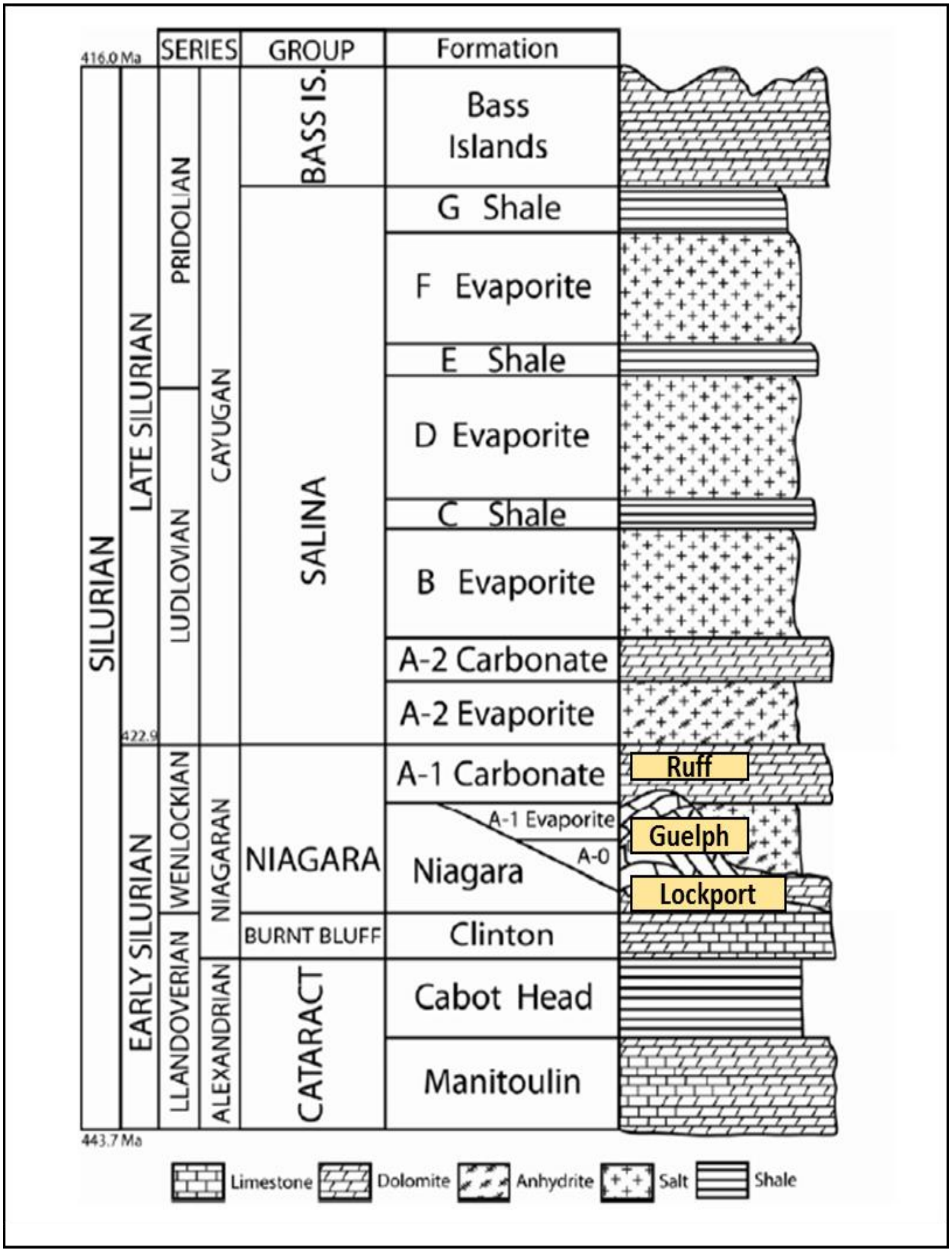

Figure 3. Generalized stratigraphic column for Silurian period deposits in the Michigan Basin, with emphasis on Niagaran reefs (Ritter, 2008).

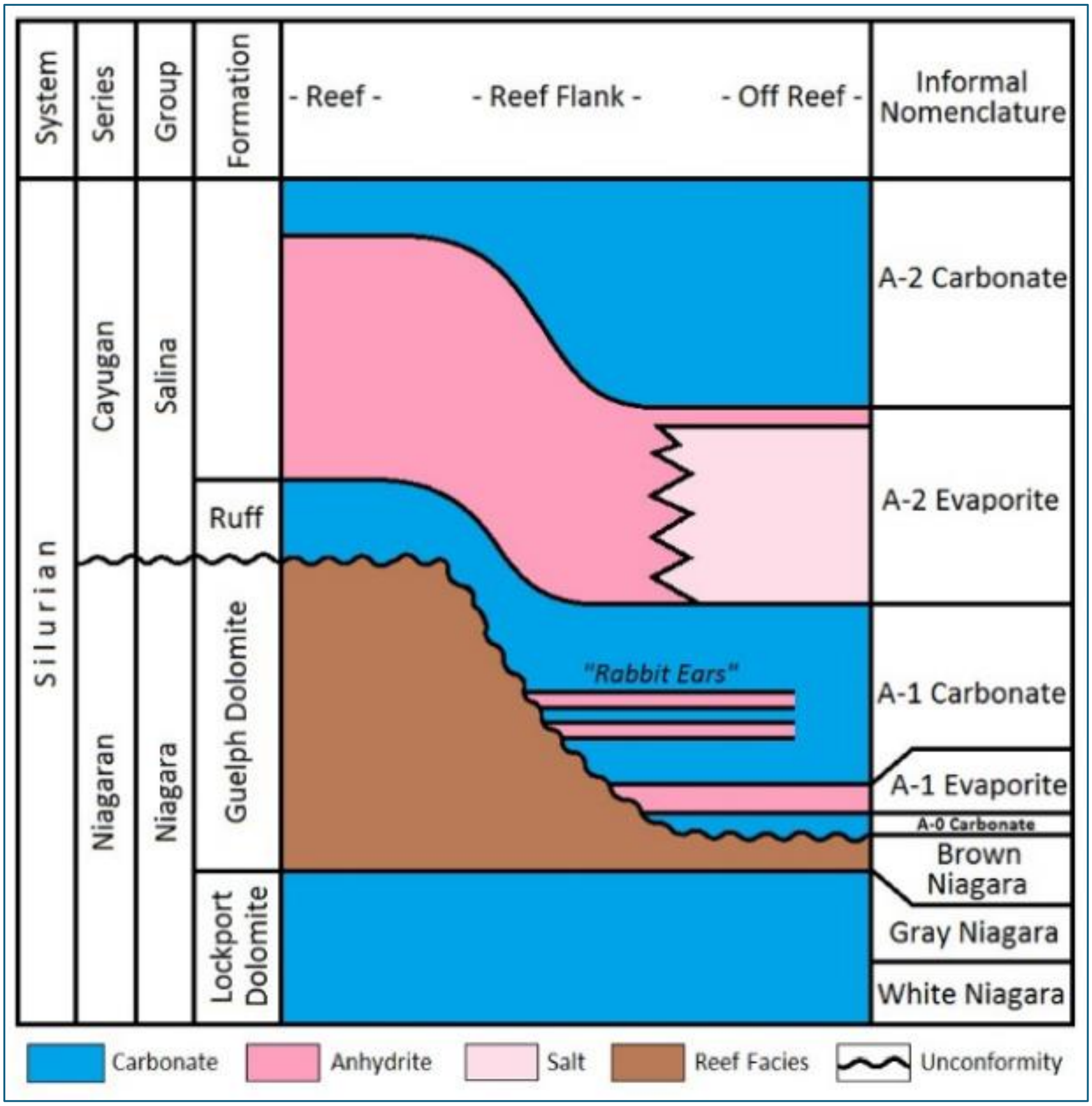

Figure 4. Lithostratigraphy visualization of a Niagaran reef interval, (Gupta et al., 2020 modified from Gill 1979 and Huh 1973).

2.2 Site Characterization

The Chester 21-29N-02W Field is a Northern Niagaran Pinnacle Reef located in Sections 21 and 22 of Township 29 North, Range 2 West, Otsego County, Michigan. The Field has a footprint of approximately 90 acres and is buried to a depth of 6,710 ft TVD (-5,472 ft subsea TVD) at its base to 6,160 ft (-4,921 ft subsea TVD) at its top.

While the reef structure itself is 550 ft tall and consists of the Brown Niagaran Formation, an additional 60 ft of A1 Carbonate Formation rests directly on top of the Brown Niagaran Formation and serves as a vertical extension of the physical reservoir observed in the Niagaran interval. Porosity of the A1 Carbonate and Brown Niagaran reservoir intervals derived from wireline logs ranges from 1 to 16% and averages 5.4%. Unless otherwise specified, all subsequent mentions in this document of the Reef, Reef Structure, or Field will mean to refer to the total interval that includes both the Brown Niagaran Formation and the A1 Carbonate Formation.

The A2 Evaporite Formation rests directly on top of the A1 Carbonate Formation and serves as the primary seal for the Storage Facility. Above the 120 ft thick A2 Evaporite Formation is a 1,300 ft thick series of massive evaporite deposits and interbedded shale and limestone deposits that make up the bulk of the Salina Group.

The following geologic data was compiled for the Chester 21-29N-02W Reef and surrounding area:

- Well data from historic wellbores including wireline logs, drillers reports, and state curated well files.
- 2D seismic data, composed of 5 lines that each traverse the Reef Structure and adjacent surrounding area.
- Oil and gas production histories as reported to the State of Michigan.

Figure 5 shows the shot point locations of 2D seismic lines used to interpret the Reef Structure at the Storage Facility. Figure 6 is a stratigraphic cross section of well logs through the Storage Facility and Figure 7 is the cross-section reference map.

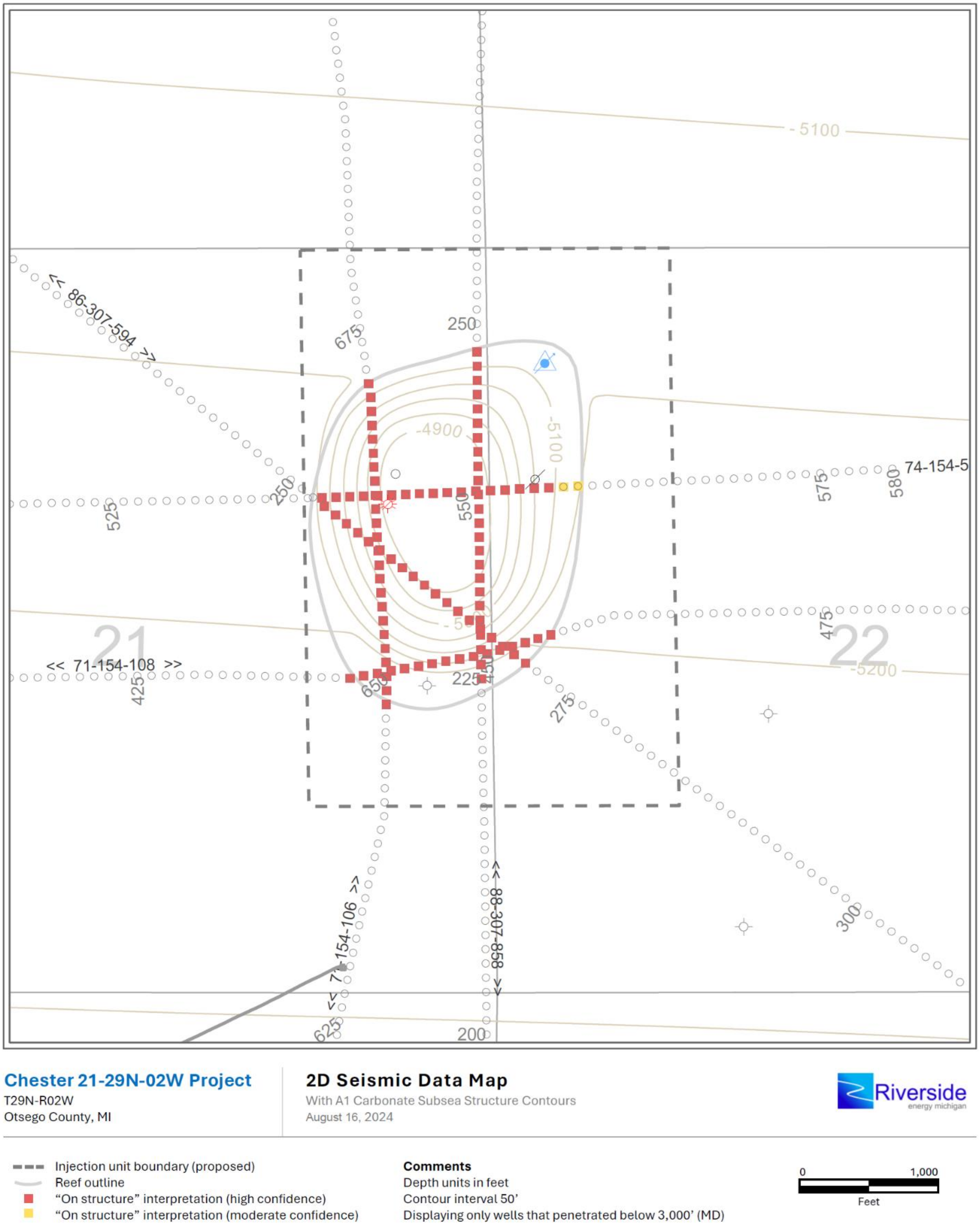

Figure 5. 2D seismic shot point locations used to determine the position of the Chester 21-29N-02W Reef Structure.

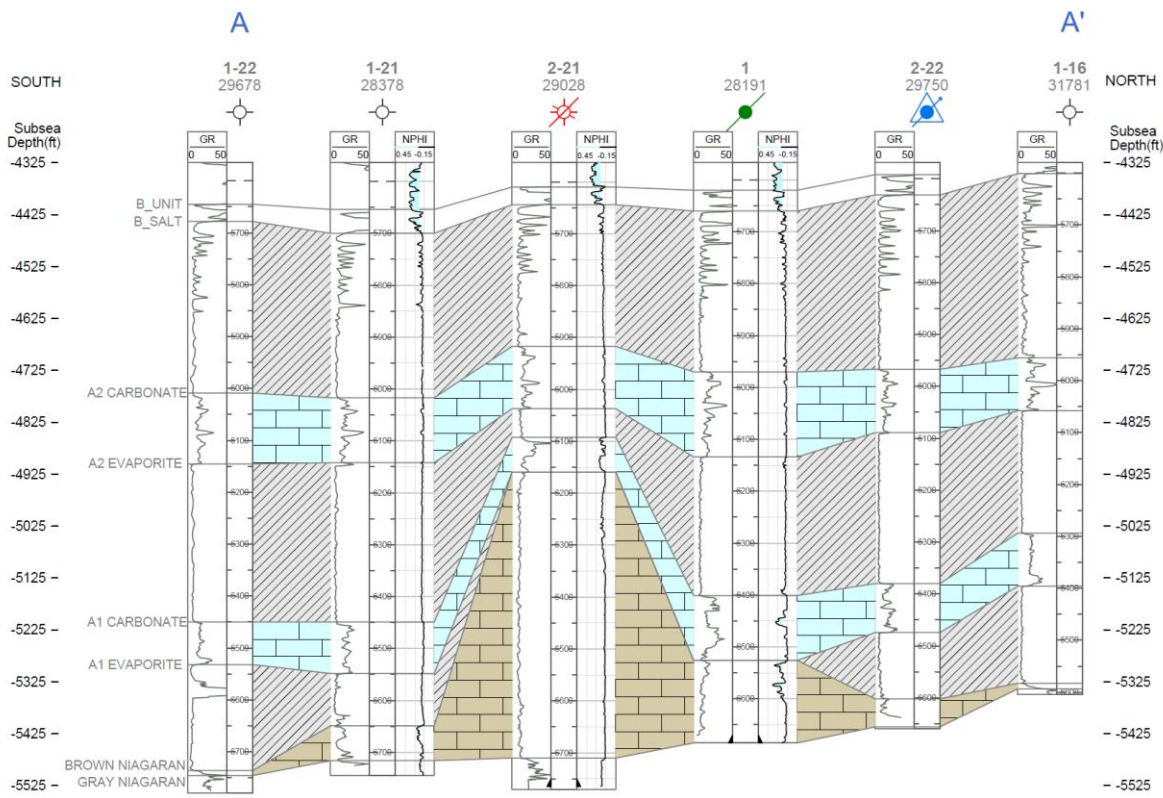

Figure 6. Stratigraphic-structural cross-section of Niagaran reef interval at the Chester 21-29N-02W Storage Facility and surrounding area. Wireline log tracks include Gamma Ray log response ("GR", scale 0 to 50 API) left of each wellbore, and where available Neutron Porosity log response ("NPHI", 0.45 to -0.15%) right of wellbore.

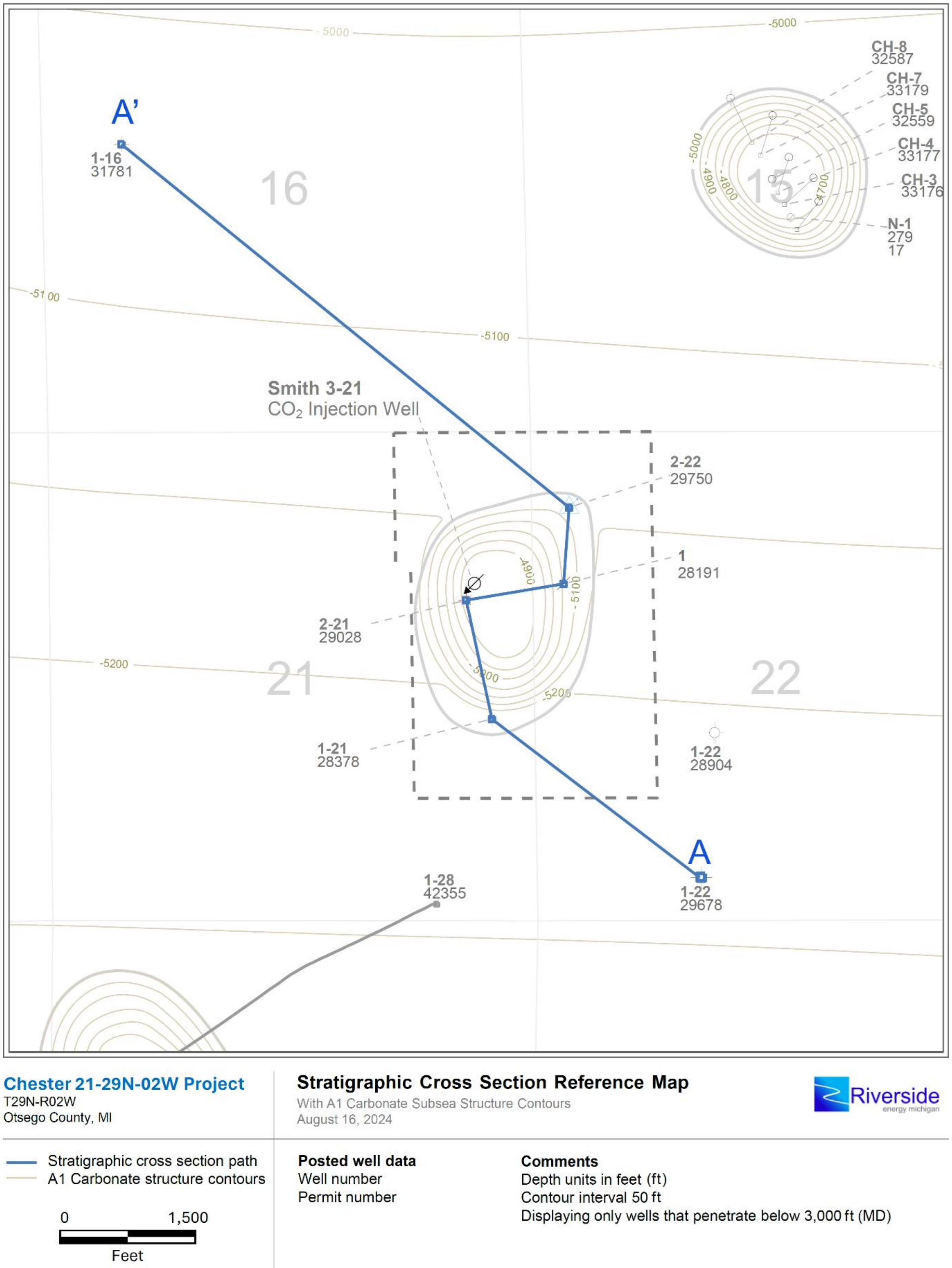

Figure 7. Reference map for the stratigraphic cross-section in Figure 6.

2.3 Operational History of the Chester 21-29N-02W Reef and Existing Wells

The Chester 21-29N-02W Reef was discovered in 1970 by Great Lakes Exploration that developed a single discovery well for oil production. The drilling of three additional wells was attempted between 1971 and 1974, resulting in one gas producing well and two dry holes. One of these dry holes, the State Chester 2-22, has been converted into a brine disposal well into the shallower Dundee Formation, disposing of water produced from Antrim Shale gas production. This well was recompleted with a cement plug within the Niagaran below. These four wells are the only wells ever drilled into the Chester 21-29N-02W Reef and summarized in Table 1.

Table 1. List of wellbore penetrations within the Reef Structure.

Well Name	Marshall, Glen	Underwood, N M & Knapp C A	Leacock Hubbard Underwood	State Chester
Well No.	1	1-21	2-21	2-22
API	21137281910000	21137283780000	21137290280000	21137297500000
MI Permit No.	28191	28378	29028	29750
Well Status	P&A	P&A	P&A	Active PBTD SWD
Well Designation	Oil	Dry Hole	Gas	Initially a Dry Hole, now PBTD SWD
First Operator	Great Lakes Exploration	Miller Brothers	Miller Brothers	Reef Petroleum Corporation
Last Operator	ANR Pipeline	Miller Brothers	Saba Energy of Texas	VCP Michigan
Formation at TD	Gray Niagaran	Gray Niagaran	Gray Niagaran	Gray Niagaran
TD (MD, TVD per KB)	6,685	6,744	6,770	6,660
Datum Elevation (KB)	1,242	1,239	1,238	1,244
SHL Latitude	44.89582	44.89186	44.89537	44.89806
SHL Longitude	-84.54549	-84.54850	-84.54952	-84.54523
BHL Latitude	44.89582	44.89186	44.89537	44.89806
BHL Longitude	-84.54549	-84.54850	-84.54952	-84.54523
Note				PBTD 4,215 ft MD
Producing Formation	Brown Niagaran	-	Brown Niagaran	-
IP oil (BBL/day)	480	-	NA	-
IP gas (Mcf/day)	NA	-	20,000	-
Cumulative oil (BBL)	25,483	-	162,238	-
Cumulative gas (Mcf)	520,175	-	9,951,270	-
Cumulative water (BBL)	Unknown	-	Unknown	-
Permit date	9/24/1970	3/23/1971	9/14/1972	5/13/1974
Well spud date	11/20/1970	4/22/1971	12/9/1972	5/23/1974
Completion date	1/25/1971	5/26/1971	2/26/1973	6/19/1974
Abandonment date	11/21/1990	5/29/1971	6/8/2002	

Table 2 summarizes the additional wells that exist within the active and maximum monitoring areas of the Storage Facility but do not penetrate the Reef Structure. The majority of these wells targeted the Antrim Shale Formation for natural gas production and typically only penetrate in depth to approximately -250 ft to -950 ft (subsea), whereas the Primary Seal and Storage

Reservoir each exceed -4,500 ft (subsea) throughout the Active and Maximum Monitoring Areas. See *Section 3* for the definition and map of the Active and Maximum Monitoring Areas.

Table 2. List of wellbore penetrations within Active and Maximum Monitoring Areas.

Evaluation Group	API	Well Name	Well No.	TD (subsea ft)	Well Type	Well Status
This Project's Pending CO2 injection well	TBD	Smith	3-21	-5,250	CO2 Injection	Permit pending
Penetrations into the Reef Structure	21-137-29028-0000	Leacock Hubbard Underwood Knapp	2-21	-5,532	Gas	P&A
	21-137-28378-0000	Underwood, N M & Knapp	1-21	-5,505	Dry Hole	P&A
	21-137-28191-0000	Marshall, Glen	1	-5,443	Oil	P&A
	21-137-29750-0000	State Chester	2-22	-5,416	SWD	Active
Penetrations depth equivalent to, but not into, the Reef Structure	21-137-28904-0000	Underwood & Knapp & Ashland Farms	1-22	-5,541	Dry Hole	P&A
	21-137-29678-0000	Underwood, Nellie M, & Knapp	1-22	-5,540	Dry Hole	P&A
	21-137-42355-0000	State Chester	1-28	-5,371	Gas	P&A
Penetrations at least 3,350 ft above Primary Seal	21-137-46107-0000	Campbell et al.	1-22	-1,454	SWD	Active
	21-137-55872-0000	State Chester	A3-28	-938	Gas	Producing
	21-137-55871-0000	State Chester	A1-27	-937	Gas	Producing
	21-137-50566-0000	State Chester	24-21	-840	Gas	P&A
	21-137-50567-0000	State Chester	23-21	-772	Gas	Producing
	21-137-55327-0000	Jaeger	D4-21	-718	Gas	Producing
	21-137-55326-0000	Jaeger	C4-21	-704	Gas	Producing
	21-137-55399-0000	Wright	B3-21	-692	Gas	Producing
	21-137-44259-0000	State Chester Venture	51	-633	Gas	Producing
	21-137-45622-0000	Campbell et al.	14-22	-604	Gas	Producing
	21-137-45588-0000	Campbell et al.	13-22	-600	Gas	Producing
	21-137-45536-0000	Campbell et al.	23-22	-593	Gas	Producing
	21-137-45537-0000	Marshall	12-22	-592	Gas	Producing
	21-137-45589-0000	Campbell et al.	24-22	-585	Gas	Producing
	21-137-44261-0000	State Chester Venture	52	-544	Gas	Producing
	21-137-40014-0000	State Chester Venture	31	-400	Gas	Producing
	21-137-39042-0000	State Chester Venture	22	-370	Gas	Producing
	21-137-41430-0000	State Chester	47	-348	Gas	Producing
	21-137-42229-0000	State Chester Venture	54	-329	Gas	Producing
	21-137-41432-0000	State Chester	45	-312	Gas	Producing
	21-137-27029-0000	State Chester	13	-260	Gas	Producing

In total, the Chester 21-29N-02W Field has produced 10,583,601 Mcf of natural gas, 203,105 barrels of oil, and an unknown volume of water. The production totals are summarized in Table 3. The Leacock Hubbard Underwood & Knapp #2-21 tested at an initial reservoir pressure of 3,227 psi at approximately 6,300 ft (0.51 psi per foot gradient) with a temperature of 114°F. It is believed the reservoir was depleted to a current pressure of approximately 300 psi or less. The Marshal, Glen #1 well was plugged and abandoned in 1990, and the Leacock Hubbard Underwood & Knapp #2-21 well was the final well at the Reef Structure to be plugged and abandoned in 2002.

Table 3. Summary of production from Chester 21-29N-02W Field.

Well Name	Date of First Production	Total Production		
		BO	Mcf	GOR
Marshall, Glen #1	1/19/1971	41,062	529,169	12,887
Leacock Hubbard Underwood & Knapp #2-21	2/6/1973	162,043	10,054,432	62,048
Total		203,105	10,583,601	52,109

As there are no longer any producing wells into the Reef Structure and as the structure is laterally limited, there will be no production associated with the Storage Facility. The Smith 3-21 UIC Class II CO_2 injection well will be the only wellbore penetrating the Reef Structure.

2.4 Mass Balance Estimate of Storage Resources

A mass balance approach using natural gas production data was used to estimate approximately 1 million metric tons of CO_2 storage resources at the Storage Facility. This mass balance approach does not consider produced water or oil that may provide additional accessible pore volume for storage. This mass balance approach does not consider a storage efficiency factor.

Determining the accessible reservoir pore volume:

10.5 Bcf produced natural gas
Formation volume gas factor Bg = 0.0042 cf/scf at 114°F and 3,168 psi
1/Bg = 238 scf/cf
Reservoir pore volume = 10,500,000,000 scf / 238 scf/cf = 44,100,000 cf

Determining the storage resources of the accessible reservoir pore volume for CO_2:

Confining interval top depth = 6,035 ft
Fracture pressure (estimate) = 0.80 psi/ft
Current reservoir pressure (estimated) = 300 psi
Injection pressure limit = 6,035 ft * 0.80 psi/ft * .90 safety factor = 4,345 psi
CO_2 density @ 4,345 psi = 55 lbs/cf
Storage resource given 44,100,000 cf of accessible pore space = 1,080,000 metric tons of CO_2

2.5 Reservoir Modelling and Injection Simulation

A simple geologic model was developed to complete computational injection simulations and evaluate the dynamic storage capacity of the Storage Facility. The model was generated from 2D seismic (structure) and well log information (top depths and porosity) in IHS' *Petra*® software. Computer Modeling Group's *GEM*™ reservoir simulation software was used to complete injection simulation.

Figure 8 shows the 3D view of the initial gridded model of the Chester 21-29N-02W Reef used for injection simulation with the position of the injection well entering the top of the reef. The model covers a 3,430 by 3,640 ft (0.65 by 0.69 miles) area and contains the approximate 90-acre (0.14 square mile) Chester 21-29N-02W Reef Structure within it. Porosity of the A1 Carbonate and Brown Niagaran reservoir intervals ranges from 2 to 9%. Permeability of the reservoir intervals ranges from 1 to 5 millidarcies and was derived from basin-wide Niagaran reef porosity-permeability cross plots by Gupta et al. (2020).

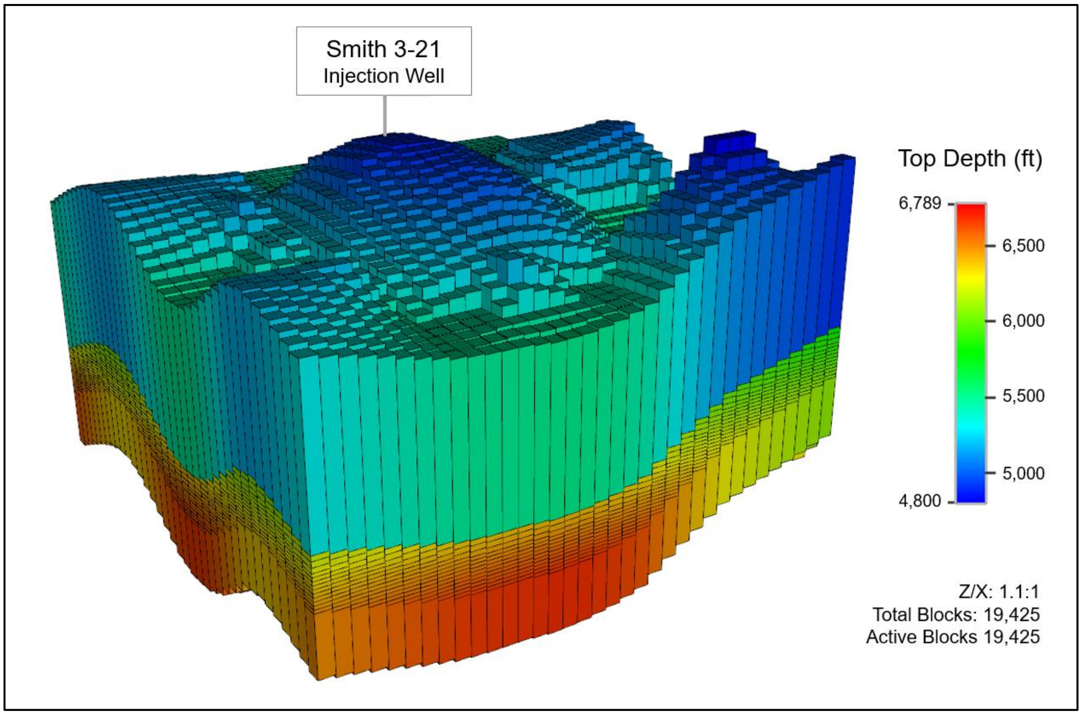

Figure 8. Gridded Model of the Chester 21-29N-02W Area Used for Injection Simulation. Also shown is the approximate location of the Smith 3-21 injection well.

The reef reservoir is modeled as a closed system with all model boundaries closed. The reef reservoir was initialized with depleted gas, oil, and water saturations at 300 psi. Injection rate was set at 12,000 Mcfd based on basin experience from CO_2 injection in other Niagaran reef projects. The maximum bottomhole pressure was limited to 4,345 psi (6,036 ft depth * 0.8 psi/ft fracture gradient * 0.9 safety factor).

The simulation was run for 15 years. After approximately 4 years, the maximum bottomhole pressure limit was reached, limiting further injection. Nearly no CO_2 was injected after 5 years. The simulation injected 16.7 Bcf of CO_2 or approximately 880,000 metric tons of CO_2 after 5 years. Figure 9 shows the development of the CO_2 plume within the Reef Structure over time. The CO_2 is limited to the 90-acre Reef Structure and contained within the dashed green Reef Structure boundary shown in Figure 14. Figure 10 shows the average Reef Structure pressure over time. Figure 11 reports the daily CO_2 injection rate and cumulative CO_2 injection totals over 5 years of injection.

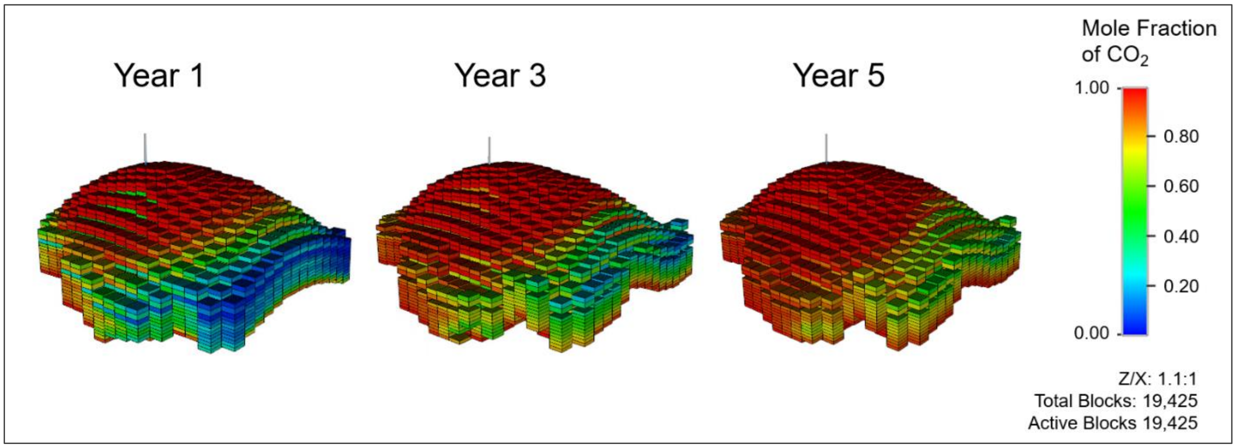

Figure 9. CO_2 plume development in the Reef Structure over 5 years of injection (Mole fraction of CO_2 in reservoir blocks). Also shown is the approximate location of the Smith 3-21 injection well where it enters the Reef Structure.

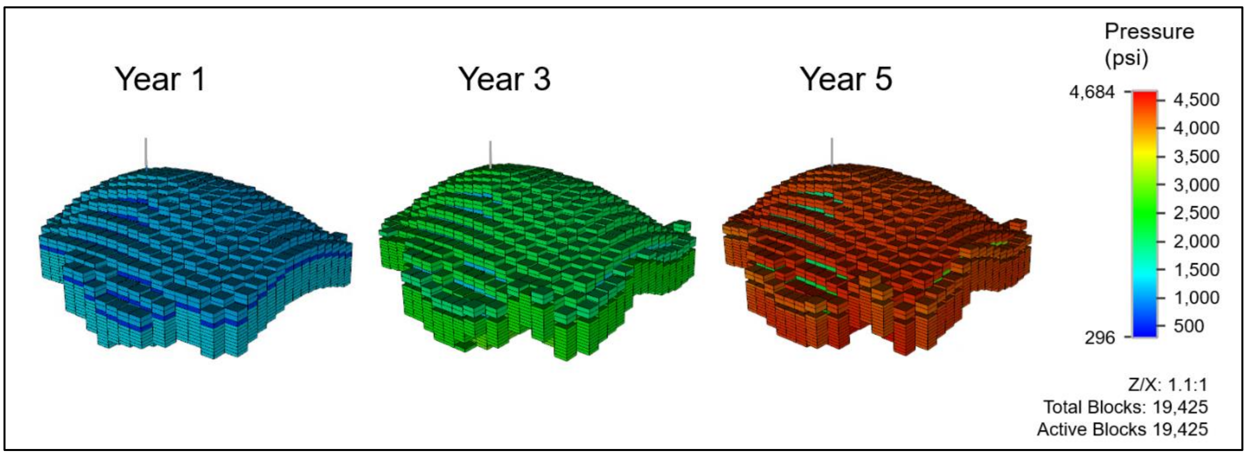

Figure 10. Pressure development in the Reef Structure over 5 years of injection from an initial pressure of 300 psi. Also shown is the approximate location of the Smith 3-21 injection well where it enters the Reef Structure.

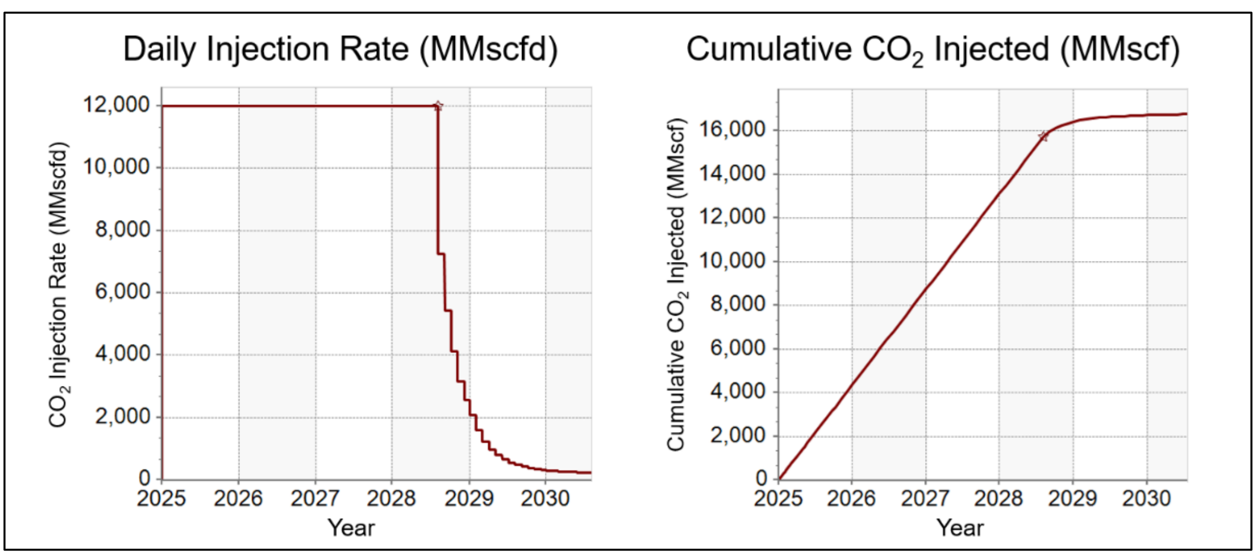

Figure 11. Daily injection rate and cumulative gas injection into the Reef Structure.

2.6 CO_2 Capture and Storage

The Antrim Shale in the northern part of the Michigan Basin is a biogenic gas reservoir. A byproduct of the microbial generation of methane is carbon dioxide that must be stripped from the gas before it is sold. The South Chester CO_2 Treating Plant (the Plant) located in Section 10 of Chester Township, Otsego County, Michigan, and operated by Phillips 66, removes CO_2 from natural gas produced from the Antrim Shale. As operator of the majority of wells producing natural gas being processed by the Plant, Riverside owns 60% of the CO_2 that would normally be vented from the natural gas plant. Riverside is currently constructing the necessary facilities to capture the entire vent stream of about 380,000 metric tons of CO_2 per year. It is expected that the Plant will continue to operate for another 10 to 20 years, dependent on market conditions. The Plant utilizes amine to strip CO_2 from the natural gas. The vent gas resulting from this process is typically 98% CO_2 or greater, and this composition is not expected to change over time. Riverside is installing four rotary screw compressors and reconfiguring one reciprocating compressor unit that in sum will comprise the Turtle Lake Capture Facility (Capture Facility) to compress the CO_2 for transportation and storage. CO_2 will be transported on a dedicated pipeline from the Capture Facility to the Chester 21-29N-02W Storage Facility. The Storage Facility will consist of one injection well (Smith 3-21) drilled into the Chester 21-29N-02W Reef Structure. In the future, the pipeline may become part of a larger distribution system for delivering CO_2 to multiple depleted gas reef storage facilities operated by Riverside for the purpose of permanently disposing and sequestering the CO_2 waste stream derived solely from the production of Antrim natural gas.

Figure 12 is a process flow diagram of the Capture Facility, pipeline, and Storage Facility. The key meter for calculating the mass of CO_2 injected is identified as the Injection Meter in this figure. This dedicated Coriolis mass flow meter will measure and verify the mass of CO_2 being received and injected.

Riverside also has the option to deliver CO_2 to a third party for Enhanced Oil Recovery (EOR). Riverside will have access to data generated by the third party's Coriolis mass flow meter (Delivery Point Meter in Figure 12) positioned near the outlet of the Capture Facility and inlet to their pipeline, which will serve as the custody transfer point. This data will be used for the accurate determination of CO_2 delivered to the third party. The third party operates their EOR projects under an approved MRV plan (facility ID 1010117) is wholly separate from this Storage Facility and this MRV plan.

The requirements of Subpart PP are applicable to the Capture Facility. Riverside will fully comply with the requirements outlined therein.

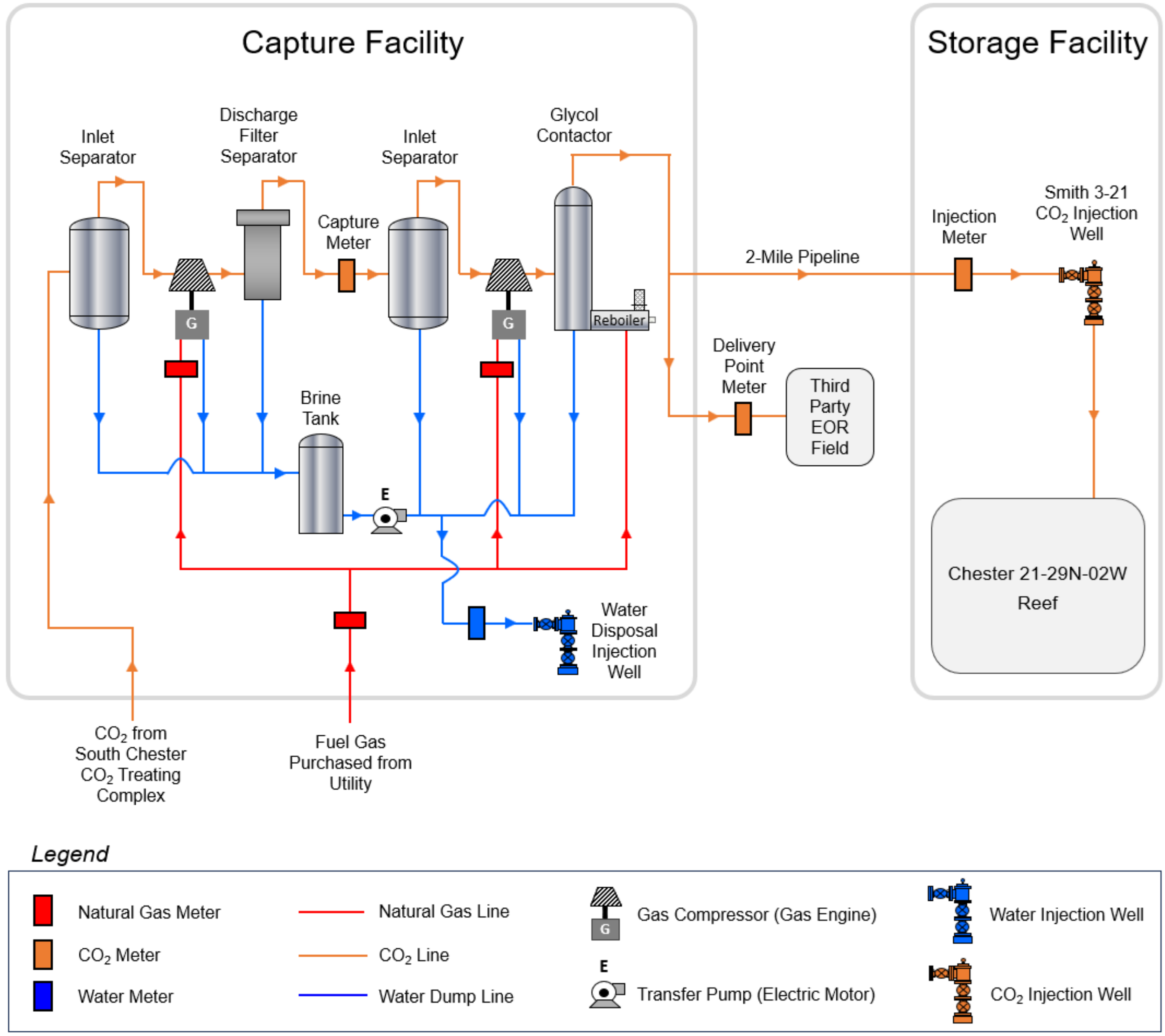

Figure 12. Process flow diagram of the Turtle Lake Capture Facility and the Chester 21-29N-02W Storage Facility.

2.7 Ownership

It is helpful to understand the corporate structure and relationship between the entities; refer to Figure 13 below. Riverside Energy Michigan, LLC (Riverside) and Riverside Carbon Holdings (RCH), LLC are 100% owned subsidiaries of Riverside Energy Holdings, LLC. Riverside is operator of the Antrim Shale natural gas wells and permittee of the injection well. Riverside Carbon Solutions, LLC, RCS Capture Antrim, LLC and RCS Storage Michigan, LLC are 100% owned subsidiaries of RCH. RCS Capture Antrim, LLC holds the Capture Facility assets including leased acreage upon which the facilities reside. RCS Storage Michigan LLC holds rights to the minerals and pore space in the Chester 21-29N-02W Reef Structure. Riverside will be the operator of the Storage Facility on behalf of Riverside Carbon Solutions, LLC.

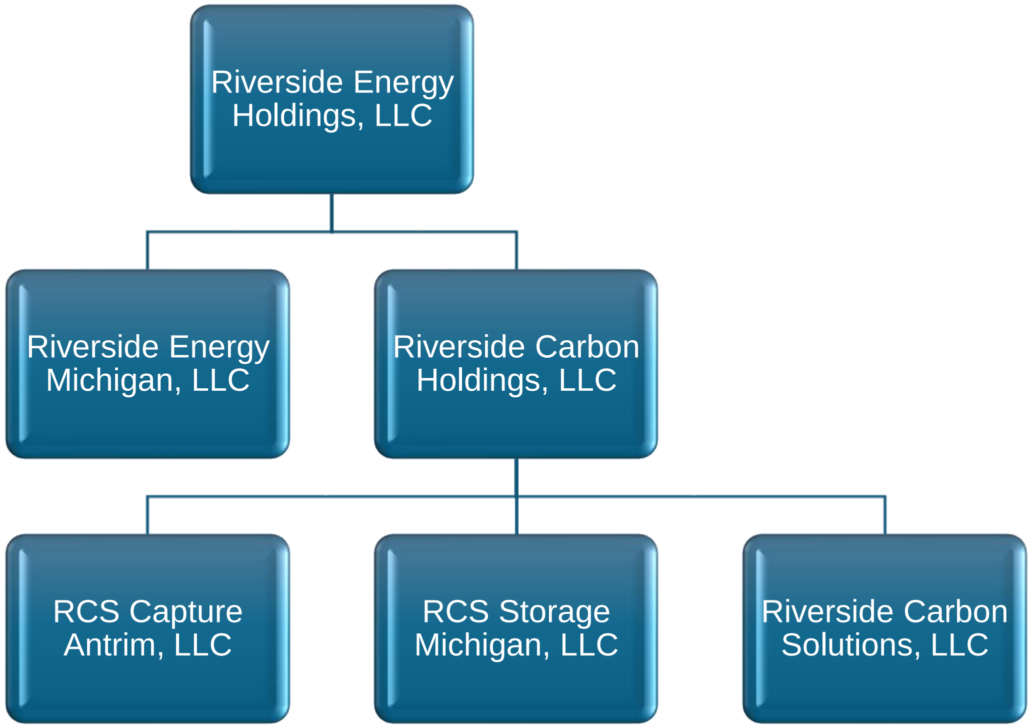

Figure 13. Organizational structure of the Riverside entities involved in the generation, capture and storage of CO_2.

2.8 Data Collection

All flow meters and other instrumentation at the Capture and Storage Facilities will be wired into Riverside's Supervisory Control and Data Acquisition (SCADA) system. The software continuously logs data from the meters and other instrumentation to a secure server with remote data backup and provides a Human-Machine Interface (HMI) for operators. It also has the capability to send an alarm to operators should parameters deviate outside of prescribed limits. Together, these data streams provide accurate accounting of all CO_2 being captured, delivered, received and injected.

Section 5.0 provides a more detailed explanation of the monitoring data that will be collected in order to detect any leakage of CO_2 from the Storage Facility. *Section 6.0* of this MRV Plan provides a more detailed explanation for how this data and other means will be used to establish baseline data for comparison to data collected during operation of the Storage Facility to detect possible surface leakage.

3. DELINEATION OF THE MONITORING AREA

3.1 Active Monitoring Area

The Active Monitoring Area (AMA) is defined (40 CFR 98.449) as follows:

Active monitoring area is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas:

(1) The area projected to contain the free phase CO_2 plume at the end of year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile.

(2) The area projected to contain the free phase CO_2 plume at the end of year t + 5.

At the Chester 21-29N-02W Storage Facility this definition translates to be the Chester 21-29N-02W Reef Structure Area (to the nearest 10-acre square) plus a one-half mile buffer zone outward in all directions. The Reef Structure and AMA are shown in Figure 14. This AMA delineation will be in place for a 10-year period which will cover the expected operational life of the Project.

Riverside plans to inject CO_2 at a rate of 12,000 Mcfd or approximately 230,000 metric tons of CO_2 per year. This rate may vary depending on site specific injection capabilities. The reef's current pressure is estimated at approximately 300 psi. Injection will continue until the reef pressure increases to the maximum bottomhole pressure of 4,345 psi. Once additional injection is constrained by bottomhole pressure limit, injection will stop. Based on the mass balance and injection simulation work described in *Sections 2.4 and 2.5*, the storage reservoir is expected to fill up after approximately 5 years at an average injection rate of 12,000 Mcfd.

Riverside is defining the time period of this AMA as 10 years in order to cover the expected operational life of the Project with some incorporated buffer time for any maintenance, downtime, or unexpected delays. 40 CFR 98.449 defines the AMA as the area projected to contain the free phase CO_2 plume at the end of year t + 5 plus a one-half mile all around buffer. Therefore, the AMA boundary is delineated based on the extent of the CO_2 plume at the end of year 15 plus a one-half mile buffer zone outward in all directions. After 15 years, the free phase CO_2 plume is projected to remain within the Reef Structure. Should the project be operational after 10 years of initial injection, Riverside will submit a revised MRV plan with an updated AMA.

The compartmentalized nature of the Niagaran reef creates conditions whereby an injection plume is limited to the shape and volume of the reef structure itself. The following factors were considered in defining the Reef Structure and AMA boundaries.

- The Reef Structure is encased within massive anhydrite and ultra-low permeability limestone, efficiently sealing the reef's storage intervals and preventing lateral and upward migration of CO_2. The effectiveness of the reef's seal is demonstrated by the trapping of hydrocarbons within the reef over geologic time.
- The boundaries of the reef structure have been defined using 2D seismic data. Where 2D seismic data is not available, reef edges were approximated using all wells surrounding and penetrating the reef, along with analog reef geometry.
- The stored CO_2 and the lateral extent of the CO_2 plume will remain within the reef and will not migrate over geologic time, as is demonstrated by the injection simulation described in *Section 2.5* and the trapping of oil and gas within the reef over geologic

time.

- There are no known leakage pathways that extend laterally from the Reef Structure that would warrant an expansion of the AMA beyond the one-half-mile buffer distance.

3.2 Maximum Monitoring Area

The project's Maximum Monitoring Area (MMA) is equal to the Active Monitoring Area (AMA) and is similarly defined as the Chester 21-29N-02W Reef Structure (to the nearest 10-acre square) plus a one-half mile buffer zone outward in all directions. This MMA is shown in Figure 14.

Pursuant to 40 CFR 98.449 the Maximum Monitoring Area is defined as equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. For the reasons described in *Section 3.1*, the stabilized plume boundary will remain within the Reef Structure at the Project.

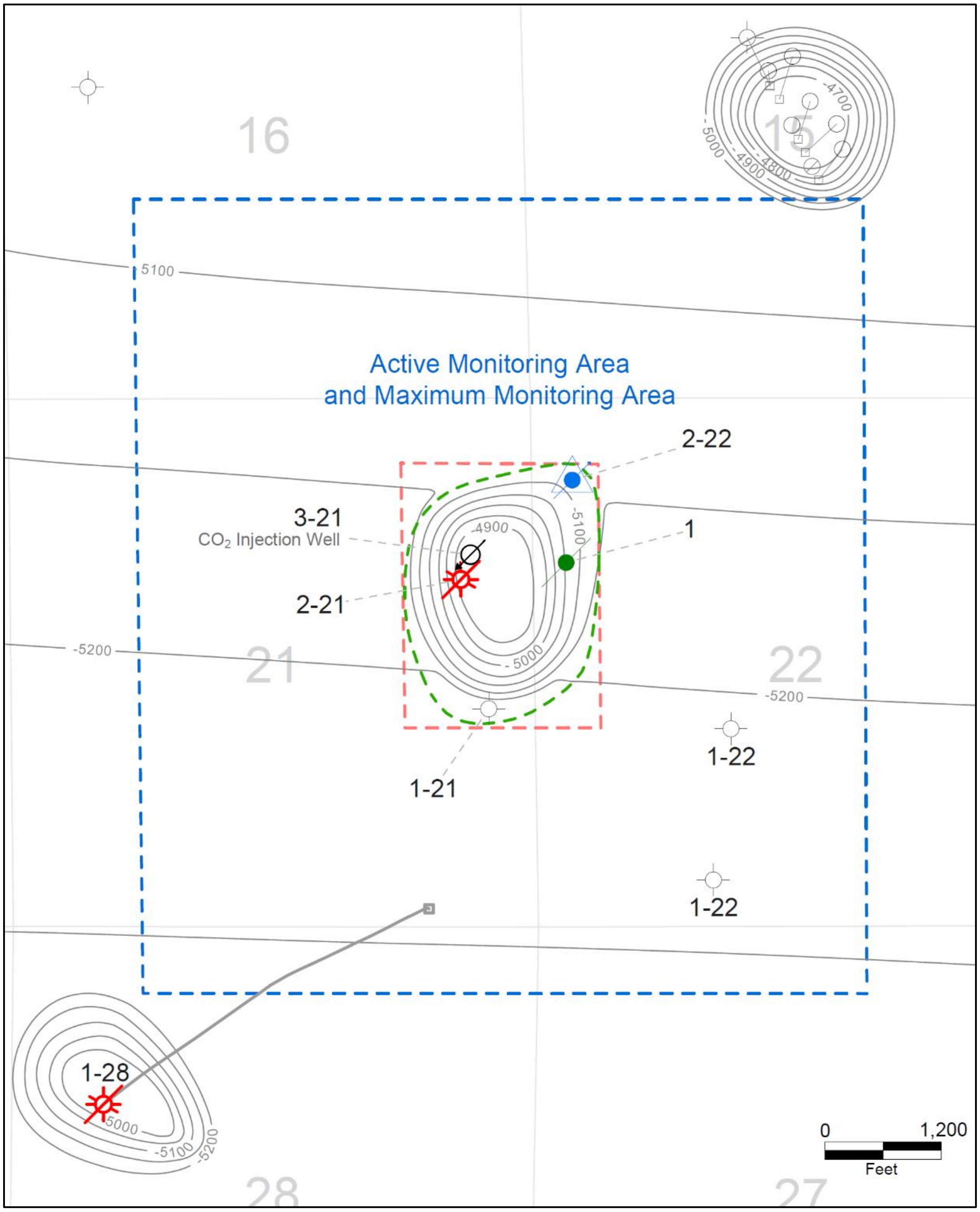

Figure 14. Map depicting the AMA/MMA (total area enclosed by the dashed blue boundary), structure contours of the top of the A1 Carbonate (top of the storage interval), and the Chester 21-29N-02W Reef (central) flanked by the Chester 15 reef to the northeast, and the Chester 28 reef to the southeast. The Chester 21-29N-02W Reef boundary (green dashed line) which is also the stabilized plume boundary, has herein also been regularized to the nearest 10-acre square (dashed red boundary) to help in establishing the boundary positions of the AMA and MMA. Well spots have been filtered to show only wells with total depths below 3,000 ft TVD, and for clarity purposes only wellbores within the AMA/MMA have been labeled. The planned 3-21 UIC Class II injection well is labeled in the northeast quadrant of the Chester 21-29N-02W Reef.

4. POTENTIAL PATHWAYS FOR LEAKAGE

Riverside has identified the following as potential surface leakage pathways at the Project per 40 CFR 98.448(a)[2]:

- Leakage from surface equipment
- Leakage from existing wellbores
- Leakage from wells not yet drilled
- Leakage from the injection wellbore
- Leakage from existing faults and fractures
- Leakage from natural or induced seismicity
- Leakage through confining layers
- Leakage from lateral migration of CO_2

This section discusses the likelihood, magnitude, and timing of potential surface leakage of CO_2 from these pathways. *Section 5* discusses the monitoring plan to detect any surface leakage and strategies for quantifying leakage from these pathways.

4.1 Leakage from Surface Equipment

The injection mass flow meter will be located on the well pad near the wellhead of the injection well. As the CO_2 that is received and metered by this mass flow meter will be wholly injected and not mixed with any other supply of CO_2 and no production from the storage formation will occur, the potential leakage pathways from surface equipment are limited to the mass flow meter, the injection wellhead, the short flowline between the two, and any pipe fittings or valves installed along the flowline or wellhead. The likelihood of leakage from these surface components is low and further mitigated by the following:

- Locating the CO_2 received and injection mass flow meter near the wellhead to minimize opportunities for potential leakage from surface equipment.
- Adhering to high material selection and construction standards when designing and constructing the wellhead and flowline.
- Continuously monitoring the wellhead and mass flow meter with the SCADA system.
- Routinely conducting audible, visual and olfactory (AVO) inspections of the surface equipment for leaks. These checks will occur each time operators visit the well site but not less than once per week. Leaks can be heard as a hissing sound, seen by the distortion of objects on the other side of the leak, or smelled as an odor downwind of the leak.
- Monitoring surface equipment with Optical Gas Imaging (OGI) technology such as an infrared (IR) or thermal imaging camera on a quarterly schedule.

The magnitude of potential leakage from these surface components is small with any leaked volume likely limited to the volume of CO_2 in the flowline or wellhead components. The timing of leakage risk spans from the start of injection and through the active injection period until the well is plugged and abandoned.

4.2 Leakage from Existing Wells

There are four boreholes that penetrate the A2 Evaporite confining layer within the Reef Structure, the area expected to contain the free-phase CO_2-occupied plume. Well data for these boreholes is listed in *Section 2.3*. Three of these boreholes, the Marshall, Glen #1 well, the Underwood, N M & Knapp, C A #1-21 well, and the Leacock Hubbard Underwood & Knapp #2-21 well have been plugged and abandoned according to State of Michigan standards and determined by Riverside to be an unlikely pathway for CO_2 migration above the confining interval. The State of Michigan requires a cement plug be placed within the wellbore to confine oil, gas, and water to the strata from which the oil, gas, and brine were produced. Upon review of the plugging reports for these three wellbores, Riverside has determined that a cement plug has been placed within the A2 Evaporite confining layer, as well as within several overlying intervals. Therefore, leakage through these legacy wellbores is unlikely.

The fourth borehole that penetrates the A2 Evaporite confining layer within the Reef Structure, the State Chester 2-22, is an active brine disposal well permitted in the Dundee formation. It was originally drilled in 1974 to a total depth of 6,660 ft below surface to the top of the Brown Niagaran formation. As this well is located at the far flank of the reef, it tested dry for hydrocarbons. It was then reworked into a brine disposal well by plugging back and completing the well within the Dundee formation at approximately 2,450 ft. The plugging records indicate a cement plug was placed at the base of the well, within the A2 Evaporite confining layer, as well as over additional intervals up hole. The well continues to pass mechanical integrity tests (MITs) in accordance with State of Michigan standards. Riverside has determined that the State Chester 2-22 well is a low risk for CO_2 leakage because it has been properly plugged downhole and recompleted above. It is subject to ongoing monitoring and MITs as an active brine disposal well by a different operator.

The magnitude of potential leakage from existing wellbores is considered to be low. Most of the existing wells are located on the reef flank, limiting their intersection with the projected CO_2 plume. The timing of leakage risk begins when the CO_2 plume intersects with an abandoned well. Riverside considers the likelihood of leakage from existing wells to be low because the four legacy wells that penetrate the Reef Structure have been abandoned to State of Michigan standards with multiple cement plugs.

Outside of the Reef Structure, but within the one-half-mile buffer distance of the AMA and MMA, there are two boreholes (Underwood, Knapp, and Ashland Farms, INC 1; and Underwood, Nellie M & Knapp, Clara Ann 1-22) that penetrate the A2 Evaporite confining layer. The surface location of one additional directionally drilled wellbore, the State Chester 1-28, is located within the AMA and MMA. However, its bottomhole location and penetration of the A2 Evaporite confining layer are located outside of the Project's AMA and MMA. These three wellbores have been plugged and abandoned according to State of Michigan standards. The likelihood of leakage from these wells is very low as they do not intersect the Reef Structure and the projected free-phase CO_2 plume.

There are 21 wellbores within the AMA and MMA that do not penetrate the A2 Evaporite confining layer (Table 2). The likelihood of CO_2 leakage through any of these wellbores is assessed to be very low because the bottom of each of these boreholes is at least 3,350 vertical feet above the top of the A2 Evaporite confining layer. Furthermore, the geologic formations within this minimum 3,350 feet of vertical separation consists primarily of regionally deposited evaporites and tight carbonates with characteristically low vertical permeability.

There are also four water wells within the AMA and MMA that pose an even lesser risk of CO_2 leakage for the same reasons stated above and the fact that they do not even reach bedrock below the glacial drift (Table 4). Note that the last two wells in Table 4 were drilled by Riverside to support the drilling operations for the Smith 3-21 injection well. One will be plugged when drilling operations have ended, and one will be retained as a ground water monitoring well as described in *Section 6.4*.

Table 4. List of water wells within the AMA/MMA.

Well ID	Owner Name	Construction Date	Depth (ft)	Geographic Coordinates	
				Latitude	Longitude
69000004263	Cody & Sandi Smith	3/8/2021	65	44.892795	-84.541395
69000004281	Doug Sheridan	5/11/2021	50	44.892034	-84.545048
69000009481	Riverside Energy Michigan	1/15/2025	60	44.895742	-84.548594
69000009482	Riverside Energy Michigan	1/15/2025	60	44.8958147	-84.548585

4.3 Leakage from Wells Not Yet Drilled

Wellbores drilled in the future through the Reef Structure may be a potential leakage pathway for CO_2. The likelihood of leakage from wells not yet drilled is low and any risk is mitigated by the following:

- Hydrocarbon production from the A1 Carbonate and Brown Niagaran formations in the Chester 21-29N-02W Reef will be no longer possible after injection of CO_2 begins.
- There are no known hydrocarbon producing formations below the Brown Niagaran in the AMA and MMA. The St. Peter Sandstone (approx.10,000 ft) is an occasional gas producer where on anticlinal structure in central and northern Michigan. There are several St. Peter dry holes within a few miles of the Storage Facility, and the Storage Facility is not on an anticline as confirmed by well control and 2D seismic.
- Future wells drilled outside of the Reef Structure but within the AMA and MMA will not interact with the free-phase CO_2 plume.
- All well records and injection data will be shared with Michigan-EGLE to ensure that potential drillers are aware of the Project for the indefinite future.
- Michigan Admin. Code R. 324.413 regulates the drilling of wellbores to strata beneath gas storage reservoirs. The rule describes specific drilling equipment, casing design, and

completion standards that must be deployed to ensure drilling occurs safely through natural gas storage reservoirs. While this rule applies to natural gas storage projects (not CO_2 storage projects), Michigan-EGLE already has experience in protecting and regulating the drilling of new wells through gas storage reservoirs.

For these reasons, it is unlikely that any future wells will be drilled through the A2 Evaporite confining layer within the Reef Structure and projected free-phase CO_2 plume. The magnitude of potential leakage from wells not yet drilled is low.

4.4 Leakage from the Injection Wellbore

The Smith 3-21 injection well will be permitted and constructed as a Class II oil field waste disposal well with Michigan-EGLE. As this injection well is an additional penetration that could offer a leakage pathway to the surface, Riverside is taking the following steps to mitigate potential leakage:

- The Smith 3-21 injection well will be constructed more rigorously than Michigan Class II standards. Figure 15 describes the proposed injection well design. Chromium alloy long-string casing will be installed from total depth through the A2 Evaporite and cemented in place with SLB's *EverCRETE* CO_2 resistant cement.
- Prior to injection, a cement bond log and MIT will be run to ensure proper well construction.
- Riverside will perform a MIT at least every 5 years per Michigan-EGLE requirements.
- The annular fluid volume between the casing and injection tubing will be monitored quarterly.
- The surface pressure of the tubing and annular space will be continuously monitored by the SCADA system to detect any abnormalities that indicate a loss of integrity or leak has occurred.
- Riverside will be monitoring surface components and the injection wellhead with OGI technology on a quarterly schedule and performing an AVO inspection weekly.
- After injection, the Smith 3-21 injection well will be plugged and abandoned with cement plugs placed to prevent any future leakage of CO_2.

Leakage from the injection wellbore is unlikely due to the constant monitoring of the wellbore and periodic mechanical integrity testing. The magnitude of leakage from the injection wellbore is small. It is unlikely that a blowdown of the wellbore would be necessary, but if one occurs, the leaked CO_2 would be limited to the volume contained in the wellbore and could be easily quantified using volume, pressure, and temperature data. The timing of leakage risk from the injection wellbore occurs from the beginning of injection until proper plugging and abandonment.

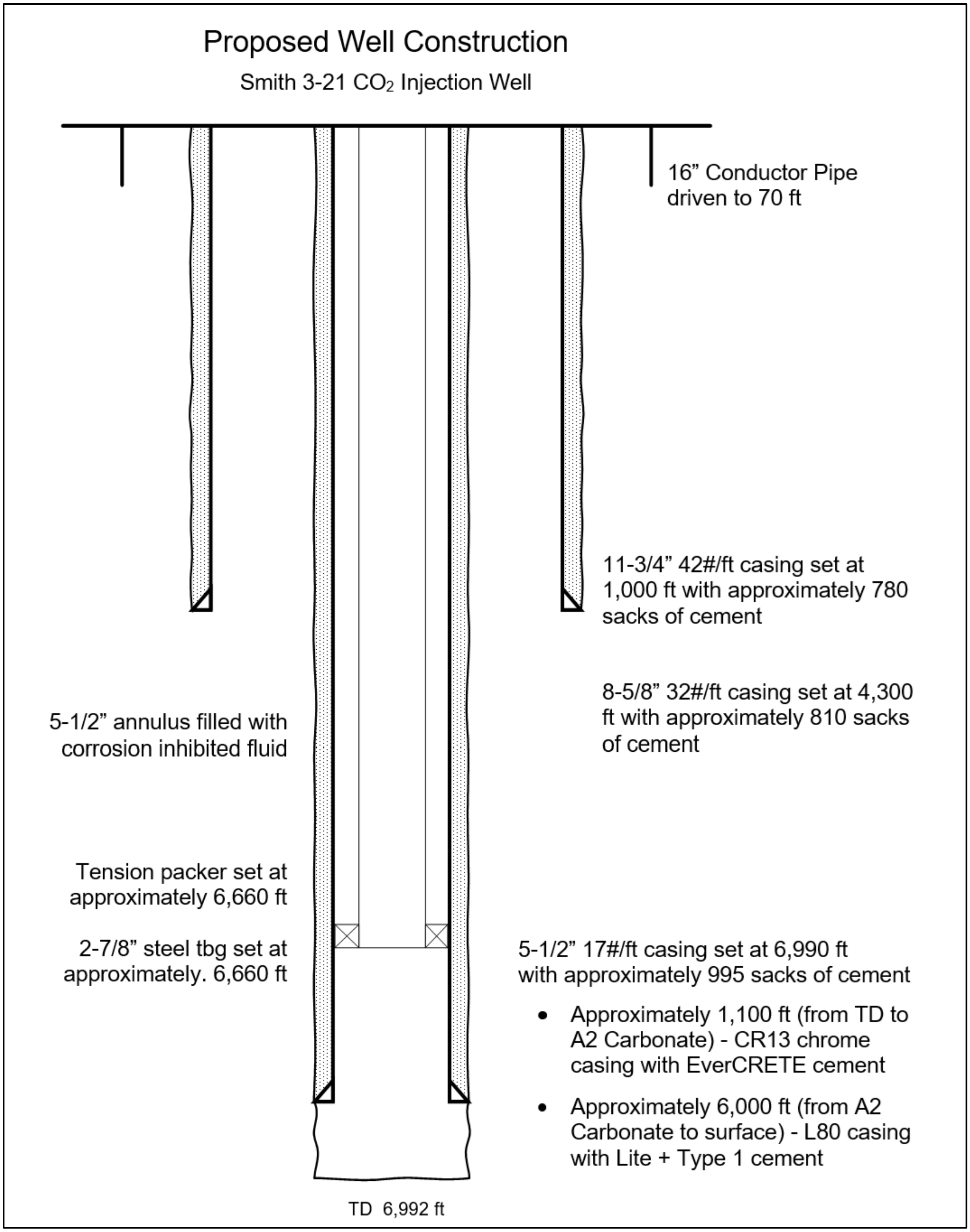

Figure 15. Proposed construction design for Smith 3-21 injection well.

4.5 Leakage from Existing Faults and Fractures

Evaluation of 2D seismic did not reveal any faults or fractures in the Reef Structure, and there are no known faults or fractures through the A2 Evaporite confining layer in the AMA and MMA that would allow CO_2 movement into overlying formations. The risk of leakage of CO_2 from an unknown fault or fracture is very low, because hydrocarbons were sealed within the Reef Structure throughout geological time.

4.6 Leakage from Natural or Induced Seismicity

The likelihood of natural seismicity is very low. The Michigan Basin is structurally stable with few major structural features. No naturally occurring earthquakes greater than magnitude 2.5 have originated within 100 miles of the Storage Facility since 1900. The USGS's 2023 50-State Long-term National Seismic Hazard Model classifies northern Michigan as having the lowest chance of experiencing a slight or greater damaging earthquake in the next 100 years[1].

Natural gas storage in nearby Niagaran reef fields offers an analog to CO_2 injection and experience with reservoir response under pressure. To date, Riverside is unaware of any induced seismicity issues associated with natural gas storage in Niagaran reefs. Many reefs are permitted with a maximum bottomhole pressure greater than 4,600 psi at depths of 6,600 to 6,800 ft[2]. The planned maximum bottomhole pressure for the Storage Facility is 4,345 psi (6,036 ft depth * 0.8 psi/ft fracture gradient * 0.9 safety factor). For these reasons, the likelihood of leakage from induced seismicity is low and the risk would be limited to the active injection period because the reservoir pressure will be highest during the injection period.

4.7 Leakage through Confining Layers

The primary seal of the Project is the A2 Evaporite confining layer. The A2 Evaporite is comprised of anhydrite which has virtually no porosity or permeability. Above the A2 Evaporite confining layer, additional evaporite and low-permeability carbonate sequences are present that further reduce the risk of upward movement of CO_2 through overlying strata.

The likelihood of leakage through confining layers is very low, because the A2 Evaporite confining layer's sealing capacity has been proven by the previous trapping of hydrocarbons throughout geologic time.

4.8 Leakage from Lateral Migration of CO_2

As shown in Figure 4, the Reef Structure is fully compartmentalized due to the unique formation of the pinnacle reef and subsequent deposition of overlying strata. The Reef Structure is encased in a tight carbonate and non-porous evaporate seal that prevents the vertical and lateral migration

[1] https://www.usgs.gov/programs/earthquake-hazards/science/2023-50-state-long-term-national-seismic-hazard-model
[2] https://www.govinfo.gov/content/pkg/FR-1994-03-28/html/94-7181.htm

of fluids. Underlying the storage formation are tight units of the Brown and Gray Niagaran formation.

Riverside does not believe that the A1 Carbonate and Brown Niagaran storage intervals are in communication with any other Niagaran reservoir or reef. Water infiltration from below the reservoir was not observed during the production history of the Chester 21-29N-02W Reef and the current reservoir pressure is expected to be at the reef's depleted pressure of approximately 300 psi.

The likelihood of leakage from lateral migration of CO_2 is very low as demonstrated by the production history of the Chester 21-29N-02W Reef. The magnitude of any potential leakage is low due to the closed structure of the reef.

5. MONITORING AND LEAK QUANTIFICATION STRATEGY

This section describes the monitoring plan to detect any surface leakage from the pathways identified in *Section 4* and the strategies for quantifying leakage should it occur.

5.1 Detecting and Quantifying Leakage from Surface Equipment

The injection mass flow meter will be located near the wellhead, limiting the amount of equipment subject to monitoring for leakage to the wellhead, the mass flow meter, and the flowline and any valves between the wellhead and mass flow meter. To detect any leakage from this equipment, OGI surveys will occur quarterly using either an IR or thermal imaging camera, and AVO inspections will be conducted by trained personnel at least weekly. In addition, the wellhead and mass flow meter will be continuously monitored by the SCADA system.

Emissions from surface equipment downstream of the mass flow meter such as the flowline, valves, fittings or the wellhead assembly will be estimated and repaired as quickly as possible. If CO_2 must be vented downstream of the meter to make a repair, the amount of CO_2 vented will be estimated using the methods specified in 40 CFR 98 Subpart W. Data that could be considered for estimating the amount of CO_2 leaked may include but not limited to: any anomalies in metered pressures or mass flow, average pressures or mass flow, the time between inspections, physical measurements of pinholes and/or the relative size and intensity of the leakage plume as detected by OGI.

5.2 Detecting and Quantifying Leakage from Existing Wellbores and Future Wells

As discussed in *Section 4*, few existing wells will encounter the CO_2 plume, and all of these wells have been plugged and abandoned to State of Michigan standards. Riverside will be conducting quarterly groundwater monitoring and optical gas imaging on the injection well pad. Pressure transducers installed in the tubing and annulus at the wellhead will be monitored by the SCADA system and bottomhole pressure and temperature surveys will occur periodically through the injection period to identify possible abnormalities in operational parameters that would indicate a subsurface leak. Riverside will conduct bottomhole pressure tests and temperature surveys every six months for the first two years and annually thereafter. Should a future well be drilled within the AMA and MMA, Riverside will work with Michigan-EGLE to ensure the well will not interfere with CO_2 storage within the Storage Facility.

If a leak is detected at a legacy well or a well not yet drilled, its volumetric flow will be attempted to be metered if possible. If not, the latest injection data and reservoir pressure, volume and temperature data will be used to estimate a leakage volume and rate with a mass balance approach from the storage intervals. The timing of the leak will be determined by an estimate of the CO_2 plume's intersection with the legacy or future well.

5.3 Detecting and Quantifying Leakage from the Injection Wellbore

Riverside will deploy multiple monitoring strategies to detect leakage from the injection wellbore. The long string casing, injection tubing string and packer assembly are subjected to a MIT every 5 years as well as once before injection begins. The annular space between the casing and tubing will be filled with a corrosion inhibiting fluid and checked quarterly for significant changes in volume. The tubing and annular pressure at the wellhead will be monitored continuously with pressure transducers tied to the SCADA system. At a minimum, Riverside will conduct bottomhole pressure tests and temperature surveys every six months for the first two years, and annually thereafter. If the temperature survey detects an anomaly suggesting CO_2 intrusion behind casing, a radioactive tracer/gamma ray tool will be run to investigate. Further, the quarterly OGI and weekly AVO inspections would also encompass the area around the wellbore at the surface.

A workover of the well to replace components may be required and surface and downhole equipment would be thoroughly inspected for signs of wear or corrosion responsible for a potential leak.

If the mechanical integrity of the injection wellbore is lost, the injection will stop and not begin again until a MIT test is passed in compliance with Michigan-EGLE regulations. If a leak is determined to have taken place, it will be quantified using the timing of the loss of integrity and any pressure or annular fluid data from the MIT that can be used to characterize the leak.

Venting of CO_2 from the well may occur while making repairs and would be estimated and documented in accordance with Subpart W procedures. Typically, wells undergoing a workover are "killed" with sufficiently dense fluid to overcome the reservoir pressure and prevent venting of gases from the well to atmosphere.

5.4 Detecting and Quantifying Leakage from Existing Faults and Fractures and Natural or Induced Seismicity

Leakage from existing faults or fractures or fractures created by natural or induced seismicity will be monitored by continuous monitoring of operational parameters at the wellbore, periodic reservoir pressure and temperature surveys, and quarterly ground water monitoring near the injection well pad. At a minimum, Riverside will conduct bottomhole pressure tests and temperature surveys every six months for the first two years, and annually thereafter. Abnormalities in operational and reservoir parameters and such as the injection tubing and reservoir pressures will be investigated to determine if there is a subsurface leak. If it is determined a subsurface leak has occurred, the latest injection data and reservoir pressure, volume and temperature data will be used with a mass balance approach to estimate a leakage volume and rate from the storage intervals. The timing of the leak will be determined by an estimate of the CO_2 plume's intersection with the leakage pathway.

As discussed in *Section 4*, natural and induced seismicity are considered to be unlikely. Riverside will subscribe to the USGS' Earthquake Hazards Program Earthquake Notification Service (ENS)[3] to receive notifications of any earthquakes with magnitude 2.0 or greater in Michigan. If an earthquake occurs, Riverside will evaluate the monitoring data to determine if the wellbore or Storage Facility are affected. Annulus pressure is continuously monitored and could indicate a loss of wellbore integrity issues caused by seismicity.

5.5 Detecting and Quantifying Leakage through Confining Layers or Lateral Migration

Leakage through the confining layers or from lateral migration will be monitored by periodic groundwater monitoring and reservoir pressure tests. Quarterly groundwater sampling and testing will occur in the water well to be drilled at the injection well pad for drilling operations and will be retained for ground water monitoring. A description of the groundwater testing that will occur is included in *Section 6.4*.

If it is determined a subsurface leak has occurred, the latest injection data and reservoir pressure, volume and temperature data will be used with a mass balance approach to estimate a leakage volume and rate from the storage intervals. The timing of the leak will be determined by an estimate of the CO_2 plume's intersection with the leakage pathway.

6. ESTABLISHING SURFACE LEAKAGE BASELINES

Prior to the start of continuous injection, the following data will have been collected to establish baselines for the Storage Facility against which future data may be compared in order to detect surface leakage.

6.1 Wellbore Integrity

After injection well construction is completed but before injection begins, a MIT and annular pressure test will be completed to confirm wellbore integrity. The initial volume of annular fluid will be noted, and it will be monitored during the start-up of injection to determine how it responds during injection start up. Its stabilized volume will be noted after at least a week of continuous injection. The injection tubing and annulus pressures at the wellhead will be recorded prior to CO_2 injection and continuously monitored thereafter with the SCADA system. MITs will occur at least every 5 years in accordance with Michigan-EGLE requirements.

[3] https://earthquake.usgs.gov/ens/help

6.2 Injection Well Operating Parameters

Riverside has established target injection and storage rates based on experience from other operators injecting and storing fluids in other Niagaran reefs. An initial model, described in *Section 2.5*, has been developed to confirm these baseline injection parameters. Riverside plans to inject CO_2 at a rate of 12,000 Mcfd or approximately 230,000 metric tons of CO_2 per year. This rate may vary depending on injection capabilities of the well.

During injection operations, Riverside will use site-specific data during wellbore construction and the initial injection period to update nominal injection parameters such as wellhead tubing and annulus pressures and injection flow rates.

6.3 Reservoir Conditions

Initial bottomhole pressure will be recorded at mid-perforations and a temperature survey with gradient stops will be completed before injection. A bottomhole pressure test and temperature survey will be conducted at least every six months for the first two years of injection and then annually thereafter. After approximately 48 hours of continuous CO_2 injection, Riverside will run in hole to mid-perforations to establish reservoir pressure and temperature and run a gradient on the way out of the hole while noting casing and tubing pressures at surface.

6.4 Groundwater Monitoring

Groundwater monitoring will occur from a water well drilled on the injection well pad (to approx. 100 ft) and include the following analyses to detect the presence of fugitive CO_2:

- Standard field parameters form a calibrated water quality meter: temperature, pH, conductivity, dissolved oxygen, oxidation reduction potential, and turbidity.
- Standard EPA UIC lab analyses barium, calcium, sodium, magnesium, potassium, total iron, chloride, sulfate, sulfide, carbonate, bicarbonate, TDS, resistivity, specific gravity, and pH.
- Lab analyses for dissolved methane, ethane, propane, and calculated dissolved CO_2 from carbonate, bicarbonate, and dissolved inorganic carbon.

A sample will be collected before injection begins from the ground water monitoring well to establish baseline parameters. During injection, groundwater sampling and testing will occur at least quarterly.

6.5 Surface Equipment Monitoring

After the site equipment is constructed but before injection begins, Riverside will conduct a baseline OGI survey with either an IR or thermal imaging camera. Within the first month of injection, an additional OGI survey will occur to ensure no leakage from surface equipment during the beginning of injection. Thereafter, Riverside will conduct OGI surveys quarterly at the injection well pad to detect for surface leakage of CO_2.

7. SITE-SPECIFIC CONSIDERATIONS FOR THE MASS BALANCE EQUATION

Riverside will utilize the mass balance equations listed in 40 CFR 98.443 to calculate the mass of CO_2 sequestered. The site-specific considerations for these equations are discussed in this section.

7.1 Mass of CO_2 Received and Injected

In accordance with 40 CFR 98.444(a)[4], Riverside will determine the annual mass of CO_2 injected as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 to calculate CO_2 received. The CO_2 received at the Storage Facility will be wholly injected and not mixed with any other supply of CO_2. There will be no production from the Storage Facility.

Equation RR-4 in 40 CFR 98.443(c) of Subpart RR will be used to calculate the mass of CO_2 received at the Storage Facility each year.

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_{2,p,u}}$$

where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.

$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).

$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flow meter.

7.2 Mass of CO_2 Produced

There will be no production from the Storage Facility. The purpose of the Storage Facility is to permanently dispose and sequester the CO2 waste stream derived solely from the production of Antrim natural gas.

7.3 Mass of CO_2 Emitted by Surface Leakage

Riverside will quantify the mass of CO_2 emitted by each identified surface leakage pathway as outlined in *Section 5*. Equation RR-10 will be used to calculate the total mass of CO_2 emitted by surface leakage at the Storage Facility.

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$$

where:

CO_{2E} = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year.

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway.

7.4 Mass of CO_2 Emitted from Equipment Leaks and Vented Emissions

As discussed in *Section 5.1*, Riverside will quantify the annual mass of CO_2 emitted in metric tons from any equipment leaks and vented emissions of CO_2 from equipment located on the surface between the injection mass flow meter and the wellhead in accordance with the procedures provided under Subpart W of 40 CFR 98. At the Storage Facility, the injection mass flow meter is located near the wellhead, limiting the equipment to the mass flow meter, the injection wellhead, the short flowline between the two, and any pipefittings or valves installed along this flowline or wellhead.

7.5 Mass of CO_2 Sequestered

Since no production will occur at the Storage Facility, Riverside will use equation RR-12 to calculate the total mass of CO_2 sequestered in the Storage Facility for the reporting year.

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the mass flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W of 40 CFR 98.

8. ESTIMATED SCHEDULE FOR IMPLEMENTATION OF MRV PLAN

Riverside will implement this plan as soon as it is approved by EPA. Riverside plans to be ready to begin CO_2 injection and to begin collecting data for calculating the total amount of CO_2 sequestered by March 1, 2025. All baselines will have been established and leakage detection strategies implemented prior to this date. This plan will be in effect until EPA approves Riverside's request for discontinuation of reporting. Riverside plans to submit a request for discontinuation of reporting after all wells in the Storage Facility are plugged and abandoned and has demonstrated that the injected CO_2 stream is not expected to migrate in the future in a manner likely to result in surface leakage, in accordance with 40 CFR 98.441(b).

9. QUALITY ASSURANCE PROGRAM

9.1 Monitoring of CO_2 Received

In accordance with 40 CFR 98.444(a)[4], Equation RR-4 will be used to calculate the total annual mass of CO_2 received because CO_2 received at the Storage Facility is wholly injected and metered by a single injection mass flow meter.

9.2 Monitoring of CO_2 Injected

At the injection well, the volume of CO_2 injected will be measured continuously by an Emerson Micro Motion ELITE Coriolis mass flow meter. Riverside will report quarterly averages of the flow rate and total mass injected. Injection stream samples will be collected at least quarterly to measure the CO_2 concentration immediately upstream or downstream of the injection mass flow meter.

The injection mass flow meter will operate continuously except as necessary for maintenance and calibration. It will be operated using the calibration and accuracy requirements in 40 CFR 98.3(i). Meter accuracy is based on accredited calibration standards according to ISO 17025/IEC 17025.

9.3 Procedures for Estimating Missing Data

In the event Riverside is unable to collect data required for performing the mass balance calculations, procedures for estimating missing data in 40 CFR 98.445 will be implemented as follows:

- Quarterly mass of injected CO_2 will be estimated using representative mass flow rate data from the nearest previous time period. Pressure data at the wellhead will be compared to previous time period's pressure data and mass of injected CO_2 to ensure similar consistency.
- Quarterly CO_2 stream concentration data will be estimated using a representative concentration value from the nearest previous time period.
- CO_2 emissions associated with equipment leaks or venting will be estimated following the missing data procedures contained in 40 CFR 98 Subpart W.

9.4 MRV Plan Revisions

Riverside will revise this plan and submit the latest version to the EPA Administrator within 180 days of making a material change to the monitoring and/or operational parameters, a change in the permit class of the UIC permit, notification of substantive errors in the MRV plan, or for any other reason Riverside should choose to revise this MRV plan in any reporting year.

10. RECORDS RETENTION

Riverside will retain the following records in accordance with 40 CFR 98.3(g).

(1) A list of all units, operations, processes, and activities for which GHG emission were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity, categorized by fuel or material type. These data include but are not limited to the following information in this paragraph (g)(2):

> (i) The GHG emissions calculations and methods used. For data required by 40 CFR 98.5(b) to be entered into verification software specified in 40 CFR 98.5(b), maintain the entered data in the format generated by the verification software according to 40 CFR 98.5(b).
>
> (ii) Analytical results for the development of site-specific emissions factors.
>
> (iii) The results of all required analyses for high heat value, carbon content, and other required fuel or feedstock parameters.
>
> (iv) Any facility operating data or process information used for the GHG emission calculations.

(3) The annual GHG reports.

(4) Missing data computations. For each missing data event, also retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.

(5) The most recent copy of this GHG Monitoring Plan.

(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

In addition, Riverside will retain the following records for at least three years in accordance with 40 CFR 98.447:

- Quarterly records of CO_2 received at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.

- Quarterly records of injected CO_2, including mass flow at standard conditions and operating conditions, operating temperature and pressure and concentration of the streams.
- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the wellhead.

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