Division of Water and Waste Management
Underground Injection Control
Permit Application for a Class 6 Well

(Collected under the authority of the WV Code 22-11-8)

For Official Use Only

Date received:

Permit Number: **TR2-1 CL6-0004-25-051;**
TR2-2 CL6-0005-25-051;
TR2-3 CL6-0006-25-051;
TR2-4 CL6-0007-25-051

Read Attached Instructions Before Starting

I. Owner Name, Address, Phone Number and/or Email	**II. Operator Name, Address, Phone Number and/or Email**
Tri-State CCS, LLC 14302 FNB Parkway Omaha, Nebraska 68154 402-691-9500	Same as owner

III. Facility Details

☒ Commercial
☐ Non-Commercial

SIC Code(s)
49530300   4619
51690203

IV. Ownership

☒ Private
☐ County
☐ State
☐ Federal
☐ Municipal
☐ Tribal Lands

V. Permit Action Requested

☒ New Permit
☐ Renewal
☐ Modification
☐ Closure
☐ Other: ____________________

VI. Type of Class 6 Well

☑ New Well Drilling
☐ Renewal
☐ Modification/Conversion
☐ Other: ____________

☐ Class 2 Conversion

API Number: ____________________

Permit Number: ____________________

Date Well Constructed: ________ Date Injection Started: ________

VII. Additional Permits within Area of Review (AoR)

Mining & reclamation (coal & non-coal related)
National Pollutant Discharge Elimination System (NPDES) surface water (general, individual and/or industrial)
State 401 Certification (federal permit or license)
Oil & Gas Program
UIC Mining Prep Plant Slurry/UIC Mining AMD Sludge
Hazardous Waste (hazardous waste disposal, treatment or storage)
Municipal or Industrial Solid Waste Landfill
Stormwater Program (Industrial or Construction Activity)
Land Application of Sewage Sludge
____________________ (Other)

Permits required for the project are listed in Table 1 of the Application Narrative (PBI_01_TR2_Narrative_R1_20251009.pdf)

VIII. Location of Well(s) Approximate Center of Well Head (Injection Wells, Monitoring Wells etc.)

Well Type: Injection : Latitude: 40.016375 Longitude: -80.606419

Well Type: Injection : Latitude: 40.011884 Longitude: -80.533589

Well Type: Injection : Latitude: 39.978333 Longitude: -80.600234

Well Type: Injection : Latitude: 39.956423 Longitude: -80.635316

[insert or attach mapping]

In-Zone: 40.02915700, -80.60265500
40.02851500, -80.52935200
39.97236800, -80.59224300
39.96443600, -80.65075200
Above-Zone: 40.01637440, -80.60624120
39.95642244, -80.63513679
Lowermost USDW: 40.02920146, -80.60265474
40.02855618, -80.52935172
39.97240722, -80.59224277
39.96447776, -80.65075179
Center of Area of Review: 39.990733, -80.592154

See Section 1 of the Application Narrative (01_TR2_Narrative_R1_20251009.pdf) for maps of the project wells and Area of Review (AoR).

IX. Area of Review (AoR)
[Show Calculations and modeling for extent and attach representative mapping]

See Section 2 of the Area of Review and Corrective Action Plan for computational modeling results, Section 3 for AoR delineation, and Section 4 for corrective action for artificial penetrations (PBI_02_TR2_AOR_CA_R1_20251009.pdf).

Tabulation of Wells within AoR:	453 known oil and gas wells and 228 known water wells
Re-evaluation Schedule of AoR:	Anually during injection, every 5 years post-injection
Corrective Action:	125 wells to be evaluated for corrective action

X. Siting and Geological Data

See subsection 2.1 of the Application Narrative for regional geology, hydrogeology, and local structure, subsection 2.2 for maps and cross sections of the AoR, subsection 2.3 for faults and fractures, subsection 2.4 for injection and confining zone details, subsection 2.5 for geomechanical and petrophysical information, subsection 2.6 for seismic history, subsection 2.7 for hydrologic and hydrogeologic information, subsection 2.8 for geochemistry, and subsection 2.9 for site suitability (PBI_01_TR2_Narrative_R1_20251009.pdf).

XI. Pre-Operational Testing Plan

See subsections 2.1 through 2.7 of the Pre-Operational Testing Program for information regarding data collection to address any uncertainties about subsurface formations and fluid geochemistry identified during geologic site characterization and to verify proper well construction and fluid geochemistry identified during geologic site characterization and to verify proper well construction (05_TR2_PreOps_R1_20251009.pdf).

XII. Injection Formation Testing

See subsection 2.1 through 2.7 of the Pre-Operational Testing Program for the data collection plan for fluid temperature, pH, conductivity, reservoir pressure, fracture pressure, static fluid level, and formation fluids for injection zones (05_TR2_PreOps_R1_20251009.pdf).

XIII. Well Construction Information

See subsection 2.6 of the Construction Details (04_TR2-1_WellConstr_R1_20251009, 04_TR2-2_WellConstr_R1_20251009 04_TR2-3_WellConstr_R1_20251009, and 04_TR2-4_WellConstr_R1_20251009.)

Casing Size (In.)	Hole Size (In.)	Casing Wt. (lb./ft.)	Depth Top (ft.)	Depth Bot (ft.)	Tot. Cement Used	Type/Grade Cement
Elev. of Datum:		Datum: MSL GL KB			Total Depth:	
Co2 Corrosion Analysis:						
Stimulation Plan (if proposed):						

XIV. Casing and Lining Information

See subsection 2.6 of the Construction Details (04_TR2-1_WellConstr_R1_20251009, 04_TR2-2_WellConstr_R1_20251009, 04_TR2-3_WellConstr_R1_20251009, and 04_TR2-4_WellConstr_R1_20251009.)

Casing Liner Size OD-In.)	Hole Size (In.)	CasingLiner Wt. (lb./ft.)	Depth Top (ft.)	Depth Bot (ft.)	Injection Pressure (Internal/External)	Injection Pressure (Axial)

XV. Conductor Pipe and Packer Specifications

See subsection 2.7 of the Construction Details (04_TR2-1_WellConstr_R1_20251009, 04_TR2-2_WellConstr_R1_20251009, 04_TR2-3_WellConstr_R1_20251009, and 04_TR2-4_WellConstr_R1_20251009.)

Hole Size (In.)	Wall Thk. (ft.)	Material Type	Diameter (In.)	Normal Wt. (lbs.)	Joint Length (ft.)	Joint Specifications

- **Attach all associated conductor pipe and packer schematics**

XVI. Pre-Operational Testing Plan

See Pre-Operational Testing Program (05_TR2_PreOps_R1_20251009.pdf).

XVII. Proposed Injection Interval

See subsection 2.8.3 and 2.9 of the Construction Details (04_TR2-1_WellConstr_R1_20251009, 04_TR2-2_WellConstr_R1_20251009, 04_TR2-3_WellConstr_R1_20251009, and 04_TR2-4_WellConstr_R1_20251009.)

Depth of Proposed Injection Zone (ft.):	**Depth Top (ft.)**	**Depth Bot. (ft.)**	**Injection Formation Name**
Injection Through:	**Perforation**	**Open Hole**	**Screen**
Proposed Perforated/Open Hole Interval(s)(ft.):			

XVIII. Proposed Injection Stream

See subsection 2 of the Summary of Requirements (06_TR2_OpsCond_R1_20251009.pdf)

Injection Pressure (psi)	Annulus Pressure (psi)	Max. Flow Rate (Sm3/h)	Cumulative Volume (t/d)	Avg. Max. Daily Rate (Sm3/h)	Avg. Injection Pressure (psi)	Max Injection Pressure (psi)

Co2 Source Information:	
Physical and Chemical Characteristics Analysis of Co2 Stream:	

XIX. Aquifer Exemption (if Applicable)

N/A

Attach Injection Waiver Request:	

XX. Testing and Monitoring Plan

Co2 Stream Analysis:	See subsection 3 of the Testing and Monitoring Plan (07_TR2_T&M_R1_20251009.pdf).
Cont. Recording & Operational Parameters:	See subsection 4 of the Testing and Monitoring Plan (07_TR2_T&M_R1_20251009.pdf).
Corrosion Monitoring:	See subsection 5 of the Testing and Monitoring Plan (07_TR2_T&M_R1_20251009.pdf).
Confining Zone Monitoring:	See subsection 6 of the Testing and Monitoring Plan (07_TR2_T&M_R1_20251009.pdf).
External MIT:	See subsection 7 of the Testing and Monitoring Plan (07_TR2_T&M_R1_20251009.pdf).
Pressure Fall-off Testing:	See subsection 8 of the Testing and Monitoring Plan (07_TR2_T&M_R1_20251009.pdf).
Co2 Plume and Pressure Front Tracking: (Direct and Indirect)	See subsection 9 of the Testing and Monitoring Plan (07_TR2_T&M_R1_20251009.pdf).
Surface Air Monitoring:	None
Soil Gas Monitoring:	None
Quality Assurance and Surveillance Plan:	See the Quality Assurance and Surveillance Plan (07_TR2_AppA_QASP_R1_20251009.pdf).

XXI. Plugging and Abandonment Plan

See Injection Well Plugging Plans (07_TR2-1_InjPlug_R1_20251009.pdf, 07_TR2-2_InjPlug_R1_20251009.pdf, 07_TR2-3_InjPlug_R1_20251009.pdf, and 07_TR2-4_InjPlug_R1_20251009.pdf).

XXII. Post Injection Site Care and Closure (PISC) Plan

See Post-Injection Site Care and Site Closure Plan (10_TR2_PISC_R1_20251009.pdf)

XXIII. Emergency and Remedial Response Plan

See Emergency and Remedial Response Plan (PBI_11_TR2_ERRP_R1_20251009.pdf)

XXIV. Financial Assurance and Responsibility

See Financial Assurance Demonstration (03_TR2_FinRes_R1_20251009.pdf)

XXV. Additional Permit Information

O&G Division Well Work Package	See Well Work Permit Package (14_TR2-1_WellWorkPckg_DRAFT_20250722, 14_TR2-2_WellWorkPckg_DRAFT_20250722, 14_TR2-3_WellWorkPckg_DRAFT_20250722, 14_TR2-4_WellWorkPckg_DRAFT_20250722).
Groundwater Protection Plan	See Groundwater Protection Plan (13_TR2_GPP_R1_20251009.pdf**)**
The Wild and Scenic Rivers Act, 16 U.S.C. 1273 et seq.	See subsection 3.11 of the Application Narrative (PBI_01_TR2_Narrative_R1_20251009.pdf)
The National Historic Preservation Act of 1966, 16 U.S.C. 470 et seq.	See subsection 3.11 of the Application Narrative (PBI_01_TR2_Narrative_R1_20251009.pdf)
The Endangered Species Act, 16 U.S.C. 1531 et seq.	See subsection 3.11 of the Application Narrative (PBI_01_TR2_Narrative_R1_20251009.pdf)
Emergency and Remedial Response Plan	See Emergency and Remedial Response Plan (PBI_11_TR2_ERRP_R1_20251009.pdf)

XXVI. Attachments

[In addition to this form, complete attachments on separate sheets. Submit complete information, as required in the instructions, and list all attachments, maps or other figures, by the applicable roman numeral.]

PBI_01_TR2_Narrative_R1_20251009 (VII, X, and XXV), PBI_02_TR2_AoR_CA_R1_20251009 (IX), 03_TR2_FinRes_ R1_20251009 (XXIV),
04_TR2-1_WellConstr_ R1_20251009, 04_TR2-2_WellConstr_ R1_20251009, 04_TR2-3_WellConstr_ R1_20251009, and 04_TR2-4_WellConstr_ R1_20251009 (XIII, XIV, XV, XVII),
05_TR2_PreOps_ R1_20251009 (XI, XII, VI),
06_TR2_OpsCond_ R1_20251009 (XVIII),
07_TR2_AppA_QASP_ R1_20251009 (XX),
07_TR2_T&M_ R1_20251009 (XX),
08_TR2-1_InjPlug_ R1_20251009, 08_TR2-2_InjPlug_ R1_20251009, 08_TR2-3_InjPlug_ R1_20251009, 08_TR2-4_InjPlug_ R1_20251009 (XXI),
09_TR2_StimPlan_ R1_20251009, 10_TR2_PISC_ R1_20251009 (XXII),
PBI_11_TR2_ERRP_ R1_20251009 (XXIII),
13_TR2_GPP_ R1_20251009, 14_TR2-1_WellWorkPckg_DRAFT_20250722, 14_TR2-2_WellWorkPckg_DRAFT_20250722, 14_TR2-3_WellWorkPckg_DRAFT_20250722, 14_TR2-4_WellWorkPckg_DRAFT_20250722 (XXV).

XXVII. Responsible Officer Certification

All permit applications must be signed by a responsible corporate officer for a corporation, by a general partner for a partnership, by the proprietor of a sole proprietorship, or by a principal executive or ranking elected official for a public agency.

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 47 CSR 10 4.6.d.)

Name and Official Title (type or print):	**Signature:**	**Date:** 10/14/25
Larry Carlson Vice President - Environmental Affairs		

XXVIII. Professional Engineer Certification

I hereby certify that this plan was prepared by me or under my direct supervision and that I am a duly licensed Professional Engineer under the laws of the State of West Virginia.

Per meeting with WVDEP on 7/14/25, PE certification is waived for applications submitted prior to this becoming a regulatory requirement.

(Seal)	**Signature:**	**Date:**
	Printed or Typed Name:	
	My license renewal date is:____________________ **Pages/Sheets/Attachments covered by this seal:** ____________________	

INSTRUCTIONS FOR PERMIT APPLICATION (CLASS 6 WELLS)

A permit application must be completed by all owners or operators of current or proposed Class 6 injection wells subject to the requirement to obtain an Underground Injection Control (UIC) permit as described at **WV Code 22-11-8, WV 47 CSR 13,** and others. Please note that this form must be signed by a responsible entity as described at **WV 47 CSR13 14.12.k.**,even if the attachments are prepared by contractors or service companies. If the application covers multiple wells, use additional pages as necessary to provide all the requested information. The following instructions and associated regulations represent significant portions of required permit application data but a complete review of both **US EPA 40 CFR 146 and WV 47 CSR 13** regulations is recommended to develop a complete and accurate permit application.

I. OWNER NAME, ADDRESS, PHONE AND/OR EMAIL: Enter the name, and street address, city/town, state, and ZIP code of the owner of the well, well field, or company. Also provide an email address (if available) and/or a phone number.

II. OPERATOR NAME, ADDRESS, PHONE AND/OR EMAIL: Enter the name and street address, city/town, state, and ZIP code of the operator of well or well field; also provide an email address (if available) and/or a phone number. If the operator is the same as the owner, enter "same as owner."

III. Facility Details: Check the appropriate box to indicate the type of facility. A commercial facility is a single or multiple well facility that is specifically engaged in the business of injection of carbon dioxide for the purpose of carbon capture and sequestration generated by third party producers that originates off-site and transported to the facility for a fee or compensation. Include the SIC code for the specific type of facility that is producing Co2 for injection.

IV. OWNERSHIP: Check the appropriate box to indicate whether the owner of the well/facility is a private, Federal, or State/County/Municipal entity.

V. TYPE OF PERMIT ACTION REQUESTED: Check "new permit" if the well has never been subject to a UIC permit (e.g., newly constructed well that has never been drilled). Check "permit renewal" for an application associated with extending an expiring UIC permit. Check "modification" for an application to modify an existing permit that was previously permitted. Check "class 2 conversion" for a class 2 EOR (Enhanced Oil and/or gas Recovery) conversion to UIC. Check "add well to area permit" if additional wells are to be covered under an existing UIC area permit. Check "other," if needed and describe the situation.

VI. TYPE OF Class 6 Well: Check "Individual" or "Area" to indicate the type of permit requested. Individual permits cover a single injection well, while area permits may cover more than one injection well. Note that area permits are issued at the discretion of the Director and that wells covered by an area permit must: be at one contiguous site and be under the control of one entity. If an area permit is requested, enter the ***number of wells*** to be included in the permit. Also provide the name of the well field and project name. Area of Review (AoR) will be calculated based on the center point radius of each well head within the well array.

VII. Additional Permits within the Area of Review (AoR): Note all permits held by both permittee and others within the Area of Review (AoR) for the proposed permit application.

VIII. Well Location: Enter the location of the well using latitude and longitude. When using latitude and longitude, use decimal degrees to five or six places after the decimal, if possible, be sure to include a negative sign for the longitude of a well. For area permit applications, provide the latitude and longitude of the approximate center of the area, as well as the individual wells. You may submit an addendum to the application if additional space is needed.

IX. Area of Review (AoR): Demonstrate that the AoR, as modeled, represents the area in which USDWs may be endangered by the injection operation and ensure that all artificial penetrations that may allow fluid movement into USDWs are identified and appropriately addressed. For complete information on the requirements of **40 CFR 146.82(a)(4), (13) and 146.84(b)** see US EPA Class VI AOR Evaluation and Corrective Action Guidance and the Class VI Project Plan Development Guidance.

WV 47CSR13: 13.5.4. For Class 6 wells, that area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.

X. Siting and Geological Data: demonstrate that the Class VI well will be sited in an area with a suitable geologic system, consisting of an injection zone with sufficient capacity to receive the CO2 and a confining zone that is free of transmissive faults or fractures. Include maps and cross sections of AoR, including but not limited to, information on faults and fractures, data on injection and confining zone(s), seismic, geologic and topographic mapping and associated cross sections. Also include, hydrologic mapping and cross sections to include, but not limited to, baseline geochemical data, demonstrated site suitability and protection and location of USDWs. For complete information on the requirements of **40 CFR 146.82(a)(2),(3),(5), and (6)** see the US EPA Class VI Well Geologic Site Characterization Guidance.

WV 47CSR13: 13.2. Minimum Criteria for Siting; **13.2.a.** Owners or operators of Class 6 wells must demonstrate to the satisfaction of the Director that the wells will be sited in areas with a suitable geologic system.

The owners or operators must demonstrate that the geologic systems comprises; **13.2.a.1.** An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream. **13.2.b.** The DIrector may require owners or operators of Class 6 wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.

XI. Pre-Operational Testing Plan: Demonstrate that information will be collected to address any uncertainties about subsurface formations and fluid geochemistry that were identified during the geologic site characterization and verify that the well is properly constructed. For complete information on the requirements of **40 CFR 146.82(a)(8) and 146.87** see the US EPA Class VI Injection Well Construction Guidance, Class VI Well Geologic Site Characterization Guidance, Class VI Reporting, Recordkeeping, and Data Management Guidance.

XII. Injection Formation Testing: Describe plans to gather information on the fluid temperature, pH, conductivity, reservoir pressure and static fluid level of the injection zone(s). Describe and calculate the target injection zone(s) fracture pressure up to and including injection pressure limits. Determine the physical/chemical characteristics of the injection and confining zones and characterize formation fluids in the injection and confining zone(s) to evaluate the compatibility of the injectate with formation fluids; **40 CFR 146.82(a)(8) and 146.87**.See Sections 4.3 and 4.4 of the US EPA Class VI Well Geologic Site Characterization Guidance.

XIII. Well Construction Information: Procedures and well construction schematics that demonstrate the injection well will be constructed in a manner that is appropriate to planned operations, is compatible with the CO2 stream, subsurface chemistry (as referenced in attached baseline geochemical data) and will maintain mechanical integrity. Provide Co2 corrosion analysis as it relates to casing and cement used in the construction of the injection well. If a stimulation plan is to be used, provide a description of stimulation fluids to be used and determination that stimulation will not interfere with containment. For complete information on the requirements of **40 CFR 146.82(a)(11), (12) and 146.86** see the US EPA Class VI Injection Well Construction Guidance.

WV 47CSR13: 13.3.; The Director shall prescribe requirements for the construction of Class 6 injection wells. Existing wells shall achieve compliance with such requirements according to a specific compliance schedule established by the Director as a condition of the permit. New wells shall be in compliance with construction requirements before injection operations begin. The owner or operator of a proposed injection well shall submit plans to the DIrector for testing, drilling, and construction and obtain the approval of the initial plans as a condition of the permit. The Director's approval of any modifications of the plan shall be obtained before incorporating them into the construction of the injection well. For additional information see; **WV 47CSR13, 13.3.a.1, 13.3.a.2., 13.3.a.3.**

XIV. Casing and Liner Information: Design and describe and include design schematics for casing strings and liners that are appropriate to the geology and planned operations to ensure that the surface casing will protect all USDWs and the long-string casing will extend to the injection zone. Demonstrate that casing and liner materials that can withstand contact with formation fluids, the injected CO2 stream, product of mixing formation fluids and CO2 and downhole stresses they will encounter so that they will not experience degradation or loss of material integrity during injection operations. For complete information on the requirements of **40 CFR 146.86(b)(1)** see the US EPA Class VI Injection Well Construction Guidance.

WV 47CSR13: 13.3.b.1.; Casing and cement or other materials used in the construction of each Class 6 well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.

XV. Conductor Pipe and Packer Information: Design, describe and include design schematics for conductor pipe tubing and packers that are compatible with the CO2 stream, the formation fluids and/or products of mixing formation and injection fluids that may be encountered so that they can resist corrosion for the duration of the project. **40 CFR 146.86(c)(1)**.

WV 47CSR 13.3.(c).1.; Tubing and packer materials must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.

XVI. Pre-Operational Testing Plan: demonstrate that information will be collected to address any uncertainties about subsurface formations and fluid geochemistry that were identified during the geologic site characterization and verify that the well is properly constructed. This information will satisfy the requirements of **40 CFR 146.82(a)(8) and 146.87**. For additional information, see the US EPA Class VI Injection Well Construction Guidance, the Class VI Well Geologic Site Characterization Guidance, and the Class VI Reporting, Recordkeeping, and Data Management Guidance.

WV 47CSR 13.5: 13.5.a.; During the drilling and construction of a Class 6 injection well, the owner or operator must run appropriate logs, surveys and tests to determine or verity the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under section 13.3 and to establish accurate baseline data against which future measurements may be compared. The owner or operator must submit to the Director a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests. For a complete description of requirements see; **WV 47CSR 13.5 sections; 13.5.a.1. thru 13.5.f.**

XVII. Proposed Injection Interval: Describe plans to gather information on the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s). Describe plans to collect and analyze core samples within the injection and confining zones to refine site characterization data and provide information to support stratigraphic correlation, interpretation of depositional environments and wireline log calibrations. For additional information, see the US EPA Class VI Well Geologic Site Characterization Guidance sections 4.2, 4.3 and 4.4.

XVIII. Proposed Injection Stream: Describe the proposed injection rate that is appropriate to the site geology, properties of the injection zone and the well construction. Describe the proposed injection pressure that is no more than 90 percent of the injection zone fracture pressure to prevent the injection zone from being fractured and reduce potential for fracture of the confining zone. Propose a total volume of CO2 to be injected throughout the life of the GS project that the injection zone can receive and contain without endangering USDWs. Provide information to demonstrate that the proposed maximum annular pressure will be greater than the injection pressure or propose an alternative annular pressure and demonstrate that it will be appropriate and protective. Include source information for Co2 and analysis of the chemical and physical characteristics of Co2 injection stream. For more information see Section 4.1 of the US EPA Class VI Well Construction Guidance and Section 3.3 of the US EPA Class VI Testing and Monitoring Guidance.

XIX. Aquifer Exemption: If appropriate, to demonstrate that USDWs above and below the injection zone are protected from endangerment if injection into non-USDWs that are located above or between USDWs is planned. This information will satisfy the requirements of **40 CFR 146.82(d). 40 CFR 146.95 (a)** requires owners or operators seeking a waiver of the Class VI injection depth requirements to submit additional information for a comprehensive assessment of site suitability to inject into a non-USDW above or between USDWs. Owners or operators must submit a waiver application report concurrent with the Class VI permit application **[40 CFR 146.82(d) and 146.95(a)]**. The waiver application report is a separate submittal which complements the Class VI permit application. For additional information, see the US EPA Class VI Reporting, Recordkeeping, and Data Management Guidance.

WV 47CSR 13.3: 13.3.1; An aquifer or a portion thereof which meets the criteria for an “underground source of drinking water” in section 2 may be determined to be an exempted aquifer if it meets the following criteria found in the following regulatory sections; **WV 47CSR 13.3 sections 13.3.1.a. Thru 13.3.1.d.3.**

XX. Testing and Monitoring Plan: Demonstrate that planned testing and monitoring of the injectate, the well, and the geologic environment will be appropriate to planned operations, the well’s construction, and site-specific geologic conditions. The testing and monitoring plan will include, but not limited to, Co2 stream analysis, continuous recording of operational parameters, corrosion monitoring, confining zone monitoring, external MIT, pressure fall-off testing, direct Co2 plume and pressure front tracking (direct and in-direct), surface air monitoring and/or soil gas monitoring. Also included will be a quality assurance and surveillance plan. This information will satisfy the requirements of **40 CFR 146.82(a)(15), 146.89, and 146.90**. For additional information, see the US EPA Class VI Well Testing and Monitoring Guidance and the Class VI Reporting, Recordkeeping, and Data Management Guidance.

WV 47CSR 13.6: 13.6.b; The owner or operator of a Class 6 well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for Director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. Testing and monitoring associated with geologic sequestration projects must, at minimum, include (see the following sections) of **WV 47CSR 13.6.b; 13.6.b.1. thru 13.6.c.1.F.v.**

XXI. Plugging and Abandonment Plan: Demonstrate that the materials and procedures proposed for injection well plugging are appropriate to the well’s construction and the site’s geology and geochemistry so that the well will not serve as a conduit for fluid movement that could endanger USDWs following cessation of injection. Prepare an Injection Well Plugging Plan that describes the procedures for properly plugging the Class VI well to prevent fluid movement that could endanger USDWs following the cessation of injection. This information will satisfy the requirements of **40 CFR 146.82(a)(16) and 146.92**. For additional information, see the US EPA Class VI Well Plugging, Post-Injection Site Care, and Site Closure Guidance and the Class VI Project Plan Development Guidance.

XXII. Post Injection Site Care and Closure (PISC) Plan: Demonstrate that post-injection monitoring strategies will ensure non-endangerment of USDWs throughout the PISC phase and the site will be properly closed. Standard PISC site plan will detail a default 50 year plan, if an alternative plan timeframe is proposed, please detail alternate timeframe PISC plan. This information will satisfy the requirements of **40 CFR 146.82(a)(17),(18) and 146.93**. For additional information, see the US EPA Class VI Well Plugging, Post-Injection Site Care, and Site Closure Guidance.

WV 47CSR 13.9: 13.9.a.; The owner or operator of a Class 6 well must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of subsection 13.9.a.2. And is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. For further guidance refer to the following sections; **WV 47CSR 13.9.a.1. thru 13.9.h.**

XXIII. Emergency and Remedial Response Plan: Demonstrate that appropriate and timely responses will be taken to protect USDWs from endangerment should an emergency event occur during the construction, operation, and post-injection phases of the project.

Prepare a proposed Emergency and Remedial Response Plan that describes the actions that would be taken in the unlikely event of an emergency in order to expeditiously mitigate any emergency situations and protect USDWs from endangerment. The Plan should consider the geologic setting, planned operations, and the well's construction. This information will satisfy the requirements of **40 CFR 146.82(a)(19) and 146.94.** For additional information, see the US EPA Class VI Project Plan Development Guidance.

WV 47CSR 13.7; 13.7a.: The owner or operator must provide the Director with an emergency and remedial response plan that describes actions the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injections site care periods. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. See the following sections for further information: **WV 47CSR 13.7.b thru 13.7.d.3.**

XXIV. Financial Assurance and Responsibility: Demonstrate that sufficient resources are available for all needed corrective action, injection well plugging, post-injection site care (PISC) and site closure, and emergency and remedial response. Provide estimates of the cost for contracting an independent third party to carry out corrective action, injection well plugging, PISC and site closure, and emergency and remedial response to prevent the general public from bearing the costs of abandoned GS projects. Describe proposed financial responsibility instruments that are secure and meet the UIC requirements to facilitate enforceability and prevent gaps in financial coverage over the duration of the project. This information will satisfy the requirements of **40 CFR 146.82(a)(14) and 146.85(a).** For additional information, see the US EPA Class VI Financial Responsibility Guidance.

WV 47CSR 14.7; 14.7.g.: The permit shall require the permittee, including the transferor of a permit, to demonstrate and maintain financial responsibility and resources to close, plug, and abandoned underground injection wells in a manner prescribed by the Director until: the well has been plugged and abandoned and the report submitted; or the well has been converted; or the transferor of the permit receives notice that the transferee has demonstrated financial responsibility. The permittee must show evidence of financial responsibility to the DIrector by submission of a surety bond, or other adequate assurance, such as a financial statement or other material acceptable to the Director. For all applicable financial assurance regulations of Class 6 permits see the following applicable provisions found within **WV 47 CSR Sections 14.7.g.1 thru 14.7.g.18.**

XXV. Additional Permit Information: Attach and include the following completed permits. Applications for these permits can be found within the West Virginia Department of Environmental Protection website.

O&G Division Well Work Package (Attached)

Groundwater Protection Plan

The Wild and Scenic Rivers Act, 16 U.S.C. 1273 et seq.

The National Historic Preservation Act of 1966, 16 U.S.C. 470 et seq.

The Endangered Species Act, 16 U.S.C. 1531 et seq.

Emergency and Remedial Response Plan

XXVI. Attachments: Attach completed mapping, analysis, cross sections and drill data.

XXVII. Certification: All permit applications must be signed by either: a responsible corporate officer for a corporation, by a general partner for a partnership, by the proprietor of a sole proprietorship, or by a principal executive or ranking elected official for a public agency.

XXVIII. Certified Professional Engineering Certification: All technical design, assessment and calculations including but not limited to; attachments, maps, schematics, cross-sections, etc. must be signed by a licensed Professional Engineer who holds a current license to practice engineering in West Virginia.

For further guidance on Class 6 permit development requirements:

Please review the *Class VI Rule* and the *EPA guidance documents*, which are available on US EPA's web site in order to gain a full understanding of the Class VI permit application process.

Also, Please review the Class 6 regulatory requirements that can be found within the West Virginia Legislature website; **wvlegislature.gov/wvcode/code.cfm**

Please feel free to contact WVDEP with any questions at;

West Virginia Department of Environmental Protection:

Department of Water and Waste Management/WVDEP DWWM/Groundwater UIC

Revision: 1
October 2025

CLASS VI PERMIT APPLICATION NARRATIVE
47 CSR 13-13.8.1

Project Name: Tri-State CCS Redbud 2

Facility Information

Facility Contact:

Tri-State CCS, LLC
14302 FNB Parkway
Omaha, Nebraska 68154
402-691-9500

Well Locations: Marshall County, West Virginia

Well Name	Latitude (WGS 84)	Longitude (WGS 84)
TR2-1	40.016375	-80.606419
TR2-2	40.011884	-80.533589
TR2-3	39.978333	-80.600234
TR2-4	39.956423	-80.635316

Table of Contents

List of Figures 4
List of Tables 8
Acronym List 9
1. Project Background and Contact Information 12
2. Site Characterization 21
  2.1. Regional Geology, Hydrogeology, and Local Structural Geology [47 CSR 13-13.8.1.c.] 21
    2.1.1. Geographic Overview 21
    2.1.2. Tectonic History........21
    2.1.3. Influence of Precambrian – Cambrian Tectonic Events 21
    2.1.4. Early Ordovician........24
    2.1.5. Ordovician-Silurian Caledonian Orogeny 26
    2.1.6. Devonian-Permian Variscan-Hercynian Orogeny 30
    2.1.7. Paleogeographic Influences on Sedimentation 30
    2.1.8. Summary........31
    2.1.9. Hydrogeology 31
    2.1.10. Mining........31
    2.1.11. Local Structural Geology........36
      2.1.11.1. Rome Trough Fault System 36
      2.1.11.2. Highlandtown Fault Zone 38
      2.1.11.3. Burning Springs – Cambridge Fault Zone........ 38
      2.1.11.4. Unnamed Compressional Faults 41
    2.1.12. Data Used for Geologic Characterization........43
  2.2. Maps and Cross Sections of the AoR [47 CSR 13-13.8.1.c.1] 51
  2.3. Faults and Fractures [47 CSR 13-13.8.1.c.2]........ 57
  2.4. Injection and Confining Zone Details [47 CSR 13-13.8.1.c.3.] 61
    2.4.1. Upper Injection Complex: Lockport Injection Complex (LIC)........63
      2.4.1.1. LIC Primary Confining Zone: Salina Group 63
      2.4.1.2. LIC Primary Injection Zone: Lockport Dolomite Group........ 69
      2.4.1.3. LIC Primary (lower) Confining Zone: Rochester Shale Formation 72
    2.4.2. Middle Injection Complex: Medina Injection Complex (MIC)........75
      2.4.2.1. MIC Primary (upper) Confining Zone: Rochester Shale........ 75
      2.4.2.2. MIC Primary Injection Zone: Sandstone in the Medina Group........ 75

2.4.2.3. MIC Primary (lower) Confining Zone: Queenston (Juniata) Shale Formation 82
2.4.3. Secondary Injection Complex for Consideration: Knox Injection Complex (KIC) 85
2.4.4. Uncertainties & Additional Required Information 90
2.4.5. Regional Estimated Injection Zone Storage Capacity 90
2.5. Geomechanical and Petrophysical Information [47 CSR 13-13.8.1.c.4.].................... 92
2.5.1. Salina Group Confining Zone Petrophysical Analysis 92
2.5.2. Lockport Dolomite Group Injection Complex Petrophysical Analysis....................94
2.5.3. Rochester Shale Formation Confining Zone Petrophysical Analysis....................96
2.5.4. Medina Group Injection Complex Petrophysical Analysis 98
2.5.5. Queenston Shale Formation Confining Zone Petrophysical Analysis....................100
2.5.6. Geomechanics....................100
2.5.6.1. Proposed Geomechanical Studies 100
2.5.6.2. Regional Stress State.................... 101
2.6. Seismic History [47 CSR 13-13.8.1.c.5.].................... 101
2.7. Hydrologic and Hydrogeologic Information [47 CSR 13-13.8.1.e.] 106
2.7.1. Hydrogeologic Description....................106
2.7.1.1. Quaternary Alluvium 108
2.7.1.2. Dunkard Group 108
2.7.1.3. Monongahela Group 108
2.7.1.4. Conemaugh Group 109
2.7.1.5. Allegheny Group.................... 109
2.7.1.6. Pottsville Group 109
2.7.1.7. Mauch Chunk Group.................... 109
2.7.2. Groundwater Flow and Principal Aquifer Zones....................110
2.7.3. Drinking Water Wells in the AoR 111
2.7.4. Water Quality in the AoR 114
2.8. Geochemistry [47 CSR 13-13.8.1.f.] 115
2.8.1. Baseline Fluid Chemistry....................115
2.8.2. Fluid-Rock Interactions 118
2.8.2.1. Lockport Injection Complex.................... 118
2.8.2.2. Medina Injection Complex 119
2.8.2.3. Knox Injection Complex.................... 119
2.8.3. Planned Testing and Modeling 119

2.9. Site Suitability [47 CSR 13-13.2.1] 120
3. Summary of Other Plans 122
3.1. Area of Review and Corrective Action Plan 122
3.2. Financial Responsibility 122
3.3. Injection Well Construction 123
3.3.1. Stimulation Program 123
3.3.2. Construction Details 124
3.4. Pre-Operational Testing Program 125
3.5. Summary of Requirements – Class VI Operating and Reporting Conditions 126
3.6. Testing and Monitoring Plan 127
3.7. Injection Well Plugging Plan 128
3.8. Post-Injection Site Care and Site Closure Plan 128
3.9. Emergency and Remedial Response Plan 129
3.10. Environmental Justice Plan 130
3.11. Groundwater Protection Plan 130
3.12. Injection Depth Waiver and Aquifer Exemption Expansion 130
3.13. Additional Project Information [47 CSR 13-13.8.1.u] 130
4. References 132
Appendix A: Detailed Water Well Completion Records for the Area of Review 142
Appendix B: Detailed Water Well Geochemistry for the Area of Review 146
Appendix C: Map of the AoR with all Oil and Gas wells and their status. See Appendices A-D in the Area of Review and Corrective Action Plan for specific well information. A larger, higher resolution version is attached separately 150

List of Figures

Figure 1: Location of project within the Tri-State CCS Hub 13
Figure 2: Locations of proposed injection and observation wells, oil and gas wells, and water wells in the Area of Review (AoR) and the 80-year plume boundary (see Appendix C for […]. 14
Figure 3: Infrastructure in the AoR, including railroads, cemeteries, schools, highways and roads, natural gas pipelines, building footprints, and jurisdictional boundaries. 18
Figure 4: Underground mines in the AoR. 19
Figure 5: Waterbodies and wetlands in the AoR. 20
Figure 6: Physiographic provinces of the Appalachian Highlands after Fenneman, 1928. The Tri-State CCS Hub location is indicated with a red dashed circle, with the project's AoR […] 23

Figure 7: Paleozoic geologic time scale, showing the occurrence and relative duration of synrift, postrift passive margin, and 13 third-order, tectophase cycles (numbered) in the […] 25
Figure 8: Schematic cross section of the Appalachian Basin from Virginia to Ohio (NW) to Virginia (SE) showing the major relationships of stratigraphic units from the […] 26
Figure 9: Distribution of Taconian Queenston Delta clastic wedge on southeastern Laurussia. Paleo currents noted by arrows. (Figure from Ettensohn, 2008). 27
Figure 10: Southwest-northeast section partially parallel to basin strike highlighting the two Salinic phases of tectonism in the Appalachian Basin and the associated formations deposited. […] 28
Figure 11: Schematized Late Silurian paleogeographic map of Salinic depositional systems. Deposition and lithologies were driven by bulge migration that reactivated regional […] 29
Figure 12: Map of coal bearing rocks in West Virginia. Project area is the red dashed oval, and the approximate AoR is the solid red oval. Modified from WVGES, 2025a. 32
Figure 13: Stratigraphic column of the major lithologic units and their associated coals in the Pennsylvanian System in West Virginia (modified from Blake et al., 2002). Major […] 34
Figure 14: Regional fault map of the study area. Major structures discussed include the Rome Trough Fault System, Highlandtown Fault System, Burning Springs – Cambridge Fault […] 37
Figure 15: Regional cross-section across the Rome Trough Fault System. See Figure 14 for location of cross-section A-B. Interior Fault and the East-Margin Fault are part of the […] 38
Figure 16: Example seismic cross-section across the Highlandtown Fault System in Ohio, see Figure 14 for location of cross-section C-D. From Root and Onasch, 1999. Note, “Big […] 40
Figure 17: Seismic reflection profile across the Burning Springs anticline in West Virginia. Located along the Burning Springs – Cambridge Fault Zone. From Root and Onasch, […] 42
Figure 18: Location of wells used to characterize the mineralogy and petrophysics, as well as core locations. See Table 2 for API numbers, latitudes, and longitudes. 44
Figure 19: Location of the six 2D seismic lines licensed for use in the project’s subsurface assessment. Note: 2D seismic data were licensed from Evans Geophysical. 49
Figure 20: Synthetic seismogram created using logs from the Birney Roy 1 well (Well No. 58 in Table 2, location in Figure 18 , to tie the 2D seismic data to the well logs. Tracks from […] 50
Figure 21: Base Map of the Appalachian Region and structural features with the cross section in Figure 22 shown in red. The approximate AoR is outlined in the dashed red circle. […] 52
Figure 22: Regional cross section from ground level to the Cambrian Mt. Simon through the AoR (The red portion of D-D’ in Figure 21 shows position of the cross section with respect […] 53

Figure 23: Base map of the project model domain (black), petrophysical wells included in the static model build (black circles), the NW-SE dip cross section (orange; Figure 24) and the […] 54
Figure 24: NW-SE Dip cross section through the project model domain with the normalized Gamma ray (far left), the depth track in feet measured depth, the calculated effective […] 55
Figure 25: S-NE Strike cross section through the project model domain with the normalized Gamma ray (far left), the depth track in feet measured depth, the calculated effective […] 56
Figure 26: Location map of faults (black dashed lines) and 2D reflection seismic lines (purple). Location of N-S seismic line EGI-OH-13-11 (Figure 27) and E-W seismic line EGI- […] 58
Figure 27: 2D north-south oriented seismic cross-section OH-13-11 (see Figure 26 for location). See text for a discussion of compressional structure A. Interpreted seismic horizons […] 59
Figure 28: 2D west-east oriented seismic cross-section EGI-OH-05-11 (see Figure 26 for location). See text for a discussion of distributed compressional structures B. Interpreted seismic […] 60
Figure 29: Generalized stratigraphic column for the project. Primary Injection Complexes: 1 - Lockport Injection Complex; 2 - Medina Injection Complex; possible secondary […] 62
Figure 30: Regional extent and thickness of the Salina Group salt beds modified from Clifford (1973). The red dashed circle is the approximate location of the Tri-State CCS Hub (map […] 64
Figure 31: SE-NW Cross-section from Lorain, County OH, to Hancock County, WV through the Salina Group. Study area in red dashed line in map. Modified from Clifford, 1973. From […] 65
Figure 32: F4 Salt Thickness map in the Tri-State CCS Hub (red dashed oval) and project AoR (solid black oval). Modified from Carter et al., 2017 66
Figure 33: Core measured Porosity vs. Permeability from the Salina Goup in the MRCSP FEGENCO 1 well (Well No. 1 in Table 2, location in Figure 18). 67
Figure 34: Top Structure (left) and Isochore (right) of the Salina Group interval (Structure C.I. = 200 ft; depths SSTVD; Isochore C.I. = 10 ft) with the four potential injection sites shown […] 68
Figure 35: Cartoon depicting the regional facies patterns interpreted for the Lockport Dolomite in the Appalachian Basin. Numbers reflect the described facies in the text. Modified from […] 70
Figure 36: Top Structure (left) and Isochore (right) of the Lockport Dolomite Group interval (Structure C.I. = 200 ft; depths SSTVD; Isochore C.I. = 20 ft) with the four potential […] 71
Figure 37: Top Structure (left) and isochore (right) of the Rochester Formation interval (Structure C.I. = 200 ft; depths SSTVD; Isochore C.I. = 20 ft) with the four potential injection sites […] 74
Figure 38: Stratigraphic correlation chart for the project area illustrating varying terminology for age equivalent sands. For this permit, the nomenclature for Eastern Ohio is recognized, […] 76

Figure 39: Type log from Riley et al., 2010, of the stratigraphy in the East Canton oil field in Stark County, Ohio (lWell No. 13 in Table 2, location in Figure 18) which directly translates […] 77
Figure 40: Top Structure (left) and Isochore (right) maps of the Medina Group interval (Structure C.I. = 200 ft; depths SSTVD; Isochore C.I. = 20 ft) with the four potential injection sites […] 81
Figure 41: (Upper) Map of late Ordovician formations in the Appalachian Basin and (Lower) depositional systems of the Queenston Shale (modified from Dennison, 1976 and Blue, […] 83
Figure 42: Top Structure (left) of the Queenston Shale Formation and isochore (right) of the Queenston Shale Formation to the top of the Wells Creek Formation interval (Structure […] 84
Figure 43: Wireline log cross section of the Knox Group from Coshocton to Harrison County, Ohio. Left track – gamma ray; middle track – depth TVD; right track – porosity, RHOB, […] 88
Figure 44: Diagram illustrating the regional thinning, and truncation, of the Knox Group, from west of the project area to the northwest into north-central Ohio, over the Findlay Arch […] 89
Figure 45: Representative log section through the Salina Group showing vertical variability of section and locations of core points used in petrophysical modeling. The log display […] 93
Figure 46: Representative log section through the Lockport Dolomite Group showing vertical variability of section and locations of core points used in petrophysical modeling The […] 95
Figure 47: Representative log section through the Rochester Shale Formation showing vertical variability of section and locations of core points used in petrophysical modeling. The […] 97
Figure 48: Representative log section through the Medina Group showing vertical variability of section and locations of core points used in petrophysical modeling. The log display […] 99
Figure 49: USGS Seismic Hazard Map, showing the frequency of damaging earthquake shaking within a 10,000-year period (Petersen et al., 2008). The project area is indicated by the […] 102
Figure 50: Seismic Hazard Map of West Virginia, Ohio, and surrounding states from the USGS National Seismic Hazard Maps illustrating the peak ground acceleration with a 2% […] 103
Figure 51: Local seismic events within 50 miles radius of the AoR. 104
Figure 52: Geologic stratigraphic section in the project area near the AoR. Adapted from USGS map (Ryder, 2009). 107
Figure 53: Generalized stratigraphic column from the AoR illustrating the freshwater aquifers and lowermost USDW. 108
Figure 54: Generalized groundwater flow directions within the AoR. 111
Figure 55: Location of groundwater wells and groundwater quality record sites within the AoR. Groundwater well and quality record details are provided in Appendix A and Appendix […] 113

Figure 56: Location map of regional baseline fluid chemistry data from the USGS National Produced Waters Geochemical Database (Blondes et al., 2023). 117

List of Tables

Table 1: Permits and Authorizations necessary for the development of the project. 16
Table 2: List of well names, API numbers, latitude and longitudes for core, type logs, literature core studies, and petrophysical model logs used to build the geologic model............ 45
Table 3: XRD results for sidewall core samples of the Lockport Dolomite Group from the Ocel #1 well, Carroll County, Ohio (Carter et al., 2010; Well No. 2 in Table 2, location in Figure 18)... 72
Table 4: Framework Grain Analysis for the Medina Group at the Ohio Division of Geological Survey CO_2 No. 1 well in Tuscarawas County, Ohio (Well No. 9 in Table 2, location in Figure 18). Modified from Wickstrom, 2011. 79
Table 5: XRD analysis (weight %) for rotary sidewall core (RSWC) collected in the Medina Group at the Ohio Division of Geological Survey CO2 No. 1 well in Tuscarawas County, Ohio (Well No. 9 in Table 2, location n Figure 18). Modified from Wickstrom, 2011........ 80
Table 6: XRD analysis (weight %) for RSWC collected in the Rose Run Sandstone at the Ohio Division of Geological Survey CO2 No. 1 well in Tuscarawas County, Ohio (Well No. 9 in Table 2, location in Figure 18). Modified from Wickstrom, 2011....................... 86
Table 7: Framework Grain Analysis for the Rose Run Sandstone at the Ohio Division of Geological Survey CO2 No. 1 well in Tuscarawas County, Ohio (Well No. 9 in Table 2, location in Figure 18). Modified from Wickstrom, 2011. 87
Table 8: Parameters used for Calculating Storage Resource Estimates for Reservoir Formations. Note: CO_2 density is based on reservoir conditions using regional gradients. ESaline Storage Efficiency = EvEd (volumetric displacement efficiency) + Ephi (effective porosity) +Eh (net-to-gross thickness). Ean/at (Net-to-total area) is assumed to be 1. Efficiency values obtained from 2017 version of NETL CO_2 Screen Tool for respective depositional environment. Area based on Tri-state CCS Hub. 91
Table 9: Cumulative and probabilistic scenarios for prospective storage resource estimates for all reservoir formations in the Tri-State CCS Hub based on the regional values. 91
Table 10: Core-based porosity and permeability measurements for confining and injection units. Locations and API Nos. in Figure 18 and Table 2. 100
Table 11: Seismic events within 50 miles of the AoR over a 40-year period. 105
Table 12: Regional Total Dissolved Solids (TDS) data for the Primary and Secondary injection complexes and USDWs. There are no data for the Rochester Formation, and data from the Queenston Shale are described in the text above. 116
Table 13: Regional Baseline Fluid Chemistry data for the primary and secondary injection complexes and USDWs from USGS (National Produced Waters Geochemical Database; Blondes et al., 2023)... 118
Table 14: Cost Estimates for Activities to be Covered by Financial Responsibility................. 123

Acronym List

AEP	American Electric Power
AGWQMP	Ambient Ground Water Quality Monitoring Program
AI	Acoustic Impedance
amsl	Above Mean Sea Level
Ank	Ankerite
ANSI	American National Standards Institute
ANSS	Advanced National Seismic System
ASME	American Society of Mechanical Engineers
AOI	Area of Interest
AoR	Area of Review
AP	Artificial Penetrations
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
Avg	Average
bgs	Below ground surface
BH	Bottom Hole
CarbonSAFE	Carbon Storage Assurance Facility Enterprise
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
CI	Casing Inspection
CBL	Cement Bond Log
cc	Cubic Centimeter
COCORP	Consortium for Continental Reflection Profiling
Cr	Chromium
DAS	Distributed Acoustic Sensing
Dol	Dolomite
DTS	Distributed Temperature Sensing
DH	Downhole
ERRP	Emergency and Remedial Response Plan
Fm	Formation
FR	Fragments
ft	Feet
Ga	Giga Annum
gal	Gallon
gm	Gram
GR	Gamma Ray
Grp	Group
GS	Geologic Sequestration
GSDT	Geologic Sequestration Data Tool

H_2S	Hydrogen Sulfide
K	Potassium
KIC	Knox Injection Complex
KY	Kentucky
lb	pound
LIC	Lockport Injection Complex
Ls	Limestone
M	Magnitude
Ma	Mega Annum
MD	Measured Depth
md	Millidarcy
MIT	Mechanical Integrity Test
MIC	Medina Injection Complex
MMI	Modified Mercalli Intensity
MMt	Million Metric Tonnes
MMt/y	Millions of Metric Tonnes per year
Mt/y	Thousand Metric Tonnes per year
NACE	National Association of Corrosion Engineers
NEPA	National Environmental Policy Act
No	Number
NY	New York
OD	Outer Diameter
OH	Ohio
OSU	Ohio State University
ppmv	Parts Per Million Volume
PA	Pennsylvania
PEF	Photoelectric Factor
phi	Krumbein phi Scale (porosity)
mol%	Percentage of total moles in a mixture made up by one constituent
PISC	Post-Injection Site Care
psi	Pounds Per Square Inch
psia	Pounds Per Square Inch, Absolute
psig	Pound Force Per Square Inch
P/T	Pressure-Temperature
PNC	Pulsed Neutron Capture
QASP	Quality Assurance and Surveillance Plan
QFL	Quartz-Feldspar-Lithic
QmFLt	Microcrystalline Quartz-Feldspar-Lithic
RC	Reflection Coefficient
RCRA	Resource Conservation and Recovery Act

RHOB	Bulk Density
RSWC	Rotary Sidewall Core
SAPT	Standard Annulus Pressure Test
sCO_2	Supercritical CO2
SIC	Standard Industrial Classification
SLB	Schlumberger
SP	Spontaneous Potential
spar	Sparite
SSTVD	Sub-Sea True Vertical Depth
strat	Stratigraphic
SU	Stratigraphic Unit
TN	Tennessee
TD	Total Depth
TDS	Total Dissolved Solids
TRI	Toxic Release Inventory
TST	Transgressive System Tract
TVD	True Vertical Depth
TWT	Two-Way Time
UIC	Underground Injection Control
Undiff	Undifferentiated
USACE	U.S. Army Corps of Engineers
USDW	Underground Source of Drinking Water
U.S. EPA	U.S. Environmental Protection Agency
USGS	United States Geologic Survey
VOC	Volatile Organic Compounds
VSP	Vertical Seismic Profile
VA	Virginia
WGS	World Geodetic System
WV	West Virginia
WVDEP	West Virginia Department of Environmental Protection
WVGES	West Virginia Geological and Economic Survey
XRD	X-Ray Diffraction

1. Project Background and Contact Information

Tri-State CCS, LLC is proposing the development of an industrial scale carbon capture and storage (CCS) hub in the tri-state region of Ohio (OH), Pennsylvania (PA), and West Virginia (WV) (Figure 1). The Tri-State CCS Hub envisions the development of several CO_2 injection wells with the capability of storing over 50-million metric tonnes (MMt) with injection taking place over 30 to 60 years. The hub was selected by the U.S. Department of Energy to receive Phase III funding under the CarbonSAFE Initiative. Partners include the Southern States Energy Board (the Prime Recipient), Tenaska Sequestration Services, LLC, which includes Tri-State CCS, LLC, Projeo Corporation, Ohio State University, West Virginia Geological and Economic Survey (WVGES), and West Virginia University.

Tri-State CCS, LLC is in the process of developing a series of injection fields that will be utilized to provide the region's emitters with a safe and secure subsurface storage solution. Nine separate emitters reporting more than 20 million metric tonnes per year (MMt/y) of aggregate CO_2 emissions have indicated their support for this project. These sources include AEP Dresden (1.9 MMt/y), AEP Mountaineer (9.2 MMt/y), Carroll County Energy (2.0 MMt/y), Ergon West Virginia (0.2 MMt/y), Hill Top Energy Center (1.5 MMt/y), Lakeview Energy (0.16 MMt/y), LS Power – Springdale (2.0 MMt/y), Southfield Energy (3.0 MMt/y), and Westmoreland Energy (2.8 MMt/y).

This narrative in support of a Class VI Underground Injection Control (UIC) permit application covers the Tri-State CCS Redbud 2 project in Marshall County, West Virginia (the "project"), which is a subset of the Tri-State CCS Hub. The project proposes development and operation of four injection wells (TR2-1, TR2-2, TR2-3, and TR2-4), four in-zone observation wells (TR2-IOB-1, TR2-IOB-2, TR2-IOB-3, and TR2-IOB-4), two above zone observation wells (TR2-AOB-1 and TR2-AOB-2), up to four lowermost underground source of drinking water (USDW) observation wells (TR2-UOB-1, TR2-UOB-2, TR2-UOB-3, and TR2-UOB-4), and up to four groundwater monitoring wells that will be drilled on the existing injection and observation well pads (Figure 2). This Application Narrative is for proposed TR2-1, TR2-2, TR2-3, and TR2-4.

Tri-State CCS, LLC is an affiliate of Tenaska, Inc. (Tenaska) who has made major, corporate-level commitments toward the development of the hub. Tenaska is a privately held, independent power company based in Omaha, Nebraska. Established in 1987, Tenaska has a generating fleet over 7,500 MW, is one of the largest gas marketing companies in North America and has balance sheet equity of $2.9 billion. Tri-State CCS, LLC will serve as the hub owner and will assume liability for development, finance, and operation of the hub.

The key project contacts are:

Claimed as PBI
Tri-State CCS, LLC
14302 FNB Parkway
Omaha, Nebraska 68154
Claimed as PBI

Claimed as PBI

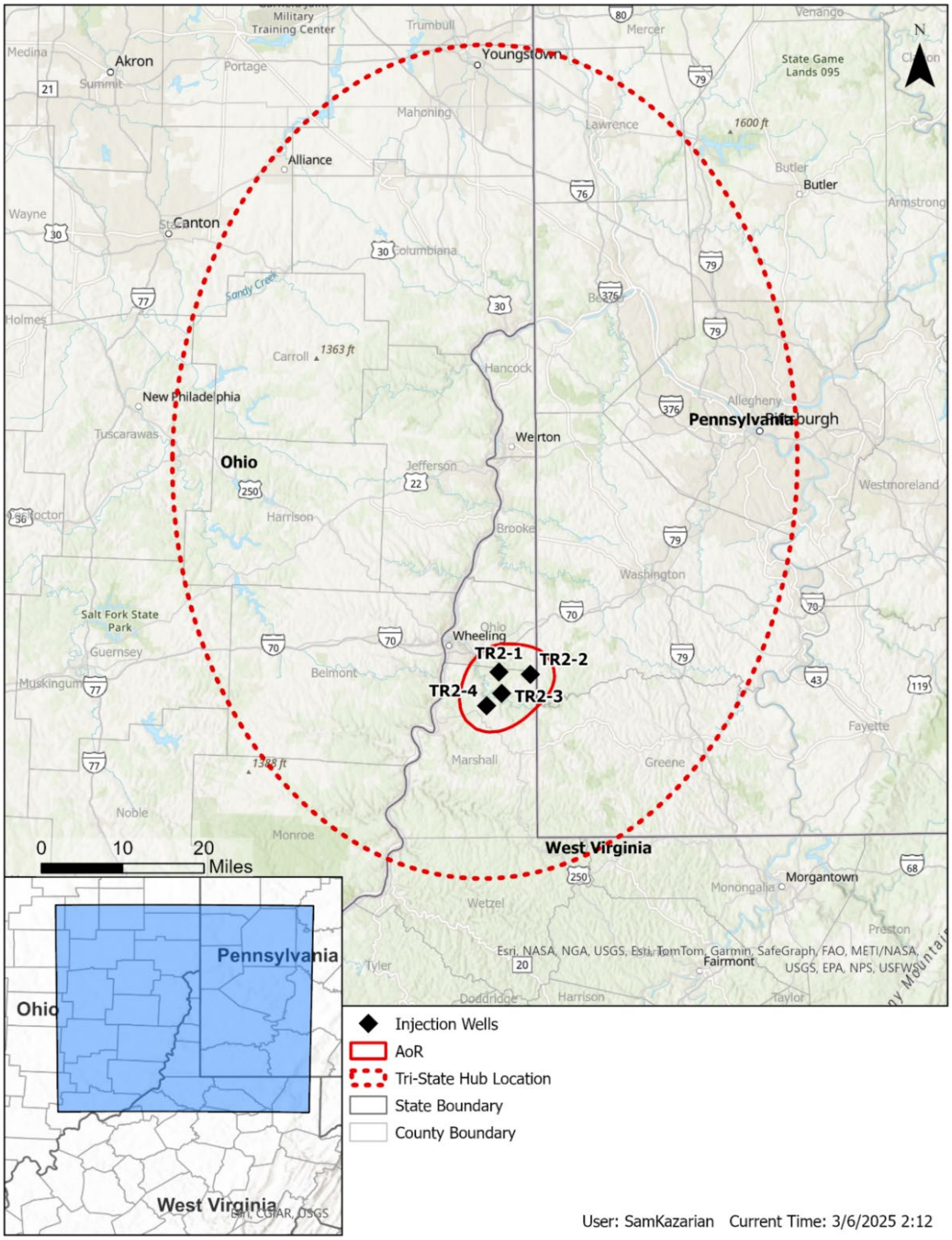

Figure 1: Location of project within the Tri-State CCS Hub.

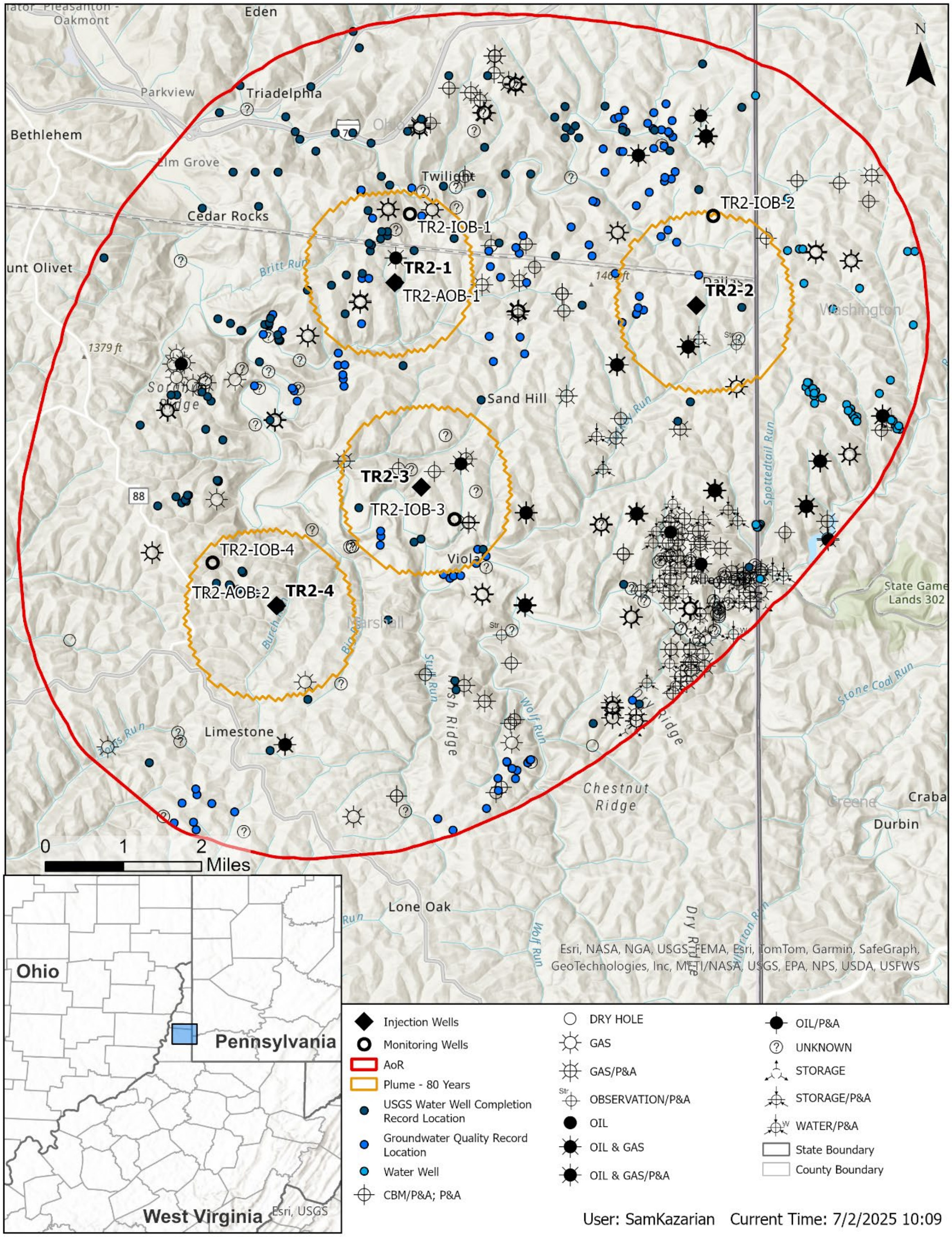

Figure 2: Locations of proposed injection and observation wells, oil and gas wells, and water wells in the Area of Review (AoR) and the 80-year plume boundary (see Appendix C for locations and number keyed to Appendices A, B and D in the Area of Review and Correction Action Plan).

The supporting documentation for this application was prepared in accordance with the West Virginia Department of Environmental Protection (WVDEP) UIC Control Program for Carbon Dioxide Geologic Sequestration Wells codified at 47 CSR 13.

With this application, Tri-State CCS, LLC is requesting permits to construct for TR2-1, TR2-2, TR2-3, and TR2-4. After issuance of the permits by the UIC Program Director, Tri-State CCS, LLC plans to start construction of the injection wells within 2 years but additionally requests two options to extend the permit term by 2 years. The reason for this request is that the project relies on the installation of capture equipment at the emitter and construction of pipeline infrastructure to the emitter, both of which may be delayed for reasons outside the control of Tri-State CCS, LLC. After submittal of required documentation to the UIC Program Director and receiving authorization to inject and once the emitter is ready to operate their CO_2 capture equipment, Tri-State CCS, LLC will initiate injection. This application assumes that the 30-year injection period will start in approximately 2028, end in 2058, and be followed by a 50-year post-injection site care period, taking the project to 2108. Start of injection could vary by 1 to 5 years.

The project is not requesting an injection depth waiver or an expansion of aquifer exemptions with this application.

There are no federally recognized Native American tribal lands or territories within the proposed Area of Review (AoR) (47 CSR 13-14.10.4.f.l).

The SIC codes applicable to the project are identified below (47 CSR 13-14.10.4.c.)

- 49530300 Nonhazardous waste disposal sites – primarily engaged in collection and disposal of refuse by processing or destruction or in operation of incinerators/waste treatment plants/landfills/other sites for disposal of such materials;
- 51690203 Carbon Dioxide – primarily engaged in wholesale distribution of CO_2; and
- 4619 Pipelines, not elsewhere classified – primarily engaged in pipeline transportation of commodities except petroleum and natural gas.

Federal and state contacts with jurisdictions within the proposed AoR include the following (47 CSR 13-13.8.1.t.):

West Virginia Department of Environmental Protection
Division of Water and Waste Management, Groundwater/UIC Program
601 57th St. SE, Charleston, WV 25304
Todd Cooper: 304-926-0499, todd.cooper@wv.gov

U.S. EPA Region 3
Source Water and UIC Section
Four Penn Center
1600 JFK Blvd.
Philadelphia, PA 19103
James Bennett: bennett.james@epa.gov, 215-814-5469

Pennsylvania Department of Environmental Protection
Southwest Regional Office
400 Waterfront Drive, Pittsburgh, PA 15222
Jim Miller: jamesmill@pa.gov, 412-442-4181 or 412-442-4000

The permits and authorizations that will likely be required for the project, the permit/authorization jurisdictions, and the associated project development activities are provided in Table 1 (47 CSR 13-14.10.4.e).

Table 1: Permits and Authorizations necessary for the development of the project.

Required Permits and Authorizations for Marshall County, West Virginia		
Permit/Authorization	**Activity**	**Jurisdiction**
UIC Class VI Permit to Construct	Drilling of Injection Wells	WVDEP Division of Water and Waste Management
UIC Class VI Authorization to Inject	Injecting CO_2	WVDEP Division of Water and Waste Management
Greenhouse Gas Rule Subpart RR Monitoring, Reporting, and Verification Plan Approval	Injecting CO_2	U.S. EPA
Section 404 Nationwide Permit	Impacts to jurisdictional waters	USACE
Construction Stormwater General Permit	Management of stormwater during construction	WVDEP Division of Water and Waste Management
Well Work Permit	Observation well construction	WVDEP Office of Oil and Gas

The project is currently proposing an AoR that includes a 1-mile buffer on the modeled maximum extent of the pressure front to mitigate the current unknowns in subsurface data that will be resolved with the planned CarbonSAFE stratigraphic test well and pre-injection testing, as further described in this Application Narrative and in the Area of Review and Corrective Action Plan. Due to the extent of the AoR, four figures were created (Figure 2, Figure 3, Figure 4, and Figure 5) to address state requirements at 47 CSR 13-13.8.1.b and 13-14.10.4.f.1 for a map of the area, with features shown or absent as noted below:

- Injection wells: There are no records of UIC wells in the AoR.
- Oil and gas wells (see Figure 2 for locations and Appendix C for locations with identifiers keyed to well records in Appendices A, B, and D of the Area of Review and Corrective Action Plan; oil and gas wells are further discussed in subsection 4.1 of the Area of Review and Corrective Action Plan):
    - Producing wells: There are 257 known producing wells (Point Pleasant and Marcellus) in the AoR.
    - Abandoned wells: There are 64 wells with the status “unreported,” “unknown,” “undetermined,” and “other” in the AoR.
    - Storage wells: There are 34 records of storage wells in the AoR with 28 marked as plugged and abandoned. There is 1 record of water storage, also plugged and abandoned, within the AoR.

  - Plugged wells or dry holes: There are 93 known plugged and abandoned wells in the AoR not including plugged and abandoned storage and observation wells. There are 2 dry holes in the AoR.
  - Deep stratigraphic boreholes: There are 2 records of deep stratigraphic boreholes in the AoR, both marked plugged and abandoned.
- State or U.S. EPA-approved subsurface cleanup sites: There are no West Virginia Voluntary Cleanup Program sites or U.S. EPA cleanup sites in the AoR. U.S. EPA's Cleanups in My Community map shows one Brownfield site in the AoR near Cedar Rocks. However, records associated with this site indicate it is actually located in Lockland, Ohio, outside of the AoR.
- Surface bodies of water: The following named surface bodies of water are in the mapped area, as shown in Figure 5: Holidays Run, Burch Run, Stull Run, Bruce Run, Turkey Run, Wherry Run, Gillespie Run, Middle Wheeling Creek, Laidley Run, Spottedrail Run, Whetstone Run, Wheeling Creek, Wolf Run, Big Run, Little Grave Creek, Britt Run, Toms Run, and Grandstaff Run. There are various unnamed tributaries and ponds in the AoR as well.
- Springs: There are 70 records of springs in the mapped area located from groundwater quality record data shown in Figure 2.
- Surface and subsurface mines: The Ohio County Mine, Bailey Mine, and Valley Camp No 3, all underground coal mines in the Pittsburgh Coal Seam, are present within the AoR. No surface mines are present within the AoR. Mining operations in the mapped area are shown in Figure 4 and further discussed in subsection 2.1.10 below.
- Quarries: There are no records of quarries in the AoR.
- Water wells: There are 134 well records and 110 groundwater quality records in the AoR (Figure 2).
- Faults: There are no faults present within the AoR (see subsection 2.3 and Figure 26 of this Application Narrative for more information on fault systems in the region).
- State, tribal, and territory boundaries: The AoR includes parts of Marshall and Ohio Counties, West Virginia and Washington County, Pennsylvania, as shown in Figure 1. There are no tribal or territory boundaries in the AoR.
- Roads: U.S. Highway 250, 70, state highway 88, and various county and town roads are in the AoR, as shown in Figure 3.
- Other pertinent surface features: The city of Wheeling, incorporated town of Triadelphia, village of Bethlehem, unincorporated communities of Viola, Limestone, Sand Hill, Allen Grove, and Twilight, and neighborhood of Cedar Rocks are in the AoR, as shown in Figure 3.

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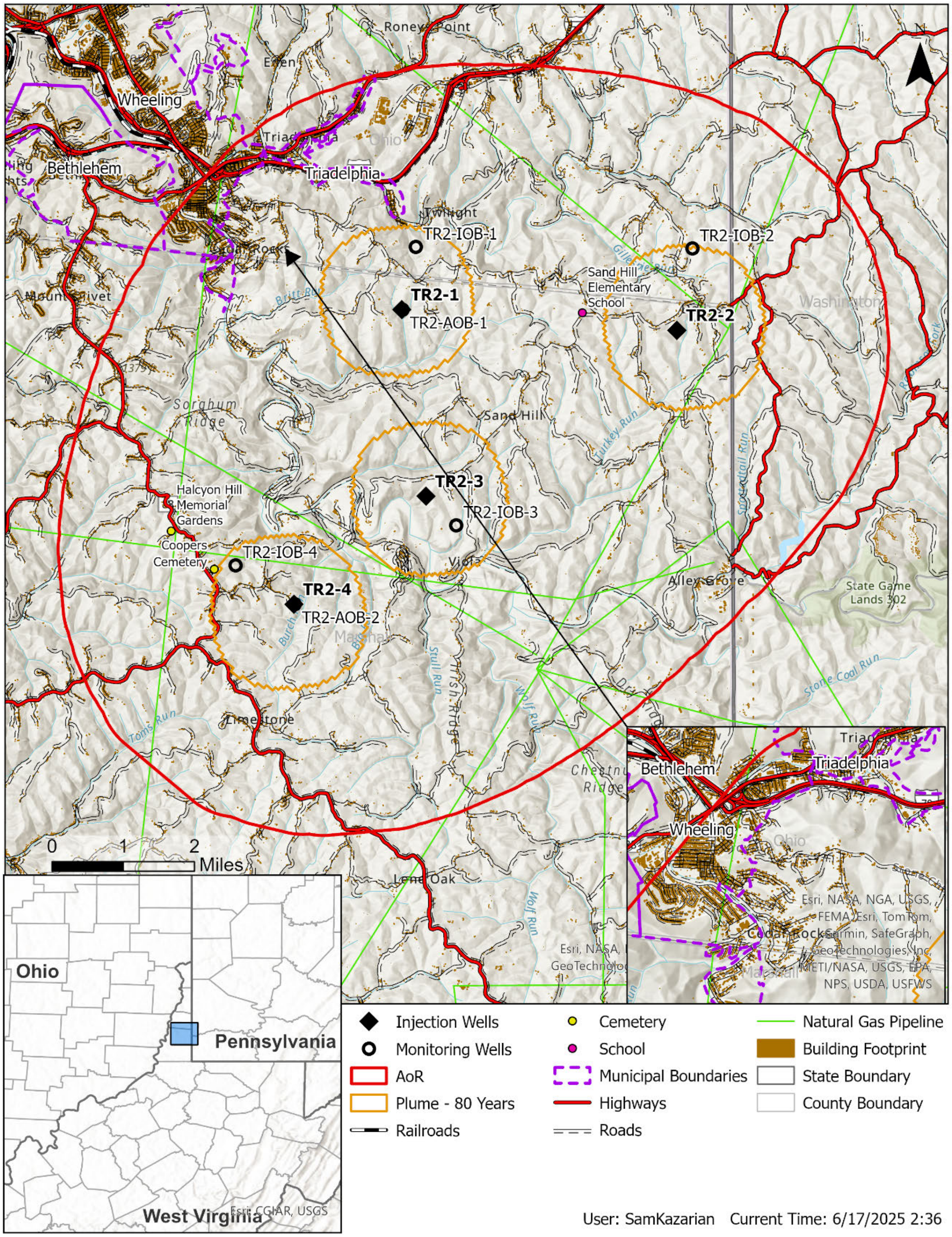

Figure 3: Infrastructure in the AoR, including railroads, cemeteries, schools, highways and roads, natural gas pipelines, building footprints, and jurisdictional boundaries.

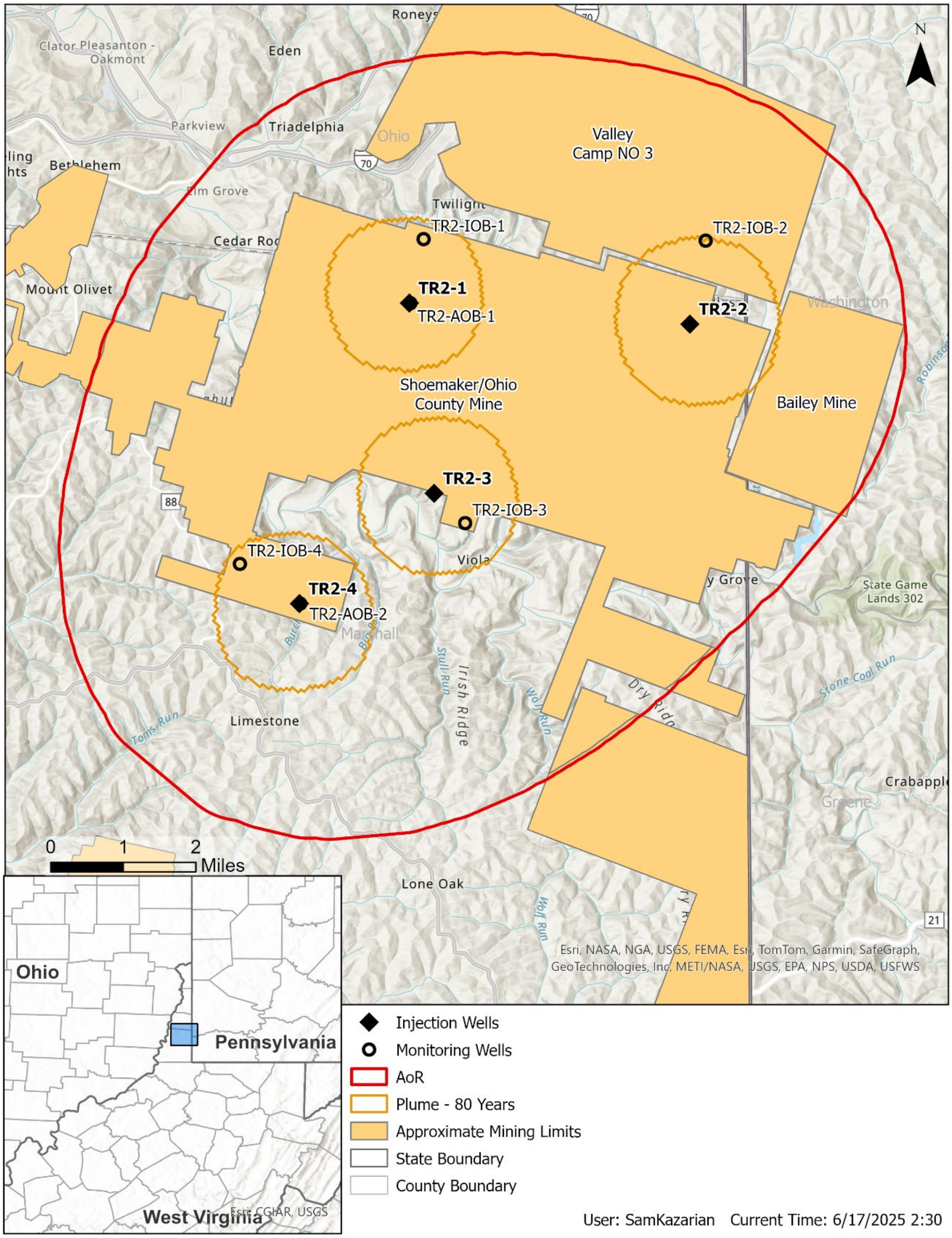

Figure 4: Underground mines in the AoR.

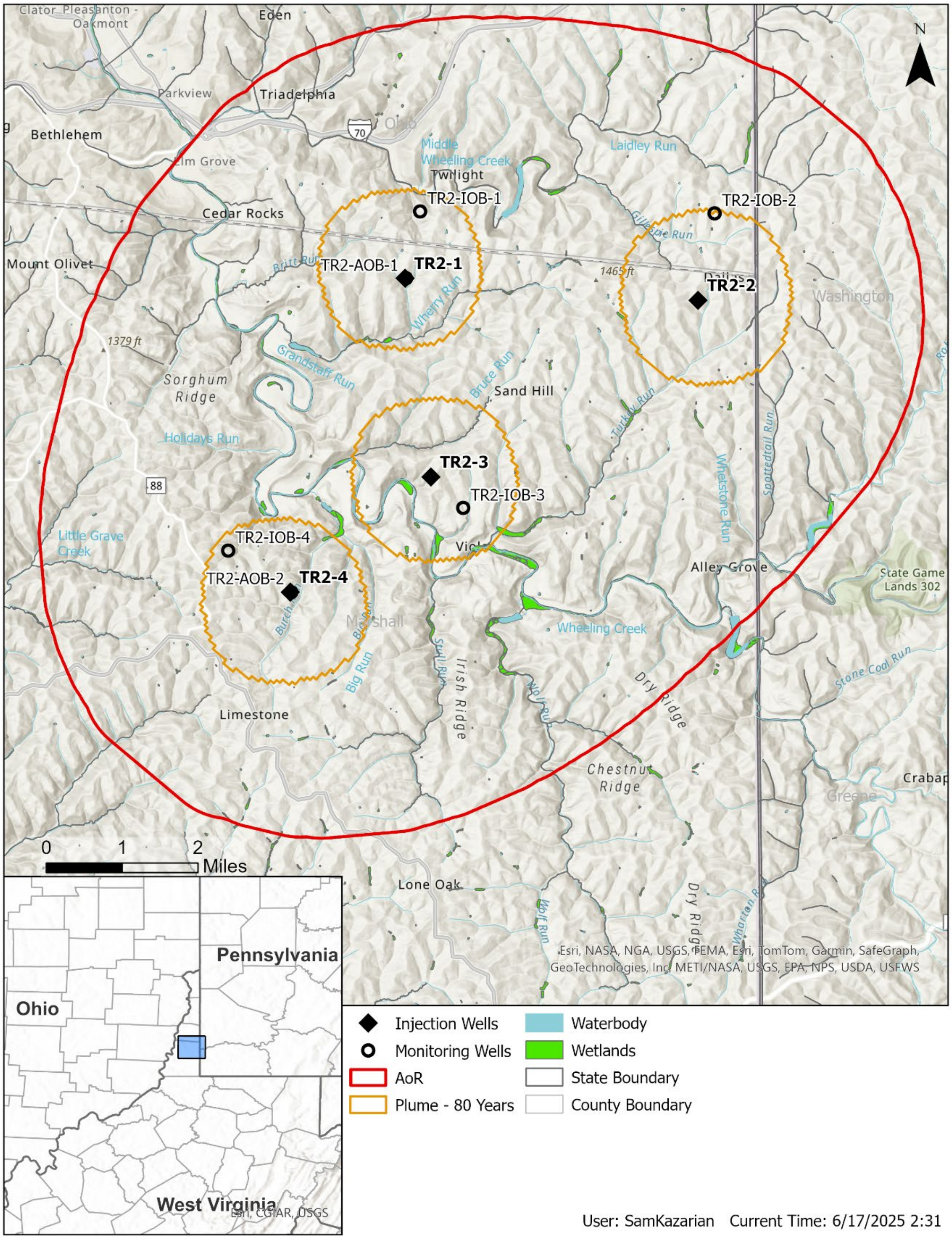

Figure 5: Waterbodies and wetlands in the AoR.

2. Site Characterization

2.1. Regional Geology, Hydrogeology, and Local Structural Geology [47 CSR 13-13.8.1.c.]

2.1.1. Geographic Overview

The Tri-State CCS Hub, which includes the project, is located within the tri-state region of eastern Ohio, northern West Virginia, and western Pennsylvania. This region lies within the Appalachian Basin, an elongate, retroarc foreland basin that sits within the physiographic province of the Appalachian Plateau (Figure 6). The Appalachian Basin extends approximately 1,270 miles from Canada to Alabama and is flanked by the Cincinnati, Findlay, Nashville Dome, and Algonquin arches to the northwest, and the Blue Ridge Mountains and New England Uplands to the east (Colton, 1970). The northern boundary of the basin is demarcated by the Laurentian and Frontenac arches of the Canadian Shield (Ettensohn, 2008), while to the south, the basin transitions into the Black Warrior Basin of northwestern Alabama and northeastern Mississippi (Figure 6).

2.1.2. Tectonic History

The Appalachian Basin developed in response to flexurally driven subsidence due to tectonic loading associated with four nearly continuous orogenic events throughout the Paleozoic. Orogenic development related to the Appalachian Basin began in the Early-Middle Ordovician (~472 Ma) and continued for almost 200 Ma until the Late Permian (Ettensohn, 2008). The orogenies include the Taconic or Taconian, the Salinic, the Acadian, and the Alleghanian tectophase orogenic cycles (Figure 7). These orogenies can be grouped into two higher-order supercycle phases related to continental collision and plate convergence with the Taconic and Salinic orogenies included in the Caledonian orogenic phase and the Acadian and Alleghanian orogenies included in the Variscan-Hercynian orogenic phase (Figure 7).

The Caledonian orogenic phase is a result of the Ordovician to Early Devonian closure of the Iapetus Ocean that formed the continent of Laurussia through the collision of the continents of Laurentia, Baltica, and the Avalonian microcontinent (Kearey et al., 2009; Torsvik and Cocks, 2016).

The Variscan-Hercynian orogenic event occurred during the Middle Devonian – Permian, as the Theic Ocean closed, and continental collision between Laurussia and Gondwana formed the supercontinent of Pangaea (Kearey et al., 2009; Ziegler, 2012; Torsvik and Cocks, 2016).

2.1.3. Influence of Precambrian – Cambrian Tectonic Events

The Paleozoic development of the Appalachian Foreland Basin was heavily influenced by Precambrian-Cambrian age tectonic events. The basement rocks that underlie the basin mainly comprise Grenvillian age crust (1.35–0.95 Ga) that were deformed and metamorphosed during the Grenville orogeny as the supercontinent Rodinia was formed (Ettensohn, 2008). Portions of the Grenville crust have been uplifted and deformed through Paleozoic orogenic events and are exposed at the surface in both the Blue Ridge physiographic province and the Adirondack dome (Figure 8).

Late Precambrian-Cambrian rifting and volcanism occurred during the separation of Laurentia from Gondwana and the formation of the Iapetus, Theic, and Rheic Oceans (Kearey et al., 2009; Torsvik and Cocks, 2016). Inboard rifting resulted in the deposition and emplacement of time-equivalent sedimentary and volcanic rocks (Figure 8) along what are currently the physiographic provinces of the Blue Ridge and Valley and Ridge (Figure 8; Ettensohn, 2008).

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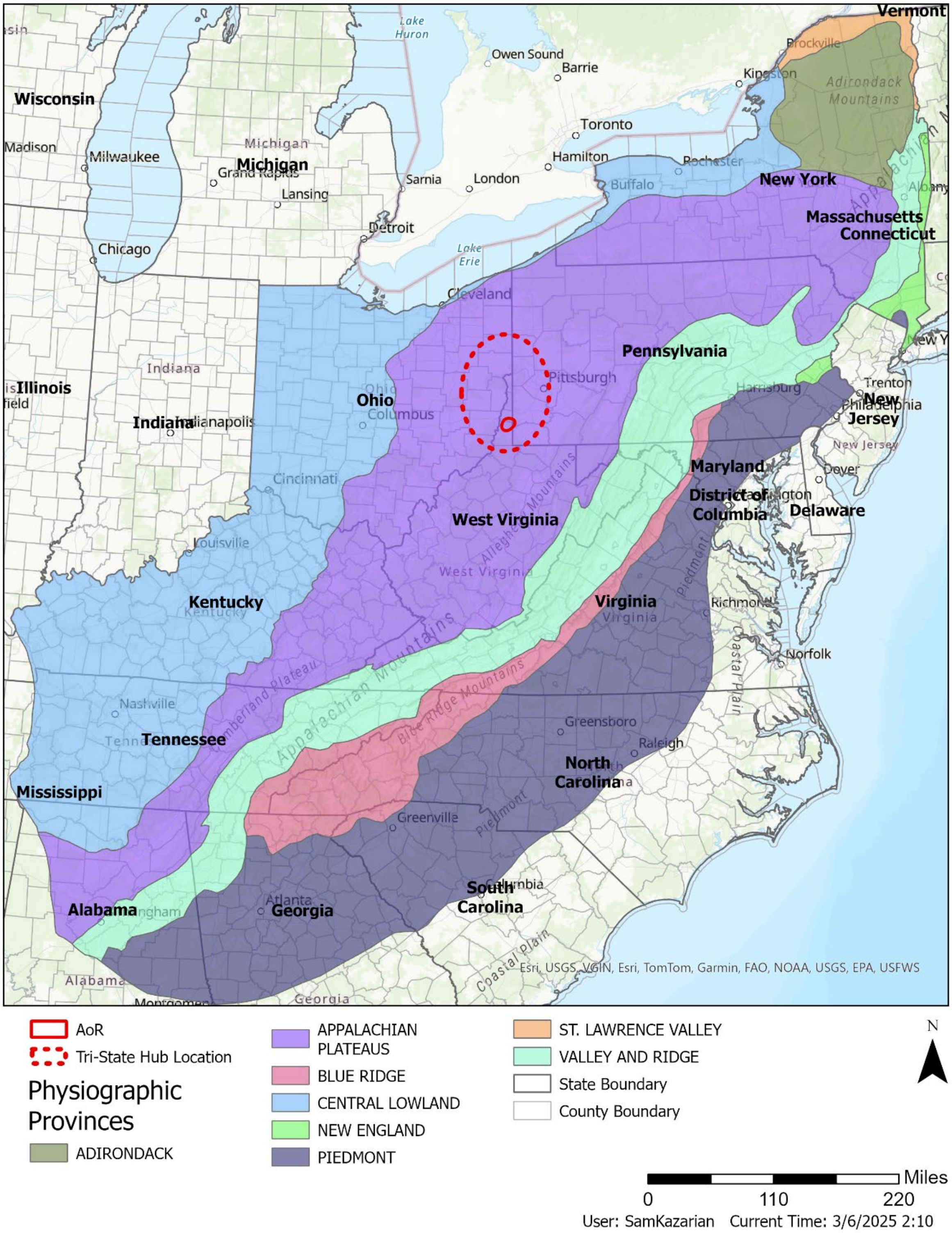

Figure 6: Physiographic provinces of the Appalachian Highlands after Fenneman, 1928. The Tri-State CCS Hub location is indicated with a red dashed circle, with the project's AoR boundary in red within it.

Rifting was followed by a period of stabilization across the margin, relative sea level rise, and thermally driven subsidence of the basin that resulted in the widespread deposition of Precambrian-Early Cambrian synrift siliciclastic sediments (Colton, 1970). During the Late Cambrian, continued submergence of the platform established the “Great American Carbonate Bank”, depositing up to 3,000 ft of mixed limestone, dolostone, and minor siliciclastic sediment (Demicco and Mitchell, 1982).

2.1.4. Early Ordovician

The Late Cambrian post-rift passive margin phase continued into the Early Ordovician as sedimentation and carbonate development continued across the passive margin (Figure 7 and Figure 8). The near equatorial paleogeographic setting and aridification of the climate, during the Early Ordovician, resulted in the uninterrupted deposition of carbonates, dolomites, and sedimentary strata of the Knox Group (Figure 8; Read, 1989; Scotese, 2003; Ettensohn, 2008).

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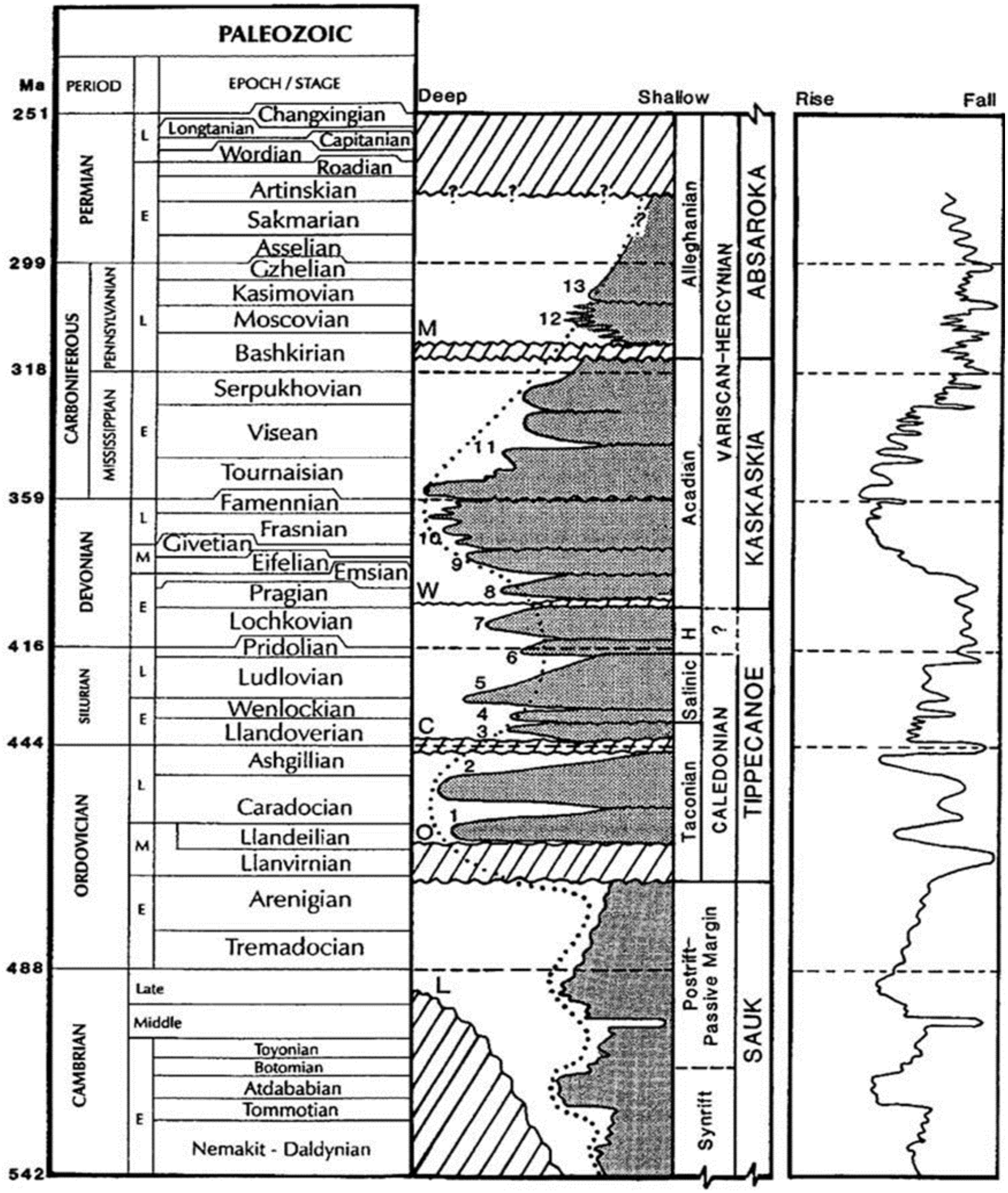

Figure 7: Paleozoic geologic time scale, showing the occurrence and relative duration of synrift, postrift passive margin, and 13 third-order, tectophase cycles (numbered) in the Appalachian Basin as a relative sea-level curve, compared with generalized sea-level curve (modified from Ross and Ross, 1988; Read, 1989; and Dennison, 1989). Unconformities are labeled on the sea-level curve: L, Lipalian; O, Owl Creek (Knox); C, Cherokee; W, Wallbridge; and M, Monday Creek. Figure from Ettensohn, 2008.

2.1.5. Ordovician-Silurian Caledonian Orogeny

Syn- and post-rift sedimentation is observed from the Late Precambrian through the Ordovician. Precambrian Grenville age basement rocks, the influence of Iapetan rifting, and the development of the Rome Trough is visible at the base of the stratigraphic section, seen in Figure 8. The transition from the Early to Middle Ordovician period is stratigraphically delineated by the Knox (Owl Creek) unconformity which is present between the top of the Knox Group and the base of the Black River-Trenton limestone stratigraphic units (Figure 8). The unconformity was formed as a result of tectonic loading and thermally driven subsidence related to the onset of Caledonian (Taconian/Taconic orogenic phase) orogenesis (Figure 9 and Figure 10; Ettensohn, 2008; Ziegler, 1989). This shift to a protracted period of mountain building and subsequent foreland basin development is reflected in the deposition of a thick and diverse assemblage of basinal sediments (Figure 10), with an expansion of sedimentary units across the basin as the foredeep of the basin progressively translates from the present-day southeast to the northwest. (Figure 8 from Ettensohn, 2008).

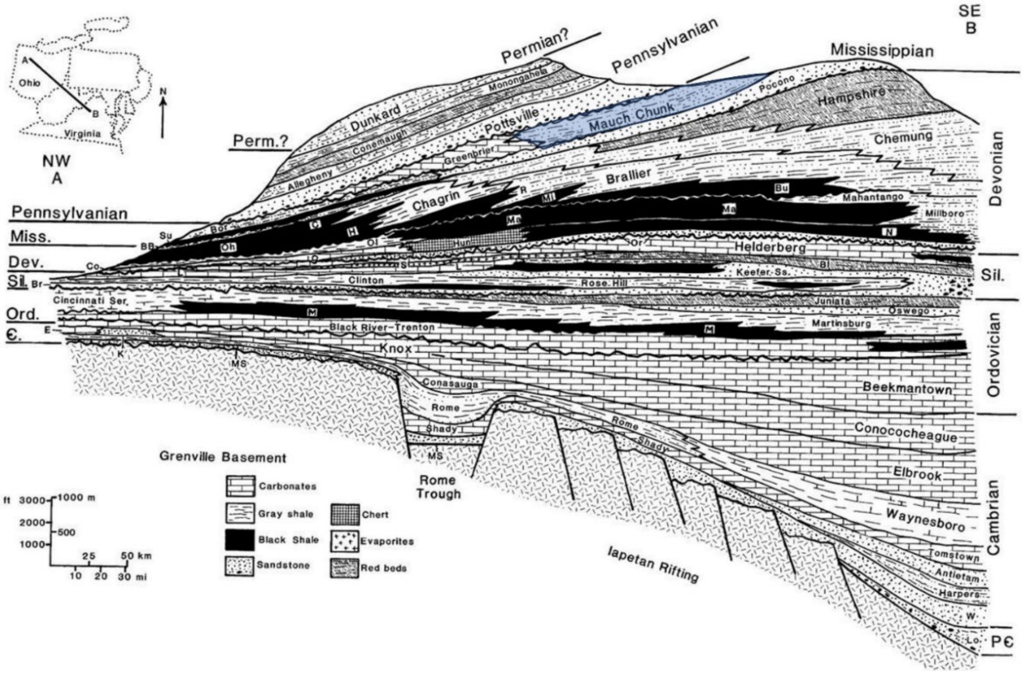

Figure 8: Schematic cross section of the Appalachian Basin from Virginia to Ohio (NW) to Virginia (SE) showing the major relationships of stratigraphic units from the Precambrian to the Permian stratigraphy. The section is flattened on the base of the Silurian. Precambrian Grenville age basement rocks and the influence of Iapetan rifting and the development of the Rome Trough is visible at the base of the section. Syn- and post-rift sedimentation is observed from the Late Precambrian through the Ordovician. The Ordovician transition to foreland basin development as a result of the Caledonian orogeny is represented by the Knox unconformity (dark black squiggly line). between the Knox Group and the Black River-Trenton limestone stratigraphic units. Subsequent flexurally and thermally driven subsidence of the foreland basin is represented by the expansion of sedimentary units across the basin as the foredeep of the basin progressively translates from the present-day southeast to the northwest (Figure from Ettensohn, 2008). Lowest underground sources of drinking water in blue.

The Early-Middle Ordovician Taconian Orogeny commenced with the Owl Creek (Knox) unconformity (Figure 7) and followed with a shift from broad deposition of carbonate facies to more structural variability, and with it, variability in sedimentation. Deposition began with the St. Peter Sandstone in the west and progressed with widening of the foreland basin and deposition of a thick (up to 7,500 ft) succession of dark shales: the Martinsburg, Reedsville, and Utica (Figure 8; Ettensohn, 2008). Dark shale deposition was followed by extensive infill of the fluvial-delta, transitional/marginal marine redbeds of the Queenston Delta (Figure 8 and Figure 9; Colton, 1970; Dennison, 1976; Blue, 2011), and development of the Cherokee discontinuity (Figure 7; Dennison and Head, 1975).

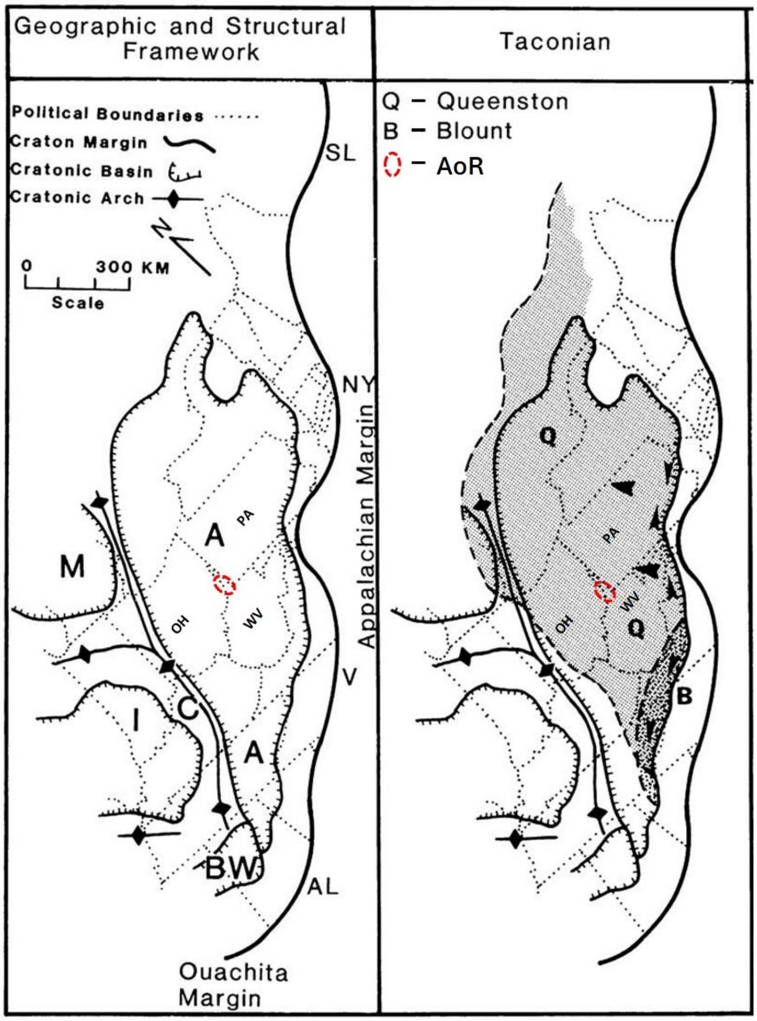

Figure 9: Distribution of Taconian Queenston Delta clastic wedge on southeastern Laurussia. Paleo currents noted by arrows. (Figure from Ettensohn, 2008).

Boucot's (1962) Salinic orogenic event was initially identified as an angular unconformity in the northeastern U.S. but marks the multi-phase north to south migration of tectonism and the accretion of Baltica to form Laurussia. A series of dark shales were deposited in the foreland basin that include the Williamson and time-equivalent Rose Hill formations (Figure 8 and Figure 9) (Ettensohn and Brett, 1998). In the project area, Early Salinic tectonism saw the deposition of a series of iron-rich siliciclastics, shed from the Taconic highlands (Folk, 1960; Colton, 1970; Cecil et al, 2004; Ettensohn, 2008). These clastic sequences are what make up the Medina Group: Grimsby, Whirlpool, Medina, the "Clinton" sands in Ohio, and the Tuscarora of Pennsylvania (see subsection 2.4 of this Application Narrative for more information on the formations that make up the project's injection zones; Figure 8 and Figure 10; Folk, 1960; Colton, 1970).

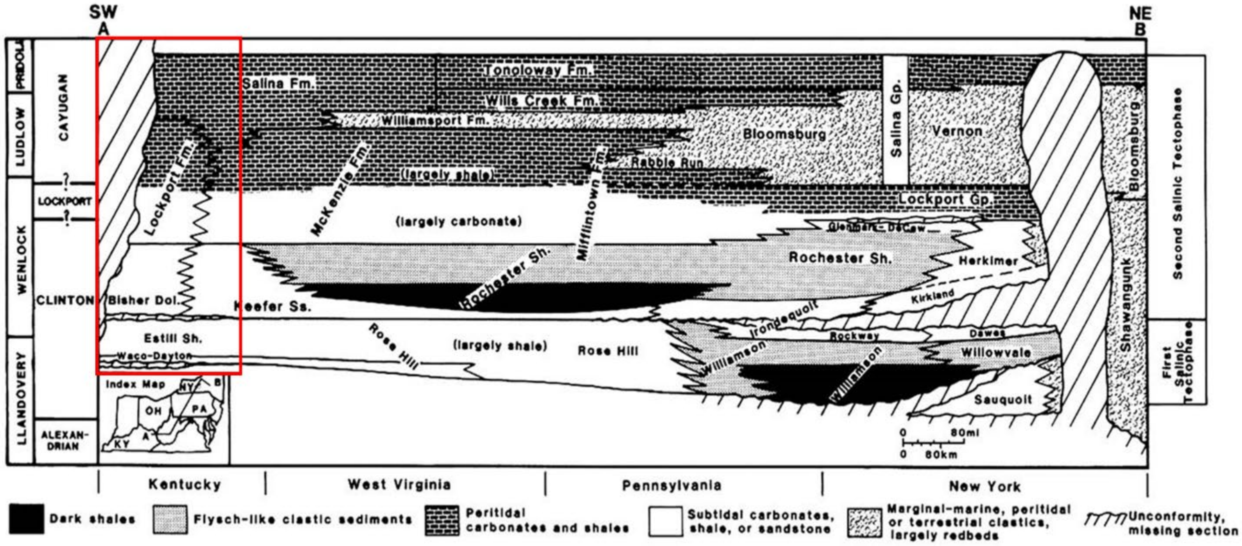

Figure 10: Southwest-northeast section partially parallel to basin strike highlighting the two Salinic phases of tectonism in the Appalachian Basin and the associated formations deposited. The red square is the approximate location of the project area. (Figure from Ettensohn, 2008).

Upper Silurian carbonates, including the Lockport Dolomite Group, were deposited during a time of relative tectonic quiescence following the Salinic disturbance, representing widespread shallow marine conditions along the craton margin (Ettensohn, 2008). In northern West Virginia, the Lockport Dolomite Group and correlative units comprise part of a thick carbonate ramp succession that developed in response to flexural forebulge migration and eustatic sea-level rise, preceding the onset of Devonian foreland basin subsidence (Figure 8 and Figure 9; Ettensohn, 2008).

Continued Salinic tectonism is evidenced by the Bloomsburg redbeds deposited in the foreland basin and the Salina evaporites covering the central Appalachians and Michigan Basin in response to restriction of the basin and eustatic sea-level fall (Ultieg, 1964; Rickard, 1969; Ziegler, 1989, Ettensohn, 2008). During the Middle Silurian, carbonate platform deposits formed on uplifted terranes, including the Cincinnati-Kankakee-Algonquin arch system, which isolated specific basin areas and led to widespread evaporite deposition in the Upper Silurian (Figure 11; Colton, 1970, Ettensohn, 2008; Coyle, 2022). The evaporite beds of the Salina group were followed by a period of tectonic quiescence and development of a thick succession of carbonates (Figure 8 and Figure 11; Ettensohn, 2008).

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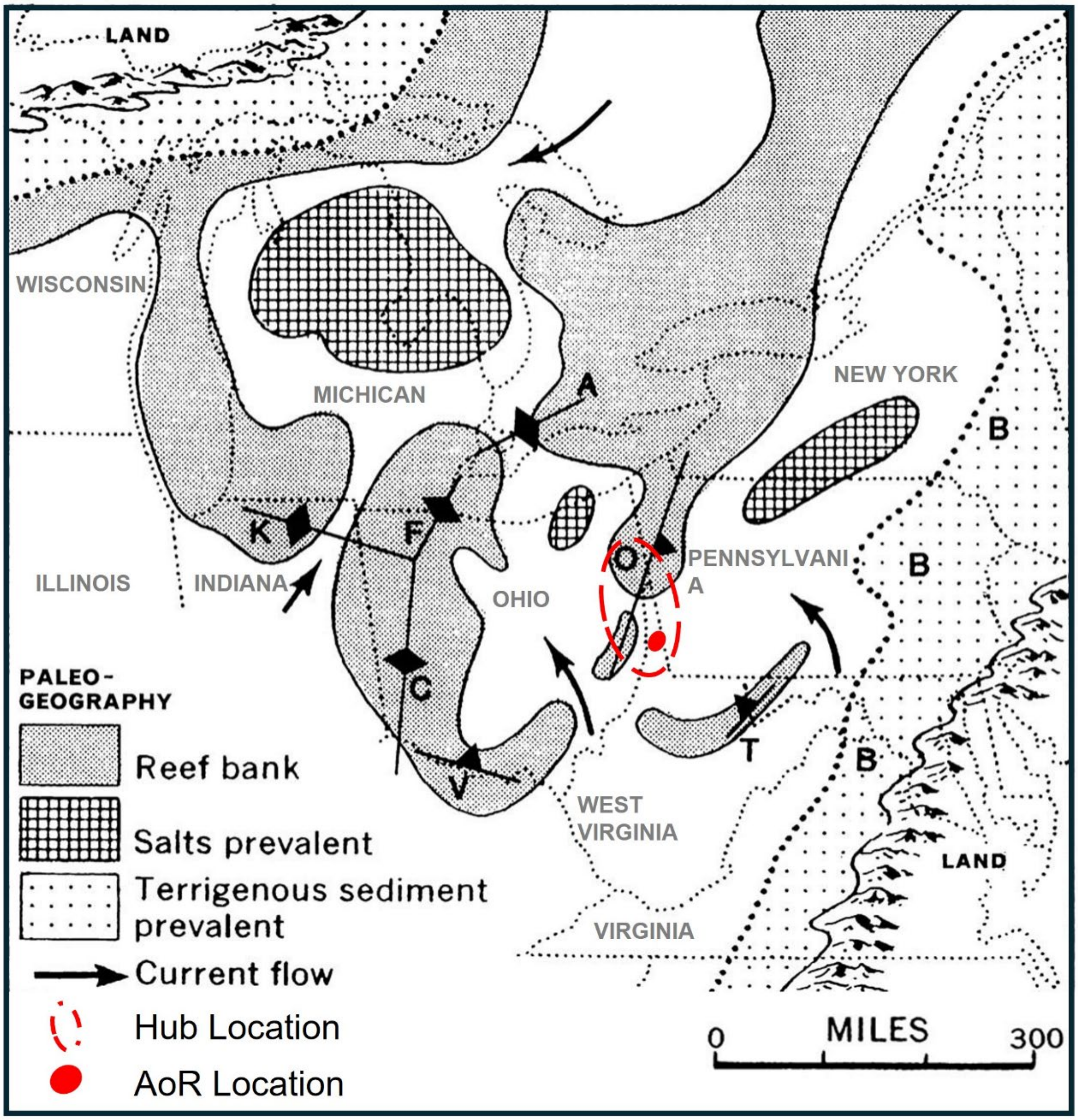

Figure 11: Schematized Late Silurian paleogeographic map of Salinic depositional systems. Deposition and lithologies were driven by bulge migration that reactivated regional basement structures, as well as by foreland subsidence. Depositional systems are labeled as the Algonquin arch (A), Findlay arch (F), Kankakee arch (K), Cincinnati arch (C), Iapetan Ohio-West Virginia hinge zone (O), Tristate block (T), and Grenvillian Vanceburg-Ironton fault zone (V). Arrows point to downthrown or down-dipping sides. Bloomsburg-Vernon redbeds (B). Adapted from Kay and Colbert (1965). Approximate Tri-State CCS Hub location in dashed red oval and approximate AoR in solid red.

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2.1.6. Devonian-Permian Variscan-Hercynian Orogeny

The Variscan–Hercynian (Acadian phase) orogenic cycle is characterized by the closure of the Rheic Ocean during collision with Gondwana to form Pangaea (Kearey et al., 2009; Torsvik and Cocks, 2016). The Early Devonian Acadian orogenic phase of the Variscan-Herynian orogeny is characterized by dextral transgressional accretion of the Avalon and Laurussian terranes moving from northeast to southwest; this contrasts with the sinistral accretion of the Salinic orogenic cycle (van Staal et al., 1998; Ettensohn, 2008). Onset of the Acadian orogeny is marked by the Wallbridge discontinuity (Figure 7) and deposition of the Lower Devonian Oriskany Sandstone (Figure 8; Colton, 1970; Etensohn, 2008). Continued cyclic orogenesis is characterized by the deposition of the Onondaga Formation and is later characterized by transgressive black shales (Marcellus Shale) alternating with clastic wedge deposits (Mahantango Formation; Figure 8; Ettensohn, 2008). The transgressive shales were deposited in the proximal foreland basin, while coarser clastics were deposited craton-ward in toward the peripheral bulge of the foreland basin (Figure 8; Colton, 1970; Ettensohn, 2008). Paleogeographically, the amalgamating supercontinent of Pangaea was moving progressively northward during this time and passing from an arid sub-tropical climatic belt to a more humid tropical equatorial region (Scotese, 2003).

The Alleghenian orogeny is the final tectonic phase of the Appalachian Foreland Basin, signifying the ultimate closure of the Rheic Ocean and the gradual amalgamation of Gondwana and Laurussia, sealing the two landmasses together from South to North and forming Pangaea (Kearey et al., 2009; Torsvik and Cocks, 2016). Alleghenian related foreland basin subsidence is recorded in the sediments deposited from the Monday Creek Unconformity in the Pennsylvanian through the Early Permian (Figure 7 and Figure 8; Sloss, 1963). Hatcher (2005) described the Central Appalachian Basin as a broad fold and thrust belt with megathrusts carrying Paleozoic crust 218 mi across the Laurentian Platform and foreland basin. The thickest accumulations of these siliciclastic sediments, reaching up to 9,500 ft in thickness, are concentrated in the foredeep of the foreland basin (Figure 8; Meckel, 1967; Colton, 1970; Patchen et al., 1985a, b). In contrast to the distribution of clastic wedges in the previous orogenic events, a blanket of siliciclastic sediment advanced westward for over 620 mi, indicative of an overfilled foreland basin (Jordan, 1995). Notably, the sedimentary profile of this orogeny deviates from previous tectophase cycles, primarily comprising terrestrial (abundant coal) and marginal-marine, molasse-like sediments (Ettensohn, 2008). Sediments associated with the Alleghenian orogeny were deposited in a humid climate in a tropical equatorial belt with various paralic, estuarine, fluvial, and alluvial-plain environments being prevalent during this time (Scotese, 2003; Cecil et al., 2004; Ettensohn, 2008).

2.1.7. Paleogeographic Influences on Sedimentation

Though the regional tectonism is the primary control on sedimentation in the basin, the cyclic nature of the sedimentary fill in the basin is also influenced by the paleogeography and glacial-interglacial eustatic cycles (Cecil et al., 2004; Ettensohn, 2008). Through early Cambrian time, the Appalachian Basin area of the Laurentian continent shifted latitudinally from 60° to 40°S, and further north to 15°S through the Late Mississippian. By Late Permian, the Appalachian Basin area was located 5°N of the Equator (Kearey et al., 2009; Torsvik and Cocks, 2016). This shift to the north is recorded in the siliciclastic-carbonate-siliciclastic pattern of basinal sedimentation as the landmass passed through varying climatic zones (Scotese, 2003; Cecil et al., 2004).

2.1.8. Summary

Sediments deposited from the late Ordovician to the end of the Silurian are the intended injection complexes for the project (see subsection 2.4 for details). They include from oldest to youngest: the Queenston Shale (lowest confining zone), the Medina Group (lower injection zone), the Rochester Shale (upper confining zone for the Medina Group and lower confining zone to the Lockport Dolomite Group), the Lockport Dolomite Group (upper injection zone), and the Salina Group (primary confining zone). Characterization, lateral continuity, and remaining uncertainties are discussed in subsection 2.4 of this Application Narrative.

2.1.9. Hydrogeology

Aquifers in the central region of the Appalachian Basin remain in the shallow subsurface and are represented by aquifers through the Lower Mississippian (Figure 8; see subsection 2.1.5 of the Application Narrative). They are the Conemaugh Group, the Allegheny Formation, the Pottsville Group, and the Mauch Chunk Formation, and in the project area, they are less than 1,000 ft below ground surface (bgs). Each of these units has various geologic intervals that serve as aquifers or aquitards and are described further in subsection 2.7 of this Application Narrative. The hydrology of the region is largely influenced by seasonal precipitation, snowmelt, and groundwater recharge.

2.1.10. Mining

Mining in West Virginia has played a significant role in the state's economic and industrial development, particularly through the extraction of coal, sand, limestone, clay, gemstones, and salt (Callaghan, 2014). The state ranks fourth in U.S. for coal reserves and was the third-largest producer in 1988, extracting 144.9 million short tons (131.4 million metric tonnes), 75% from underground mines; it led the nation in longwall mining sections (Repine et al., 1993). The Appalachian Coal Basin, which includes the Tri-State CCS Hub project area of southeastern Ohio, northern West Virgina, and southwestern Pennsylvania has historically been a major coal-producing region, with deposits from the Pennsylvanian-age Allegheny and Monongahela formations being widely mined for use in power generation and industrial production (Milici, 2014; Wright and Erber, 2018; Repine et al., 1993; WVGES, 2013). These coal beds have also been evaluated for their resource potential in coalbed methane (Milici, 2014). Additionally, West Virginia's salt resources, primarily solution mined from the Silurian Salina Group near the Kanawha River and along the Ohio River in southeast Marshall County, have been mined for use in chemical industries and more recently for consumption (WVGES, 2004).

The Tri-State CCS Hub is located mostly within the western, unfolded, portion of the Dunkard Basin, but Marshall County is located in the westernmost portion of the folded eastern Dunkard basin, where some coalbed methane has been produced (Milici, 2014). West Virginia has over 100 named coal beds in its Pennsylvanian rock formations, with at least 60 mined commercially. These beds originally contained nearly 106.1 billion metric tons (117 billion tons) of coal (Figure 12 and Figure 13; Repine et al., 1993; Blake et al., 2002). The coals occur in the same Pennsylvanian-aged stratigraphic intervals that have been identified as USDWs as outlined in subsection 2.7 of the Application Narrative: the Pottsville Group (Pocahontas Formation, New River Formation, and the Kanawha Formation), the Allegheny Formation, the Conemaugh Group, the Monongahela Formation, and the Dunkard Group (Repine et al., 1993; WVGES, 2013; Milici, 2014).

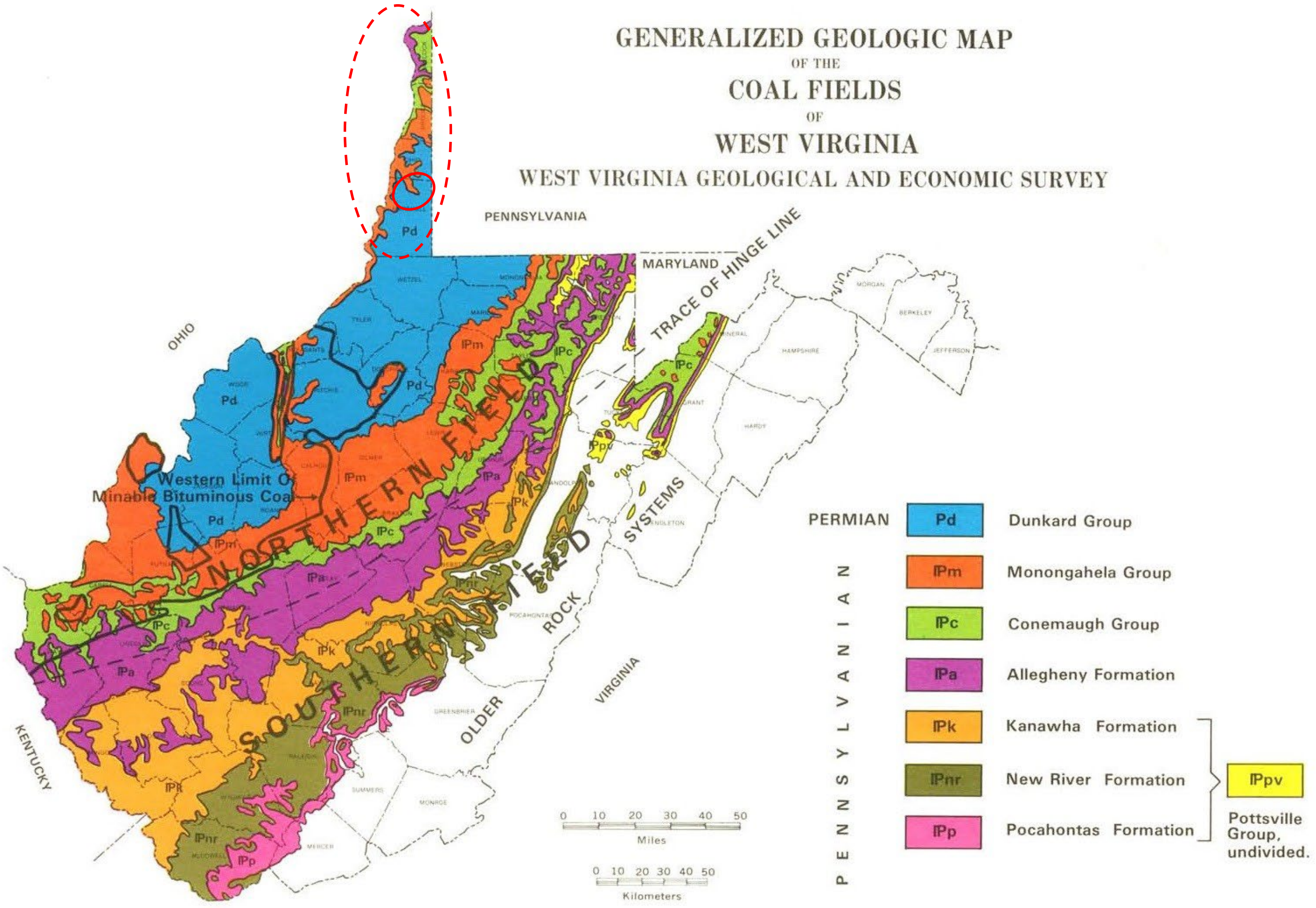

Figure 12: Map of coal bearing rocks in West Virginia. Project area is the red dashed oval, and the approximate AoR is the solid red oval. Modified from WVGES, 2025a.

Figure 13 shows the stratigraphic column of the major lithologic units and their associated coals in the Pennsylvanian and Permian Systems in West Virginia (Blake et al., 2002). The majority of mined coal in Marshall County is from the Pittsburgh coal outlined in solid red; outlined in the dashed red lines are minor coals present in Marshall County, West Virginia.

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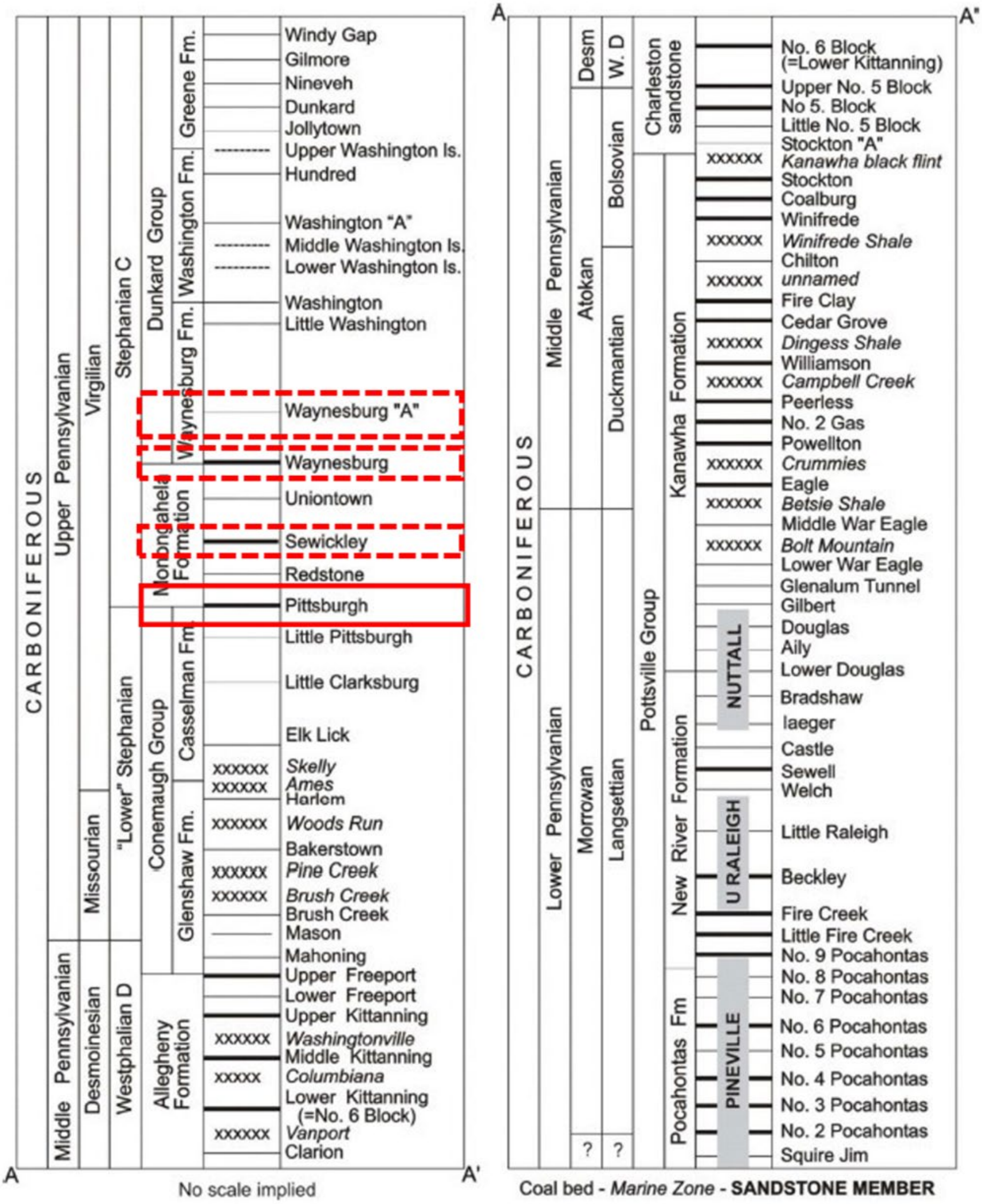

Figure 13: Stratigraphic column of the major lithologic units and their associated coals in the Pennsylvanian System in West Virginia (modified from Blake et al., 2002). Major contribution from the Pittsburgh outlined in solid red with minor contributions from coal with dashed red.

The West Virginia Geological and Economic Survey's 2013 Coal Bed Mapping Project (CBMP) was used to investigate the coal beds present in West Virginia and in the project area. CBMP is part of a collaboration called the Mineral Lands Mapping Program (MLMP) with the West Virginia Department of Tax and Revenue (Mineral Parcel Mapping Project) and West Virginia University GIS Technical Center in the Department of Geology and Geography (Digital Line Graph Project). It is noted that the database is not a complete documentation of the historical mining, but an amalgamation of the data received. To that end, the following summary of mineable West Virginia coal seams was supported with published maps and data from the additional referenced sources (Figure 13; Repine et al, 1993; Tewalt et al., 2001; Milici, 2014; WVGES, 2013; WVGES, 2025a):

- The following mineable coal Formations and Groups are present in the AoR:
  - The Dunkard Group: the Washington and Waynesburg “A” coals are noted to be present and have been historically mined or noted to produce coalbed methane in Marshall County.
  - The Monongahela Formation: the Waynesburg, Sewickley, Redstone, and Pittsburgh are noted in Marshall County. The Uniontown is present farther south near Doddridge County.
- The rest of the mineable coal Formations and Groups in West Virginia are not present in the AoR:
  - The Conemaugh Group: the Elk Lick, Harlem, Bakerstown, Brush creek, and Mahoning, are all present or historically mined near Preston, Monongalia, and Taylor Counties in the Northern Coalfield (Figure 12).
  - The Allegheny Formation: The Upper freeport, Lower Freeport, Upper Kittanning, Middle Kittanning, Lower Kittanning, and the Clarion coals in the Northern Coalfield and the No. 6 Block and the Upper No. 5, No.5, and Little No. 5 Block coal are all present or have been historically mined in the Southern Coalfield (Figure 12).
  - The Pottsville Group: The Pottsville consists of the Kanawha Formation, the New River Formation, and the Pocahontas Formation. The coals from these formations have been mined and are noted as present in the Southern Coalfield (Figure 12).

The coal reserves of Marshall County, West Virginia are primarily derived from the Upper Pennsylvanian Monongahela Formation’s Pittsburgh Coal bed. In the project area, the Pittsburgh Coal occurs between the elevations of approximately 650 and 500 feet above mean sea level (amsl). Tewalt (2001) estimates the thickness of the coal in the project area to be ~5.83-8.17 feet, thickening to the southeast toward the Rome Trough. Repine (1993) and Tewalt (2001) both describe the structure of the Pittsburgh Coal as consisting of a main bench with non-coal partings in the middle of the bench and one to several roof coals that are usually not mined. The Pittsburgh coal is the thickest and most extensive coal in the Appalachian Basin, with about 16 billion short tons remaining in Pennsylvania, West Virginia, and Ohio (Tewalt et al., 2001). The available original resources for the Pittsburgh Coal in West Virginia have been estimated at 13 billion short tons with ~7.8 billion short tons remaining (Tewalt et al, 2001).

There are 3 permitted underground mines and at least 1 mine opening in the AoR (Figure 4). The underground mines in the AoR are permitted for the Pittsburgh Coal seam and will necessitate the addition of a mine-string for the well design. To ensure operational and USDW safety, geotechnical surveys and underground and surface mine map reviews will be conducted prior to construction, and baseline surface USDW sampling will be performed. (see Construction Details for each well for well design details and subsection 4.1.2 of the Area of Review and Corrective Action Plan for permitted mine details).

2.1.11. Local Structural Geology

The following list includes the major structural geologic features regional to the project area, which are discussed further below:

- Rome Trough Fault System;
- Highlandtown Fault Zone;
- Burning Springs – Cambridge Fault Zone; and
- Unnamed Compressional Faults.

Additional discussion of faults and fractures in relation to the AoR can be found in subsection 2.3 of the Application Narrative.

2.1.11.1. Rome Trough Fault System

The Rome Trough Fault System is a major structural feature of the region (Figure 14) and extends from central Kentucky to the northeast, crossing West Virginia, and into western Pennsylvania. The Rome Trough Fault System represents a broad zone of deformation related to failed Eastern Interior rifting during the Early and Middle Cambrian that is associated with the opening of the Iapetus-Theic Ocean (Woodward, 1961; McGuire and Howell, 1963; Shumaker, 1986; Thomas, 1991).

In northern West Virginia the failed rift graben of the Rome Trough is characterized by a broad, tilted horst block that is bound on its western margin by the Interior Fault and to the east by the East-Margin Fault (Figure 15; Gao et al, 2000). Seismic interpretation across the Rome Trough Fault System (Figure 15) suggests that the East-Margin Fault influenced both the basin geometry and depositional systems during the Early to Middle Cambrian rifting stage; however, during the Late Cambrian to Ordovician passive-margin and Middle to Late Paleozoic foreland basin stages, the structure is interpreted to be inactive (Gao et al., 2000).

The Rome Trough Fault System and related structures transect southeastern-most Marshall County, West Virginia; they are located approximately 30 miles to the south and east of the AoR, see Figure 14.

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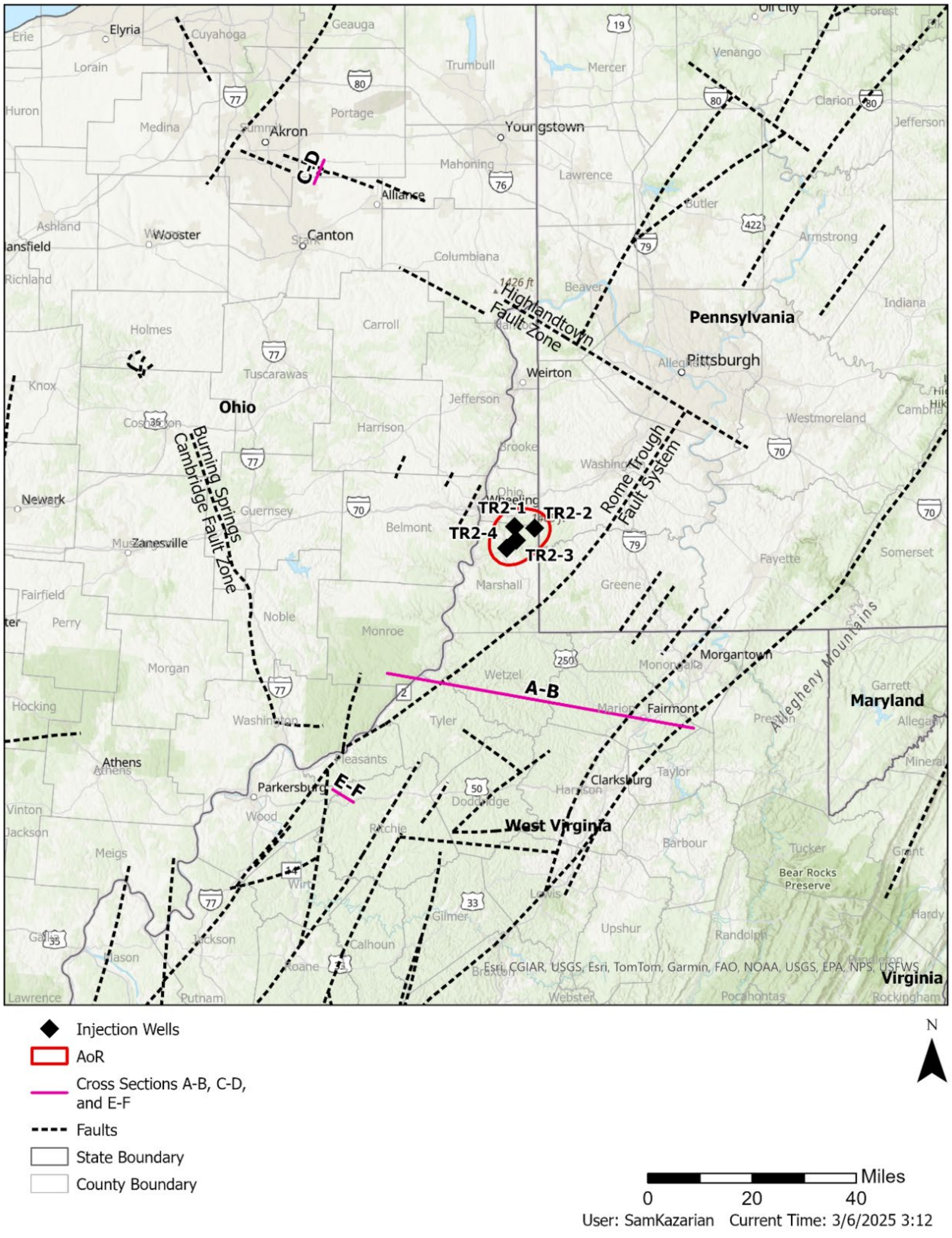

Figure 14: Regional fault map of the study area. Major structures discussed include the Rome Trough Fault System, Highlandtown Fault System, Burning Springs – Cambridge Fault Zone, and unnamed compressional faults. Location of cross-section A-B (Figure 15), C-D (Figure 16), and E-F (Figure 17) are shown by solid purple lines. Fault locations adapted from Baranoski, 2013; Root and Onasch, 1999. The AoR boundary is shown as a red oval.

2.1.11.2. Highlandtown Fault Zone

The Highlandtown Fault Zone (Figure 14) extends from southwestern Pennsylvania through northernmost West Virginia, continuing across northeastern Ohio (Root and Onasch, 1999). The Highlandtown Fault Zone is composed of multiple en-echelon fault segments. Near northern West Virginia, this segment of the fault is referred to as the Pittsburgh-Washington lineament (Gray, 1982) or the Pittsburgh-Washington cross-strike structural discontinuity (Baranoski, 2013). The Highlandtown Fault Zone is located approximately 31 miles from the northeast corner of the AoR.

The Highlandtown Fault Zone is characterized by a series of steeply dipping basement faults that transect the structural grain of the region at a high angle (Root and Onasch, 1999). The fault system generally dips to the south and exhibits normal displacement that occurred intermittently throughout the Paleozoic affecting both the distribution and thickness of Cambrian to Permian age sediments (Root and Onasch, 1999). Figure 16 shows an example seismic line and interpretation across the Highlandtown Fault Zone in Ohio showing normal fault displacement and development of a flexural monocline in Paleozoic strata (Root and Onasch, 1999).

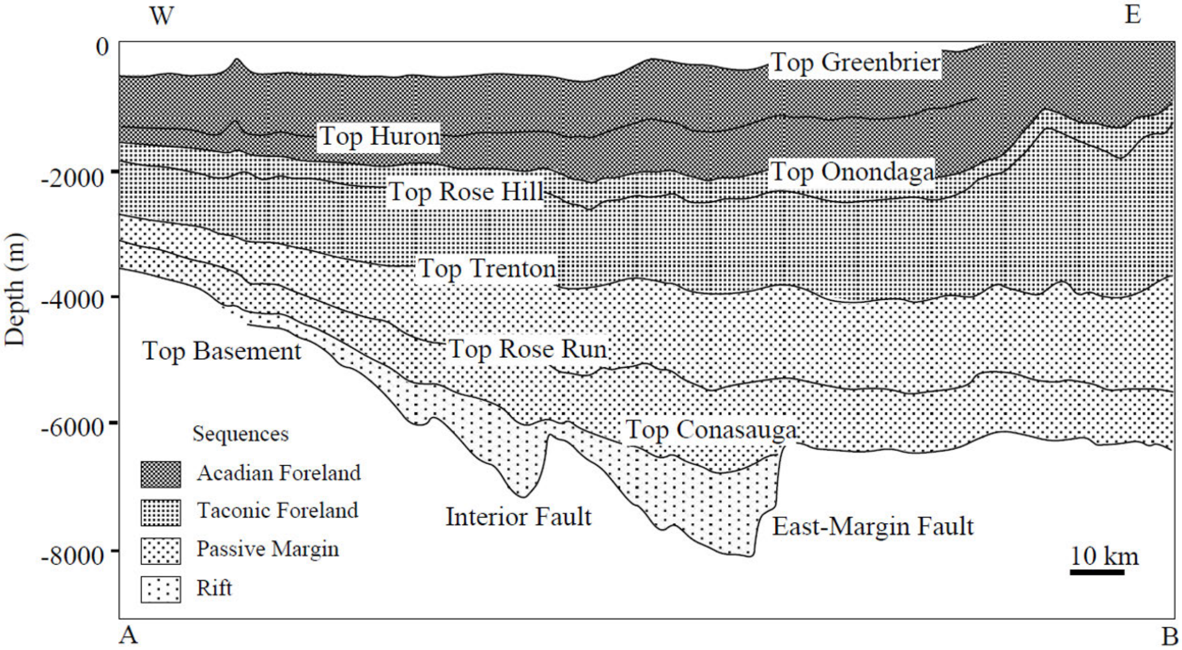

Figure 15: Regional cross-section across the Rome Trough Fault System. See Figure 14 for location of cross-section A-B. Interior Fault and the East-Margin Fault are part of the Rome Trough Fault System. From Gao et al., 2000.

2.1.11.3. Burning Springs – Cambridge Fault Zone

The Burning Springs – Cambridge Fault Zone, also known as the Cambridge cross-strike structural discontinuity (Baranoski, 2013), trends north-northwest and extends from north-central West Virginia across Ohio toward Lake Erie (Root, 1996; Figure 14). The Burning Springs segment of the fault is located in West Virginia and transects the Rome Trough Fault System at a high angle.

The Burning Springs segment of the fault zone is characterized by a broad zone of deformation that includes both basement-involved high-angle normal faulting and northwestward directed thrust faulting (Root and Onasch, 1999). Basement involved normal faulting, similar to the timing of other structures in the area, occurred on the Burning Springs fault segment from the Cambrian to the Pennsylvanian-Permian (Root, 1996). Later episodes of detached thrust faulting along the Burning Springs – Cambridge Fault Zone is attributed to the Pennsylvanian-Permian age Alleghanian orogeny (Root and Onasch, 1999). Compressional deformation associated with the Alleghanian orogeny forms several well developed anticlines, which includes the Burning Springs anticline, as a result of fault-related thrust faulting (Figure 17).

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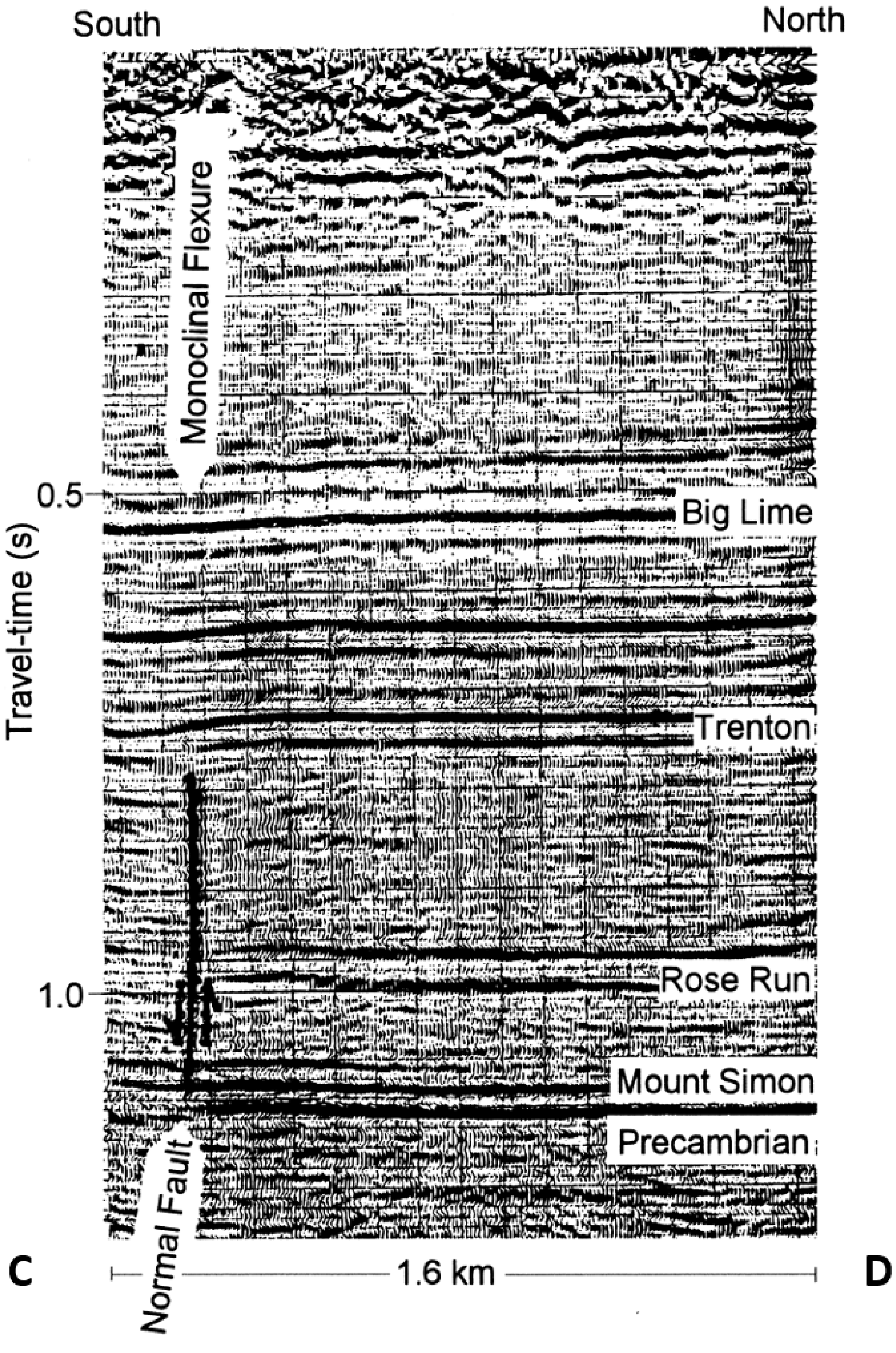

Figure 16: Example seismic cross-section across the Highlandtown Fault System in Ohio, see Figure 14 for location of cross-section C-D. From Root and Onasch, 1999. Note, "Big Lime" nomenclature is equivalent to the Greenbrier series in Southern West Virginia (Wilpolt and Marden, 1959).

2.1.11.4. Unnamed Compressional Faults

Several examples of unnamed compressional faults are observed from seismic reflection data in northernmost West Virginia and eastern Ohio (Figure 14). These faults were originally observed on reprocessed seismic reflection data collected as part of the Consortium for Continental Reflection Profiling (COCORP) in Ohio (Dean et al., 1998; Baranoski, 2013). Similar structures are also observed on seismic reflection data interpreted in West Virginia and Ohio as part of this project (see subsection 2.3 of this Application Narrative for a discussion of these structures).

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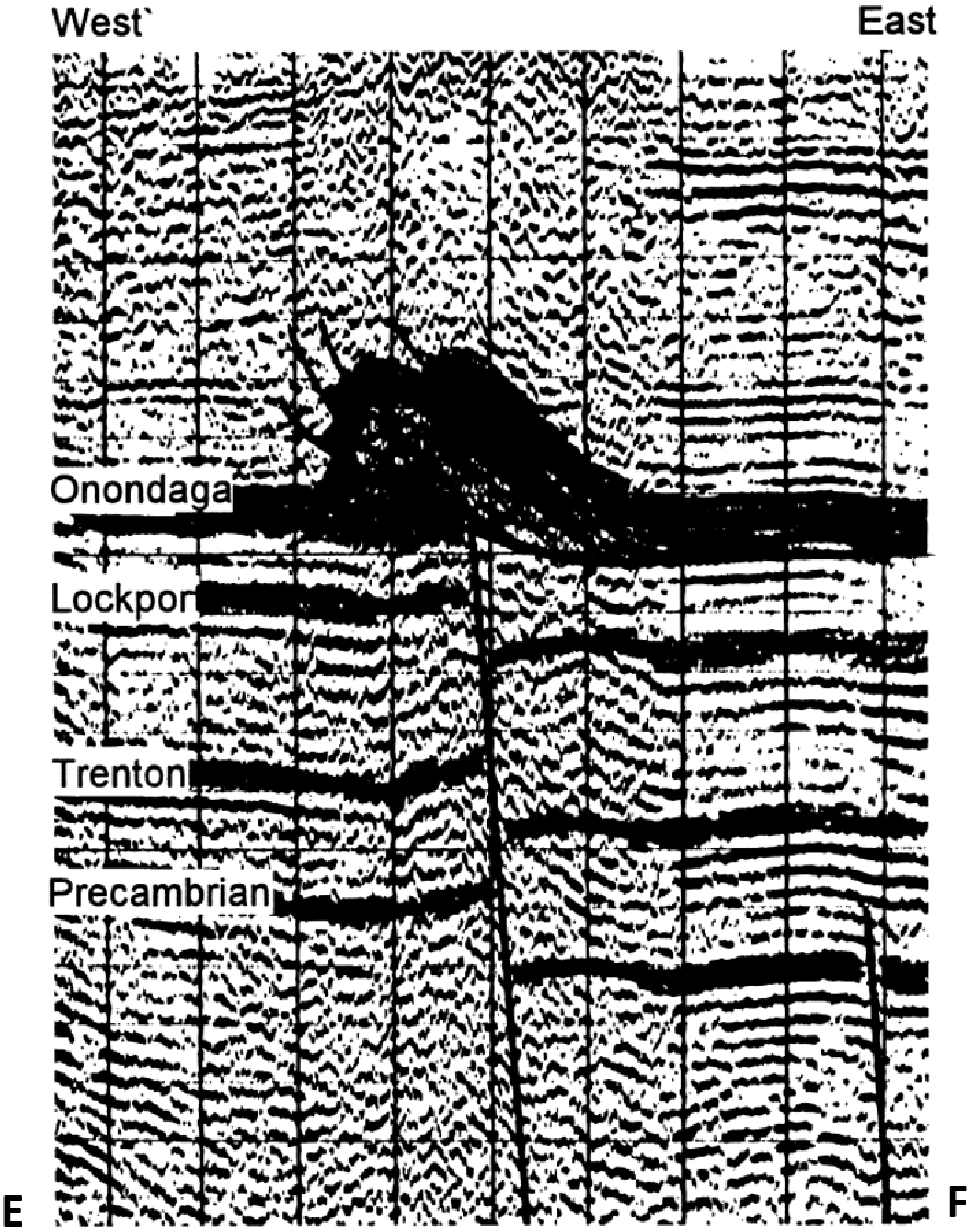

Figure 17: Seismic reflection profile across the Burning Springs anticline in West Virginia. Located along the Burning Springs – Cambridge Fault Zone. From Root and Onasch, 1999.

2.1.12. Data Used for Geologic Characterization

The data used to develop the geologic model for the project includes drilled well information and two-dimensional (2D) seismic data. Drilled well information includes location, deviation surveys, well logs, hydrocarbon production, and wastewater injection rates from various 3rd party vendors, State databases (ODNR, WVGES), and publicly shared research. The well logs include Measured Depth, Gamma Ray (GR), Neutron Porosity Sandstone, Density Porosity Sandstone, Bulk Density, Spontaneous Potential (SP), Caliper, Shallow, Medium and Deep Resistivity, and Sonic. In addition, historic core analyses from 9 wells along with literature analyses from other core were used to characterize the injection complexes (Table 2).

Digital well logs from 111 legacy wells were licensed and loaded into Petrel geologic interpretation software (Petrel is trademarked by and licensed from Schlumberger (SLB) Corporation) and used for petrophysical evaluation and picking tops for the three CCS Systems' reservoirs and confining units. An additional 141 wells with formation tops were used for structural control. Well log cross sections, shown later in this Application Narrative, were created using a subset of these logs. Subsets of these data sets were used to build the petrophysical model and calculate the porosity and permeabilities for the injection complexes (further discussed in subsections 2.4 and 2.5 of this Application Narrative). Locations of wells, cores, and type logs used to evaluate the subsurface and build the geologic model are outlined in Table 2, and their locations are shown in Figure 18.

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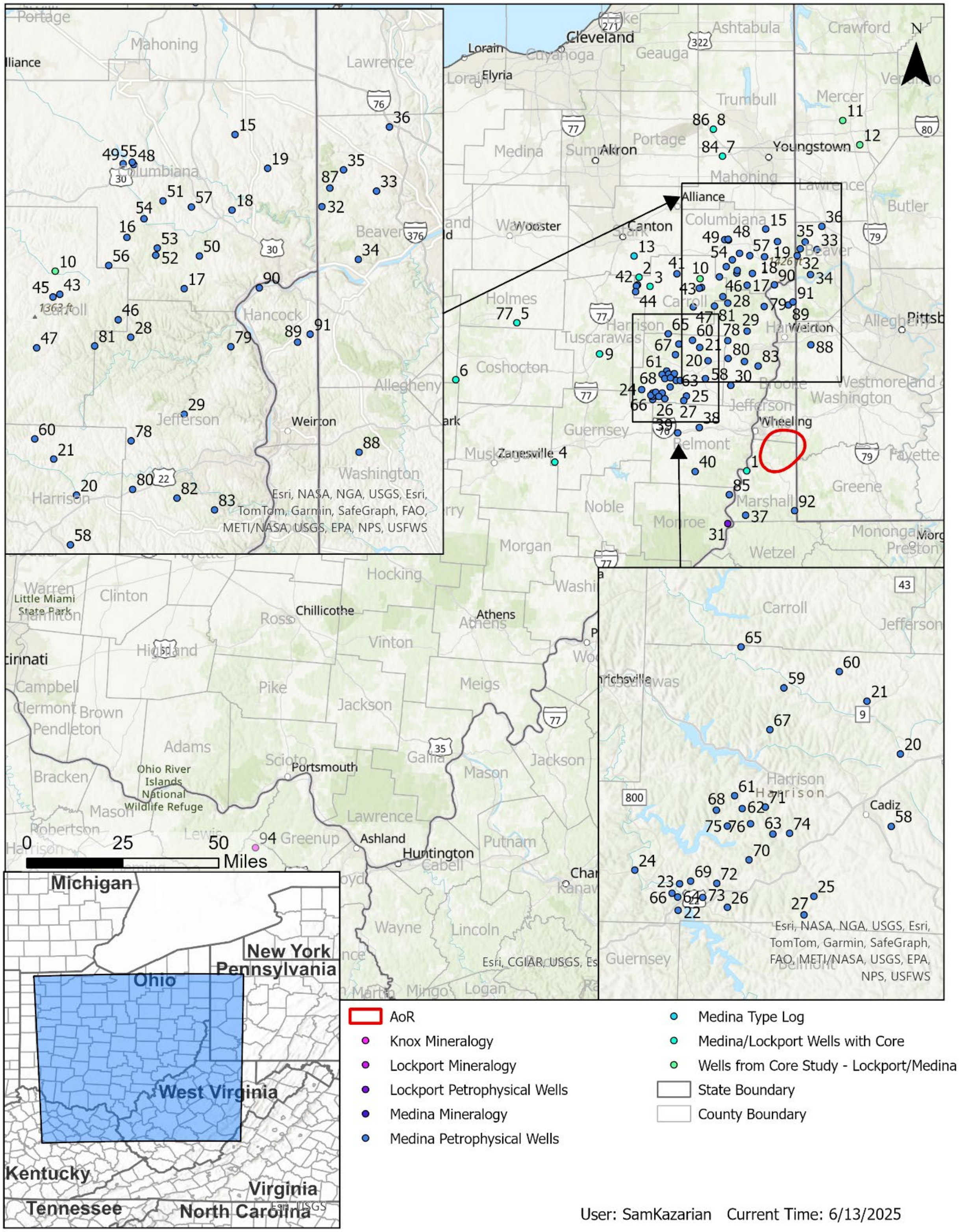

Figure 18: Location of wells used to characterize the mineralogy and petrophysics, as well as core locations. See Table 2 for API numbers, latitudes, and longitudes.

Table 2: List of well names, API numbers, latitude and longitudes for core, type logs, literature core studies, and petrophysical model logs used to build the geologic model.

Well Name and Number	API	Lat (WGS 84)	Long (WGS 84)	Well Numbers
Medina/Lockport Wells with Core				
MRCSP-FEGENCO 1	34013205860000	39.9128346	-80.7642922	1
SMITH B P & EVANS S T 4	34019202560000	40.6439492	-81.2971430	2
KAPLAN UNIT 3	34019204460000	40.6101800	-81.2412000	3
LINKHORN 1	34059209210000	39.9448517	-81.7066625	4
WAGERS WILLIAM 1	34075209900000	40.4690814	-81.9009046	5
WILT JOHN & EVELYN 1	34083212600000	40.2512567	-82.1989563	6
INTERSTATE INTERCHANGE 1	34099204320000	41.1019946	-80.8807876	7
SHERMAN WM C 1	34155200390000	41.2048016	-80.9274195	8
BELDEN BRICK UNIT (OHIO GEOLOGICAL SURVEY CO2) 9 (1)	34157253340000	40.3537051	-81.4899615	9
Wells from Core Study - Lockport/Medina				
Great Lakes Energy Ocel #1 well in Carroll County, Ohio	34019219720000	40.6386210	-80.9930420	10
Johnson #1 well in Mercer County, Pennsylvania	37085214680000	41.2357100	-80.2780390	11
Baker #1 well at Kilgore pool, Mercer County, PA	37085216960000	41.1427300	-80.1950440	12
Medina Type Log				
Sickafoose-Morris #1	34151220180000	40.7248570	-81.3218370	13
Medina Mineralogy				
BELDEN BRICK UNIT (OHIO GEOLOGICAL SURVEY CO2) 9 (1)	34157253340000	40.3537050	-81.4899620	9
Lockport Mineralogy				
Great Lakes Energy Ocel #1 well in Carroll County, Ohio	34019219720000	40.6386210	-80.9930420	10
Lockport Petrophysical Wells				
MRCSP-FEGENCO 1	34013205860000	39.9128346	-80.7642922	1
HICKORY CLAY 12	34019219200000	40.6153861	-81.3044823	14
COLBOURN UNIT 1	34029216560000	40.8263292	-80.6674270	15
ALBANESO 24-14-4 8H	34029217050100	40.6849170	-80.8632860	16
JANIE TRUST 5-12-3 1	34029217060000	40.6141223	-80.7603322	17
KERNICH 3-10-2 1	34029217240000	40.7224470	-80.6728360	18
CARNEY 17-7-1 3	34029217270000	40.7796295	-80.6083972	19
CHARLENE SCHANEY ETAL 1	34067203550000	40.3301239	-80.9547212	20
ARBAUGH BRUCE 1	34067204270000	40.3798018	-80.9956969	21
MORRISON P 1	34067205260000	40.1825700	-81.2278256	22
DUNLAP HARVEY L & SHIRLEY 1	34067205310000	40.2076717	-81.2263962	23
PERKOWSKI - BOND 2	34067208600000	40.2201488	-81.2813112	24
ALPHA ATH HR 1P-24	34067210740000	40.1960200	-81.0611690	25

Well Name and Number	API	Lat (WGS 84)	Long (WGS 84)	Well Numbers
BK STEPHENS 3-16H	34067211360000	40.1853990	-81.1675360	26
DARLA 2-22H	34067211640000	40.1785579	-81.0733873	27
BROWN 36-11-3 10	34081205070000	40.5475620	-80.8566000	28
DENOON 5-10-3 3	34081205130000	40.4415108	-80.7609847	29
SMITHFIELD A 1H-27	34081205430000	40.2362792	-80.8411730	30
ORMET 10-15UH	34111244590000	39.7134210	-80.8579040	31
JAMES THARP 3H	37007203050000	40.7262390	-80.5102250	32
ROLLING ACRES 8H	37007203070000	40.7475280	-80.4115000	33
FERREBEE BEA 3H	37007203110000	40.6534720	-80.4451940	34
POWELL BEA 6H	37007203180000	40.7768610	-80.4705830	35
WALL BEA 3H	37007203520000	40.8356390	-80.3875000	36
SIMMS NO. U-5H	47051017310000	39.7459710	-80.7702650	37
Medina Petrophysical Wells				
MRCSP-FEGENCO 1	34013205860000	39.9128346	-80.7642922	1
SMITH B P & EVANS S T 4	34019202560000	40.6439491	-81.2971430	2
HICKORY CLAY 12	34019219200000	40.6153861	-81.3044826	14
COLBOURN UNIT 1	34029216560000	40.8263292	-80.6674270	15
ALBANESO 24-14-4 8H	34029217050100	40.6849170	-80.8632860	16
JANIE TRUST 5-12-3 1	34029217060000	40.6141224	-80.7603322	17
KERNICH 3-10-2 1	34029217240000	40.7224470	-80.6728360	18
CARNEY 17-7-1 3	34029217270000	40.7796295	-80.6083972	19
CHARLENE SCHANEY ETAL 1	34067203550000	40.3301243	-80.9547208	20
ARBAUGH BRUCE 1	34067204270000	40.3798020	-80.9956971	21
MORRISON P 1	34067205260000	40.1825698	-81.2278261	22
DUNLAP HARVEY L & SHIRLEY 1	34067205310000	40.2076720	-81.2263958	23
PERKOWSKI - BOND 2	34067208600000	40.2201493	-81.2813107	24
ALPHA ATH HR 1P-24	34067210740000	40.1960200	-81.0611690	25
BK STEPHENS 3-16H	34067211360000	40.1853990	-81.1675360	26
DARLA 2-22H	34067211640000	40.1785579	-81.0733873	27
BROWN 36-11-3 10	34081205070000	40.5475620	-80.8566000	28
DENOON 5-10-3 3	34081205130000	40.4415108	-80.7609848	29
SMITHFIELD A 1H-27	34081205430000	40.2362792	-80.8411730	30
JAMES THARP 3H	37007203050000	40.7262390	-80.5102250	32
ROLLING ACRES 8H	37007203070000	40.7475280	-80.4115000	33
FERREBEE BEA 3H	37007203110000	40.6534720	-80.4451940	34
POWELL BEA 6H	37007203180000	40.7768610	-80.4705830	35
WALL BEA 3H	37007203520000	40.8356390	-80.3875000	36
SIMMS NO. U-5H	47051017310000	39.7459710	-80.7702650	37

Well Name and Number	API	Lat (WGS 84)	Long (WGS 84)	Well Numbers
LUDE # 1H-34 1H-34	34013206790000	40.0770380	-80.9973170	38
FAMILY 1-32H	34013207090000	40.0567570	-81.1036620	39
PERKINS 1-4H	34013207340000	39.9113173	-81.0170403	40
CLARK ETAL UNIT 1	34019202860000	40.6572825	-81.1077008	41
HICKORY CARROLL CO 4	34019204780000	40.6113490	-81.3087914	42
MCALLISTER JOHN O 1	34019205530000	40.6065593	-80.9849794	43
SWEANY-JAMES UNIT 1	34019206100000	40.5895701	-81.3131064	44
NEIDER UNIT 1	34019215830000	40.6030383	-80.9969461	45
BEADNELL UNIT 1	34019216520000	40.5717596	-80.8795629	46
WHITE 1	34019220590000	40.5331573	-81.0264830	47
DONALD SELL UNIT 1	34029206070000	40.7850788	-80.8510498	48
MURRAY FRANK 3	34029206480000	40.7861729	-80.8699857	49
WILLIAMS C E & M F 1	34029206680000	40.6593033	-80.7324988	50
HILL RICHARD 1	34029207190000	40.7352959	-80.7977871	51
SOLOMON AQUILA E 21750	34029214760000	40.6606261	-80.8110942	52
HEIRS BURTON AL 21971	34029215070000	40.6703910	-80.8086462	53
THOMPSON H & S 1	34029215470000	40.7104938	-80.8325185	54
ALLIANCE/SEI UNIT 1	34029216040000	40.7885146	-80.8536301	55
SUMMITCREST INC 12785	34029216270000	40.6465978	-80.8967211	56
SOWARDS UNIT 1-K	34029216370000	40.7267276	-80.7465809	57
BIRNEY ROY 1	34067201030000	40.2619089	-80.9661006	58
SPIKER - SCIO POTTERY CO UNIT 2	34067201880000	40.3922738	-81.0980544	59
ENSLEY-LOGAN 1	34067202090000	40.4074850	-81.0301957	60
WALLACE MAX 1	34067202920000	40.2905588	-81.1588551	61
HEAVILIN EUGENE 1	34067202930000	40.2785078	-81.1495987	62
STALEY GUY & NORMA 1	34067203440000	40.2544394	-81.1113884	63
HOUSEHOLDER RAYMOND 1	34067205290000	40.1950689	-81.2285977	64
WEBB ANNA 2	34067205600000	40.4306119	-81.1511861	65
BOUSKA ANDREW JR 1	34067205830000	40.1985116	-81.2355239	66
BERRY B 1	34067205910000	40.3527693	-81.1155491	67
MALLARNEE MARION 1	34067206110000	40.2770933	-81.1811686	68
DAVIDSON BUELL M 1	34067206120000	40.2101133	-81.2125675	69
SPROULL CLYDE 2	34067206630000	40.2300886	-81.1409065	70
WALLACE KEITH 1	34067207150000	40.2800876	-81.1210706	71
MIZER THOMAS 1	34067207170000	40.2078550	-81.1807767	72
ZECHMAN THOMAS UNIT 1	34067207370000	40.1948912	-81.1978362	73
LAWLIS ELMER 1	34067207410000	40.2551535	-81.0913081	74
D C JONES 7	34067207770000	40.2619761	-81.1677784	75

Well Name and Number	API	Lat (WGS 84)	Long (WGS 84)	Well Numbers
ROSE ALFRED 1	34067208040000	40.2643281	-81.1391705	76
WAGERS WILLIAM 1	34075209900000	40.4690814	-81.9009046	77
COLDEBELLA V & A 1	34081203530000	40.4049240	-80.8565050	78
JACKSON J&J ETAL 1	34081204610000	40.5339639	-80.6759156	79
PELEGREEN A JR 12420	34081204810000	40.3383650	-80.8538180	80
ALLENDER J & W 45308	34081204830000	40.5356866	-80.9218305	81
NORTH AMERICAN COAL 45294	34081204900000	40.3261196	-80.7739182	82
NAC 3P-20	34081205280000	40.3095840	-80.7063310	83
INTERSTATE INTERCHANGE 1	34099204320000	41.1019946	-80.8807876	84
MONROE NORTH UNIT 2S	34111243650000	39.8227460	-80.8503840	85
SHERMAN WM C 1	34155200390000	41.2048016	-80.9274195	86
DAVID THOMPSON 3H	37007203030000	40.7520280	-80.4957780	87
STARVAGGI 1	37125222780000	40.3880750	-80.4459750	88
MINESINGER, S. 1	47029000800000	40.5398460	-80.5559060	89
GLOBE REFRACTORIES 1	47029000860000	40.6152730	-80.6243070	90
HILLCREST 1	47029000870000	40.5509900	-80.5326620	91
JOHN BURLEY 1 M-1738	47051005390000	39.7616690	-80.5299910	92
Knox Mineralogy				
BELDEN BRICK UNIT (OHIO GEOLOGICAL SURVEY CO2) 9 (1)	34157253340000	40.3537051	-81.4899615	9
KGS Hanson Aggregates 1	16043001050000	38.4695520	-83.1325970	94

Tri-State CCS, LLC licensed a total of ~250 linear miles of existing 2D seismic lines from Evans Geophysical that transect the project area (Figure 19). These data were used to interpret site-specific and regional geologic structure, to determine lateral continuity, and build the geologic inputs used for computational modeling. The seismic data included six lines that provided data to refine the structural interpretation of the project area. Additionally, seismic data were used to confirm the lateral continuity of the injection and confining zones.

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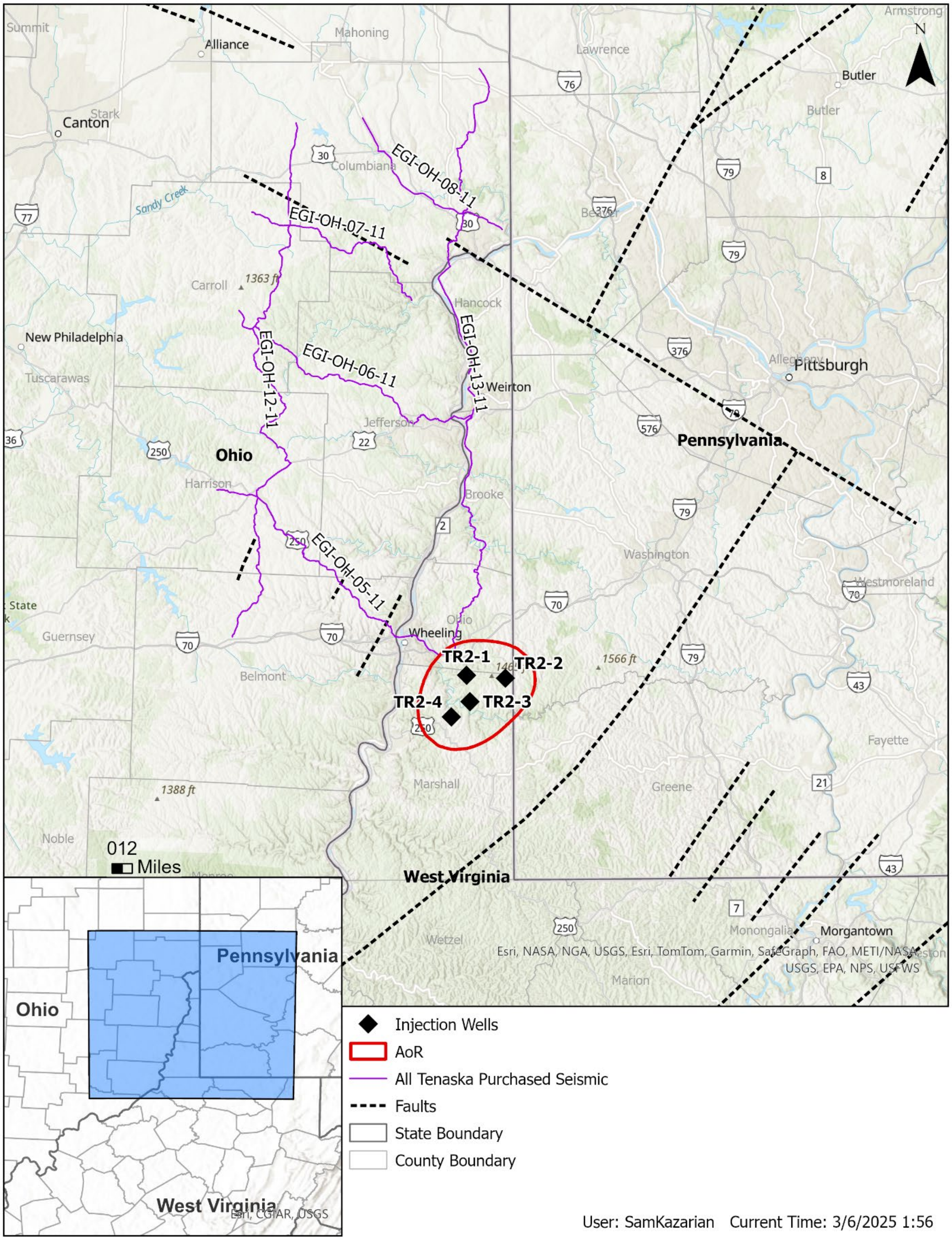

Figure 19: Location of the six 2D seismic lines licensed for use in the project's subsurface assessment. Note: 2D seismic data were licensed from Evans Geophysical.

A synthetic seismogram was created to tie the seismic data to the well data. During the synthetic seismogram creation, the 2D seismic lines were tied to sonic measurements taken in the Birney Roy 1 well (Figure 20; Well No. 58, in Table 2, location in Figure 18) to correlate the structural interpretation of the project area to the porosity and permeability model developed using the well log data.

Claimed as PBI

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Figure 20: Synthetic seismogram created using logs from the Birney Roy 1 well (Well No. 58 in Table 2, location in Figure 18 , to tie the 2D seismic data to the well logs. Tracks from left to right: True Vertical Depth (TVD), Two-Way Time (TWT), Gamma Ray (GR), Bulk Density (RHOB), Acoustic Impedance (AI), Reflection Coefficient (RC), 2D seismic with wavelets overlain by the synthetic seismogram, and Interval Velocity.

Geologic formations were then mapped on the 2D seismic data (Figure 19), and structure and isopach maps were created using both the well log tops and 2D seismic data. Together, these data sets were used to build a 3D static model in the Petrel geological modeling software suite, representative of the geologic and petrophysical characteristics within the Tri-State CCS Hub. The areal extent of the 3D static model is shown in subsection 2.4 of this Application Narrative.

2.2. Maps and Cross Sections of the AoR [47 CSR 13-13.8.1.c.1]

The project consists of two primary injection complexes: the Lockport Injection Complex (LIC) and the Medina Injection Complex (MIC). Regional structural features are shown in Figure 21, in which the AoR and the regional cross section in Figure 22 are both highlighted. The regional cross section in Figure 22 and the cross sections confined to the injection complexes and the model domain in Figure 23, Figure 24, and Figure 25 highlight the regional and local lateral continuity and thickness of both the Lockport Dolomite Group (LIC injection zone) and the Medina Group (MIC injection zone). In addition, the Salina Group, the primary confining zone, the Rochester Shale Formation, and the Queenston Shale Formation confining zones also exhibit regional and local lateral continuity and consistent thickness. Further discussion of the regional geology, primary seal thickness and lateral extent, injection zone thickness and lateral extent and other site-specific geologic characteristics is in subsections 2.1 and 2.4, respectively, of this Application Narrative.

The Gamma Ray and the petrophysical character of both the Lockport Dolomite Group and the Medina Group in the static model domain is consistent in both the dip and the strike direction; however, there are fewer Lockport wells with petrophysical analysis and, thus, more uncertainty in the characterization of the interval. The lowermost USDW, the Mauch Chunk Group is approximately 5,000 ft above the top of the Salina Group and is shown in Figure 22. Further discussion of the petrophysics of the LIC and MIC is in subsection 2.5 of this Application Narrative, and further discussion of the Mauch Chunk Group continues in subsection 2.7 of this Application Narrative.

The Rome Trough Fault System is the only known regional fault near the project area and passes ~ 9 miles South of the AoR, however, it does not pose a threat to containment for this project due to its location far below the injection zones and lower confining zone. Information concerning the faults and fractures and their spatial relation to the injection wells is further discussed in subsection 2.3 of this Application Narrative.

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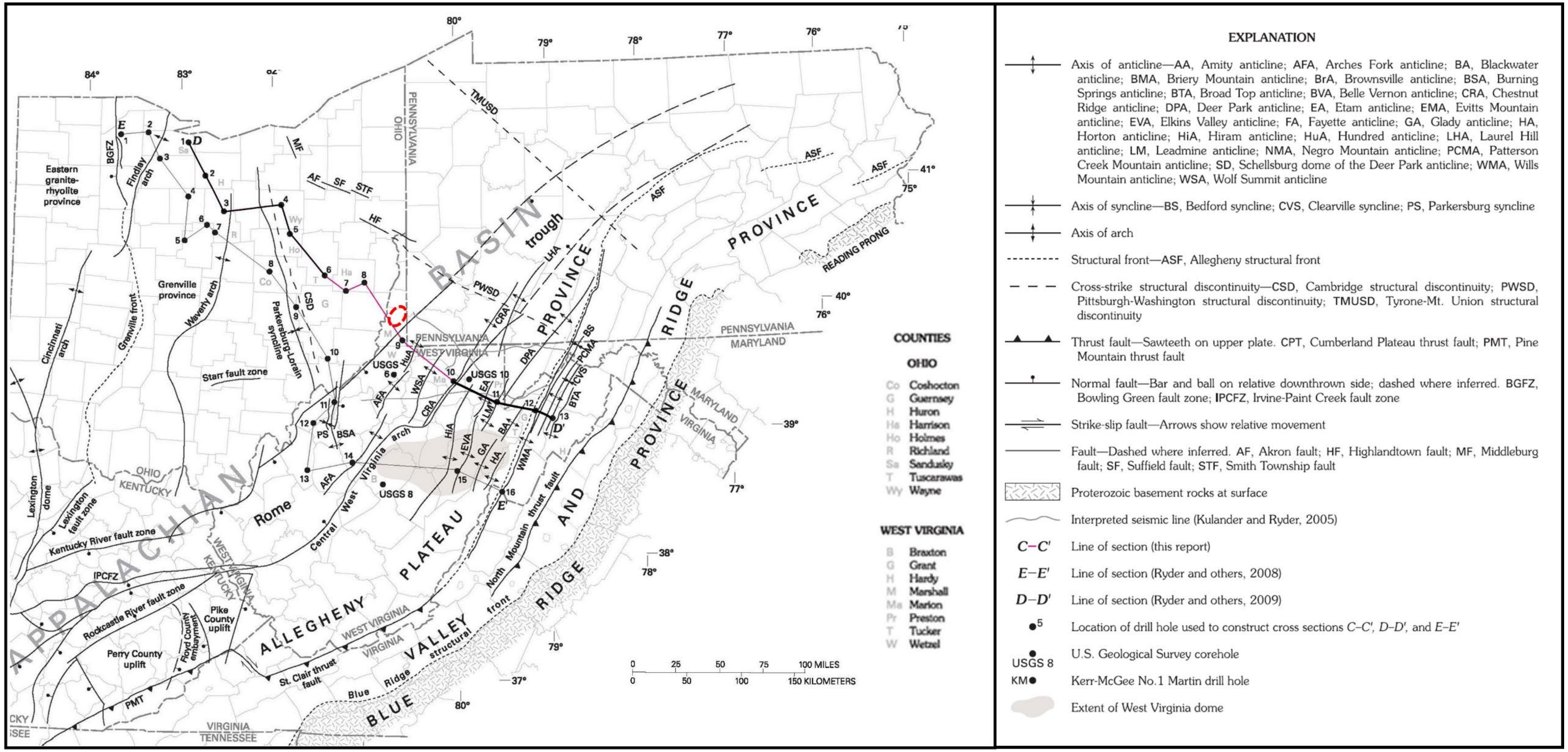

Figure 21: Base Map of the Appalachian Region and structural features with the cross section in Figure 22 shown in red. The approximate AoR is outlined in the dashed red circle. Modified from Ryder et al., 2012.

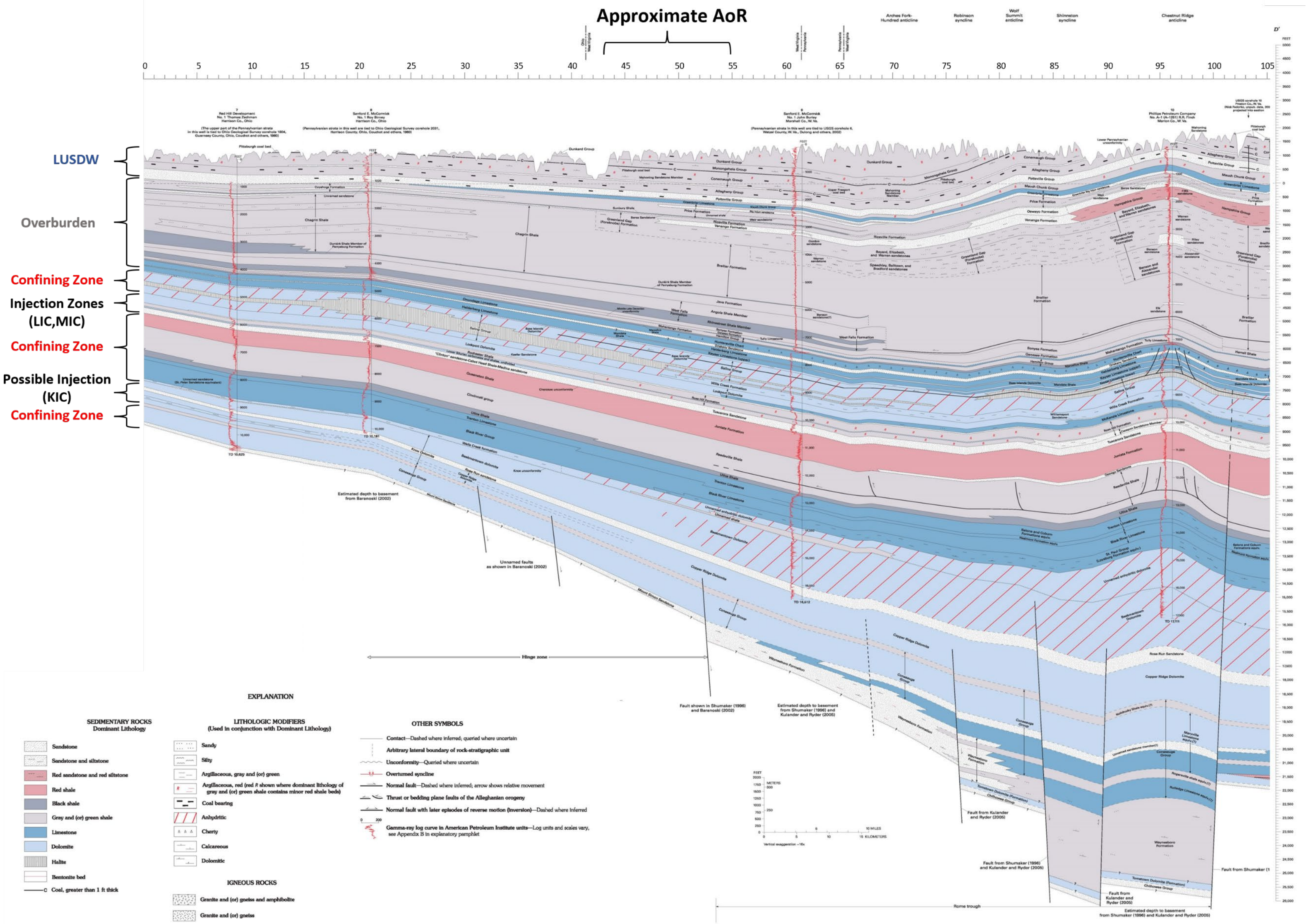

Figure 22: Regional cross section from ground level to the Cambrian Mt. Simon through the AoR (The red portion of D-D' in Figure 21 shows position of the cross section with respect to the AoR). LIC (Lockport injection complex), MIC (Medina injection complex) and KIC (Knox injection complex). Modified from Ryder et al., 2012.

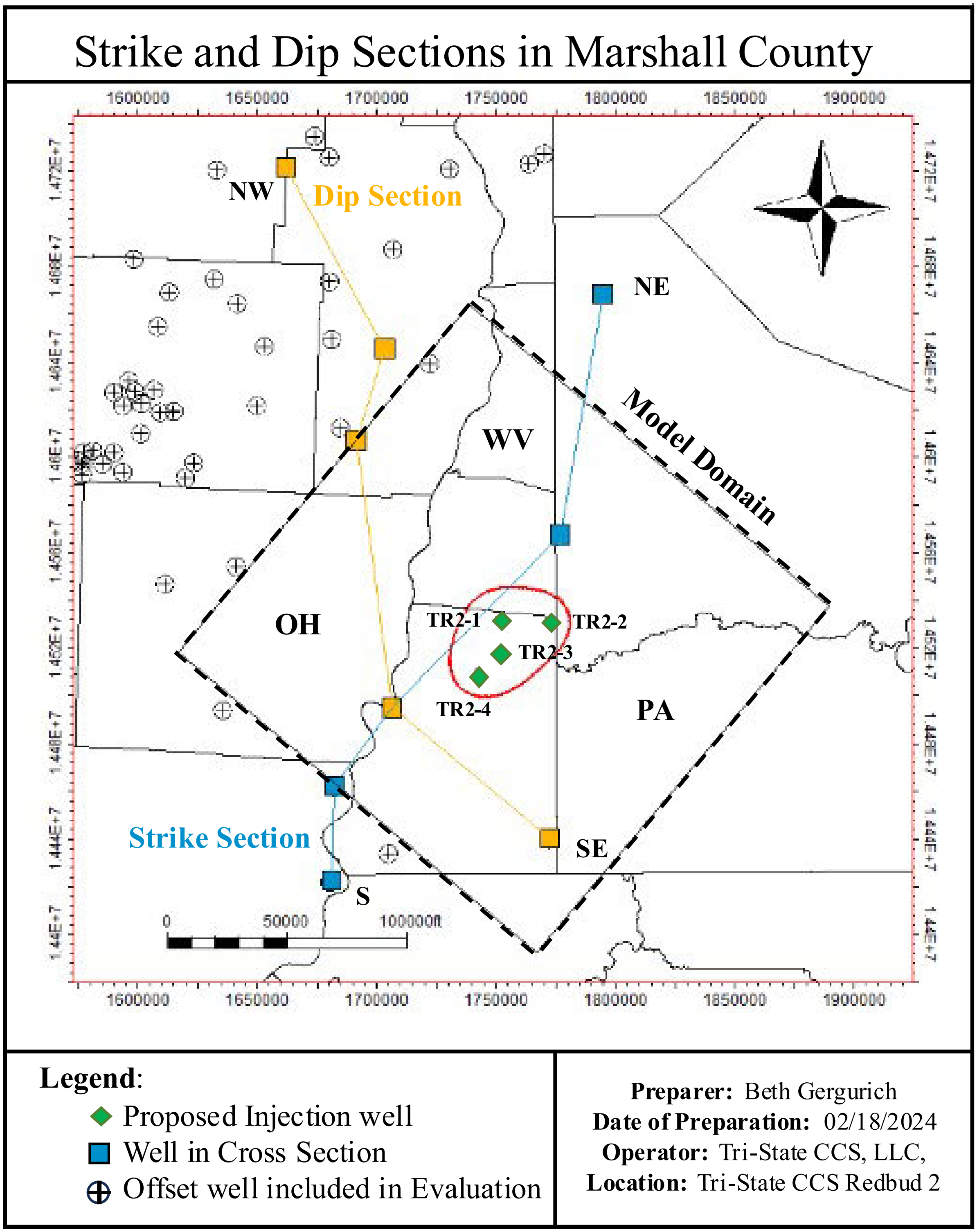

Figure 23: Base map of the project model domain (black), petrophysical wells included in the static model build (black circles), the NW-SE dip cross section (orange; Figure 24) and the NE-S strike cross section (teal; Figure 25) highlighted. The AoR is delineated by the red oval.

Claimed as PBI

Figure 24: NW-SE Dip cross section through the project model domain with the normalized Gamma ray (far left), the depth track in feet measured depth, the calculated effective porosity, and the calculated Klingenberg permeability in millidarcies. For detailed discussions on the petrophysical model and the specific wells used in this analysis, refer to subsections 2.1.12 and 2.5 of this Application Narrative. The Rochester Shale is the datum.

Claimed as PBI

Figure 25: S-NE Strike cross section through the project model domain with the normalized Gamma ray (far left), the depth track in feet measured depth, the calculated effective porosity, and the calculated Klingenberg permeability in millidarcies. For detailed discussions on the petrophysical model and the specific wells used in this analysis, refer to subsections 2.1.12 and 2.5 of this Application Narrative. The top Saina C is the datum.

2.3. Faults and Fractures [47 CSR 13-13.8.1.c.2]

Faulting local to northern Marshall County and the proposed injection well locations include the regional Rome rough fault system and distributed compressional faulting. Seismic data used to characterize the subsurface consists of two 2D lines located adjacent to the project and partially within the AoR (Figure 26). The north-south oriented 2D seismic line, OH-13-11, traverses Marshall County directly to the west of the proposed injection well sites (Figure 26) and images several faults and related folds in the subsurface (Figure 27). While this licensed dataset only partially covers the AoR, additional seismic data will be licensed and/or acquired as part of the CarbonSAFE Initiative. Seismic interpretation, fault interpretation, and a further assessment of any risks related to containment will be completed as part of the CarbonSAFE Initiative.

The Rome trough fault system is located ~9 miles to the south and east of the injection well locations and AoR (Figure 26). Due to the distance from the AoR to the fault zone, it is not considered a risk to containment. The geologic history of the Rome trough and other local fault systems is further discussed in subsection 2.1.11.1 of this Application Narrative.

Several unnamed faults and fault-related folds are observed along seismic lines EGI-OH-13-11 (Figure 27) and EGI-OH-05-11 (Figure 28) in northwestern Marshall County (Figure 26). The observed structures are interpreted as compressional faults with fault-related anticlinal folding (A on Figure 27 and the group of structures labeled B on Figure 28). Anticlinal fault-related folds are well developed through the lower Paleozoic stratigraphy of the basin and ceased development by the end of deposition of the Medina group (A on Figure 27 and B on Figure 28). The fault related fold development of structure A on Figure 27 is interpreted to offset the Knox group sediments with displacement across the top Knox group horizon of approximately 500 feet. Similar compressional faults and related folding are observed to the west of the AoR (see structures B on Figure 28). Compressional faulting is attributed to east-west directed shortening during the Pennsylvanian-Permian age Alleghanian orogeny (see subsection 2.5.6.2 below for further discussion). To determine that Paleozoic compressional faulting is not a risk to containment, additional seismic datasets will be licensed/acquired over the AoR.

Identification of any fractures or fracture networks that may be a risk to containment are beyond the resolution of the seismic reflection data available but will be one of the many factors addressed in the collection of geophysical and well data associated with this permit application (see the discussion of data collection related to geomechanics in subsection 2.5.6.1 below). These data collection efforts and associated studies will further understanding of fault stability and examine the possibility that fracture networks may provide preferential fluid flow conduits. Additional uncertainties in the identification of faults or geologic structures not identified on the available 2D seismic reflection data will be addressed in the collection of 3D seismic and well data under the CarbonSAFE Initiative.

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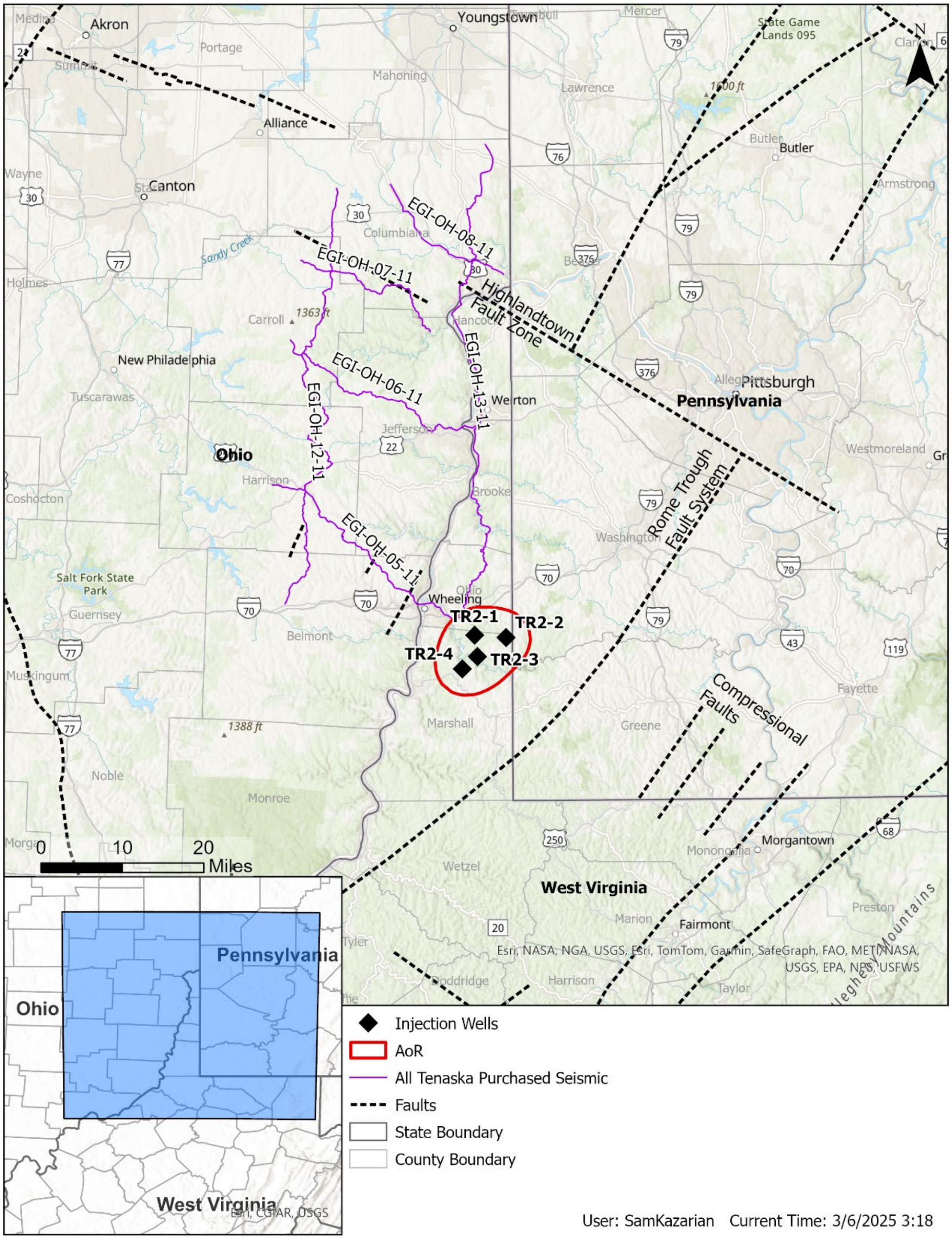

Figure 26: Location map of faults (black dashed lines) and 2D reflection seismic lines (purple). Location of N-S seismic line EGI-OH-13-11 (Figure 27) and E-W seismic line EGI-OH-05-11 (Figure 28). The AoR is delineated by the red line.

Claimed as PBI

Figure 27: 2D north-south oriented seismic cross-section OH-13-11 (see Figure 26 for location). See text for a discussion of compressional structure A. Interpreted seismic horizons include top Onondaga Ls. Fm. (light blue), top Medina Grp. (pink), top Trenton Ls. Grp. (purple), and top Knox Grp. (green). V.E. = 5X.

Claimed as PBI

Figure 28: 2D west-east oriented seismic cross-section EGI-OH-05-11 (see Figure 26 for location). See text for a discussion of distributed compressional structures B. Interpreted seismic horizons include top Onondaga Ls. Fm. (light blue), top Medina Grp. (pink), top Trenton Ls. Grp. (purple), and top Knox Grp. (green). V.E. = 5X.

2.4. Injection and Confining Zone Details [47 CSR 13-13.8.1.c.3.]

The stratigraphy in the project area is composed of ~12,000 ft of sediments on top of Precambrian basement, ranging in age from Cambrian up to Pennsylvanian (Virgilian) at the surface (Figure 29). Freshwater aquifers occupy porous units within the Pennsylvanian and Upper Mississippian, and historic oil production has been largely from Lower Mississippian sandstones. Recently, unconventional oil and gas production has been established in the Middle Devonian and Upper Ordovician.

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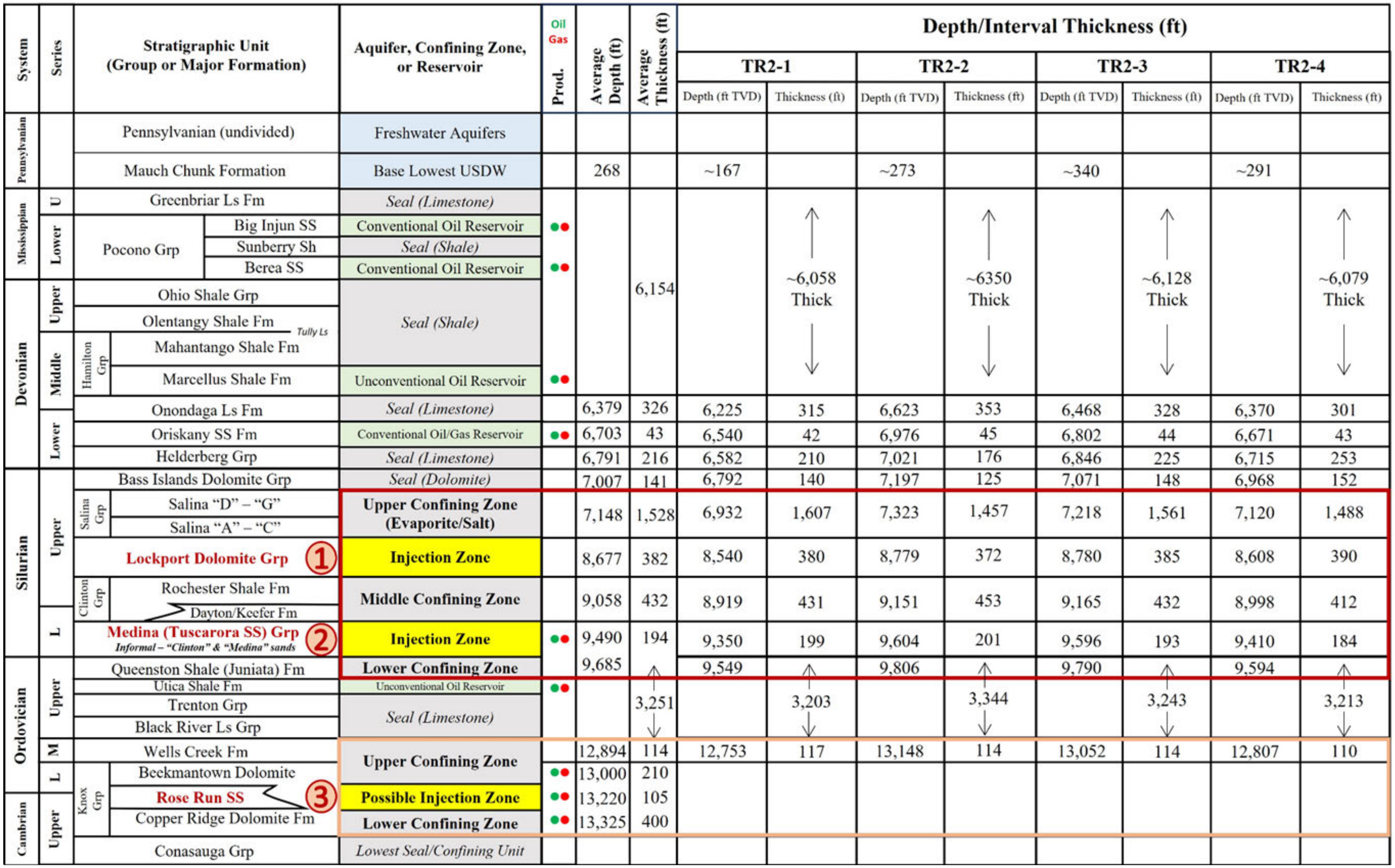

System	Series	Stratigraphic Unit (Group or Major Formation)		Aquifer, Confining Zone, or Reservoir	Oil Gas Prod.	Average Depth (ft)	Average Thickness (ft)	Depth/Interval Thickness (ft)							
								TR2-1		TR2-2		TR2-3		TR2-4	
								Depth (ft TVD)	Thickness (ft)	Depth (ft TVD)	Thickness (ft)	Depth (ft TVD)	Thickness (ft)	Depth (ft TVD)	Thickness (ft)
Pennsylvanian		Pennsylvanian (undivided)		Freshwater Aquifers											
		Mauch Chunk Formation		Base Lowest USDW		268		~167		~273		~340		~291	
Mississippian	U	Greenbriar Ls Fm		*Seal (Limestone)*			6,154		↑ ~6,058 Thick ↓		↑ ~6350 Thick ↓		↑ ~6,128 Thick ↓		↑ ~6,079 Thick ↓
	Lower	Pocono Grp	Big Injun SS	Conventional Oil Reservoir	●●										
			Sunberry Sh	*Seal (Shale)*											
			Berea SS	Conventional Oil Reservoir	●●										
Devonian	Upper	Ohio Shale Grp		*Seal (Shale)*											
		Olentangy Shale Fm *Tully Ls*													
	Middle	Hamilton Grp	Mahantango Shale Fm												
			Marcellus Shale Fm	Unconventional Oil Reservoir	●●										
	Lower	Onondaga Ls Fm		*Seal (Limestone)*		6,379	326	6,225	315	6,623	353	6,468	328	6,370	301
		Oriskany SS Fm		Conventional Oil/Gas Reservoir	●●	6,703	43	6,540	42	6,976	45	6,802	44	6,671	43
		Helderberg Grp		*Seal (Limestone)*		6,791	216	6,582	210	7,021	176	6,846	225	6,715	253
Silurian	Upper	Bass Islands Dolomite Grp		*Seal (Dolomite)*		7,007	141	6,792	140	7,197	125	7,071	148	6,968	152
		Salina Grp	Salina "D" – "G"	**Upper Confining Zone (Evaporite/Salt)**		7,148	1,528	6,932	1,607	7,323	1,457	7,218	1,561	7,120	1,488
			Salina "A" – "C"												
		Lockport Dolomite Grp ①		**Injection Zone**		8,677	382	8,540	380	8,779	372	8,780	385	8,608	390
		Clinton Grp	Rochester Shale Fm	**Middle Confining Zone**		9,058	432	8,919	431	9,151	453	9,165	432	8,998	412
			Dayton/Keefer Fm												
	L	**Medina (Tuscarora SS) Grp** ② ***Informal – "Clinton" & "Medina" sands***		**Injection Zone**	●●	9,490	194	9,350	199	9,604	201	9,596	193	9,410	184
Ordovician	Upper	Queenston Shale (Juniata) Fm		**Lower Confining Zone**		9,685	↑ 3,251 ↓	9,549	↑ 3,203 ↓	9,806	↑ 3,344 ↓	9,790	↑ 3,243 ↓	9,594	↑ 3,213 ↓
		Utica Shale Fm		Unconventional Oil Reservoir	●●										
		Trenton Grp		*Seal (Limestone)*											
		Black River Ls Grp													
	M	Wells Creek Fm		**Upper Confining Zone**		12,894	114	12,753	117	13,148	114	13,052	114	12,807	110
	L	Knox Grp	Beekmantown Dolomite		●●	13,000	210								
Cambrian	Upper		**Rose Run SS** ③	**Possible Injection Zone**	●●	13,220	105								
			Copper Ridge Dolomite Fm	**Lower Confining Zone**	●●	13,325	400								
		Conasauga Grp		*Lowest Seal/Confining Unit*											

Figure 29: Generalized stratigraphic column for the project. Primary Injection Complexes: 1 - Lockport Injection Complex; 2 - Medina Injection Complex; possible secondary injection complex: 3 - Knox Injection Complex. Modified from Childs, 1985; Patchen et al., 1985b; Riley et al., 2010; Wickstrom et al., 2005; WVGES, 2019.

Subsurface analysis in the project area indicates several stacked, porous reservoirs with suitable confining seals for sequestration. These intervals exist beneath the 2,800 ft MD threshold for storage of supercritical CO_2 (sCO_2) and are, likewise, greater than 1,000 vertical feet from known producing oil reservoirs. Three potential injection complexes, each composed of an upper confining zone, a lower confining zone, and an injection zone, have been identified (Figure 29). All three will be evaluated after data collection and evaluation from the CarbonSAFE stratigraphic wells in the region. There are two primary injection complexes proposed in this application: the upper injection complex is the Lockport Injection Complex (LIC – 1 on Figure 29) and the middle injection complex is the Medina Injection Complex (MIC – 2 on Figure 29). There is also an alternate injection complex, to be evaluated after data collection from the CarbonSAFE stratigraphic wells: the lower injection complex, the Knox Injection Complex (KIC – 3 on Figure 29). Throughout this permit, when referring to the entire injection complex, the nomenclature outlined above will be used, and when describing or indicating specific intervals, the Group, Formation, or appropriate formal interval (i.e., “Shale” or “Sandstone”) name will be used.

2.4.1. Upper Injection Complex: Lockport Injection Complex (LIC)

The LIC is composed of, from top to base: the Salina Group, which forms the primary confining zone, the Lockport Dolomite Group, which is the objective injection zone, and the Rochester Shale Formation, which forms the basal confining zone. All three stratigraphic units are Upper Silurian in age (Figure 29).

2.4.1.1. LIC Primary Confining Zone: Salina Group

The Salina Group is a series of regionally extensive interbedded shales, dolomites, and evaporites (Figure 30). These deposits extend across the Appalachian and Michigan basins and provide the seal for Niagaran oil and gas reef trends in the Michigan Basin (Carter et al., 2010; Coyle, 2022). Original subdivision of the units “A-G” was identified by Landes (1945) in the Michigan Basin and correlated to the Appalachian Basin by Ulteig (1963) and Rickard (1969). They were deposited in a restricted marine (A-C) to sabkha/peritidal and supratidal environment (D-G) as a result of the paleogeographic location in tropical latitudes, an arid long-term paleoclimate, and isolation/rain shadow from orogenic uplift (Clifford, 1973; Ettensohn, 2008).

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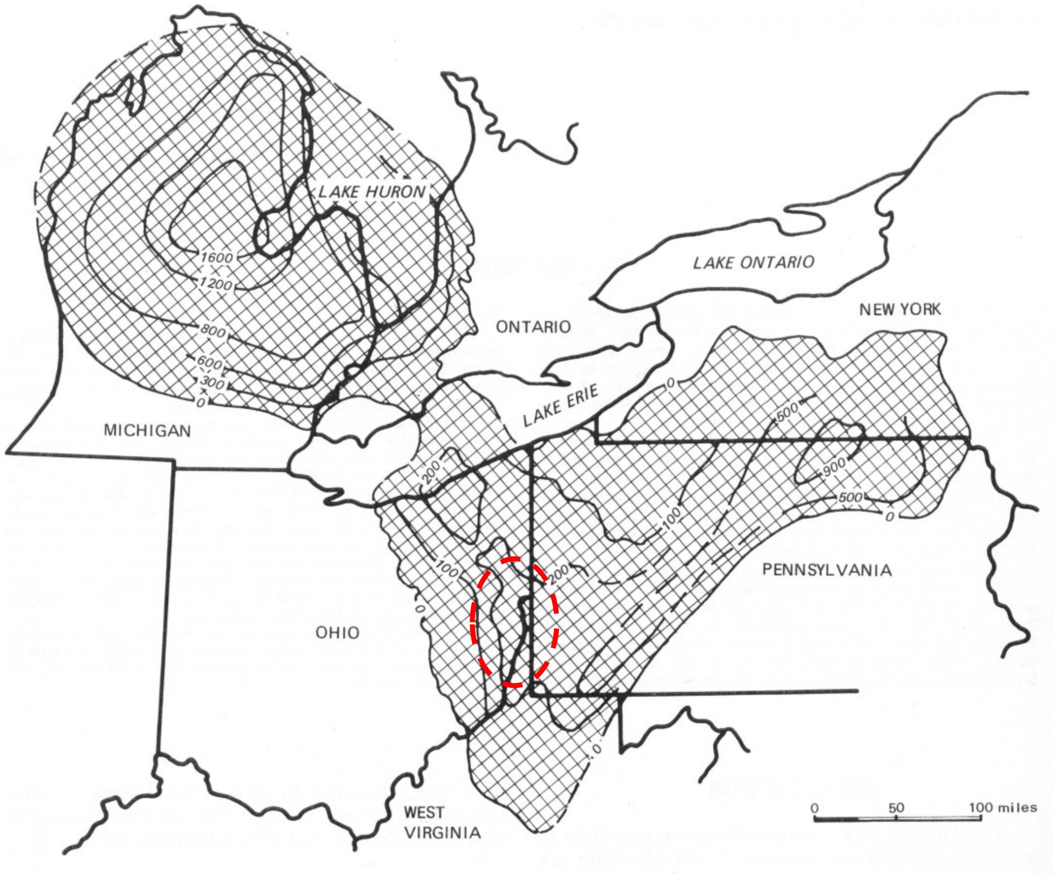

Figure 30: Regional extent and thickness of the Salina Group salt beds modified from Clifford (1973). The red dashed circle is the approximate location of the Tri-State CCS Hub (map contour interval varies).

The Salina Group, named for the halite in this section, is divided into two intervals. The lower interval, called the “A-C” units, is known as the Vernon in New York and the upper Wills Creek in West Virginia (Rickard, 1969; Coyle, 2022). In the project area, this interval is composed predominantly of dolomite and shale beds, though some salt beds are present outside the area. The overlying “D-G” units are a thick section dominated by salt, evaporites, and shales. Figure 31 shows a cross-section from the Humble #1 Minesinger Well (Well No. 89 in Table 2, location in Figure 18) in Hancock County, approximately 36 miles north of the project area, to the Kin-Ark #1 Hasenpflug well in Lorain County, Ohio (API# 34093209080000). This cross-section demonstrates that the “E” interval has a laterally continuous salt bed with an approximate thickness of 60 ft, and the “F” interval has numerous, thick, and laterally continuous salt beds in the project area. The “F4” salt can reach thicknesses greater than 100 ft in the project area and greater than 50 ft in the AoR (Figure 32; Clifford, 1973; Carter et al., 2017).

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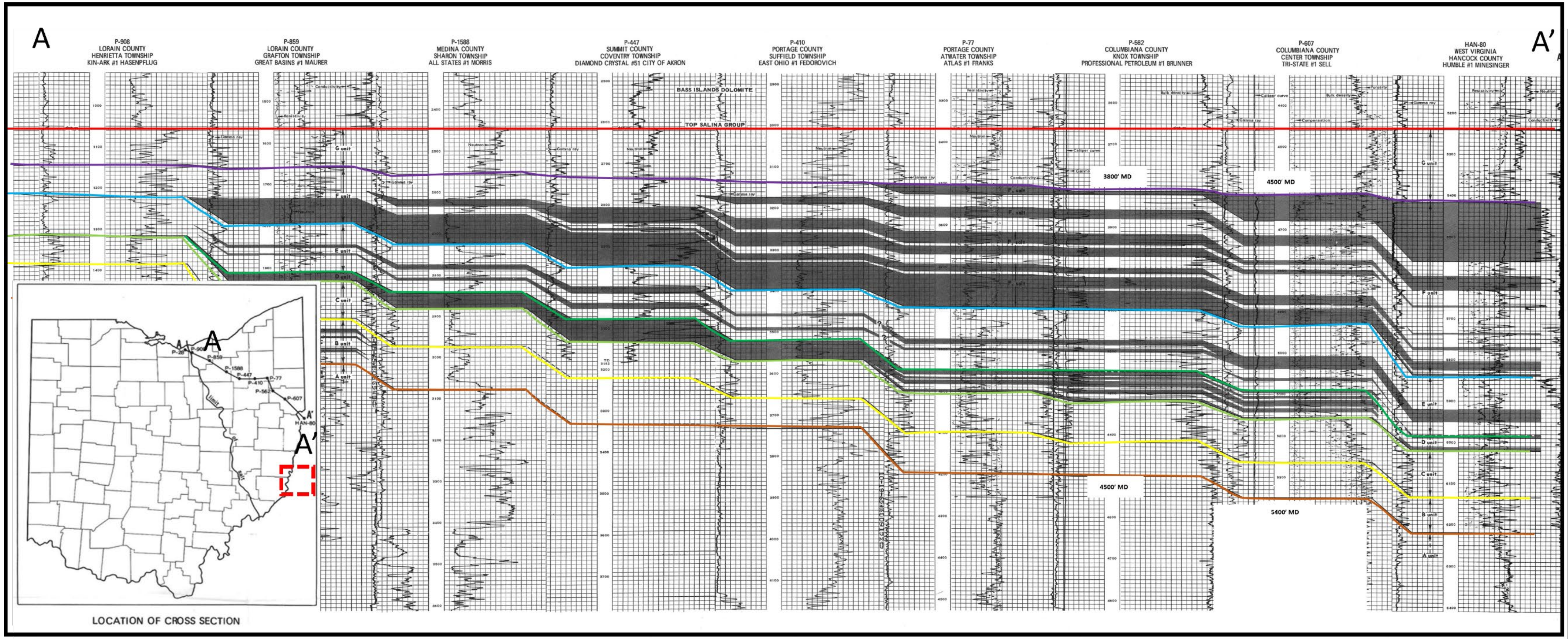

Figure 31: SE-NW Cross-section from Lorain, County OH, to Hancock County, WV through the Salina Group. Study area in red dashed line in map. Modified from Clifford, 1973. From Top to Base: The Top "G" unit (red), the Top "F" unit (Purple), the Top "E" unit (blue), the Top "D" unit (dark green), the Top "C" unit (light green), the Top "B" unit (yellow), the Top "A" unit (orange). Well APIs from left to right: 34093209080000, 34093208590000, 34103215880000, 34153204470000, 34133204100000, 34133200770000, 34029205620000, 34020206070000, 47029000800000.

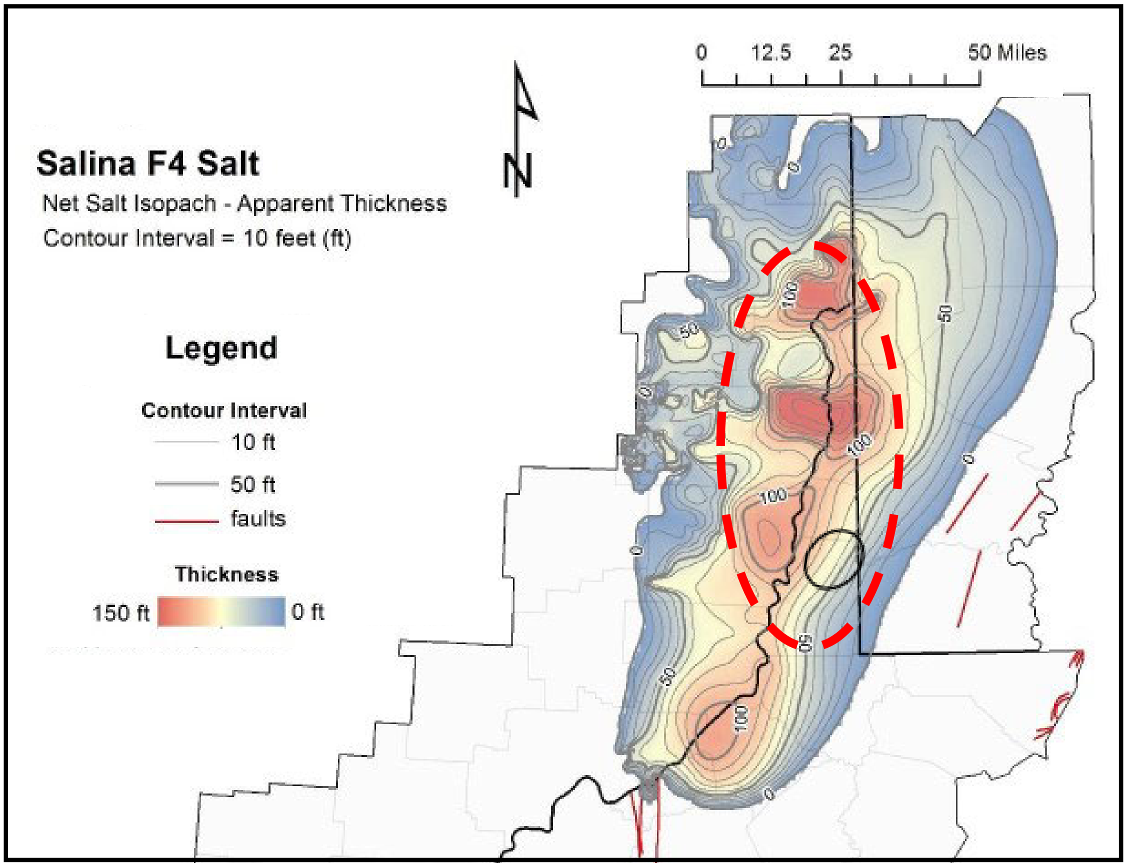

Figure 32: F4 Salt Thickness map in the Tri-State CCS Hub (red dashed oval) and project AoR (solid black oval). Modified from Carter et al., 2017.

There are multiple lines of evidence that support that the Salina Group serves as an effective long-term seal for CO_2 injection. First, historical data from the oil and gas industry show that evaporites, such as those found in the Salina, have consistently acted as competent long-term seals; 14 of the world's 25 largest oil fields and 9 of the world's 25 largest gas fields are sealed by evaporites, despite evaporites constituting less than 2% of the world's sedimentary rocks (Warren, 2017). Additionally, a widely accepted guideline in the oil and gas industry suggests that a halite bed can function as a seal if it is at least 20 m (65.6 ft) thick. This is corroborated by the low permeabilities observed in evaporites, with halite typically exhibiting permeabilities on the order of 10^{-7} md and anhydrite around 10^{-5} md (Beauheim and Roberts, 2002).

Furthermore, studies have identified beds in the F salt of the Salina Group as possessing both the requisite halite purity and thickness (over 100 ft) necessary for solution mining and long-term storage of natural gas liquids in the relevant area (Carter et al., 2017). Lastly, the distinct geochemical fingerprint observed between regional petroleum systems younger than the Salinan evaporites and those predating them further bolster the argument for the Salina's efficacy as a long-term seal (Cole et al., 1987; Drozd and Cole, 1994; Swezey, 2002; Ettensohn, 2008).

Available core analyses from the MRCSP-FEGENCO 1 well (Well No. 1 in Table 2, location in Figure 18) in Belmont County, Ohio are primarily from dolomite intervals in units A, B, F, and G of the Salina Group (Figure 33). There are no core measurements from the actual salt layers.

Permeabilities from these cores range from <0.01 to 2.45 md (average 0.3 md), and measured porosities range from <1.0% to 13% (average 6.6 %; Figure 33). These units are stratigraphically older than the laterally continuous F4 salt and are not expected to put containment at risk. Further discussion of the petrophysics continues in subsection 2.5 of this Application Narrative.

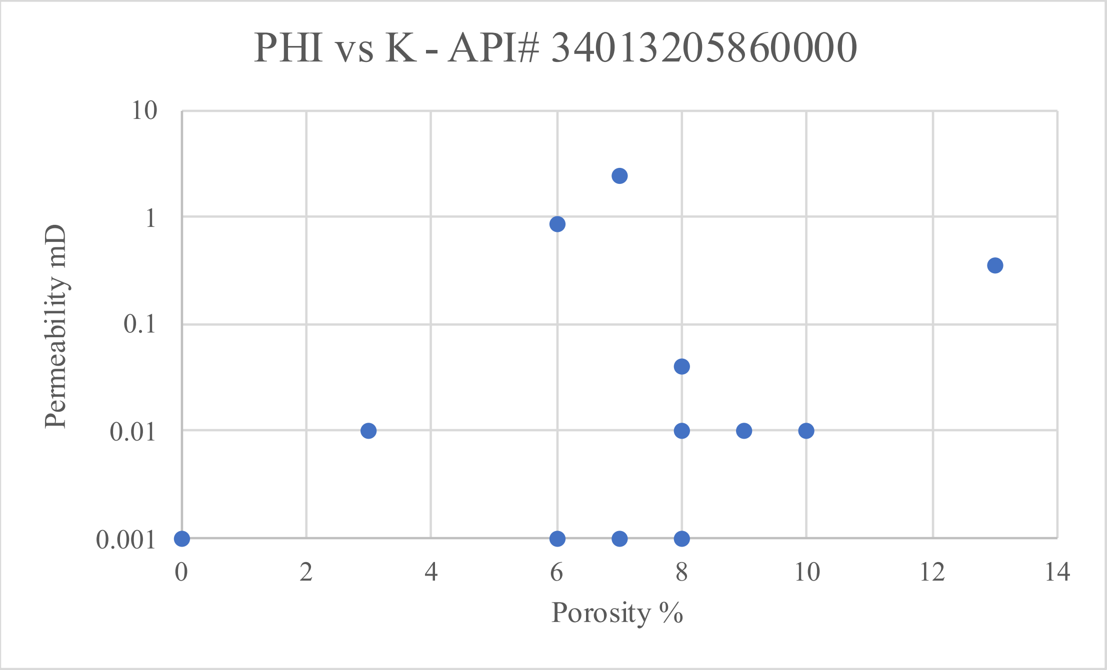

Figure 33: Core measured Porosity vs. Permeability from the Salina Goup in the MRCSP FEGENCO 1 well (Well No. 1 in Table 2, location in Figure 18).

In the project area, the Salina Group ranges in depth from -4,500 ft SSTVD in the northwest, towards the Findlay Arch, and dips to the southeast to a depth of -7,200 ft SSTVD (Figure 34). The Salina Group (Figure 34) thickens to the southeast of the proposed injection sites, corroborating Clifford (1973). The Top Salina interval is at a depth of approximately 6,930 ft to 7,325 ft TVD and has an average total thickness greater than 1,500 ft at the proposed injection well sites.

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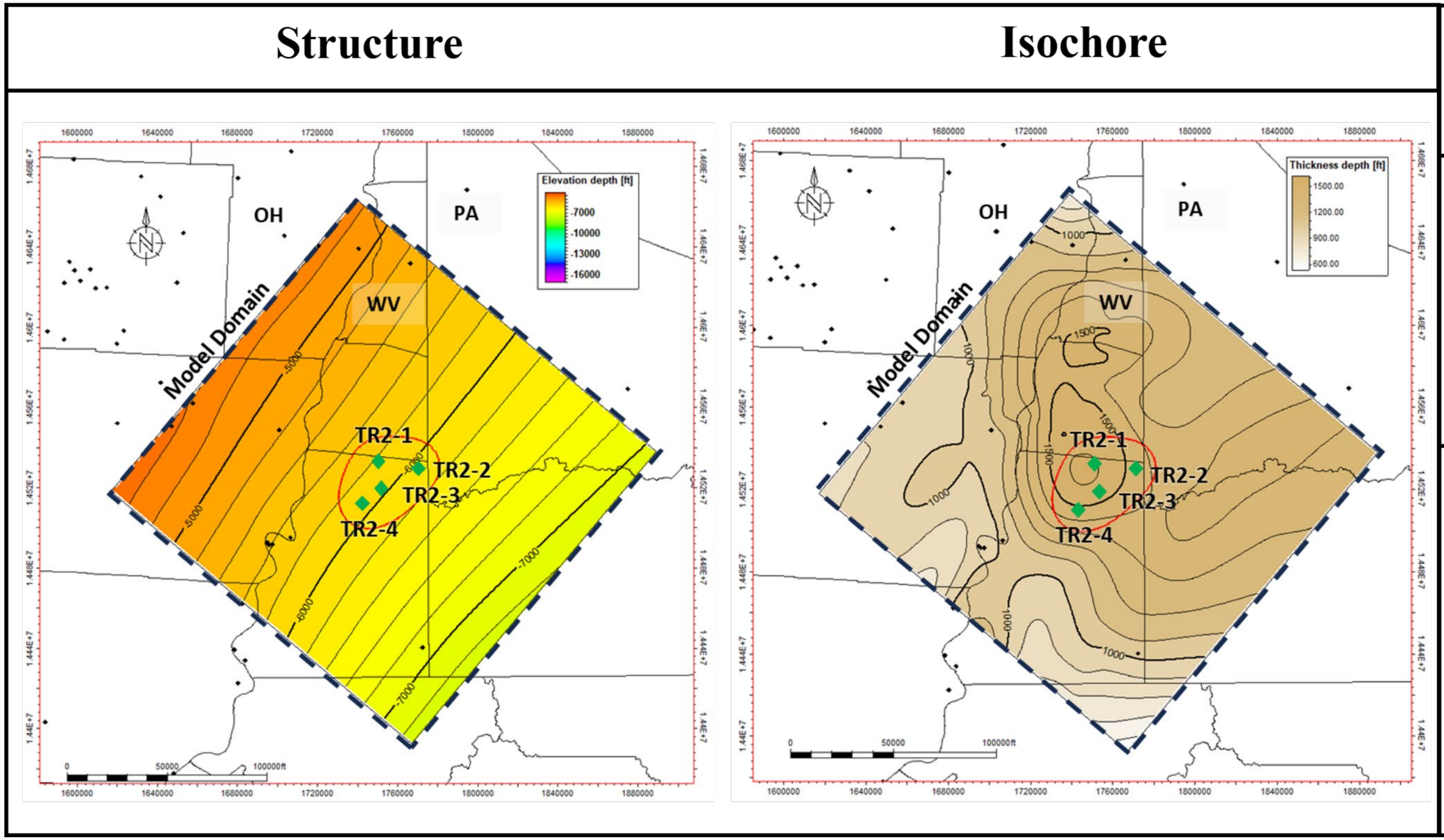

TOP SALINA GROUP

Legend:

- 🟩 Injection Well
- 🟥 AoR Boundary
- ⬚ Model Domain
- ◆ Structural Control

Preparer:
Beth Gergurich

Date of Preparation:
02/11/2024

Operator:
Tri-State CCS, LLC

Location:
Tri-State CCS Redbud 2

Figure 34: Top Structure (left) and Isochore (right) of the Salina Group interval (Structure C.I. = 200 ft; depths SSTVD; Isochore C.I. = 10 ft) with the four potential injection sites shown in Marshall County, West Virgina. The static model domain is dashed in black. Wells used for structural control of the surface and isochore are noted with black diamonds.

2.4.1.2. LIC Primary Injection Zone: Lockport Dolomite Group

The primary injection zone for the LIC is the Lockport Dolomite Group. The Lockport Dolomite Group, sometimes referred to as the McKenzie Formation (Horvath, 1970), is extensive across the Appalachian Basin region and into Michigan (called the Niagara Group) and was deposited in similar paleogeographic, eustatic, and tectonic conditions to the Salina Evaporites (Figure 35; see subsection 2.4.2 above; Carter et al., 2010; Ettensohn, 2008). This geologic unit has been described with sub-units as the Lockport Group (Hansen, 1998), and it has been described as a single unit called the Lockport Dolomite (Gupta, 2020). Lockport Dolomite Group is used here as a placeholder name until a more precise determination can be made using core data from stratigraphic test wells planned in the region as part of the CarbonSAFE project.

Regionally, the Lockport Dolomite Group dips to the southeast and has an average thickness range of 150 ft to 200 ft. A study in Eastern Ohio measured the maximum thickness of the Lockport at ~400 ft adjacent to the project area (Gupta et al., 2020; Wickstrom, 2010; Janssens, 1970; Carter et al., 2010). At the proposed injection sites, the Lockport Dolomite Group has a thickness of approximately 380 ft and occurs at TVD between 8,540 ft and 8,780 ft (Figure 36). The surface of the Lockport Dolomite Group is from -5,400 to -8,400 SSTVD in the static model.

This relatively thick section of carbonate is composed of a fine to coarsely crystalline, fossiliferous, slightly argillaceous dolostone, accumulated in a shallow epicontinental sea that stretched westward from New York to Ohio and south to Kentucky, extending along the Cincinnati-Findlay-Algonquin axis into the basins of Indiana, Illinois, and Michigan (Carter et al., 2010; Ettensohn, 2008). Carter et al. (2010) identified seven lithofacies types in core from the Lockport Dolomite Group, all indicative of shallow subtidal to nearshore deposition (Figure 35):

1. mixed intertidal to supratidal dolomite (with a mixed gray biostromal subfacies)
2. interreef or interbioherm dark dolomite
3. grainstone – shoals, banks, reef flanks, and inter-reef sediments
4. biohermal dolomite (reefs, bioherms, and patch reefs)
5. subtidal crinoidal dolomite
6. quartzose dolomite associated with barrier island
7. shallow subtidal shaley dolomite

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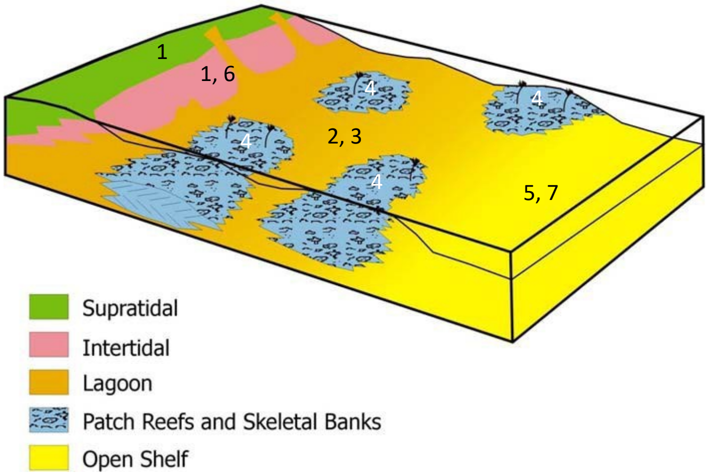

Figure 35: Cartoon depicting the regional facies patterns interpreted for the Lockport Dolomite in the Appalachian Basin. Numbers reflect the described facies in the text. Modified from Smosna et al., 1989.

Detailed core analysis was not available for the Lockport Dolomite Group near the proposed injection well sites. A study (Carter et al., 2010) of several cores in Mercer County, Pennsylvania and Caroll County, Ohio, as a part of the MRCSP Phase II Topical Report evaluating the CO_2 sequestration potential in the middle Devonian to the middle Silurian formations in the Appalachian Basin, was used to characterize the reservoir (locations shown in Figure 18 and Table 2; subsection 2.1.12).

Porosity types in the Lockport Dolomite Group include vuggy, moldic, inter/intraparticle, and intercrystalline porosity (Carter et al., 2010; Wickstrom et al., 2010). Early eogenic and syngenic diagenesis facilitated the creation of vugs and moldic pore textures, though much of the secondary porosity has been lost through burial diagenesis. Core and log analysis measure an average of 9% porosity in vuggy dolomites and between 1 and 3.5% in dolomites characterized with intracrystalline porosities. Average permeabilities in Lockport dolomites with intercrystalline permeability are measured at <0.1 md, and vuggy permeability averages 3 to 10 md but can be as high as 55 md (Carter et al., 2010; Wickstrom et al., 2010). Fracture porosity and permeability are present in the Lockport Dolomite as well, enhancing reservoir petrophysics (Wickstrom et al., 2010). Cyclic stacking of reservoir facies in response to sea-level fluctuations yields opportunity for multiple disposal zones in the Lockport Dolomite Group (Figure 24 and Figure 25). Site-specific petrophysical analysis is discussed in subsection 2.5 of this Application Narrative.

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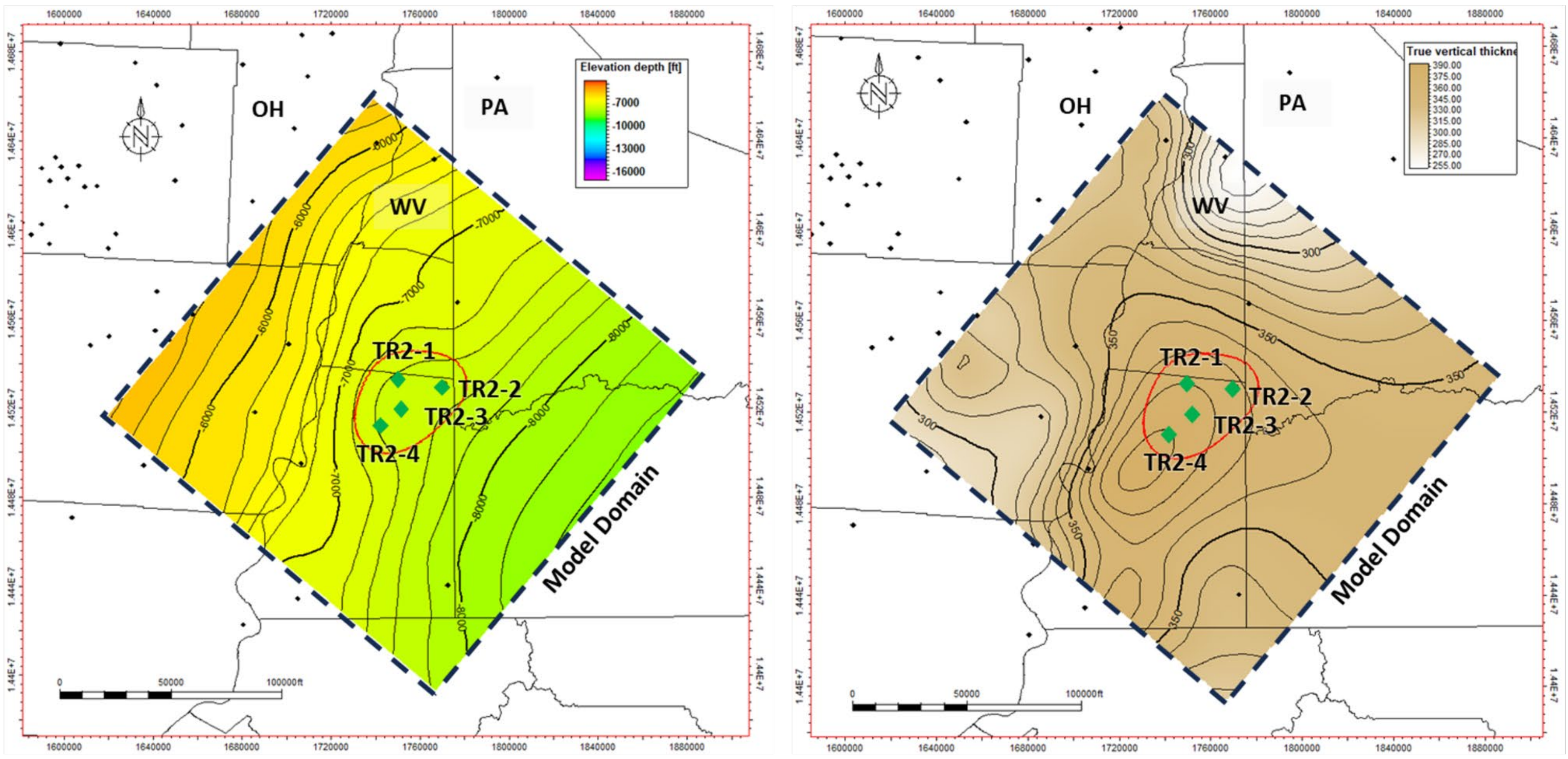
Structure

Isochore



LOCKPORT DOLOMITE GROUP

Legend:

◆ Injection Well

▭ AoR Boundary

⬚ Model Domain

◆ Structural Control

Preparer:

Beth Gergurich

Date of Preparation:

02/11/2024

Operator:

Tri-State CCS, LLC

Location:

Tri-State CCS Redbud 2

Figure 36: Top Structure (left) and Isochore (right) of the Lockport Dolomite Group interval (Structure C.I. = 200 ft; depths SSTVD; Isochore C.I. = 20 ft) with the four potential injection sites shown in Marshall County, WV. The static model domain is shown as a black dashed line. Wells used for structural control of the surface and isochore are noted with black diamonds.

Measurements from four sidewall core samples in the Lockport Dolomite Group identify the mineralogy to be predominantly dolomite with minor quartz and illite (Table 3). Carter's 2010 study also documented pyrite and pyrobitumen, likely from diagenesis, in the sidewall core samples. Reactivity of the Lockport Dolomite Group mineralogy with the CO_2 stream is further addressed in subsection 2.8 of this Application Narrative.

Table 3: XRD results for sidewall core samples of the Lockport Dolomite Group from the Ocel #1 well, Carroll County, Ohio (Carter et al., 2010; Well No. 2 in Table 2, location in Figure 18).

Sample	**Percent of Total Composition**										
Depth MD (ft)	**Quartz**	**K-Spar**	**Plag.**	**Pyrite**	**Dol/Ank**	**Chlorite**	**Kaolinite**	**Illite**	**Smectite**	**Calcite**	**Siderite**
5,422	13	0	0	1	84	Trace	0	2	0	0	Trace
5,436	1	0	0	1	97	Trace	0	1	0	0	Trace
5,460	1	0	0	1	96	Trace	0	2	0	0	Trace
5,468	Trace	0	0	1	98	Trace	0	1	0	0	Trace
Avg.	4	0	0	1	94	Trace	0	1	0	0	Trace

2.4.1.3. LIC Primary (lower) Confining Zone: Rochester Shale Formation

The Rochester Shale Formation, known to drillers as the "Clinton Shale," lies below the Lockport Dolomite Group and serves as the basal confining zone to the LIC, as well as the upper confining zone for the MIC discussed in subsection 2.4.2 below.

In West Virginia, Woodward (1941) identified the Rochester as the upper section of the Clinton Group. He and Folk (1962) characterized the shale as gray to black in color, thin-bedded, fissile, or platy, and interspersed with occasional dense, fossil-rich blue-gray micritic-biosparite limestone, deposited in a lagoonal environment associated with the time-correlative Keefer sandstone barrier bar. In New York and Ontario, Brett (1983) described the Rochester as a gray, fossiliferous, shaley mudstone with abundant interbedded carbonates indicative of storm-wave action on the southwards facing slope. He correlated it west to eastern Ohio and Kentucky where it grades into an argillaceous dolostone referred to as the "Bisher" in the literature (Horvath, 1969; Janssens, 1977). Janssen (1977) notes that the shale in the Rochester thins and becomes virtually absent near the western boundary of Hancock County. There, it is underlain by the Dayton Formation: a non-argillaceous slightly glauconitic dolomite, though the GR log from the MRCSP-FEGENCO 1 well (Well No. 1 in Table 2, location in Figure 18) indicates a thick shale with thin dolomite beds (Figure 24).

Subsurface log correlations show the shale is an average of 430 ft thick in the Marshall County area in WV and ranges from ~8,920 to 8,780 ft TVD at the injection sites (Figure 37Figure 29). Across the model domain, the top of the Rochester Shale ranges in depth from -5,800 to -8,800 ft (SSTVD) (Figure 37). In the West Virginia northern panhandle, the shale is organic-lean and does not have high radioactivity on gamma ray log (average of 80 API units).

Porosity in the formation is generally less than 3%, and permeability is similar to other shales at less than 1×10^{-6} md (Mudd et al., 2003). Given the lateral continuity and the impermeability of the shales, the Rochester Shale and its time-equivalents in the project area should serve as an effective base confining zone for the LIC and upper confining zone for the MIC.

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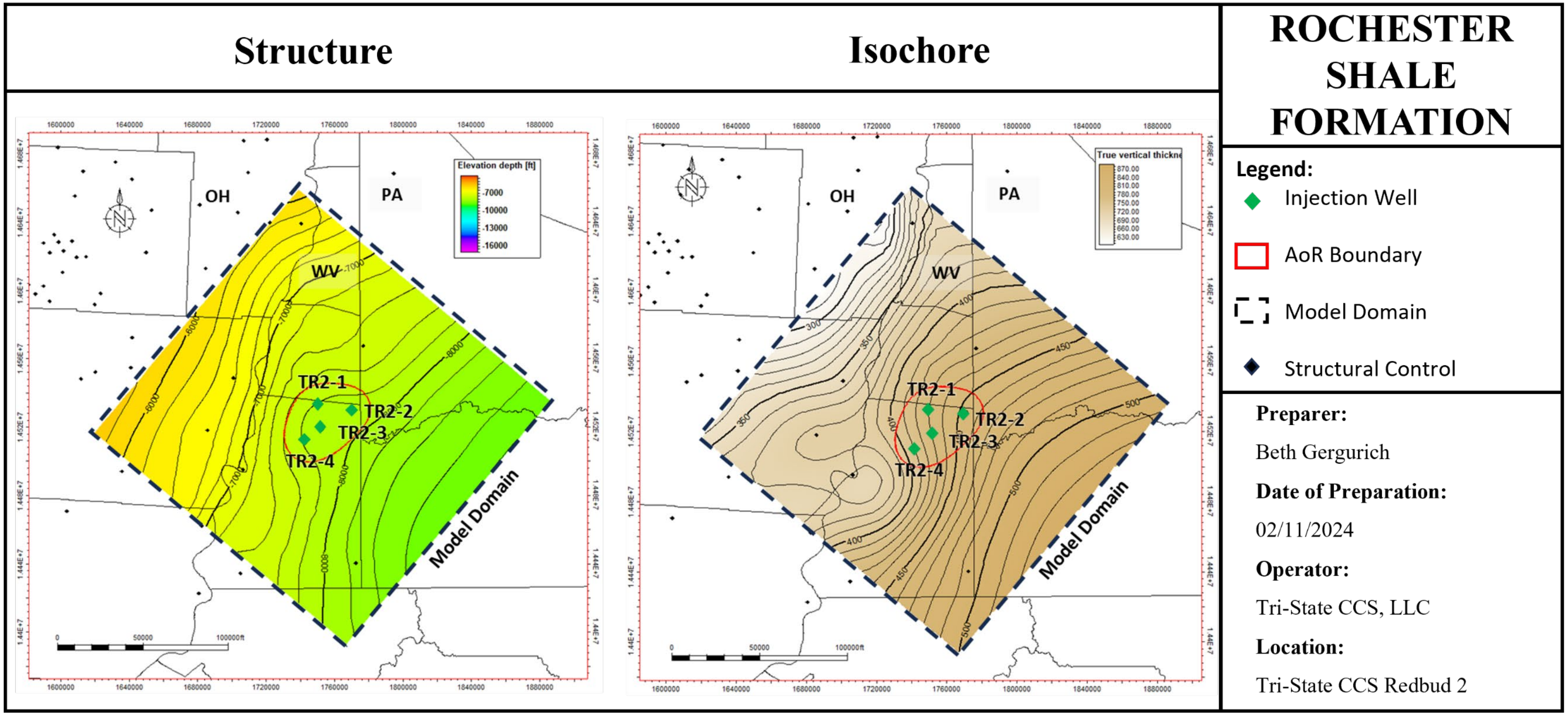

ROCHESTER SHALE FORMATION

Legend:

◆	Injection Well
🟥	AoR Boundary
⌜⌟	Model Domain
◆	Structural Control

Preparer:
Beth Gergurich
Date of Preparation:
02/11/2024
Operator:
Tri-State CCS, LLC
Location:
Tri-State CCS Redbud 2

Figure 37: Top Structure (left) and isochore (right) of the Rochester Formation interval (Structure C.I. = 200 ft; depths SSTVD; Isochore C.I. = 20 ft) with the four potential injection sites shown in Marshall County, WV. The static model domain is shown as a black dashed line. Wells used for structural control of the surface and isochore are noted with black diamonds.

2.4.2. Middle Injection Complex: Medina Injection Complex (MIC)

The second primary injection complex for consideration is the MIC; the MIC is composed of three units. The Upper Silurian Rochester Shale Formation forms the upper seal and confining zone (“2” on Figure 29). The Medina Group, which is a series of stacked sandstones in the Lower Silurian, is informally referred to as the “Clinton” sandstone and is the proposed injection zone(s) (Wickstrom, 2010). At the base, the thick, Ordovician-aged Queenston Shale or Juniata Formation, comprises the lower confining member of the MIC.

2.4.2.1. MIC Primary (upper) Confining Zone: Rochester Shale

The upper confining zone for the MIC is the same basal confining unit for the LIC and is addressed in subsection 2.4.1.3 above.

2.4.2.2. MIC Primary Injection Zone: Sandstone in the Medina Group

The correlation of sandstones in the Lower Silurian of the Appalachian Basin historically have been problematic due to nomenclature inconsistencies in stratigraphic terminology from state to state. Multiple names for age-equivalent zones (Figure 38) in the literature have led to confusion and cross-correlation of stratigraphic units. Sandstones in this interval have been referred to as Tuscarora, Grimsby, Whirlpool, and informally the “Medina” and “Clinton” sandstones, the latter including drillers’ terminology.

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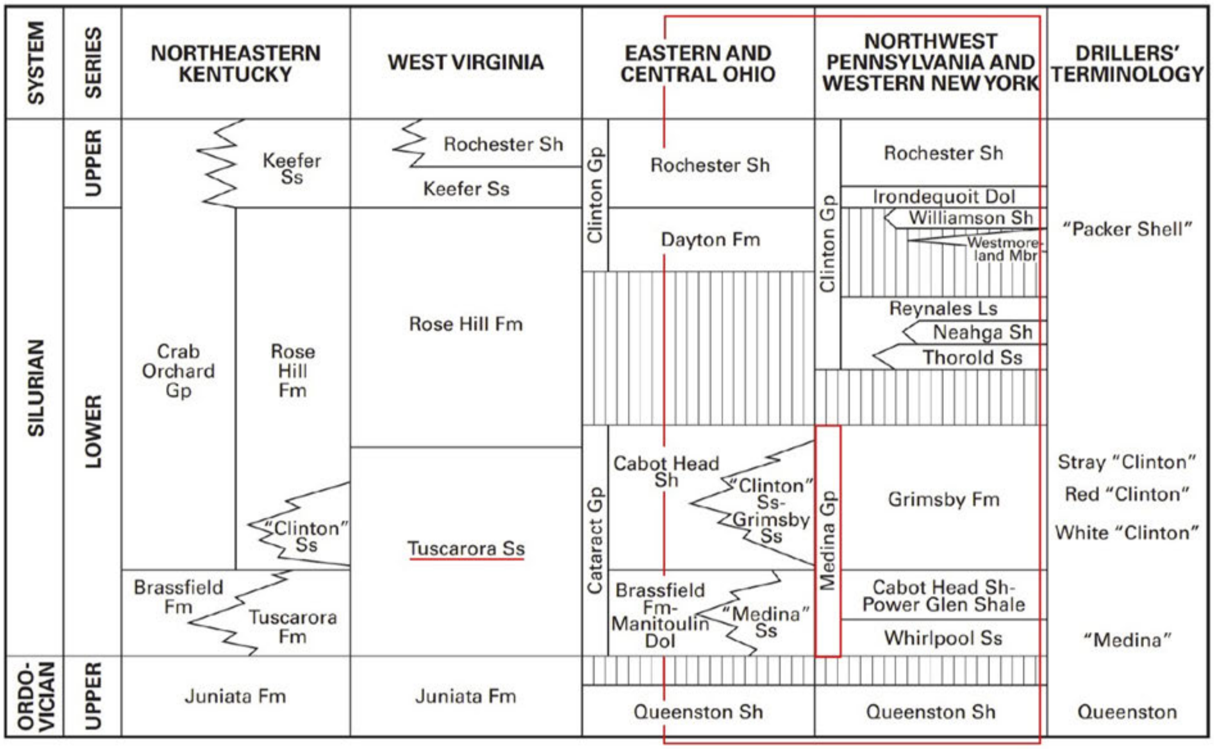

Figure 38: Stratigraphic correlation chart for the project area illustrating varying terminology for age equivalent sands. For this permit, the nomenclature for Eastern Ohio is recognized, and the interval is referred to as the Medina Group (Riley et al., 2010).

For the purpose of this permit application, the MIC injection interval will be referred to as the Medina Group of Eastern Ohio and northwest Pennsylvania. The Medina Group is composed of the Whirlpool Sandstone, the overlying Cabot Head Shale, and the interfingering Grimsby ("Clinton" and "Medina") reservoir sandstone(s), as is illustrated by the type log by Riley et al. (2010) from eastern Ohio in Figure 39.

The Medina Group is an unconformity-bound wedge of Lower Silurian clastic sediment deposited in the Appalachian foreland basin. These deposits represent a low frequency (3rd or 4th order) cycle of deposition in which transgressive and high-stand systems tracts are preserved (Castle, 1998). The lower approximate one-half of the Medina Group is composed of the Whirlpool (Medina) Sandstone and the Lower Cabot Head (Power Glen) Shale and is recognized as the transgressive systems tract (TST) for this cycle. The Whirlpool transgressive sandstone is composed of white to light gray, red, fine to very fine-grained quartzose sand that is moderately to well sorted (Wickstrom et al., 2010). This sandstone is gradational up into the Lower Cabot Head Shale and is recognized by the increase in gamma ray response on log (Figure 39). The Lower Cabot Head Shale is dark green to black, marine shale, with thin quartzose, silt and sand laminations that increase in number and thickness towards the upper part of the unit (Wickstrom et al., 2010). The Lower Cabot Head Shale interval is interpreted to represent marine deposition on the shelf during continued eustatic sea-level rise. Sandstone beds do occur in this unit, particularly eastward towards the Taconic highlands, but are of more local extent and probably storm-deposited shelf bars formed below the normal wave base (Castle, 1998).

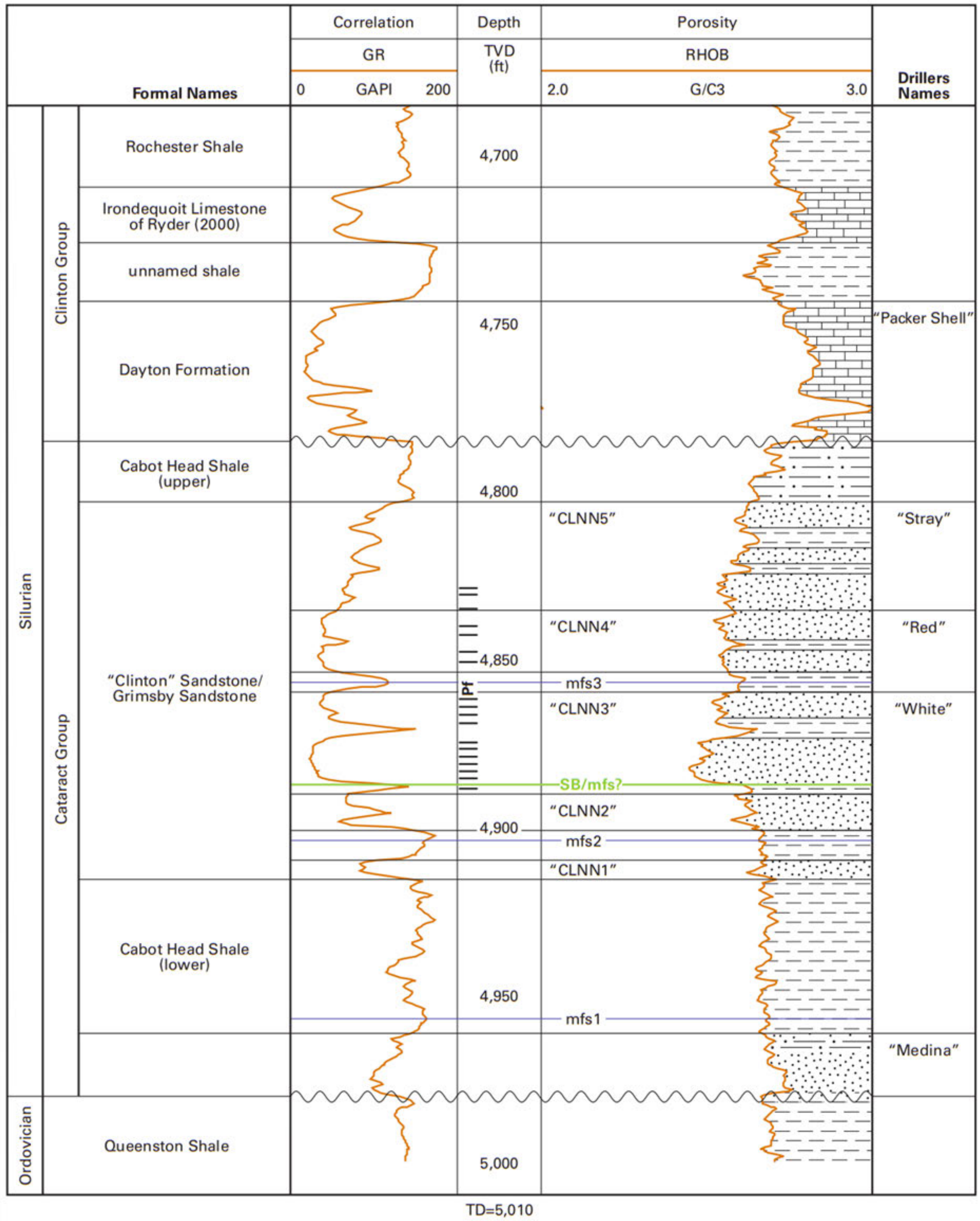

Figure 39: Type log from Riley et al., 2010, of the stratigraphy in the East Canton oil field in Stark County, Ohio (lWell No. 13 in Table 2, location in Figure 18) which directly translates to the project area. The Cataract Group correlates to the Medina Group, as shown in Figure 38 above. Clinton sand intervals identified by the abbreviation "CLNN," wavy line indicates an unconformity surface, and maximum flooding surfaces identified by "mfs."

The upper one-half of the Medina Group is represented by the Grimsby ("Clinton") Sandstone and overlying Upper Cabot Head Shale and is recognized as the high-stand systems tract (HST) for this cycle. The sandstones in the Grimsby Formation are composed of very fine to medium-grained, monocrystalline, quartzose rocks with silty shale interbeds (Wickstrom et al., 2005). The upward, rapidly gradational, change from the Lower Cabot Head Shale into the sandstone rich Grimsby Formation is due to uplift and erosion along the Taconic highlands to the southeast, which initiated a forced regression into the HST. These sandstones were deposited in marine, shoreface/shoreline, and deltaic environments in response to episodic northwest progradation and shallowing, associated with relative base-level drop across the project area (Castle, 1998; Wickstrom et al., 2010). The Upper Cabot Head Shale is composed of argillaceous sandstones and muds interpreted to be intertidal, coastal plains deposits (Castle, 1998). These sediments mark the final shallowing of the Medina Group prior to exposure at the top of the unit, i.e., pre-Dayton Formation transgression.

The Medina Group has multiple sandstone targets for sequestration with interbedded confining zones that segregate the sands into individual flow-units (Figure 38 and Figure 39). The basal Whirlpool Sandstone is typically of poor reservoir quality due to carbonate and dolomite cement (Riley et al., 2010) and is not discussed here; however, this interval will be evaluated for injection viability in the CarbonSAFE stratigraphic test wells and during pre-operational testing. The Grimsby / "Clinton" sandstones are the objective injection intervals based on their rich history of oil and gas production, from Eastern Ohio to Northwestern Pennsylvania.

The "Clinton" sandstones are typically "tight" with respect to porosity and permeability due to early cementation, primarily by silica (quartz overgrowths) as well as accessory hematite, chlorite, carbonate, and evaporite minerals. Porosity is variable based on their heterolithic sand facies. Porosity types include relict primary porosity to microporosity, intra constituent, and secondary porosity from the dissolution of unstable cement components (Wickstrom et al., 2010; Riley et al., 2010). Wickstrom and others (2005) reported a porosity range of 2 to 23% in the "Clinton" sands, with an average of 7.8%. Measurement from core data (Figure 18) near the project area yields an average porosity of ~5%, and permeabilities average ~10 md. Reported permeabilities within the sandstones range from less than 0.1 md to 40 md, although some producing oil fields averaged 100 md with peaks in excess of 200 md (Wickstrom et al., 2010). Fracture porosity and permeability exist, but distribution is poorly understood (Riley et al., 2010). Based on historic oil and gas production, as well as gas storage in "Clinton" sandstone reservoirs, the Medina Group holds good potential for sequestration of miscible CO_2 but due to lithologic variations, detailed characterization of the sandstones will be needed and will be addressed in the pre-operational testing.

Framework grain analysis of rotary sidewall cores from the Ohio Division of Geological Survey CO_2 No. 1 well in Tuscarawas County, Ohio (Well No. 9 in Table 2, location in Figure 18), east of the AoR (Wickstrom, 2011), classify the Medina Group injection interval (referred to as the Clinton) as a Quarzarenite/Sublitharenite with minor feldspar and lithic fragments (<8%) (Table 4). Cements account for 14-18% of the total point count and are predominantly quartz overgrowths with secondary pore filling clays. XRD analysis corroborates the framework grain analysis with 85-92% quartz, 5-13% clay, and minor percentages of other minerals (Table 5). This analysis suggests that there are few mineral constituents that will react with the injected CO_2 stream, though the literature suggests the cements are variable: e.g., quartz, hematite, and carbonate, which may cause dissolution and precipitation of different mineral species. In addition, mineralogic information specific to the project area will be collected during pre-operational testing and as a part of the data collection for the CarbonSAFE stratigraphic wells.

Table 4: Framework Grain Analysis for the Medina Group at the Ohio Division of Geological Survey CO_2 No. 1 well in Tuscarawas County, Ohio (Well No. 9 in Table 2, location in Figure 18). Modified from Wickstrom, 2011.

Measured Depth (ft):	4,771	4,790	4,840
Sample Number:	1-3R	1-5R	1-9R
Grain Size Avg (mm):	0.1	0.11	0.15
Grain Size Range (mm):	<0.01-0.32	<0.01-0.38	0.03-0.32
Sorting:	Moderately well	Moderate	Well
Rock Type:	Quartzarenite	Sublitharenite	Sublith./Subark.
Quartz:	68%	51%	68%
Feldspar:	1%	3%	2%
Lithic FR:	1%	4%	2%
Accessory Grains:	Trace	2%	1%
Environmental Indicators:	2%	3%	Trace
Detrital Matrix:	5%	16%	0%
Cement/Replacement:	18%	14%	18%
Porosity:	5%	6%	9%
TOTALS:	**100%**	**99%**	**100%**

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Table 5: XRD analysis (weight %) for rotary sidewall core (RSWC) collected in the Medina Group at the Ohio Division of Geological Survey CO2 No. 1 well in Tuscarawas County, Ohio (Well No. 9 in Table 2, location n Figure 18). Modified from Wickstrom, 2011.

Measured Depth (ft):	4,771	4,790	4,840
Sample Number:	1-3R	1-5R	1-9R
Chlorite	1%	3%	1%
Kaolinite	1%	1%	Trace
Illite	3%	8%	4%
Mx I/S	Trace	1%	Trace
Total Clay	**5%**	**13%**	**5%**
Calcite	Trace	Trace	0%
Dol/Ank	0%	Trace	2%
Siderite	Trace	Trace	Trace
Total Carbonates	**Trace**	**Trace**	**2%**
Quartz	92%	85%	90%
K-spar	1%	1%	1%
Plag.	1%	1%	1%
Pyrite	1%	Trace	1%
Hematite	Trace	0%	0%
Barite	0%	0%	0%
Total Other Minerals	**95%**	**87%**	**93%**

Based on the static model, the top of the Medina Group in the project area ranges in depth from -6,000 ft (SSTVD) to the west in Ohio to –9,300 ft (SSTVD) to the southeast in Pennsylvania (Figure 40); average depth in the vicinity of the proposed injection wells ranges from ~8,920 to 9,165 ft TVD (Figure 29). Gross thickness of the Medina Group in the Tri-State CCS Hub is relatively uniform, averaging ~180 ft to 200 ft, and at the injection locations in Marshall County, the average thickness is 194 ft (Figure 40 and Figure 29).

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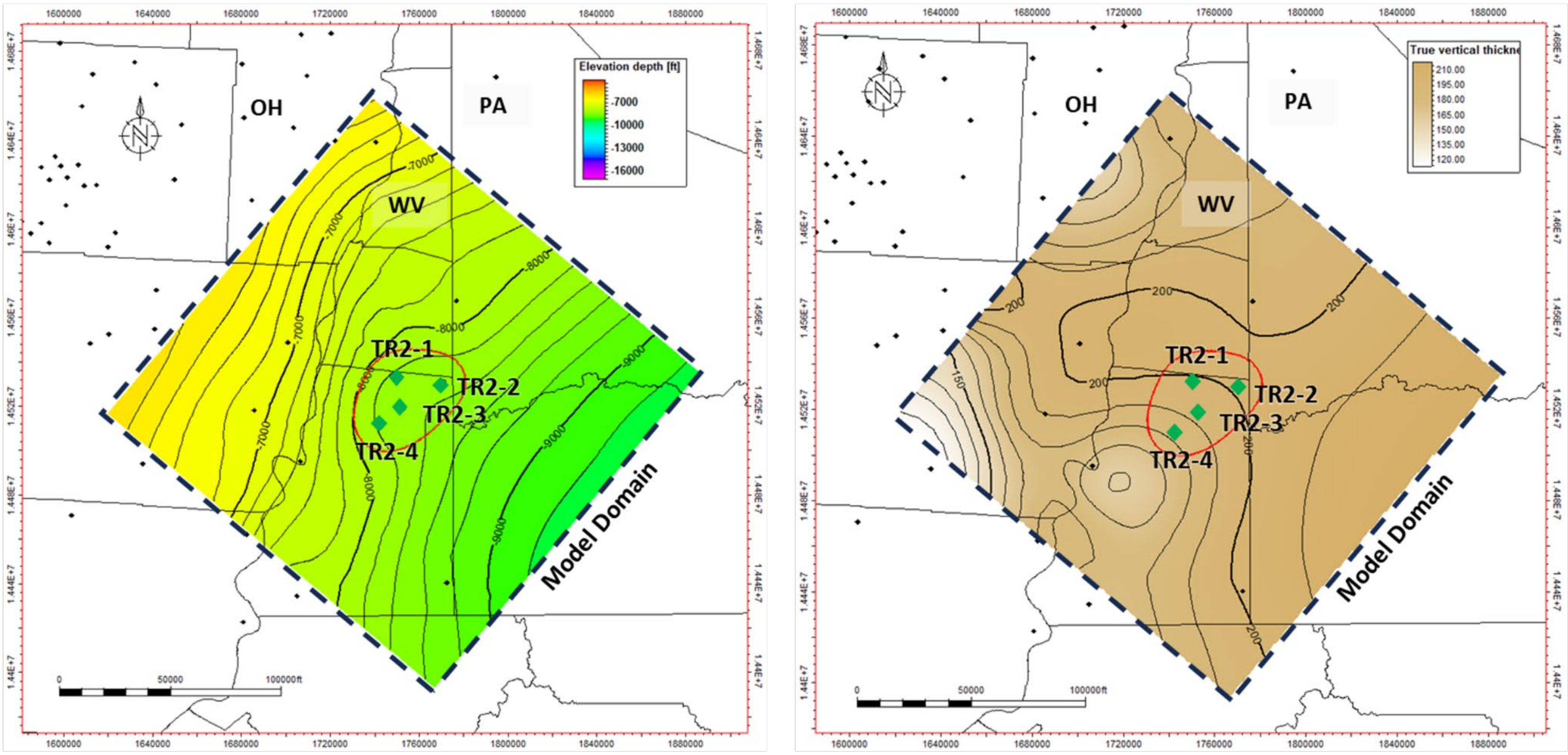
Structure

Isochore



MEDINA GROUP

Legend:

◆ Injection Well

☐ AoR Boundary

⌜⌟ Model Domain

◆ Structural Control

Preparer:

Beth Gergurich

Date of Preparation:

02/11/2024

Operator:

Tri-State CCS, LLC

Location:

Tri-State CCS Redbud 2

Figure 40: Top Structure (left) and Isochore (right) maps of the Medina Group interval (Structure C.I. = 200 ft; depths SSTVD; Isochore C.I. = 20 ft) with the four potential injection sites shown in Marshall County, WV. The static model domain is shown as a black dashed line. Wells used for structural control of the surface and isochore are noted with black diamonds.

2.4.2.3. MIC Primary (lower) Confining Zone: Queenston (Juniata) Shale Formation

The Queenston Shale Formation (OH, PA, NY, ON), also referred to as the Juniata Shale Formation (WV, PA, VA, NY), or the Sequatchie Formation (KY, TN), lies beneath the Medina Group and serves as the basal confining zone for the MIC (Figure 29). Regionally, it has been interpreted as a fluvial and subaerial delta shedding off the Taconic highlands, coined the "Queenston Delta Complex," into transitional and shallow marine environments (Figure 41; Blue, 2011; Brogly, 1984; Dennison, 1976). Brogly (1984) described it at outcrops in Southern Ontario as a siltstone with between 40-70% carbonate, non-aeolian sands, and some gypsum deposited in a supratidal mudflat fed by sediment from a N-S river, while further south, in outcrop in West Virginia, the Juniata Formation is described as a heterolithic red mudstone with coarsening sandstones and conglomerates deposited in the transitional tidal flat to shoreface (Blue, 2011). Figure 41 shows the proposed injection location in Marshall County coinciding with the transition between the coarser, more subaerial deposited Juniata Formation and the transitional marine Queenston Shale Formation (Blue, 2011).

The Queenston Shale Formation is in excess of 1,500 ft thick and at a depth ranging from ~-6,200 to -9,400 ft (SSTVD) in the model area (Figure 42). The top of the Queenston Shale Formation at the proposed injection sites ranges from ~9,550 to 9,600 TVD (Figure 29). In addition, a study investigating the depth of penetration of variable fluids with different viscosities in the Queenston Shale of southern Ontario measured the hydraulic conductivity of water in the Queenston Shale as 1.9×10^{-9} cm/s (23 cm max depth), which would classify it as impermeable (Al-Maamori, et al., 2017). Based on the shale's vast thickness and low permeability, the Queenston Shale is expected to serve as an effective bottom seal for the MIC.

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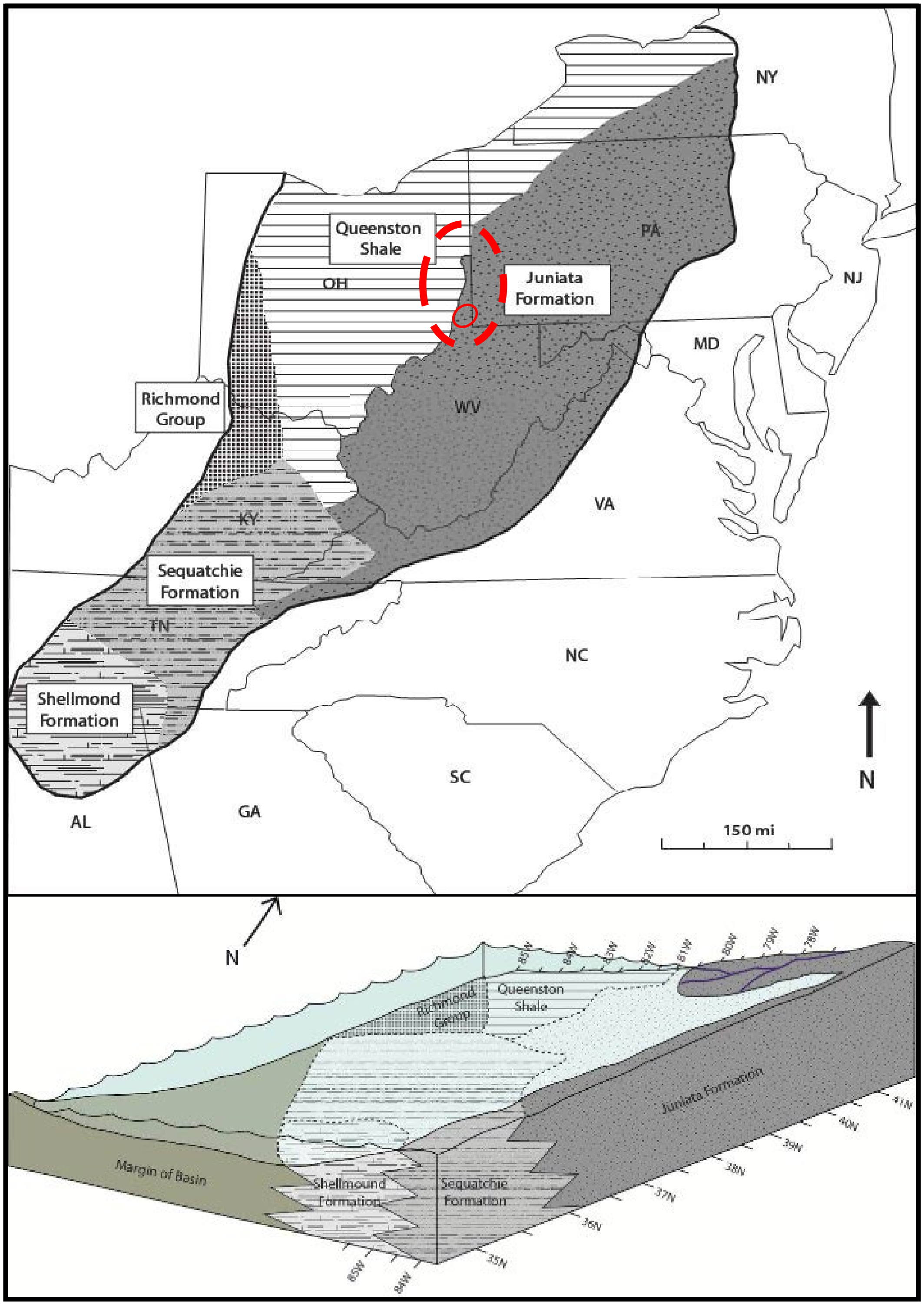
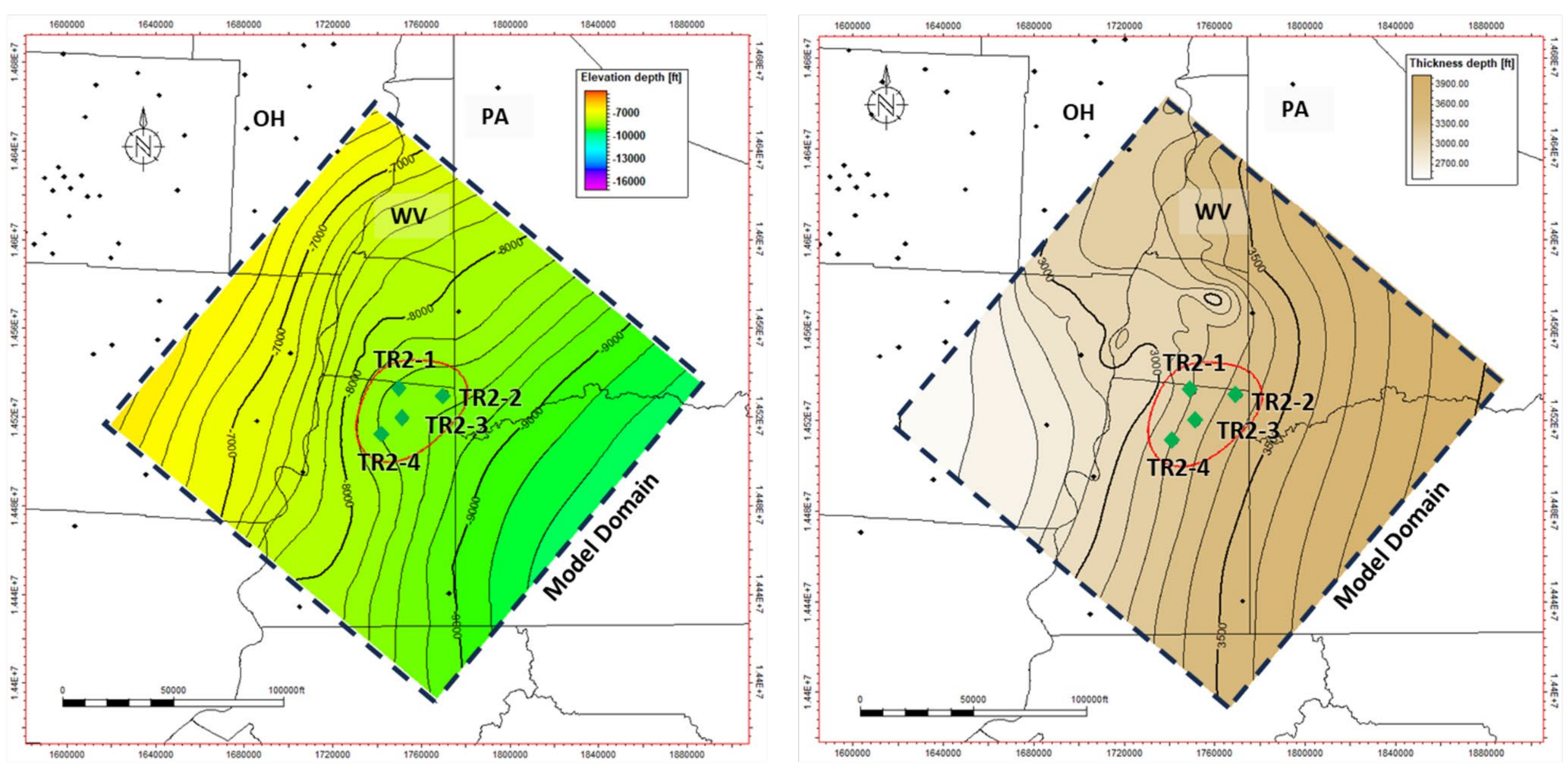


Figure 41: (Upper) Map of late Ordovician formations in the Appalachian Basin and (Lower) depositional systems of the Queenston Shale (modified from Dennison, 1976 and Blue, 2011). The Tri-State CCS Hub location is indicated with a red dashed circle and the approximate AoR with a solid red oval.

Structure **Isochore**



QUEENSTON SHALE FORMATION

Legend:

- ◆ Injection Well
- 🟥 AoR Boundary
- ⬚ Model Domain
- ◆ Structural Control

Preparer:

Beth Gergurich

Date of Preparation:

02/11/2024

Operator:

Tri-State CCS, LLC

Location:

Tri-State CCS Redbud 2

Figure 42: Top Structure (left) of the Queenston Shale Formation and isochore (right) of the Queenston Shale Formation to the top of the Wells Creek Formation interval (Structure C.I. = 200 ft; depths SSTVD; Isochore C.I. = 100 ft) with the four potential injection sites shown in Marshall County, WV. The static model domain is shown as a black dashed line. Wells used for structural control of the surface and isochore are noted with black diamonds.

2.4.3. Secondary Injection Complex for Consideration: Knox Injection Complex (KIC)

A lower stratigraphic interval, the Cambro-Ordovician Knox Group (and members therein), is being considered as a secondary possible injection zone along with the Lockport Dolomite and Medina Groups. This anticipated injection complex, complete with upper and lower confining zones, is shown as "3" in Figure 29. This injection complex was included as a secondary injection complex due to the initial evaluation of the reservoir by the offset data. Should new data collection change the evaluation of this interval to be considered suitable for injection, its status will change. The Knox Group has been the subject of study for CO_2 sequestration (e.g., Wickstrom et al., 2008; Skeen, 2010; Gupta et al., 2020) and will be evaluated in the CarbonSAFE stratigraphic test wells planned in the region.

The Cambro-Ordovician Knox Group, and age-equivalents in other parts of the U.S., has been the subject of evaluation for CO_2 sequestration, e.g., the Illinois Basin (Kirksey et al., 2014) and the Midcontinent region (Watney and Holubnyak, 2017), the Ohio River Valley (Gupta et al., 2005), and likewise, is present in the project area. Here, the Knox Group is composed of three major formations, from bottom to top, the Copper Ridge Dolomite, the Rose Run Sandstone, and the Beekmantown Dolomite. Regionally, the upper confining member to the Knox Injection Complex (KIC) is the Wells Creek Formation and is additionally overlain by the tight limestones of the Black River and Trenton Limestone Groups (Figure 29 and Figure 43). At its base, the KIC is confined by tight carbonates and shales of the Conasauga Group. Cumulative isopach mapping in the project area illustrates the KIC to be an average of ~800 ft thick near the proposed injection wells and thickens to the south-southeast to greater than 1,600 ft (Figure 44).

The Knox Group dolomite sections, the Beekmantown and Copper Ridge Dolomites, are predominantly well-cemented with little to no permeability; however, discrete zones of porosity and permeability exist and are traceable over distance (Greb et al., 2008). In Tuscarawas County, Ohio, measurements of the Rose Run Sandstone rotary sidewall cores had average measured porosities of 4.6% with a high of 16.8% and permeabilities averaging 6.5 md with the maximum of 10.8 md. Intrinsic permeability was measured in three intervals in the well with the middle interval having an intrinsic permeability of 22.1 md (Wickstrom, 2011). The evaluation of the Rose Run Sandstone for the Ohio River Valley CO_2 Storage Project by Gupta et al., (2005) recorded a similar pattern to what was recorded in Tuscarawas County (Figure 43). Porosity was as high as 12% in the sandstone facies, whereas the intervening dolomitic sandstones were closer to 5%. The measured permeabilities mimicked this pattern alternating between highs of as much as 70 md and lows of 0.001 md. The presence of porous units with intervening non-porous and impermeable zones ('aquitards') offers opportunity for numerous intra-Knox sequestration targets as individual flow units, similar to the Wellington Project area in the Midcontinent (Watney and Holubnyak, 2017) and the Ohio River Valley CO_2 Storage Project (Gupta et al., 2005), but could also inhibit injectivity.

Framework grain analysis of the Rose Run Sandstone indicates it is a fine to medium grained quartzose to subarkosic, moderate to well-sorted sandstone with dolomitic cement from samples taken in Northern Kentucky, Western West Virginia, and Eastern Ohio (Table 7; Wickstrom, 2011; Bowersox, 2021). Illite, feldspars, and detrital carbonate occur in varying amounts. XRD analysis shows the Rose Run to be composed of a range of 71-89% quartz, 1-30% pore-filling dolomite cement, 2-6% illite/smectite clays and micas, 1-17% authigenic potassium feldspar, and other trace minerals in Northern Kentucky at the KGS 1 Hanson Aggregates well and the Ohio Division of Geological Survey CO2 No. 1 well in Tuscarawas County, Ohio (Table 6; Wickstrom, 2011; Bowersox, 2021; Well Nos. 94 and 9 in Table 2, locations in Figure 18).

The thick carbonates in the Knox, as well as the sandstones of the Rose Run, offer tremendous potential for sequestration of miscible CO_2 but at this time is considered a secondary sequestration objective due to a paucity of data in the region (Perry et al., 2022). Data collection in the AoR during drilling and pre-operational testing and from the CarbonSAFE stratigraphic wells planned in the region, and seismic acquisition will enable a full evaluation and vetting of potential disposal in the Knox Group in the area.

Table 6: XRD analysis (weight %) for RSWC collected in the Rose Run Sandstone at the Ohio Division of Geological Survey CO2 No. 1 well in Tuscarawas County, Ohio (Well No. 9 in Table 2, location in Figure 18). Modified from Wickstrom, 2011.

Measured Depth (ft):	7,377	7,392	7,441	7,506
Sample Number:	1-37R	1-39R	1-43R	1-47R
Chlorite	1%	1%	1%	1%
Kaolinite	1%	1%	1%	1%
Illite	1%	1%	3%	2%
Mx I/S	1%	1%	1%	1%
Total Clay	**4%**	**4%**	**6%**	**5%**
Calcite	0%	0%	Trace	Trace
Dol/Ank	5%	8%	2%	1%
Siderite	Trace	Trace	Trace	Trace
Total Carbonates	**5%**	**8%**	**2%**	**1%**
Quartz	89%	85%	74%	89%
K-spar	1%	1%	17%	4%
Plagioclase	1%	1%	1%	1%
Pyrite	Tr	1%	Trace	Trace
Hematite	0%	0%	0%	0%
Barite	0%	0%	0%	0%
Total Other Minerals	**91%**	**88%**	**92%**	**94%**

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Table 7: Framework Grain Analysis for the Rose Run Sandstone at the Ohio Division of Geological Survey CO2 No. 1 well in Tuscarawas County, Ohio (Well No. 9 in Table 2, location in Figure 18). Modified from Wickstrom, 2011.

Measured Depth (ft):	7,377	7,392	7,441	7,506
Sample Number:	1-37R	1-39R	1-43R	1-47R
Grain Size Avg (mm):	0.48	0.35	0.31	0.27
Grain Size Range (mm):	0.09-1.09	<0.01-1.06	0.06-1.23	0.03-0.97
Sorting:	Moderately well	Moderate	Moderate	Moderately poor
Rock Type:	Quartzarenite	Quartzarenite	Subarkose	Subarkose
Quartz:	77%	67%	62%	46%
Feldspar:	1%	2%	17%	9%
Lithic FR:	Trace	1%	1%	Trace
Accessory Grains:	0%	Trace	Trace	Trace
Environmental Indicators:	Trace	1%	Trace	1%
Detrital Matrix:	0%	1%	0%	0%
Cement/Replacement:	13%	17%	10%	33%
Porosity:	9%	11%	10%	11%
TOTALS:	100%	100%	100%	100%

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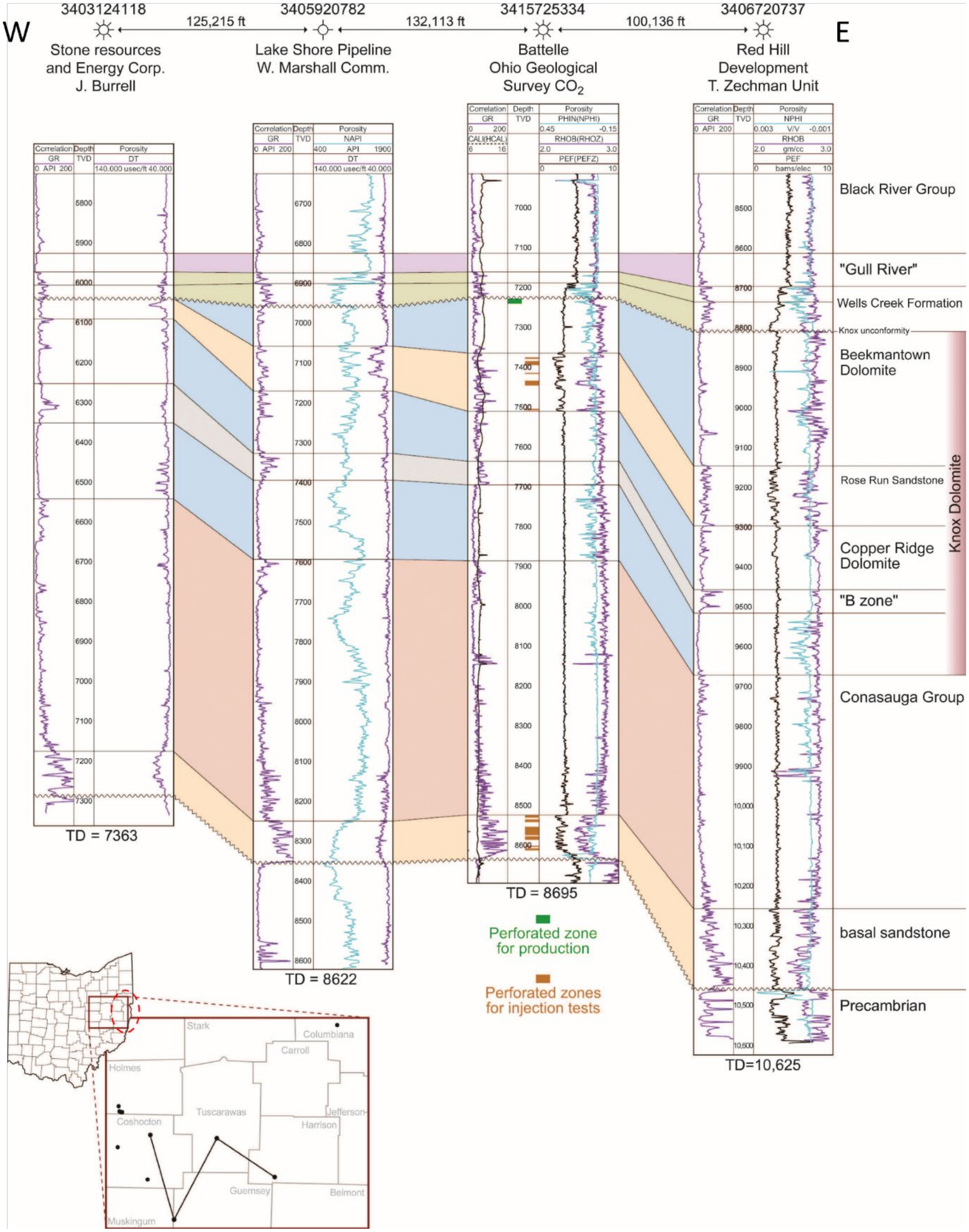

Figure 43: Wireline log cross section of the Knox Group from Coshocton to Harrison County, Ohio. Left track – gamma ray; middle track – depth TVD; right track – porosity, RHOB, and PEF logs. (from Greb et al., 2012). Dashed red oval is the Tri-State CCS Hub.

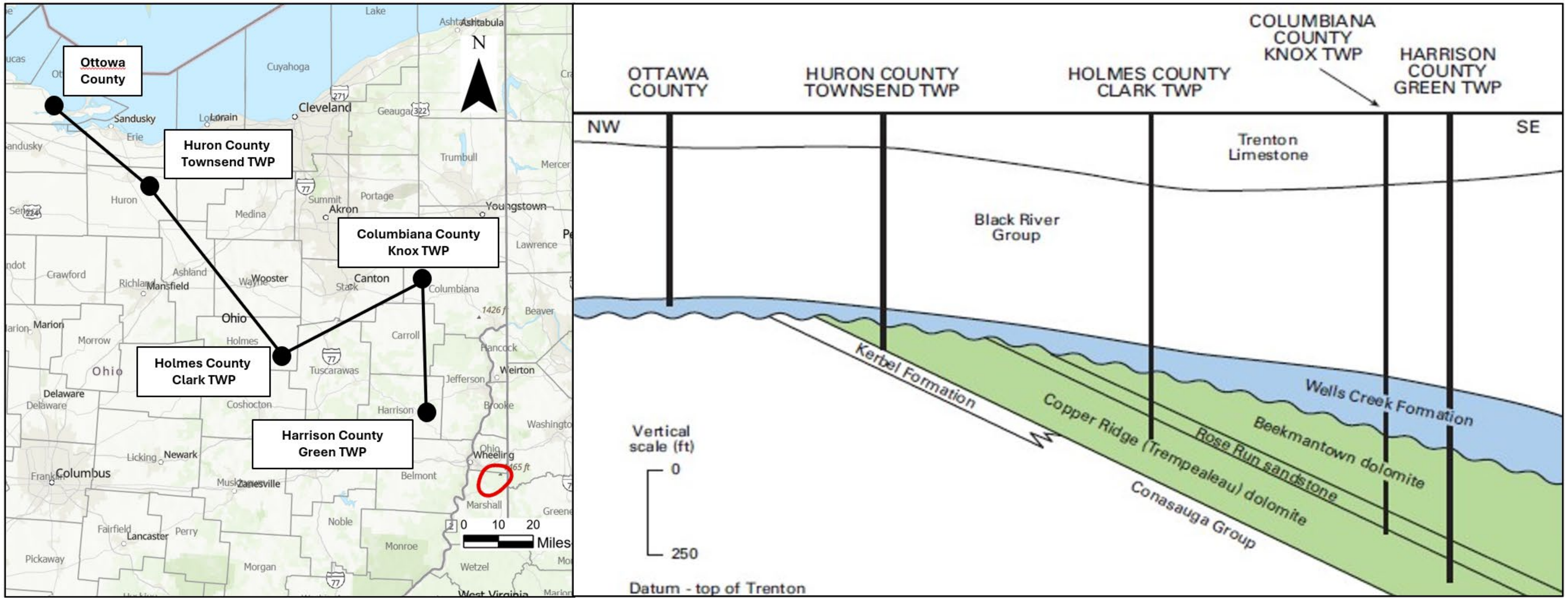

Figure 44: Diagram illustrating the regional thinning, and truncation, of the Knox Group, from west of the project area to the northwest into north-central Ohio, over the Findlay Arch (Wickstrom et al., 2008).

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2.4.4. Uncertainties & Additional Required Information

Given the sparse subsurface data in the project area, data collection will be imperative to appropriately characterize the injection and confining zones. Subsurface characterization in the project area using wireline logs, whole and rotary sidewall core, and 3D seismic will be performed prior to the start of injection. These data will also be collected for the CarbonSAFE stratigraphic wells planned in the region. Additional whole rock data and logging and testing data will be collected as part of the pre-operational testing for the project (see Pre-Operational Testing Program). Successful collection of downhole data, core, and the subsequent tests and measurements will provide greater clarity around current uncertainties in lithology and facies, reservoir properties, including capillary pressure and relative permeability, geomechanics, and mineralogy.

2.4.5. Regional Estimated Injection Zone Storage Capacity

Prospective storage resource estimates for the project were calculated for the Carbonate and Sandstone reservoirs using the methodology detailed in Goodman et al. (2011) and Goodman et al. (2016) for saline formations. This methodology generates storage resource estimates using equations (1) and (2) (from Goodman, 2016):

$$G_{\mathrm{CO2}} = A_{\mathrm{t}} h_{\mathrm{g}} \emptyset_{\mathrm{total}} \rho_{\mathrm{CO2}} E_{\mathrm{Saline}} \qquad \text{(Equation 1)},$$

where E_{saline} is the CO_2 storage efficiency factor that reflects a fraction of the total pore volume that is filled by CO_2,

$$E_{\mathrm{Saline}} = E_{\mathrm{A}} E_{\mathrm{h}} E_{\emptyset} E_{\mathrm{V}} E_{\mathrm{D}} \qquad \text{(Equation 2)},$$

where A is area, h is thickness, $\emptyset$ is porosity, V is volumetric displacement, and d is microscopic displacement.

Prospective storage resource estimates were calculated in Excel using average properties across all reservoir formations within the Tri-State CCS Hub. For the Lockport, Beekmantown, and Copper Ridge Dolomites, gross formation statistics were used to obtain physical characteristics used for the resource estimate. Sandstone intervals were isolated for the Medina and Rose Run formations, and average physical characteristics were calculated for a resource estimate. Due to limited availability of site-specific data, values from the 2017 version of the DOE-NETL CO_2 SCREEN tool were used to calculate saline storage efficiency factors. All physical inputs, storage efficiencies, and assumptions are shown in Table 8. The resource estimate suggests that all reservoir formations, together, may be able to store between 434.1 (P10) to nearly 2,190 (P90) MMt of CO_2. Table 9 details the results of the prospective storage resource calculations.

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Table 8: Parameters used for Calculating Storage Resource Estimates for Reservoir Formations. Note: CO_2 density is based on reservoir conditions using regional gradients. ESaline Storage Efficiency = EvEd (volumetric displacement efficiency) + Ephi (effective porosity) +Eh (net-to-gross thickness). Ean/at (Net-to-total area) is assumed to be 1. Efficiency values obtained from 2017 version of NETL CO_2 Screen Tool for respective depositional environment. Area based on Tri-state CCS Hub.

Resource Estimate Inputs						
Attribute		**Lockport Dolomite Grp**	**Medina Grp**	**Beekmantown Dolomite**	**Rose Run Sandstone**	**Copper Ridge Dolomite**
Mean Reservoir Thickness (m)		367.61	142	567	27	337
Mean Porosity (%)		3	5	3	3	3
Mean CO_2 Density (lb/ft^3)		44	44.1	44.4	44.4	44.5
Area (mi^2)		820				
Depositional Environment		Dolomite Unspecified	Clastic Shallow Shelf	Dolomite Unspecified	Clastic Peritidal	Dolomite Unspecified
Saline Storage Efficiency	**P10**	0.02	0.022	0.02	0.018	0.02
	P50	0.049	0.068	0.049	0.057	0.049
	P90	0.0917	0.162	0.0917	0.1423	0.0917

Table 9: Cumulative and probabilistic scenarios for prospective storage resource estimates for all reservoir formations in the Tri-State CCS Hub based on the regional values.

Reservoir		**Total CO_2 (MMt)**			**Total CO_2 ($MMt/mile^2$)**		
		P10	**P50**	**P90**	**P10**	**P50**	**P90**
LIC	Lockport Dolomite	102.1	247.6	461.2	0.02	0.048	0.09
MIC	Medina Sandstone	71.5	221.1	526.4	0.014	0.043	0.103
KIC	Beekmantown Dolomite	159.2	386.1	719	0.031	0.076	0.141
	Rose Run Sandstone	6.8	21.8	53.9	0.001	0.004	0.011
	Copper Ridge Dolomite	94.5	229.2	426.8	0.018	0.045	0.083
Total Summed Storage		**434.1**	**1,105.8**	**2,187.3**	**0.084**	**0.216**	**0.428**

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2.5. Geomechanical and Petrophysical Information [47 CSR 13-13.8.1.c.4.]

2.5.1. Salina Group Confining Zone Petrophysical Analysis

The Salina Group comprises a group of generally impermeable shales, dolomite, and salts with variable internal stratigraphy. No porosity and permeability data were available from the salt layers; however, permeability of interbedded salts is often taken to be 0 in petrophysical analyses and for this analysis was considered to be approximately 1 nd. One well near the AoR (Well No. 1 in Table 2, location in Figure 18) provided core data in the Salina Group that could be used in the petrophysical analysis (Figure 45). This data comes from the dolomitic layers in the Vernon (Units A and B), Syracuse (Unit F), Camillus (Unit G) and Bass Islands/Bertie. There are no data points from the actual salt layers. The permeability ranges from 0 to 2.45 md, averaging 0.3 md. These measurements are corroborated by the measurements from publicly available core analyses (Table 10; Figure 18). Porosity and permeability data from the Stark County well did not have corresponding logs and therefore could not be used in the petrophysical analysis. Regional data collection from the CarbonSAFE stratigraphic test wells and site-specific data collection during the pre-operational testing program will provide additional detail on the specific internal variability of the Salina Group.

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Claimed as PBI

Figure 45: Representative log section through the Salina Group showing vertical variability of section and locations of core points used in petrophysical modeling. The log display shows the normalized gamma ray curve (far left track), the depth track in feet measured depth, the porosity curves, the lithology track resulting from the petrophysical mineral model, the calculated porosities with core data points and the calculated permeability curve with core data points (far right). Data are from API No. 34013205860000 (Well No. 1 inTable 2, location in Figure 18).

2.5.2. Lockport Dolomite Group Injection Complex Petrophysical Analysis

Minimal core data was available for constructing a petrophysical model of the Lockport Dolomite Group. Four samples from two wells were available, of which the two from API No. 34013205860000 (Table 10; Well No. 1 in Table 2, location in Figure 18) were used in the analysis. Given the paucity of data, geophysical well logs, including the gamma ray, bulk density, and neutron porosity logs, were used to build a petrophysical model and yield porosity estimates. Carter et al., 2010 provided nine porosity and permeability data points from the Lockport Dolomite Group from two wells, the Johnson #1 in Pennsylvania, and the Ocel #1 in Ohio (Well Nos. 11 and 10, respectively, locations in Figure 18). This data set was used to model permeability as a function of porosity in the Lockport Dolomite Group.

The data set in this petrophysical analysis included a total of 13 sample points (four from the database and 9 from publications) through the Lockport Dolomite Group. To match the petrophysical model to core, one well (Well No. 1 in Table 2, location in Figure 18) with geophysical well logs and core data was used, with two samples within the Lockport Dolomite Group.

Given our current best estimate approach, we utilized a basic three-mineral system to estimate the mineralogy of the Lockport Dolomite Group. The gamma ray curve provided insights into clay content, and in the absence of photoelectric factor logs, we employed a neutron-density cross plot to determine the relative abundance of calcite and dolomite. The model's results were considered reasonable and will be compared to results from pre-operational testing of the injection wells which will include mineralogic, porosity, permeability, and facies data. The carbonate lithology is variable throughout the Lockport Dolomite Group, as shown in Figure 46, and it is expected that the pre-operational testing program will add significantly to the understanding of the mineralogical system and its calibration to core, and the petrophysical model will be updated if significant changes are found from the current petrophysical model.

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Claimed as PBI

Figure 46: Representative log section through the Lockport Dolomite Group showing vertical variability of section and locations of core points used in petrophysical modeling The log display shows the normalized gamma ray curve (far left track), the depth track in feet measured depth, the porosity curves, the lithology track resulting from the petrophysical mineral model, the calculated porosities with core data points and the calculated permeability curve with core data points (API No. 34013205860000; far right track Well No. 1 in Table 2, location in Figure 18).

2.5.3. Rochester Shale Formation Confining Zone Petrophysical Analysis

The Rochester Shale Formation comprises two members, the lower Lewiston Member and the upper Burleigh Hill Member. Both members are predominantly mudstone with some more carbonate-rich sections (Figure 47). The mudstone packages of the lower and upper section are 46 ft and 194 ft thick, respectively, with local variation possible within a few feet. Porosity and permeability have been assigned to the Rochester Shale Formation based on log evaluation. Two different log evaluation approaches have been used to assess the porosity and permeability, focused on the mudstone sections. The porosity of both members is found to be approximately 1%, and using Yang and Aplin (2010), this yields a corresponding permeability of < 0.001 nd, or < 2 nd using Byrnes (2005).

The more carbonate-rich sections of the Rochester Shale Formation have marginally higher porosity and permeability than is seen in the mudstone sections, up to 0.3 nd and 500 nd using Yang and Aplin (2010) and Byrnes (2005), respectively. However, this permeability is still quite low and is not expected to be vertically or horizontally connected.

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Figure 47: Representative log section through the Rochester Shale Formation showing vertical variability of section and locations of core points used in petrophysical modeling. The log display shows the normalized gamma ray curve (far left track), the depth track in feet measured depth, the porosity curves, the lithology track resulting from the petrophysical mineral model, the calculated porosities with core data points, and the calculated permeability curve with core data points (API No. 34013205860000; far right track Well No. 1 in Table 2, location in Figure 18).

2.5.4. Medina Group Injection Complex Petrophysical Analysis

Nine wells with core data, including some combination of bulk density, grain density, porosity, water saturation, and permeability, were used to build the petrophysical models. The locations of these wells range from approximately 5 to 81 miles from the project area. Of the nine, only two wells, API Nos. 34019202560000 and 34013205860000 (approximately 54 and 5 miles from the project area, respectively), had geophysical well logs to test the fit of the model against core data. Based on geophysical well log response, the core data covered a gradient from low porosity silty mudstone/mudstone to higher porosity clean sandstone. The core data set did not include any mineralogy data.

Eighty wells in the region (including the two wells with core data) had sufficient well log data over the Medina Group to produce and run a petrophysical model and estimate porosity and permeability. Data from the gamma ray and bulk density logs were used to calculate these parameters. Permeability calculations in the Medina Group were made using equations defined by Byrnes (2005) using data generated by Castle and Byrnes (1998, 2005) on the Medina Group in northwestern Pennsylvania, adjacent to the project.

The data set included a total of 428 sample points through the Medina Group section. To match the petrophysical model to core, two wells with geophysical well logs and core data were used, API No. 34019202560000 with 93 samples and API No. 34013205860000 with 7 samples across the Medina Group (Figure 48; see Well No. 1 and 2 in Table 2, location in Figure 18).

A basic two-mineral system was used to estimate the mineralogy of the Medina Group section. The gamma ray curve was used to estimate clay content and the balance was assigned to quartz. Such a model was able to adequately match porosity (and grain density) data where available, suggesting the assumptions of basic mineralogy are representative of the formation. Using this two-mineral system, the top of the section is notably less permeable and is estimated to have a higher clay content than the lower Medina Group, which is consistent with the core measurements from the two different parts of the section.

Mineralogic data will be collected from the CarbonSAFE stratigraphic test wells planned in the region and during the pre-operational testing program at the injection locations to verify the model. The additional mineralogical detail collected will provide information about the variation in clay types and give insight into the likely impact on matrix behavior in the injection zone.

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Claimed as PBI

Figure 48: Representative log section through the Medina Group showing vertical variability of section and locations of core points used in petrophysical modeling. The log display shows the normalized gamma ray curve (far left track), the depth track in feet measured depth, the porosity curves, the lithology track resulting from the petrophysical mineral model, the calculated porosities with core data points, and the calculated permeability curve with core data points (API No. 34013205860000; far right track Well No. 1 in Table 2, location in Figure 18).

2.5.5. Queenston Shale Formation Confining Zone Petrophysical Analysis

The Queenston Shale Formation is a regionally extensive shale, which is also referred to as the Juniata Shale Formation (WV, PA, VA, NY) or the Sequatchie Formation (KY, TN). In the project area, the deposition coincides with transitional marine shales and the subaerial facies of the Juniata Shale Formation (heterolithic red mudstone with coarsening sandstones and conglomerates deposited in the transitional tidal flat to shoreface). The Queenston Shale Formation is more than 1500 ft thick in the project area, with generally low porosity and permeability associated with the shale members of the unit.

Few local core-based measurements of the Queenston Shale Formation are available, with only one well (API No. 34013205860000; Table 10; Well No. 1 in Table 2, location in Figure 18) having porosity and permeability reported (3% and 0 md, respectively). Nevertheless, the extensive thickness of the shale is expected to form a robust confining unit. Regional data collection from the CarbonSAFE stratigraphic test wells and site-specific data collection during the pre-operational testing program will provide additional detail on the specific internal variability of the Queenston Shale Formation and provide detailed petrophysical information on the different members.

Table 10: Core-based porosity and permeability measurements for confining and injection units. Locations and API Nos. in Figure 18 and Table 2.

Formation	Porosity (decimal)	No. pts.	Permeability (md)	No. pts.	Wells
Salina Group	0.048	39	5.46	38	1
Lockport Dolomite Group	0.051	2	1.38	1	2
Rochester Shale Formation	0.060	1	0.00	1	1
Medina Group	0.046	388	8.26	339	9
Queenston Shale Formation	0.030	1	0.00	1	1

2.5.6. Geomechanics

2.5.6.1. Proposed Geomechanical Studies

A series of geomechanical studies under the CarbonSAFE initiative will be conducted to address key questions regarding the geomechanical properties of the confining zone intervals. Cores collected from the stratigraphic test wells proposed for this program will provide measurements of rock strength and ductility for the confining zone intervals. The following geotechnical tests will be conducted on each confining zone interval:

- Triaxial compression – ductility;
- Triaxial compression – failure;
- Mohr-Coulomb criterion - failure envelope analysis; and
- Brazilian test - tensile analysis.

The stratigraphic test wells and core samples will also allow for detailed fracture analysis. Pore pressure of the confining zones and in situ local stress measurements will also be made available with the stratigraphic test wells.

2.5.6.2. Regional Stress State

Orientation of the maximum horizontal stress state in the region is available from a variety of data sets and compiled in the world stress map and regional studies of the Appalachian basin (Morris et al., 2017; Heidbach et al., 2018; Brudzinski and Kozlowska, 2019). The orientation of the maximum horizontal stress in northern West Virginia is generally ENE-WSW and exhibits a mix of tensors from focal mechanism solutions that place it in the strike-slip or thrust faulting regimes (Morris et al., 2017). According to Morris et al. (2017), the combination of coexisting thrust-faulting and strike-slip faulting regimes indicates that the intermediate principal stress component (σ_2) is closer in magnitude to the minimum principal stress component (σ_3) than it is to the maximum principal stress component (σ_1), and that the stress difference ratio (φ) is less than 0.5, where:

$$\varphi=(\sigma_2 - \sigma_3)/(\sigma_1 - \sigma_3). \qquad \text{(Equation 3).}$$

2.6. Seismic History [47 CSR 13-13.8.1.c.5.]

The USGS ANSS (Advanced National Seismic System) Comprehensive Earthquake Catalog network was used to provide the historical seismicity record for the AoR locally and regionally (Figure 49 and Figure 50; USGS, 2023). Regional historical seismicity was considered for a 50-mi radius around the approximate center of the AoR for a 40-year time period (extending from December 1984 to December 2024) with a magnitude greater than M2.5 (Figure 51; USGS, 2023).

The project is located within an area of relatively low seismicity. In the AoR, there is no known source of natural seismicity that would compromise the containment of CO_2. The surrounding region of the northern tip of West Virginia, southeastern Ohio, and southwestern Pennsylvania has a very low risk of damaging seismic activity, while western Ohio lies on the edge of the New Madrid Seismic Zone and the Anna Seismic Zone, and northeastern Ohio contains the Northeast Ohio Seismic Zone, both of which have increased activity (Dart and Hansen, 2008). However, very few of the earthquakes that have historically occurred are known to be associated with faults (Dart and Hansen, 2008). Pennsylvania has a very low risk of seismic activity, and Southern West Virginia touches the outer edge of the Giles County Seismic Zone, though it is unlikely that it will have an effect on the project area (Figure 49 and Figure 50).

The USGS-published National Seismic Hazard Map shows the frequency of damaging earthquake shaking expected in a 10,000-year period (Figure 49). Based on this information, the AoR is considered to have the lowest risk of damaging earthquakes on the scale, with fewer than two expected within a 10,000-year period. The surrounding region also has a comparatively low risk of two to four damaging earthquakes expected within a 10,000-year period. According to the USGS, damaging earthquakes are identified as those that have a of Modified Mercalli Intensity (MMI) of level VI (6) or higher. They are characterized by “strong” shaking and “*felt by nearly everyone, many awakened. Some heavy furniture moved; few instances of fallen plaster. Damage slight”* (USGS, 2023).

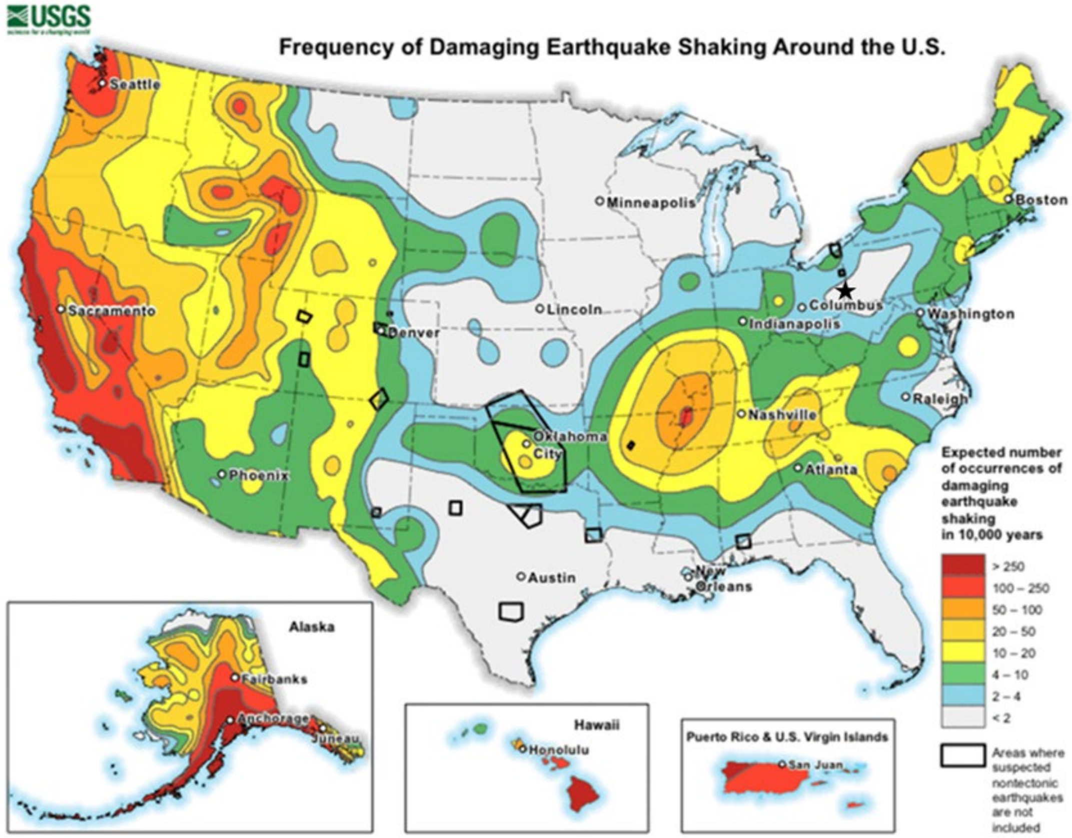
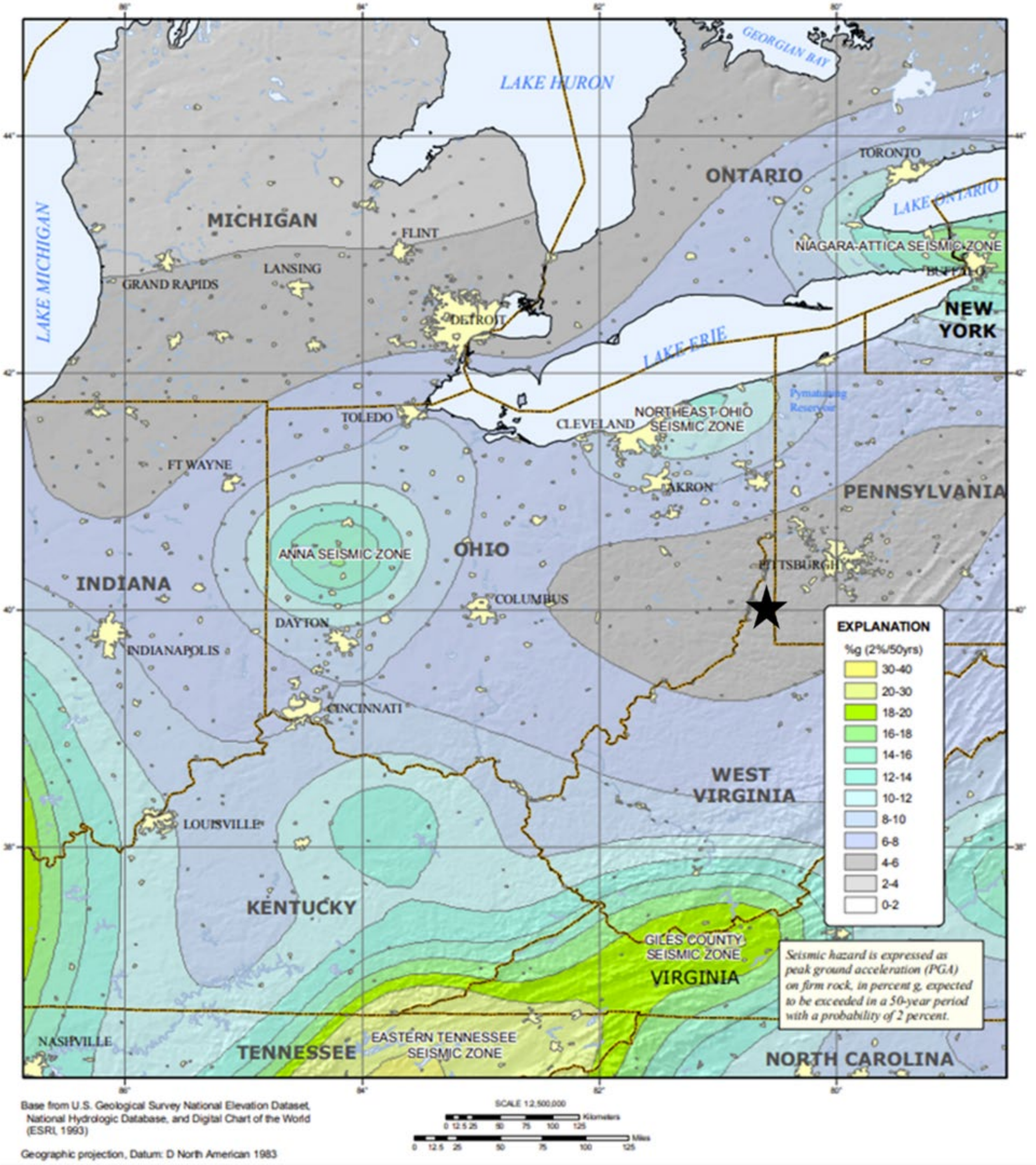


Figure 49: USGS Seismic Hazard Map, showing the frequency of damaging earthquake shaking within a 10,000-year period (Petersen et al., 2008). The project area is indicated by the star on the map in the tri-state region of West Virginia, Ohio, and Pennsylvania.

The Appalachian Basin of Northern West Virginia, where the project is located, is a region of low natural seismicity, with any earthquakes that do occur being of low magnitude. Peak ground acceleration (as a percentage of the gravity constant 9.8 m/s^2) with a 2% likelihood of being exceeded within a 50-year period is illustrated for the region in Figure 50. The peak ground acceleration for the project area is estimated to be 4 to 6 percent of gravity, which would correlate to a Modified Mercalli Intensity of IV-V (light to moderate shaking with limited damage to unstable or delicate objects).

Historically, the Northeast Ohio seismic zone, north of the AoR, has recorded few moderate earthquakes per decade, but felt earthquakes have been reported more frequently in recent decades, likely due to induced activity. The largest earthquake in this zone, with a magnitude of 5.0, occurred in 1986. This seismic event created Modified Mercalli intensities of VI in the region. Another damaging earthquake with a magnitude of 5.2 occurred in 1998 in northwestern Pennsylvania, just east of the border with Ohio (Dart and Hansen, 2008). Within 50 miles of the injection locations, there have been seven earthquakes and five seismic events caused by explosions in the last 40 years (Figure 51). The location, magnitude, and distance from the AoR for each of these earthquakes and explosions is in Table 11.



Seismic hazard is expressed as peak ground acceleration (PGA) on firm rock, in percent g, expected to be exceeded in a 50-year period with a probability of 2 percent.

Base from U.S. Geological Survey National Elevation Dataset, National Hydrologic Database, and Digital Chart of the World (ESRI, 1993)

Geographic projection, Datum: D North American 1983

Figure 50: Seismic Hazard Map of West Virginia, Ohio, and surrounding states from the USGS National Seismic Hazard Maps illustrating the peak ground acceleration with a 2% likelihood of being exceeded within a 50-year period (U.S. Geological Survey). The project is indicated with a star on the map.

The Emergency and Remedial Response Plan (ERRP) includes information on conducting a formal risk assessment of potential risk scenarios, including microseismic events that could potentially be associated with industrial activities.

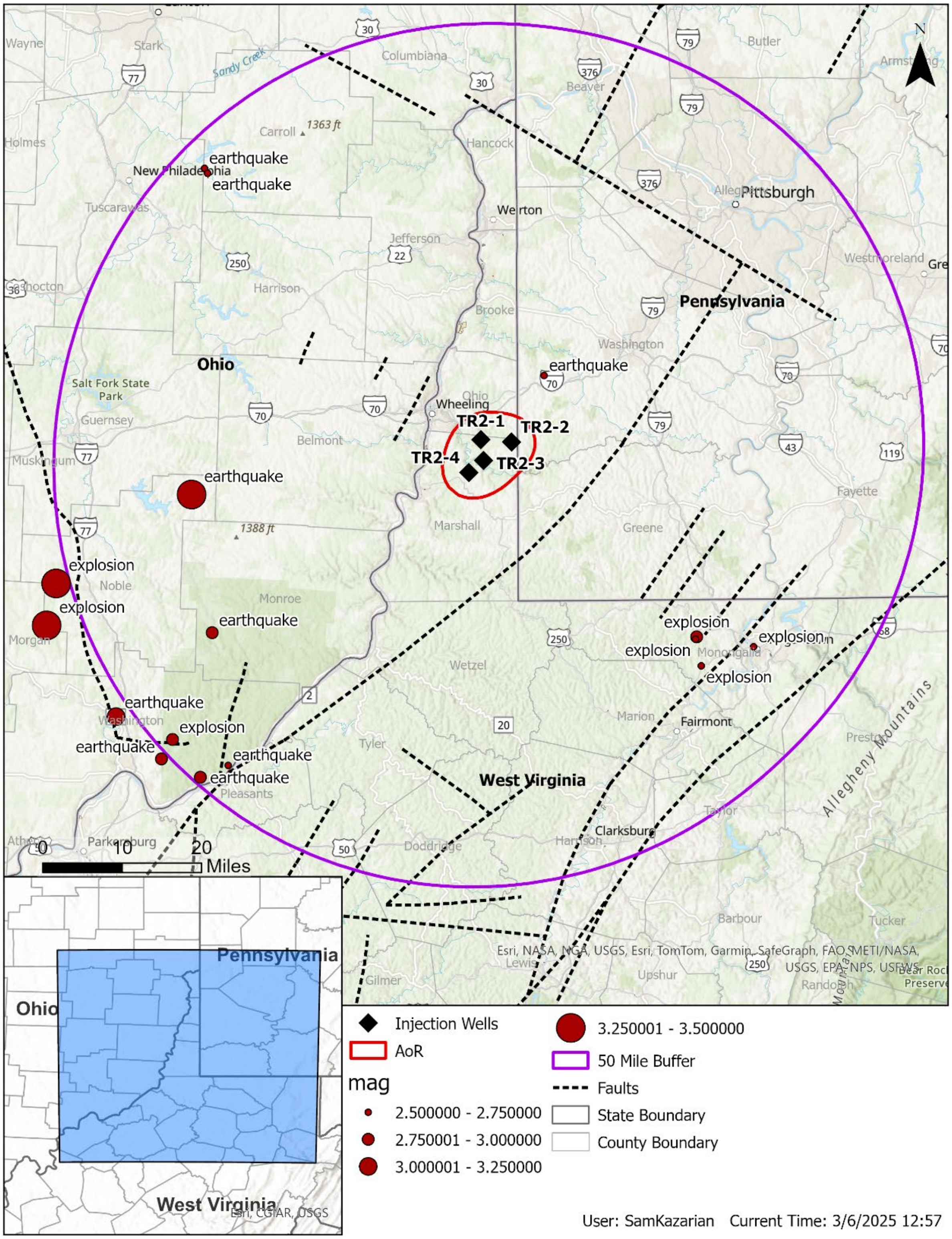


Figure 51: Local seismic events within 50 miles radius of the AoR.

Table 11: Seismic events within 50 miles of the AoR over a 40-year period.

Date	Latitude (WGS 84)	Longitude (WGS 84)	Depth (km)	Magnitude	Distance to AoR (mi)	Type
9/11/2024	40.1327	-80.4549	4.348	2.5	7.71	earthquake
11/19/2021	40.5121	-81.265	5	2.6	46.5	earthquake
10/28/2021	40.5029	-81.2577	5	2.6	45.8	earthquake
6/3/2017	39.9166	-81.2934	1.73	3.4	32.9	earthquake
4/3/2017	39.6644	-81.2434	3.93	3	36.1	earthquake
9/4/2011	39.422	-81.205	5	2.6	45.7	earthquake
8/31/2011	39.4	-81.27	5	2.8	49.2	earthquake
5/7/1998	39.634	-79.964	0	2.5	37.7	explosion
5/6/1998	39.6	-80.088	0	2.6	34.6	explosion
10/15/1997	39.469	-81.336	0	3	48.2	explosion
9/24/1997	39.653	-80.098	0	2.9	31.6	explosion
6/18/1997	39.649	-80.101	0	2.5	31.6	explosion

Since the early 2010s, the Eastern Ohio area of the Appalachian Basin has experienced a significant increase in induced seismic activity, which has been linked with the operations associated with the intensification of unconventional gas extraction conducted in the basin (Skoumal et al, 2018; Brudzinski and Kozłowska, 2019), more specifically, hydraulic fracturing and the disposal of the wastewater associated with production from the Utica Shale (Skoumal et al, 2018). Several known occurrences of induced seismicity have occurred in and around Youngstown, OH, approximately 42 miles northeast of the AoR. This seismicity is concentrated in a corridor from eastern Ohio and into central West Virginia, which may be due to geologic variations in the subsurface or extraction operations.

Several regional studies have documented the importance of the proximity to Precambrian basement when considering the possibility of induced microseismicity as related to wastewater disposal wells and hydraulic fracturing. In general, the low permeability of the Precambrian basement rock as compared to the relatively higher permeability of fractured basement rocks and pre-existing faults is interpreted to be a key factor in the potential for fault reactivation (Morris et al., 2017). Additionally, the proximity to critically stressed and optimally oriented faults that are pre-existing in basement lithologies is thought to impact the likelihood of induced recordable seismicity (Skoumal et al., 2018). Considering these factors, Skoumal et al. (2018) suggests that injection within 3,280 ft, or 1,000 m, of basement has the greatest risk of inducing seismicity. The Medina Group injection complex, the shallow target in the project, is greater than 4,000 ft above the Precambrian basement rocks and, therefore, is not interpreted to be a risk for induced microseismicity.

To date, there have been no known induced seismic events in northern Marshall County, WV, and the historical seismicity record suggests that the proposed storage location is not in a seismically hazardous location. Thus, loss of containment due to seismicity is considered a low risk.

2.7. Hydrologic and Hydrogeologic Information [47 CSR 13-13.8.1.e.]

The AoR is located within the Appalachian Plateau physiographic province in the Ohio River Watershed (Upper Ohio-Wheeling HUC 8 subbasin 05030106). The Upper Ohio-Wheeling subbasin covers approximately 1,511 square miles. Surface water features are dominated by the Ohio River bordering Marshall County, WV to the west and its tributaries. Overall, the hydrology of the region is largely influenced by seasonal precipitation, snowmelt, and groundwater recharge.

The two types of groundwater sources in the area are the Quaternary Alluvial aquifers and the Lower Permian to Upper Mississippian age sedimentary bedrock aquifers of the Appalachian Plateaus. The Quaternary Alluvial aquifers consist of clay, sand, silt, and unconsolidated gravel and are generally unconfined. The bedrock aquifers are generally confined and dip gently to the southeast, with slightly folded, flat lying beds of conglomerate, sandstone, shale, siltstone, and coal, with local beds of dolomite and limestone (Wunsch, 1992). A generalized stratigraphic column of the Appalachian Basin near the AoR is shown in Figure 52 and a cross-sectional view is shown in Figure 22.

The bedrock aquifers are grouped into six units: the Dunkard Group, Monongahela Group, Conemaugh Group, Allegheny Group, Pottsville Group, and the Mauch Chunk Group. Each of these units has various layers of aquifer and aquitard materials described further in the following subsections.

2.7.1. Hydrogeologic Description

EPA defines a USDW as having less than 10,000 ppm Total Dissolved Solids (TDS). Water quality samples reported by the West Virginia Department of Environmental Protection from aquifers in the area are sparse and from shallow (<200 ft bgs) sampling points. All measured less than 10,000 ppm TDS. Thus, the determination of the lowermost USDW for the project was based on saltwater/freshwater interface mapping done by the USGS in 1980 (Foster, 1980), lithologic well logs from the West Virginia oil and gas well database, and historical oil/gas extraction and subsequent brine water injections to deeper formations.

The following description of freshwater aquifers in the area, which comprise the USDWs, is explained from shallowest to deepest formation. This section describes the generalized stratigraphic section from the ground surface to the bottom of the Mauch Chunk Formation, considered to contain the base of freshwater, and is also defined as the lowermost USDW in the AoR. An illustration of this stratigraphic section is shown as Figure 53.

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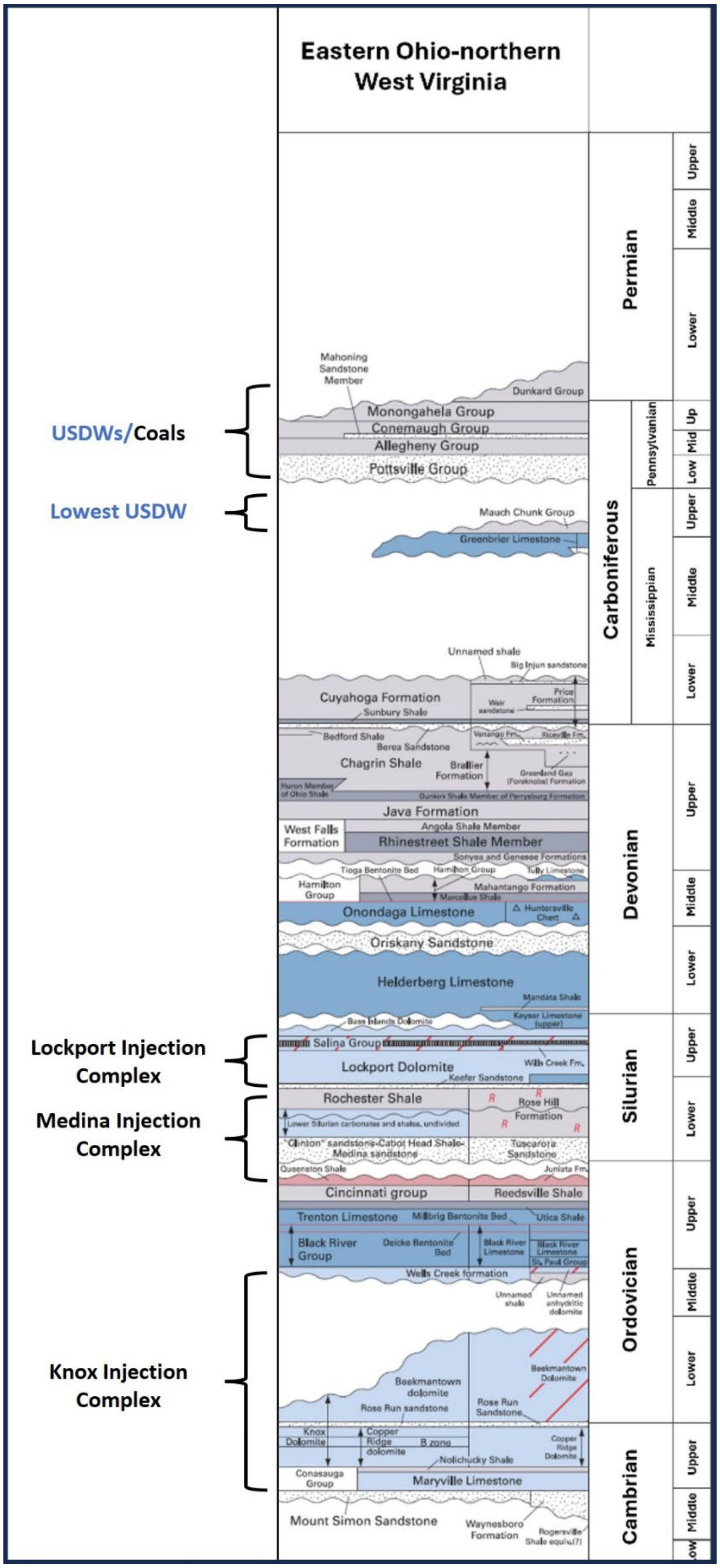
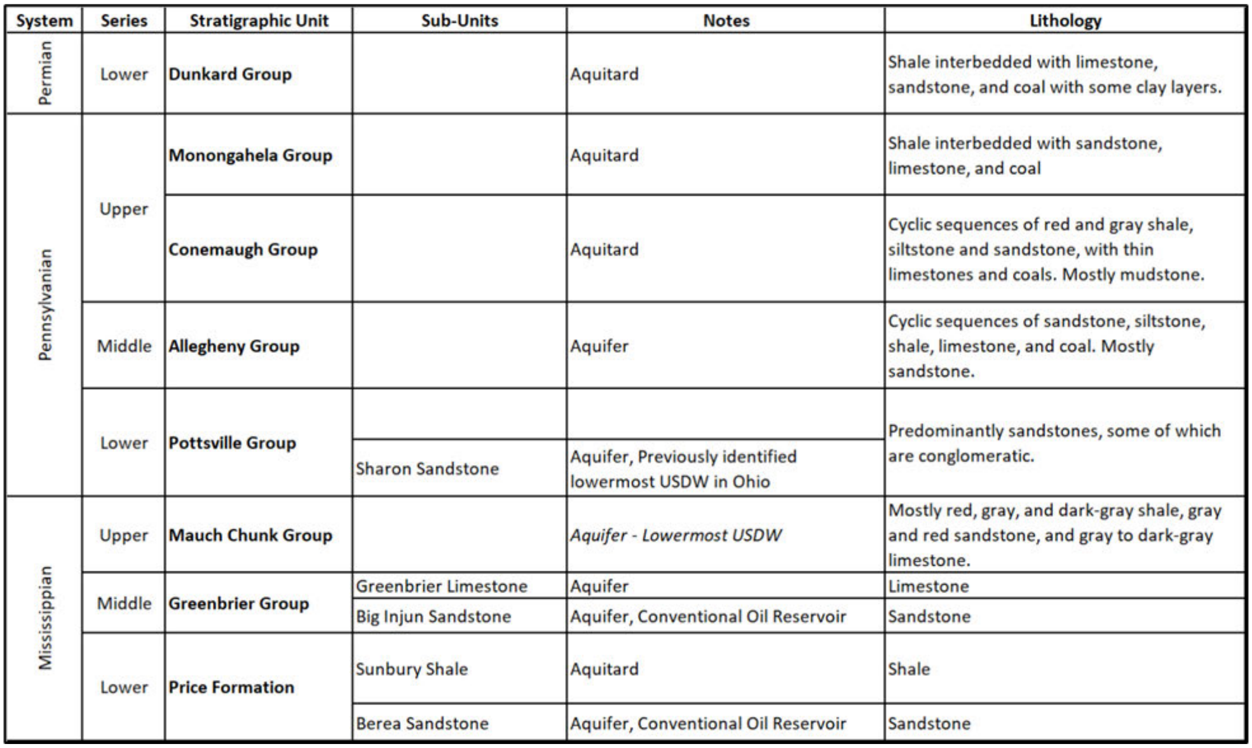


Figure 52: Geologic stratigraphic section in the project area near the AoR. Adapted from USGS map (Ryder, 2009).



System	Series	Stratigraphic Unit	Sub-Units	Notes	Lithology
Permian	Lower	**Dunkard Group**		Aquitard	Shale interbedded with limestone, sandstone, and coal with some clay layers.
Pennsylvanian	Upper	**Monongahela Group**		Aquitard	Shale interbedded with sandstone, limestone, and coal
		Conemaugh Group		Aquitard	Cyclic sequences of red and gray shale, siltstone and sandstone, with thin limestones and coals. Mostly mudstone.
	Middle	**Allegheny Group**		Aquifer	Cyclic sequences of sandstone, siltstone, shale, limestone, and coal. Mostly sandstone.
	Lower	**Pottsville Group**			Predominantly sandstones, some of which are conglomeratic.
			Sharon Sandstone	Aquifer, Previously identified lowermost USDW in Ohio	
Mississippian	Upper	**Mauch Chunk Group**		*Aquifer - Lowermost USDW*	Mostly red, gray, and dark-gray shale, gray and red sandstone, and gray to dark-gray limestone.
	Middle	**Greenbrier Group**	Greenbrier Limestone	Aquifer	Limestone
			Big Injun Sandstone	Aquifer, Conventional Oil Reservoir	Sandstone
	Lower	**Price Formation**	Sunbury Shale	Aquitard	Shale
			Berea Sandstone	Aquifer, Conventional Oil Reservoir	Sandstone

Figure 53: Generalized stratigraphic column from the AoR illustrating the freshwater aquifers and lowermost USDW.

2.7.1.1. *Quaternary Alluvium*

The uppermost aquifer unit in the AoR is the unconsolidated quaternary alluvial deposits of the Ohio River and its tributaries. This aquifer is the most productive unit in the area and has a median transmissivity of 4,800 ft^2/d throughout West Virginia (Kozar and Mathes, 2001). Most of the Public Water Supply systems in the area utilize this aquifer for their water supply. Alluvium, consisting of stream-deposited or glacially deposited sand, clay, and gravel typically overlain by fluvial silts and clays, is found in the river terraces within the Ohio Valley. The thickness of alluvium in the county can exceed 100 ft (Shultz, 1988).

2.7.1.2. *Dunkard Group*

Marshall County lies within the northern part of the Lower Permian and Upper Pennsylvanian Dunkard Basin. This aquifer has a median transmissivity of 130 ft^2/d (Kozar and Mathes, 2001). The Dunkard Group reaches a thickness of around 1,150 ft in the county and is made up of shale interbedded with limestone, sandstone, and coal with some clay layers (Shultz, 1988).

2.7.1.3. *Monongahela Group*

The Monongahela Group has a maximum thickness of 300 to 350 ft in the county. The Monongahela Group extends from the top of the Waynesburg coal to the base of the Pittsburgh coal and is comprised of shale interbedded with sandstone, limestone, and coal (Shultz, 1988). This aquifer has a median transmissivity of 150 ft^2/d (Kozar and Mathes, 2001).

2.7.1.4. Conemaugh Group

The Conemaugh Group is Upper Pennsylvanian in age and mostly non-marine in origin. The group mainly consists of mudstones with cyclic sequences of red and gray shale, siltstone, and sandstone, with thin limestones and coals (Cardwell, 1968). This aquifer has a median transmissivity of 170 ft^2/d (Kozar and Mathes, 2001). The Conemaugh Group extends from the base of the Pittsburgh coal to the top of the Upper Freeport coal and is around 475 to 575 ft in thickness (Shultz, 1988). The group also includes the Elk Lick, Bakerstown, and Mahoning coals, as well as the Ames and Brush Creek Limestones.

2.7.1.5. Allegheny Group

The Allegheny Group comprises mostly sandstone with cyclic sequences of siltstone, shale, limestone, and coal (Cardwell, 1968). The group is Middle Pennsylvanian in age and is known as a major coal bearing unit. The group includes the Freeport, Kittanning, and Clarion coals. The Allegheny Group extends from the top of the Upper Freeport coal to the top of the Homewood Sandstone. This aquifer has a median transmissivity of 850 ft^2/d (Kozar and Mathes, 2001). Within the area, the thickness of this group can exceed 300 ft.

2.7.1.6. Pottsville Group

The Pottsville Group consists of predominantly sandstones, some of which are conglomeratic (Cardwell, 1968). The group includes the Kanawha, New River, Sharon, and Pocahontas formations. Drillers in the area commonly refer to the basal sandstone unit as the Salt Sands. This aquifer has a median transmissivity of 1,300 ft^2/d (Kozar and Mathes, 2001). The base of this unit ranges from approximately 400 to 600 ft bgs within the area.

To the northwest of the AoR, in Carroll County, Ohio, the Pennsylvanian Sharon Sandstone at the base of the Pottsville Group was identified as the lowermost USDW with a bottom elevation range of ~150 to 600 ft amsl (Riley, 2012).

2.7.1.7. Mauch Chunk Group

The Mauch Chunk Group contains mostly red, gray, and dark-gray shale, gray and red sandstone, and gray to dark-gray limestone (Cardwell, 1968). This group consists of the Bluestone Formation, Princeton Sandstone, and Hinton Formation. In the area, this group is about 150 to 250 ft thick and is underlain by the Big Injun Sandstone of the Greenbriar Formation. The base of this formation ranges from approximately 750 to 1,000 ft amsl within the AoR. The Big Injun Sandstone has been used as an oil and gas production unit with subsequent brine water injections within the AoR, so it is assumed that water quality below the Mauch Chunk is non-potable with high TDS values.

The Mauch Chunk Group has a median transmissivity of 1,300 ft^2/d (Kozar and Mathes, 2001). A conservative assumption was made to select the Mauch Chunk Group, which is below the Pottsville Group, as the lowermost USDW until depth-specific water quality samples are obtained. The USGS National Produced Waters Geochemical Database, version 3.0, contains results of two water samples collected in Marshall County; one obtained from the Pottsville Group (TDS = 5,460 ppm) and another from the Pocono (Price) Formation (TDS = 110,525 ppm). The depth of the base of the lowermost USDW and USDW TDS concentrations will be identified and defined through fluid sampling and analysis from planned stratigraphic test wells in the region and during pre-operational testing of the injection wells.

2.7.2. Groundwater Flow and Principal Aquifer Zones

Groundwater within the shallow Quaternary Alluvium generally flows from higher elevation to lower elevations, towards the major drainageways, ultimately discharging to the Ohio River. Groundwater within the bedrock aquifer systems similarly flows from areas of higher elevation to areas of lower elevation, towards the major surface drainageways, but taking a longer and deeper path. The groundwater in these bedrock aquifers flows approximately perpendicular to local tributary streams, through an intricate network of stress-relief fractures and interconnected bedding-plane separations, commonly in a stair-step pattern (Wyrick, 1981). The groundwater within the bedrock likely discharges locally to surface water or may recharge to subregional or regional aquifers (Kozar et al., 2012). Nevertheless, enhanced permeability of bedrock in valleys, due to stress relief fractures, may result in groundwater flow parallel to and beneath local tributary streams before ultimately discharging to surface-water bodies (Kozar et al., 2012). The deeper bedrock aquifers usually contain much older water, which is usually brackish and has not been flushed by shallow groundwater circulation.

Water level data and potentiometric surface data were not available for Marshall County. Therefore, a map of potentiometric surface was obtained from neighboring Carroll County, Ohio (Angle, 2006). This map regionally illustrates the potentiometric surface mirroring the topographic surface, where water flows from higher elevations to lower elevations in both the surficial alluvial aquifers and deeper bedrock formations.

Figure 54 shows the generalized groundwater flow directions within the AoR.

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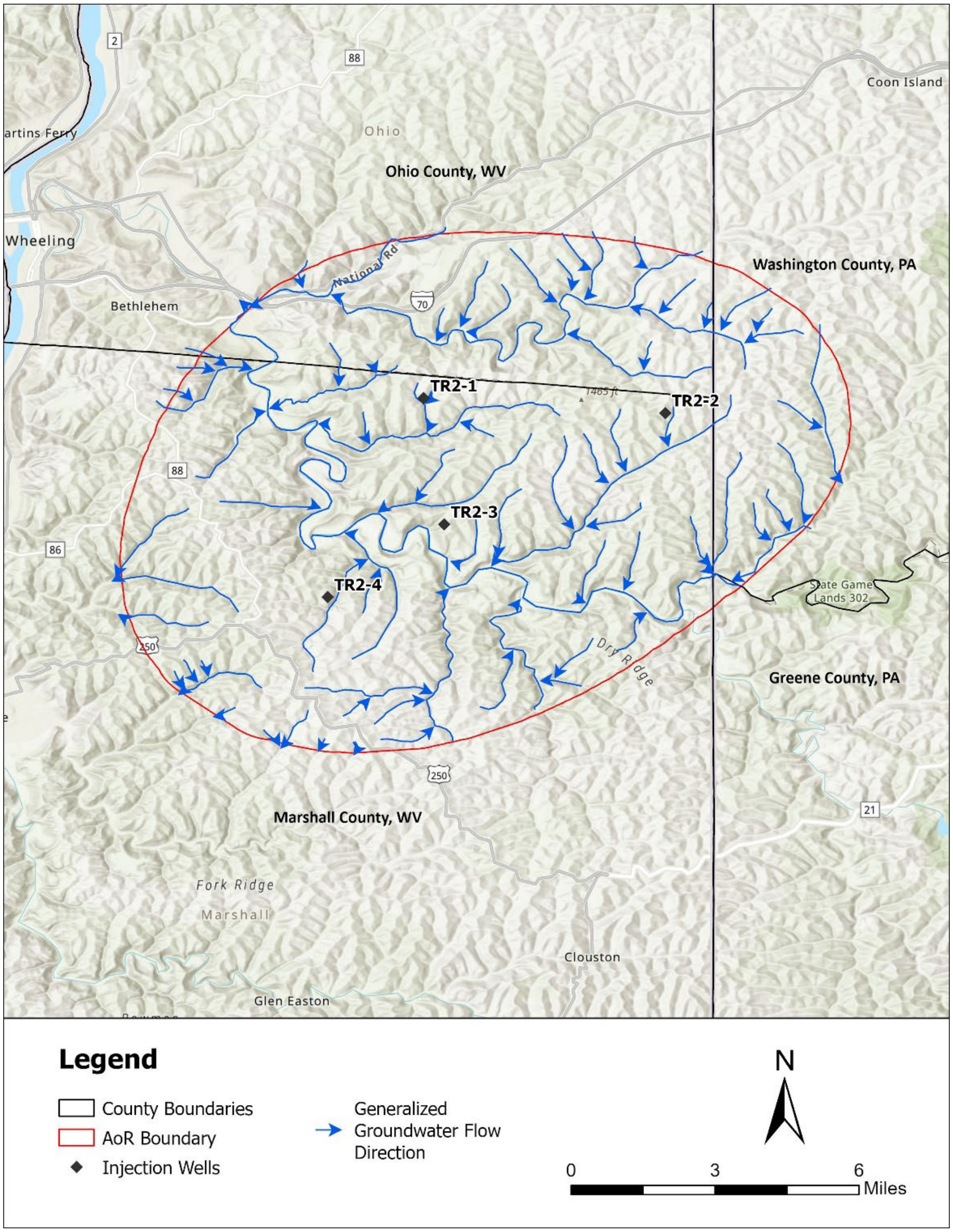

Figure 54: Generalized groundwater flow directions within the AoR.

2.7.3. Drinking Water Wells in the AoR

Water well completion records were obtained from the USGS Water Quality Portal, with data provided by the USGS West Virginia Water Science Center. Groundwater quality records were obtained from the West Virginia Water Quality Impact Portal, with data provided by the West Virginia Department of Environmental Protection Office of Oil and Gas and USGS West Virginia Water Science Center. There are 78 well completion records and 64 groundwater sample points from Marshall County, and 55 well records and 46 groundwater samples from Ohio County within the AoR. There is one additional well completion record from Greene County, Pennsylvania for a total of 134 well records and 110 groundwater quality records within the AoR. A map showing the locations of these wells and groundwater samples is in Figure 55. It is important to note that these well records are counts of completion records, not active domestic wells, as some may be for monitoring wells, abandoned wells, or were never equipped with a pump. The well completion record data source does not provide information on well types or usage. The groundwater quality records are obtained from well and spring sites. The 134 well records within the AoR have depths ranging from 10 to 300 ft bgs. Depths and locations for each water well are in Appendix A. The 110 groundwater quality sample records are described in the following section with groundwater quality data for each well in Appendix B.

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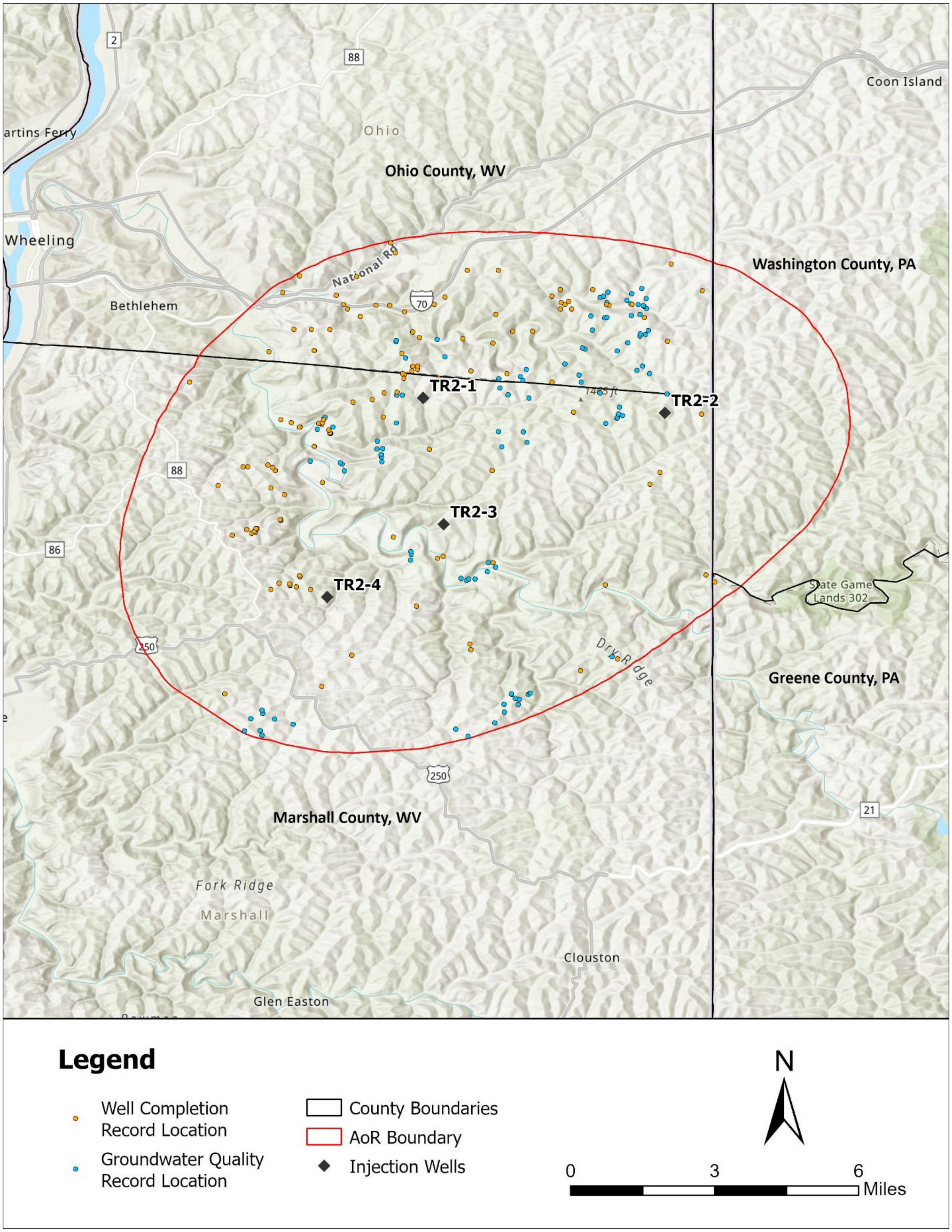

Figure 55: Location of groundwater wells and groundwater quality record sites within the AoR. Groundwater well and quality record details are provided in Appendix A and Appendix B.

2.7.4. Water Quality in the AoR

Water quality within the AoR varies with depth and geologic formation. Near the surface, in the alluvial aquifer along the Ohio River, data collected from the USGS between 1950 and 1985 show water is generally very hard with a median hardness of 220 mg/L. Median concentration of manganese in the alluvium was measured at 340 mg/L. The Ohio Alluvial aquifer was also found to be high in iron (Ferrell, 1987). The same study showed high median values of manganese in water from Mississippian bedrock aquifers and high iron in Lower Pennsylvanian aquifers. Additionally, the study found that groundwater containing concentrations of chloride over 250 mg/L underlie most of West Virginia at depths of about 300 ft below major streams (Ferrell, 1987).

Data sourced from the West Virginia Department of Environmental Protection Office of Oil and Gas consists of 110 groundwater quality records collected from springs and wells from 2008 to 2018. A map showing the locations of these groundwater quality samples is in Figure 55, and record details are provided in Appendix B. Groundwater quality sampling depths were not listed in the original data, so pH, water temperature, and TDS are included in Appendix B in order to approximate the depth or aquifer sampled. The data reports median values for pH, water temperature, and TDS at 7.7, 14.1°C, and 264 mg/L, respectively. Median values are relatively high for pH and low for water temperature and TDS when compared to groundwater from deeper aquifers such as the Salina Group. Data from the USGS National Produced Waters Geochemical Database contains a record of groundwater quality within the Salina Group from nearby Ritchie County with a reported 360,824 mg/L TDS and 82.4°C (Blondes et al, 2023). A Salina Group groundwater sample record from Erie County, Pennsylvania reports a pH of 6.1 and TDS of 190,000 mg/L (Blondes et al, 2023).

Groundwater wells located in valleys generally have higher alkalinity, pH, and TDS. Sodium (Na), pH, alkalinity, chloride (Cl), and TDS concentrations increase with well depth, while calcium and magnesium decrease. Generally, there is little difference in water quality and water type between different geologic units, with dominantly calcium bicarbonate composition in most areas, followed by a sodium bicarbonate water type (Harkness, 2017).

Dissolved chemical contaminants, such as volatile organic compounds (VOCs) and nitrate, are typically not removed by sediments (Chambers, 2012). Given the potential for alluvial aquifers to receive significant recharge from adjacent rivers and given the capacity for the alluvial sediments to act as microbial filters, alluvial aquifers have a low intrinsic susceptibility to microbial contaminants but a high intrinsic susceptibility to VOCs, nitrate, or other chemicals released or spilled at or near the surface (Kozar and Paybins, 2016).

Previous mapping in West Virginia shows contours for the base of the fresh water and the top of the saline water using information gathered from oil and gas drilling logs (Foster, 1980). It is noted that the data used in producing these maps was not quantitative but, instead, relied on the field determination of either fresh or saline water by drillers in the field and reported on their logs. These maps indicate that the top of the saline water is between 500 and 650 ft amsl in the AoR.

Typically, only the first 10 to 30 ft of a well that taps consolidated bedrock aquifers in West Virginia is cased. The rest of the well typically is an open borehole that ranges from 10 to several hundred feet in depth and usually is 6 in. in diameter. Water typically is derived from several water bearing zones because of the lithologic variability of the aquifers. The amounts and chemical properties of the water from each zone can be different; thus, the quality of water pumped from a well depends on which zones are tapped and the proportion of water derived from each zone (Kozar et al., 2012).

2.8. Geochemistry [47 CSR 13-13.8.1.f.]

2.8.1. Baseline Fluid Chemistry

Average salinity was calculated and initial fluid chemistry data were collected from the USGS Produced Water Database for the USDWs, the injection zones, and the confining zones and are shown in Table 12 and Table 13 (Blondes et al., 2023). The database was filtered to include regional data from the states of Ohio, Pennsylvania, eastern Kentucky, and West Virginia (Figure 56). Anomalous and outlier data points were investigated to determine validity, and in some cases, these data points were removed from the dataset due to their high uncertainty.

The determination of the lowermost USDW for the project relied on freshwater/saltwater interface mapping from previously drilled oil and gas wells (Foster, 1980). Water quality samples discussed in subsection 2.7.3 from bedrock aquifers in the AoR are primarily from shallow sampling points (< 200 ft TVD below ground surface) while average TDS calculations in this section are from regional averages with depths > 1,000 ft TVD, which accounts for the increase in average calculated TDS for these shallow intervals. Fluid samples will be acquired during the construction of injection wells as part of the Pre-Operational Testing Plan as well as during the construction of the CarbonSAFE stratigraphic test wells in the region to validate or update these data.

The USGS sampling data indicate that the Lockport Dolomite Group (primary upper injection zone) has an average TDS of 264,717 mg/L, whereas the Salina Group (primary confining zone) averages 256,156 mg/L. No TDS measurements were available for the Rochester Shale, and the calculated average TDS of the Medina Group (primary middle injection zone) is 266,865 mg/L. TDS measurements for the Queenston Shale (Juniata) Formation in the project area were unavailable, but in the state of New York, the average salinity is recorded at 216,383 mg/L. The Knox injection complex (potential secondary lower injection zone), including the Beekmantown Dolomite and Rose Run Sandstone, has an average TDS > 300,000 mg/L (Table 12). The brines of the intended injection complexes and USDWs are predominantly Na^+ and Cl^- with secondary Ba^{2+}, HCO_3^-, Ca^{2+}, K^+, Mg^{2+}, and SO_4^{2-}. For reference, initial fluid chemistry data collected from the USGS National Produced Waters Geochemical Database for the USDWs, the injection zones, and the confining zones are shown in Table 13.

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Table 12: Regional Total Dissolved Solids (TDS) data for the Primary and Secondary injection complexes and USDWs. There are no data for the Rochester Formation, and data from the Queenston Shale are described in the text above.

Total Dissolved Solids			
Formation Type	**Formation**	**TDS (mg/L)**	**n =**
USDW	Conemaugh Group	22,008	6
USDW	Allegheny Group	15,825	2
USDW	Pennsylvanian Age (undiff)	36,421	6
USDW	Pottsville Group/Salt Sand	71,394	172
Lowermost USDW	Mauch Chunk Formation	81,410	27
Formation below Lowermost USDW	Greenbrier Formation	156,678	10
Primary Confining (LIC)	Salina Group	256,156	12
Primary Injection (LIC)	Lockport Dolomite Group	264,717	11
Primary Injection (MIC)	Medina Group	266,865	376
Secondary Confining/Injection (KIC)	Beekmantown Dolomite	379,676	1
Secondary Injection (KIC)	Rose Run Sandstone	320,833	13

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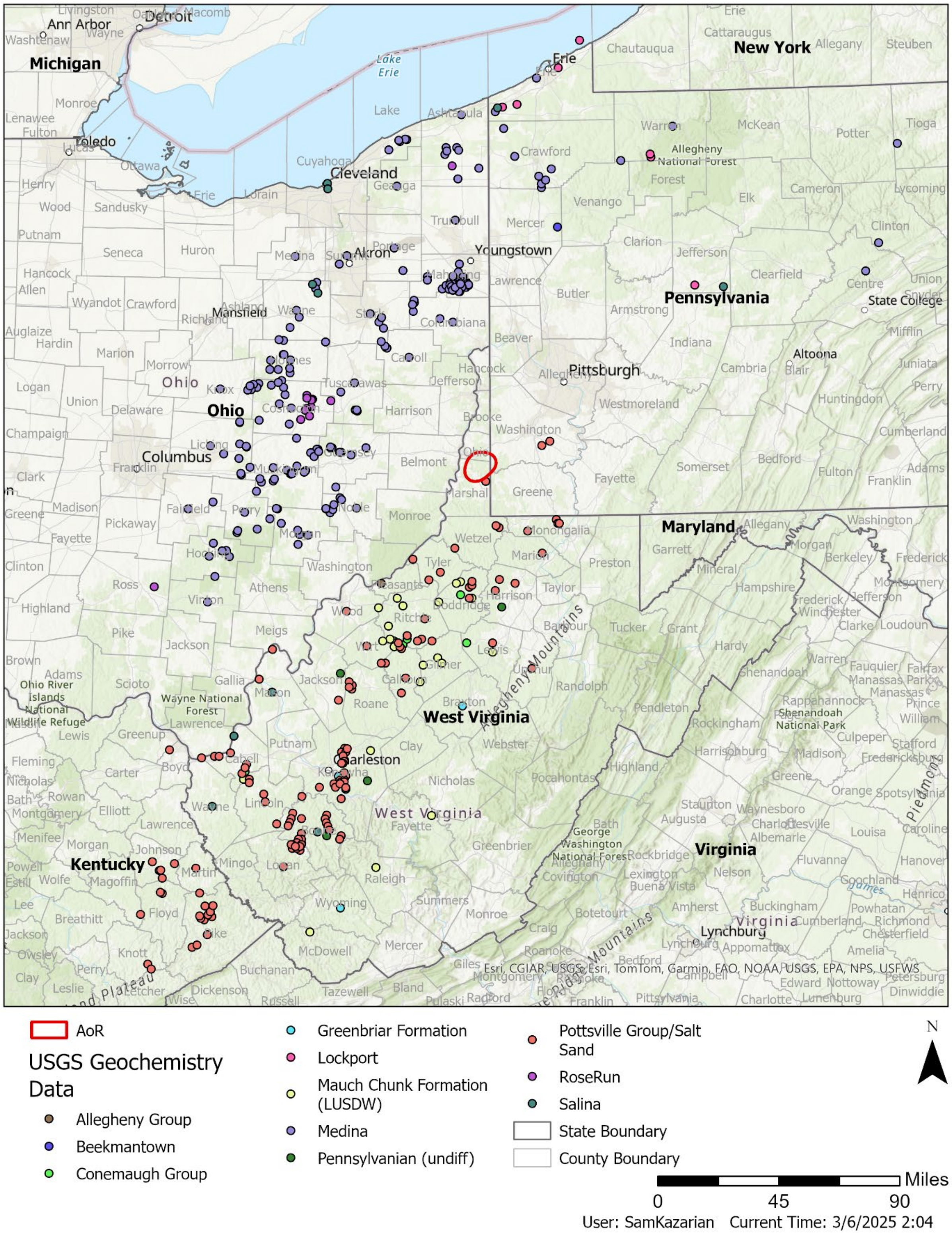

Figure 56: Location map of regional baseline fluid chemistry data from the USGS National Produced Waters Geochemical Database (Blondes et al., 2023).

Table 13: Regional Baseline Fluid Chemistry data for the primary and secondary injection complexes and USDWs from USGS (National Produced Waters Geochemical Database; Blondes et al., 2023).

Baseline Fluid Chemistry (mg/L)					
Parameter/Constituent	Primary (LIC)		Primary (MIC)	Secondary (KIC)	
	Salina	Lockport	Medina	Beekmantown	Rose Run
pH	6.1	6.56	5.53	1.21	5.46
Ba^{2+}	700	--	22.2	--	--
HCO^{3-}	211.3	98.9	91.3	208.0	80.7
Ca^{2+}	17,296.5	25,202.5	33,238.1	52,889.0	43,000.1
Cl^{-}	158,758.5	143,949.4	164,034.6	232,741.0	208,059.7
K^{+}	3438.1	2930.7	1637.8	--	4,169.1
Mg^{2+}	3,012.2	4,907.0	4,055.8	6,100.0	6,479.9
Na^{+}	76,927.0	71,421.2	59,121.6	78,824.0	68,138.0
SO_4^{2-}	1,971.8	647.6	409.4	93.0	417.7

Baseline Fluid Chemistry (mg/L)						
Parameter/ Constituent	Underground Source of Drinking Water					
	Conemaugh Group	Allegheny Group	Pennsylvanian (undiff)	Pottsville Group/ Salt Sand	Mauch Chunk (LUSDW)	Green-brier
pH	--	--	--	6.9	--	--
Ba^{2+}	53.3	40.0	--	382.2	646.4	--
HCO^{3-}	--	--	--	211.0	594.0	68.5
Ca^{2+}	1,070.0	250.0	1,358.0	5,161.4	6,603.4	13,631.7
Cl^{-}	13,055.0	9,345.0	--	42,878.1	52,914.4	96,744.4
K^{+}	62.4	45.0	15,762.0	490.8	252.0	414.8
Mg^{2+}	295.3	185.5	97.0	1,066.3	1,467.4	3,192.0
Na^{+}	6,758.8	5,825.0	374.0	19,770.0	23,674.0	41,177.4
$SO4^{2-}$	45.2	167.5	8,134.0	35.9	68.3	524.6

2.8.2. Fluid-Rock Interactions

A literature review was conducted to evaluate the potential for reactivity between the fluid and solid phases during injection into the LIC, MIC, and KIC. There are no studies on the primary injection intervals, the LIC and the MIC, so analog studies were reviewed based on the mineralogy of the intended injection complexes discussed in subsection 2.4 of this Application Narrative.

2.8.2.1. Lockport Injection Complex

There are currently no studies investigating the fluid-rock reactivity of the Lockport Dolomite. Wang et al. (2013) investigated the reactivity of the mineral dolomite ($CaMg(CO_3)_2$) with water-saturated CO_2 in a series of laboratory experiments performed at 55 and 110 °C to mimic reservoir conditions and at 220 °C to accelerate the reactions at laboratory time scales. Wang concluded that dolomite exhibits no reaction with anhydrous supercritical CO_2 but dissolves and precipitates carbonate minerals when exposed to water-saturated supercritical CO_2. The main drivers for the morphology and composition of the mineral precipitates are temperature and reaction time, though heterogeneity in dolomite mineralogy was not studied. Further, mineral dissolution and precipitation could have an effect on the hysteresis of drainage and imbibition, rock wettability, and capillary pressure, which affect the flowability and trapping of CO_2. The magnitude of these effects was not measured in the study.

2.8.2.2. Medina Injection Complex

Minimal quartz chemical dissolution and subsequent porosity changes due to CO_2 injection are expected in the MIC during the life of the project. Mineralogical analysis, discussed in subsection 2.4.3.2 of this Application Narrative, suggests few reactive minerals and cements in the MIC. Feldspars and pyrite are minor constituents, and XRD measured trace amounts of carbonate present in the formation that are unlikely to significantly alter the reservoir matrix during the project. Literature suggests some variability in the cement type and variable interstitial shale beds, so there is the possibility of the presence of reactive minerals (see subsection 2.4.2.2 of the Application Narrative). To date, no work has been performed to model the reactivity of the Medina sandstones with supercritical CO_2. Future testing to address this uncertainty is discussed below.

2.8.2.3. Knox Injection Complex

Zerai et al. (2005) modeled the equilibrium and kinetic reactions of the Rose Run Sandstone mineralogy and brine under no-flow conditions. Equilibrium modeling highlighted the critical role of albite, K-feldspar, and glauconite dissolution, with siderite and dawsonite precipitation, in CO_2 mineral trapping in the Rose Run. The dominant precipitated minerals were quartz, muscovite, and microcline, which have opposing negative and positive effects of lowering the injectability or improving sealing capacity. These results are sensitive to both the brine composition and site-specific mineralogy, in addition to temperature and CO_2 fugacity. The kinetic modeling indicated that solubility trapping was key over short timescales, and CO_2 mineral trapping was significant over longer (100,000 years) timescales. The modeling showed that the mineralogy of the Rose Run Sandstone is suitable for significant mineral trapping of CO_2, though the reactions are sensitive to the brine-rock ratio, CO_2 pressure, and the reaction rates. Further modeling for the project may be performed if site-specific data is collected.

2.8.3. Planned Testing and Modeling

The data utilized for evaluating geochemical interactions within the Lockport Dolomite, the Medina Group, and the Rose Run Sandstone (Knox Group) siliciclastic reservoirs are regional and not specific to the project area. Consequently, following the completion of pre-operational testing and logging and data collection for the CarbonSAFE stratigraphic wells planned in the region, it will be determined if reactive transport modeling should be conducted.

Tri-State CCS, LLC will acquire sidewall core samples from the proposed injection zones to determine the petrophysical and mineralogical properties of the LIC, MIC, and KIC (see Pre-Operational Testing Program). Mineralogical analysis will determine the type percent composition of potentially reactive minerals within the Lockport Dolomite Group, the Medina Group siliciclastics, and possibly the Knox Group at the proposed injection locations.

Tri-State CCS, LLC also plans to gather fluid samples from the injection zone and shallower zones to establish a baseline geochemical description of reservoir fluids. Collected fluid samples are planned to be used to develop synthetic brine compositions to run core flooding studies to assess possible interactions between injected CO_2, reservoir matrix, and in-situ brine. Fluid samples will allow pre- and post- CO_2 injection analysis to determine the changes in brine chemistry, which can be compared with reservoir samples subjected to geochemical testing to assess changes in the rock matrix. If Tri-State CCS, LLC determines geochemical changes to reservoir rock or fluids are prominent as concluded from these tests, a reactive transport model will be built and coupled with the current reservoir model to assess long term fate of injected CO_2 as it is related to mineralogical changes in the reservoir.

2.9. Site Suitability [47 CSR 13-13.2.1]

Based on all available data and research presented in this Application Narrative, the project area meets the suitability requirement outlined in the regulations for CO_2 injection. The LIC consists of the Salina Group as the primary confining zone, the Lockport Dolomite Group as the injection target, and the Rochester Shale Formation, which acts as the lower confining unit for the Lockport Dolomite Group and the upper confining unit for the MIC. The remainder of the MIC consists of the Medina Group sandstones as the lower injection target and the Queenston Shale Formation as the lowest confining unit.

The Lockport Dolomite Group is laterally continuous, averages 380 ft in thickness at the injection sites, and is lithologically variable. It exhibits seven main facies types: (1) mixed intertidal to supratidal dolomite (with a mixed gray biostromal subfacies), (2) interreef or interbioherm dark dolomite, (3) grainstone - shoals, banks, reef flanks, and inter-reef sediments, (4) biohermal dolomite (reefs, bioherms and patch reefs), (5) subtidal crinoidal dolomite, (6) quartzose dolomite associated with barrier island, and (7) shallow subtidal shaley dolomite. The reservoir quality is linked to both the initial depositional facies and diagenetic alteration, which can either occlude or enlarge pores. This variability results in reported ranges of porosities from 1 to 9% and permeabilities of < 0.01 md to 55 md. Wireline logs, core, and petrophysical evaluation from wells in the nearby subsurface resulted in an average model porosity of ~5% and an average permeability of ~1 md.

The MIC is a series of interbedded sandstones, shales, and siltstones, with minor carbonates. They were shed from the Taconic highlands, in a fluvial-deltaic to shallow marine environment, recording 3-4 marine incursions and a sea-level change, as evidenced by the different sand intervals. The sandstones vary in quality due to quartz cementation. Reported porosities range from 2 to 23%, and permeabilities range from 1 md to 40 md, with some oil fields reporting as high as 200 md. In the project's model domain, the average porosity is ~5%, and average permeability is 8 md.

Static modeling and simulation of the project area resulted in an average range of total injection mass of 12.34 MMt CO_2 in the LIC and 15.70 MMt CO_2 in the MIC for the potential injection locations over 30 years. Due to the low porosity and permeability in the nearby area, the CO_2 plume does not migrate far from the injection site (~ 1 mile radius) in the 30-year injection period and the following 50-year PISC period. Using the US-DOE-NETL methods, it was calculated that the LIC has the potential to be able to sequester P10:102.1, P50: 247.6, P90: 461.2 MMt of CO_2. The MIC has the potential to be able to sequester P10: 71.5, P50: 221.1, P90 526.4 MMt of CO_2. Detailed regional reservoir characterization from the CarbonSAFE stratigraphic test wells will de-risk the current uncertainties, and site-specific data collection from the pre-operational testing for the injection wells will narrow the uncertainty range prior to injection.

Literature review and regional well log analysis indicate the project's confining zones will provide long-term containment of CO_2. The primary confining zone, the Salina Group, consists of laterally extensive, tight dolomites and thick bedded salts and anhydrites across multiple states. This interval is >1,000 ft thick in total and has bedded salts with cumulative thicknesses >200 ft locally and has acted as a barrier between two distinct geochemical fingerprints between the petroleum systems younger than the Salina Group and those older than the Salina Group. The Rochester Shale Formation, which sits above the MIC and below the LIC, is an average of ~430 ft thick in the AoR, laterally continuous throughout the region, and reported as impermeable (1×10^{-6} md). Finally, the Queenston Shale Formation has a thickness >1,000 ft, has been measured as impermeable, and is laterally continuous across the basin. These confining zones and their historical longevity are robust, indicating that secondary confining zone identification is unnecessary.

No faults were identified though 2D seismic interpretation, or literature search, that offset the Salina Group or create leakage pathways to the lowermost USDW. There are, however, at least 41 confirmed legacy oil and gas wells that penetrate the caprock within the AoR as seen in Figure 50 of subsection 4.1 of the Area of Review and Corrective Action Plan. These wells are addressed in the plan, along with those wells without depth data, to ensure that the legacy wells are not conduits for potential leakage.

Literature review of the fluid chemistry, injection and confining zone mineralogy, and analogs for the injection complexes suggest that the siliciclastic intervals will have minimal reaction with the injected CO_2. Laboratory analysis of anhydrous CO_2 interaction with dolomite suggests no reaction, but dolomite dissolves and alternate carbonate minerals precipitate when the CO_2 is water saturated. The rate and magnitude of these reactions will be evaluated in the future CarbonSAFE site characterization and pre-operational testing for these systems. Surface and well infrastructure materials are being designed using CO_2 compatible materials and techniques, and the proposed CO_2 stream is dry (95% CO_2); thus, no adverse interactions are anticipated. Corrosion testing prior to construction will take place to confirm material compatibility.

3. Summary of Other Plans

3.1. Area of Review and Corrective Action Plan

The information and files submitted in the Area of Review and Corrective Action Plan satisfy the West Virginia state requirements of 47 CSR 13-13.8.1.m. This plan addresses how the project AoR is delineated and uses corrective action techniques to address all deficient artificial penetrations and other features that compromise the integrity of the confining zones above the injection zones. The AoR encompasses the entire region surrounding the project's injection wells where USDWs may be endangered by injection activity.

The computational model describes modeling of the subsurface injection of CO_2 into the LIC and MIC at the project injection wellsites. The STOMPX-CO2 simulator was used to assess the development of the CO_2 plume, the pressure front, and the long-term outcome of the injected CO_2. Simulation indicated that the maximum extent of the pressure front will be larger than the maximum extent of the CO_2 plumes over the lifetime of the project. Therefore, the AoR for the project is defined as the maximum extent of the threshold pressure front (304 psi for the Lockport Dolomite Group), which occurs at the end of 30 years of injection into the LIC, with an additional 1-mile buffer to account for uncertainties in the subsurface data. This plan details the computational modeling, assumptions that were made, and site characterization data that the model was based on to satisfy the requirements of 47 CSR13.5.4 and 47 CSR 13.14.9.b.5.

A public record search identified 453 existing oil and gas wellbores and 134 known water wells within the AoR. Per 47 CSR 13-13.8.1.d, wells that penetrate the injection or confining zone within the AoR must be tabulated. None of the water wells penetrate the injection or confining zones, but there are at least 41 oil and gas wellbores that may penetrate the upper confining unit for the LIC within the AoR, 11 of which may additionally penetrate the upper confining unit for the MIC. Depth data was not available for 84 of the oil and gas wellbores identified in the record search. Tri-State CCS, LLC proposes a phased corrective action strategy for the 41 wells that penetrate the upper confining zone and 84 wells with unknown depths, based on temporal evolution of the threshold pressure boundary and CO_2 plume over 30 years of injection.

Tri-State CCS, LLC will review the AoR annually during the injection phase and once every five years during the post-injection phase to ensure the initial model predictions are adequate for predicting the extent of the CO_2 plume and pressure front.

3.2. Financial Responsibility

Tri-State CCS, LLC has prepared the Financial Assurance Demonstration to comply with federal requirements at 47 CSR 13-13.8.1.n. The plan estimates costs of project activities and provides information on financial instruments that Tri-State CCS, LLC will use to demonstrate Financial Assurance for the following activities: (1) Corrective Action; (2) Injection Well Plugging; (3) Post-Injection Site Care (PISC); (4) Site Closure; and (5) Emergency and Remedial Response. The estimated costs of each of these activities are presented in Table 14 below.

Table 14: Cost Estimates for Activities to be Covered by Financial Responsibility.

Activity	Total Cost ($)	Timeline of Coverage
Corrective Action	$9,774,063	2027-2057
Plugging Injection Wells	$846,372	2062
Post-Injection Site Care	$11,296,100	2058-2107
Site Closure	$1,361,908	2107
Emergency and Remedial Response	$35,087,143	2027-2107
TOTAL	**$58,365,586**	

Tri-State will execute a combination of financial instruments prior to issuance of the Class VI UIC Permit to Construct. These financial instruments will cover the costs of one emergency leakage event as discussed in the Emergency and Remedial Response Plan, all of the costs of injection well plugging as discussed in the Injection Well Plugging Plan, all of the costs of corrective action as discussed in the Area of Review and Corrective Action Plan, and all of the costs of 50 years of PISC and site closure as discussed in the Post-Injection Site Care and Site Closure Plan.

3.3. Injection Well Construction

The project's injection wells, TR2-1, TR2-2, TR2-3, and TR2-4, will be newly drilled and are designed to accommodate the mass of CO_2 that will be delivered to the project and the subsurface characteristics of the CO_2 injection intervals. Injection well construction is further described in the following plans that are part of this application: (1) Stimulation Program and (2) Construction Details for each injection well.

3.3.1. Stimulation Program

The proposed Stimulation Program outlines the stimulation measures that the project may use to mitigate drilling-induced damage near the wellbore without interfering with containment, per 47 CSR 13-13.8.1.l. It is expected to effectively clear the perforated interval of fines, perforation charge residue, and debris from cement or casing. Additionally, stimulation helps eliminate drilling mud filtrate and dissolved minerals present in the formation. This process is common, as the untreated presence of these elements can lead to elevated downhole injection pressures and reduced injectivity, underscoring the significance of thorough treatment. Specific stimulation fluids, additives, and diverters will be based on injection well site conditions from pre-operational testing results and the type of stimulation needed.

Additionally, treatment may be necessary to mitigate the precipitation of evaporite minerals in and near the well bore due to the high salinity of the injection formation fluids. The precipitation of these minerals reduces well injectivity, impacts pressure buildup by blocking pore space near the wellbore and reduces reservoir porosity and permeability. The current simulation data suggest that salt precipitation is not a problem for the proposed injection intervals over the 30-year injection period; however, further modeling will be performed using additional data collected from the

CarbonSAFE stratigraphic test wells planned in the region and site-specific pre-operational testing. The necessity for mitigation efforts will be re-evaluated at that time, prior to seeking authorization to inject.

At least 30 days in advance of proposed stimulation, Tri-State CCS, LLC will submit details to the UIC Program Director on the purpose of stimulation, procedures, and stimulation fluids to be used and their anticipated volumes and concentrations.

3.3.2. Construction Details

The Construction Details for each injection well describes the analysis conducted and proposed designs for injection wells TR2-1, TR2-2, TR2-3, and TR2-4 that ensure the prevention of the movement of fluids into or between USDWs, that allow the use of testing devices and workover tools, and that allow continuous monitoring of the annulus space between the injection tubing and long string casing, in compliance with 47 CSR 13-13.8.1.l. For all four wells, injection into both the LIC and MIC are planned to be contemporaneous, so the maximum wellhead pressure for injection into the LIC and MIC will be the same. Maximum injection pressure at the wellhead is defined by not exceeding 90% of the fracture gradient of the shallowest injection interval, the LIC, assuming a maximum injection rate of 0.5 MMt/y.

The well design for TR2-1 utilizes a 3.5-inch outer diameter (OD) tubing with 22Cr-110 grade duplex stainless steel (22Cr-110) and a maximum wellhead pressure of 2,525 psig. The design features a 20-inch conductor casing set at 120 ft, a 13.375-inch surface casing at 704 ft, a 9.625-inch intermediate casing at 2,002 ft, and a 7-inch long-string casing reaching 9,649 ft, with sections of L80 grade steel (L80) and 22Cr-110 materials. The Lockport Dolomite Group injection interval and the Medina Group injection interval will be perforated from 8,621 ft to 8,918 ft TVD and from 9,351 ft TVD to 9,548 ft TVD, respectively. To isolate the tubing annulus and the perforated intervals, retrievable packers will be set at 8,556 ft and 8,983 ft TVD. Injection modeling ensured suitability for tubing sizes, selecting 3.5-inch OD for efficiency. All casing strings, except conductor if driven, will be cemented to the surface using CO_2-resistant cement for critical zones. Operational parameters and construction schematics for TR2-1, including perforation plans, are in Figures 10 and 11 of the Construction Details for TR2-1.

The TR2-2 well design utilizes a 3.5-inch OD 22Cr-110 tubing and a maximum wellhead pressure of 2,585 psig. The casing design consists of a 20-inch conductor set at 120 ft, a 13.375-inch surface casing at 817 ft, a 9.625-inch intermediate casing at 2,223 ft, and a 7-inch long-string casing at 9,906 ft. The Lockport Dolomite Group injection interval and the Medina Group injection interval will be perforated from 8,858 ft to 9,150 ft TVD and from 9,605 ft to 9,805 ft TVD, respectively. To isolate the tubing annulus and the perforated intervals, retrievable packers will be set at 8,793 ft and 9,209 ft TVD. All casing strings, except conductor if driven, will be cemented to the surface using CO_2-resistant cement in critical zones. Design details, including perforation and construction schematics for TR2-2, are in Figures 10 and 11 of the Construction Details for TR2-2.

The TR2-3 well design utilizes a 3.5-inch OD 22Cr-110 tubing and a maximum wellhead pressure of 2,585 psig. The casing design consists of a 20-inch conductor set at 120 ft, a 13.375-inch surface casing at 778 ft, a 9.625-inch intermediate casing at 2,080 ft, and a 7-inch long-string casing at 9,890 ft. The Lockport Dolomite Group injection interval and the Medina Group injection interval will be perforated from 8,861 ft to 9,164 ft TVD and from 9,597 ft to 9,789 ft TVD, respectively. To isolate the tubing annulus and the perforated intervals, retrievable packers will be set at 8,796 ft and 9,224 ft TVD. All casing strings, except conductor if driven, will be cemented to the surface using CO_2-resistant cement in critical zones. Design details, including perforation and construction schematics for TR2-3, are in Figures 10 and 11 of the Construction Details for TR2-3.

The TR2-4 well design utilizes a 3.5-inch OD 22Cr-110 tubing and a maximum wellhead pressure of 2,545 psig. The casing design consists of a 20-inch conductor set at 120 ft, a 13.375-inch surface casing at 736 ft, a 9.625-inch intermediate casing at 2,106 ft, and a 7-inch long-string casing at 9,694 ft. The Lockport Dolomite Group injection interval and the Medina Group injection interval will be perforated from 8,690 ft to 8,997 ft TVD and from 9,411 ft to 9,593 ft TVD, respectively. To isolate the tubing annulus and the perforated intervals, retrievable packers will be set at 8,625 ft and 9,057 ft TVD. All casing strings, except conductor if driven, will be cemented to the surface, utilizing CO_2-resistant cement for critical zones. Design details, including perforation and construction schematics for TR2-4, are in Figures 10 and 11 of the Construction Details for TR2-4.

Each well was designed to account for active underground mining, with drilling in mined areas planned through pillars to avoid voids. Tri-State CCS, LLC will work with WVDEP and the mine operator to finalize drilling locations and, during field operations, to determine the final depth of surface casing.

Measures are in place to prevent exceeding fracture gradients or mandated injection pressures. Adjustments may be made based on future reservoir characterization. The final nodal analysis recommends a tubing configuration and operational parameters to ensure pressure and rate limitations are met while considering factors such as zonal isolation and well integrity.

3.4. Pre-Operational Testing Program

The Pre-Operational Testing Program is designed to meet the requirements of 47 CSR 13-13.5. and 47 CSR 13-13.3, ensuring accurate baseline datasets, verification of injection and confining zone characteristics, and compliance with injection well construction requirements. This program will be implemented at all four injection wells (TR2-1, TR2-2, TR2-3, TR2-4) to characterize the LIC and MIC in the project area. The testing program will include a combination of logging, coring, hydrogeologic formation testing, and other activities during the drilling and construction phases of injection and observation wells.

The pre-operational testing will involve sidewall coring and an extensive well logging program, including wireline logging in injection and observation wells. Formation geohydrologic testing, such as pump tests and injectivity tests, will verify the chemical and physical characteristics of the LIC and MIC injection and confining zones. Fracture pressure will be determined using formation testing tools and mini-fracture tests, ensuring borehole stability and optimal cement installation.

This program will determine or verify the depth, thickness, mineralogy, lithology, porosity, permeability, and geomechanical properties of the upper confining zones (Salina Group, Rochester Shale Formation), lower confining zone (Queenston Shale Formation), and injection intervals (Lockport Dolomite Group and Medina Group). Formation fluid characteristics will also be obtained from the injection intervals to establish baseline data for future comparisons. The wells, including injection and observation types, will support site characterization efforts.

Reports detailing the results of all testing operations, including interpretations, will be submitted to the UIC Program Director within 60 days of completing each injection well. These reports will include data on casing and cement integrity, well logs, core analysis, fluid sampling, and hydrogeologic test results. This ensures that all pre-injection conditions are documented and comply with regulatory requirements.

Upon completion of characterization and testing, the boreholes will be finalized as injection wells. Mechanical integrity tests (e.g., pressure and wireline tests) will verify well construction and integrity. Cement bond, variable density, and temperature logs will confirm the quality of the cement jobs for each well after long-string casing installation, ensuring conformance with project and regulatory standards.

3.5. Summary of Requirements – Class VI Operating and Reporting Conditions

The Summary of Requirements – Class VI Operating and Reporting Conditions outlines the operational design developed to comply with 47 CSR 13.13.8.1.g and 13-13.8.1.j and provides a plan for safe injection into TR2-1, TR2-2, TR2-3, and TR2-4.

Tri-State CCS, LLC aims to safely inject CO_2 at a maximum rate of 0.5 MMt/y in each of the four injection wells, ensuring well integrity while maintaining pressures below 90% of the fracture pressure in the active injection zone. The maximum injection pressures were modeled as 2,525 psig for TR2-1, 2,585 psig for TR2-2, 2,585 psig for TR2-3, and 2,545 psig for TR2-4 for injection into the LIC and MIC. Operating conditions for all four wells are detailed in Table 1 for the LIC and MIC in the Summary of Requirements.

Each injection well will be continuously monitored to ensure safe operations and compliance with 47 CSR 13-13.6.2. Operational monitoring includes real-time observation of injection pressures at the wellhead and downhole, continuous fiber optic temperature monitoring along the wellbore, annular space pressure monitoring, and corrosion coupon monitoring to detect potential corrosion. Details of these monitoring systems are provided in Sections 3.0, 4.0, and 5.0 of the Testing and Monitoring Plan. All automatic shutdowns will be thoroughly investigated prior to resuming injection to confirm the absence of mechanical integrity issues. If a shutdown or loss of mechanical integrity occurs, Tri-State CCS, LLC will immediately investigate the root cause and take necessary remedial actions as outlined in Appendix A of the Emergency and Remedial Response Plan.

Tri-State CCS, LLC will maintain the mechanical integrity of each well through routine maintenance and workover operations. These operations will be carefully monitored to ensure safety and compliance with 47 CSR 13-13.6.2. Well maintenance procedures and testing will be reported to the UIC Program Director, as outlined in the Testing and Monitoring Plan. Operational contingency plans include measures to handle potential upset conditions, such as process disturbances or equipment malfunctions. These plans ensure environmental protection by shutting in wells and monitoring pressure fall-off as necessary. Details of these plans are outlined in Section 5 of the Summary of Requirements.

The CO_2 for injection will be sourced from industrial facilities and power plants in the Tri-State area, transported by pipeline to the project site, and injected in a liquid or supercritical phase. Continuous monitoring of the CO_2 stream composition will ensure adherence to specifications, which are detailed in Table 2 of the Summary of Requirements.

To mitigate CO_2-induced corrosion risks, Tri-State CCS, LLC will adhere to monitoring practices outlined in Section 5 of the Testing and Monitoring Plan.

Tri-State CCS, LLC will submit semi-annual operating reports to the UIC Program Director, including injection data, monitoring results, and any events impacting mechanical integrity. Reporting requirements are fully detailed in Section 6 of the Summary of Requirements.

3.6. Testing and Monitoring Plan

The Testing and Monitoring Plan outlines how Tri-State CCS, LLC will monitor the project to ensure it does not endanger USDWs, meeting the requirements of 47 CSR 13-13.6.2. Monitoring and testing data will track the CO_2 plume and pressure front, validate and refine geological models and simulations, support AoR re-evaluations, and demonstrate non-endangerment. A Quality Assurance and Surveillance Plan, meeting the requirements of 47 CSR 13-13.6.2.k, is included as an appendix to this plan.

Tri-State CCS, LLC plans to drill and monitor up to 18 wells for the project, including four in-zone observation wells in the Lockport Group and Medina Group, two above-zone observation wells in the first permeable interval above the confining zone (Oriskany Formation), four lowermost USDW observation wells in the Mauch Chunk Group, and up to four shallow USDW observation wells in the Pennsylvanian unit. Details on these wells including locations and their approximate depths are provided in Table 1 of the Testing and Monitoring Plan, with proposed monitoring activities and frequencies summarized in Table 3.

The Testing and Monitoring Plan incorporates direct and indirect monitoring technologies to observe:

- Injectate composition per Section 3 of the plan (47 CSR 13-13.6.2.a);
- Operational parameters per Section 4 of the plan (47 CSR 13-13.6.1.d.1 and 13.6.2.b);
- Corrosion of well materials and components per Section 5 of the plan (47 CSR 13-13.6.2.c);
- Any migration of CO_2 or brine above the confining zones per Section 6 of the plan (47 CSR 13-13.6.2.d);
- USDW groundwater quality per Section 6 of the plan (47 CSR 13-13.6.2.d);
- Well integrity over the injection phase per Section 7 of the plan (47 CSR 13-13.6.2 and 47 CSR 13-13.7);
- Near-wellbore environment using pressure fall-off testing per Section 8 of the plan (47 CSR 13-13.6.2.f); and
- Development of the CO_2 plume and pressure front in the storage formations over time per Section 9 of the plan (47 CSR 13-13.6.2.g).

3.7. Injection Well Plugging Plan

The Injection Well Plugging Plan for each injection well describes the process Tri-State CCS, LLC proposes to plug TR2-1, TR2-2, TR2-3, and TR2-4 in conformance with state requirements at 47 CSR 13-13.4. After completing the planned CO_2 injection, the tubing and completion hardware will be retrieved, and the perforated intervals will be squeezed and plugged off with CO_2 resistant cement. The well will be plugged and abandoned with cement plugs across each casing shoe until surface. Tri-State CCS, LLC may elect to delay plugging the well to monitor in-zone reservoir conditions post-injection to enhance monitoring of reservoir conditions.

The plugging process and materials are designed to prevent unwanted fluid movement, resist corrosion caused by CO_2/water mixtures, and safeguard USDWs. Prior to plugging either injection zone, the final bottom-hole pressure of the injection wells will be measured, and an inhibited spacer fluid (brine) will be used to flush and fill the wells to maintain pressure control and inhibit corrosion. The measured bottom-hole pressure and temperature will guide the selection of the appropriate weight of brine to stabilize the well and inform decisions regarding the blend of cement needed to plug the well, addressing considerations such as preventing leak-off or premature setting. Mechanical integrity tests (MITs), including external methods such as temperature logs, oxygen activation logs, noise logs, and pulsed neutron logs, will be conducted before plugging. If mechanical integrity is compromised, repairs will be made before proceeding with plugging operations.

The injection tubing and completion hardware will be removed from the wells. If the packers cannot be removed after flushing, they may be cut from the tubing and left in the well. The injection zones will be plugged using the retainer method, squeezing CO_2-resistant cement into the perforations. Balanced plugs will be used to isolate the remainder of the well, with CO_2-resistant cement employed in the injection and confining zones and Class A neat cement or equivalent used in shallower plugs.

Tri-State CCS, LLC will submit updates to the plan, notifications, and reports as detailed in subsection 5.1 of the Injection Well Plugging Plan for each injection well. This includes delayed plugging notifications, 60-day notifications prior to plugging, and well plugging reports to ensure regulatory compliance and transparency.

3.8. Post-Injection Site Care and Site Closure Plan

The Post-Injection Site Care and Site Closure Plan outlines activities Tri-State CCS, LLC will undertake to meet the requirements of 47 CSR 13-13.8.1.q. Monitoring will continue for 50 years post-injection for the Lockport Dolomite and Medina Groups, focusing on groundwater quality, CO_2 plume, and pressure front tracking. Monitoring will not cease until a demonstration of non-endangerment of USDWs is approved by the UIC Program Director under 40 CFR 146.93(b)(3). Upon site closure approval, all monitoring wells will be plugged, the site restored, and a closure report submitted.

Figures 1 through 4 in the Post-Injection Site Care and Site Closure Plan illustrate pressure differential trends, CO_2 plume extent, and predicted pressure fronts. Monitoring includes groundwater sampling, pressure and temperature measurements, and direct and indirect plume tracking, as detailed in Tables 1 through 6 of the plan. Results will be reported annually within 60 days of the injection cessation anniversary.

Non-endangerment demonstrations will utilize monitoring data and computational modeling to confirm reservoir stability and USDW protection. Plume behavior, pressure decline, and groundwater quality comparisons to baseline data will validate these findings. All injection wells will be plugged and abandoned per the Injection Well Plugging Plan for each injection well and applicable state regulations.

Site closure activities include equipment decommissioning, observation well plugging, and site restoration to pre-injection conditions. A final Site Closure Report, including well plugging details and injection records, will be submitted to the UIC Program Director and retained for 10 years. Records from the post-injection period will also be maintained and submitted as required.

3.9. Emergency and Remedial Response Plan

The ERRP describes actions that Tri-State CCS, LLC will take to address an emergency in the AoR that may cause movement of the injection fluid or formation fluid in a manner that may endanger a USDW during the construction, operation, or PISC periods, pursuant to 47 CSR 13-13.7.

Examples of potential risks include: (1) injection or observation well integrity failure, (2) injection well monitoring and/or surface equipment failure, (3) natural disaster, (4) fluid leakage into a USDW, (5) CO_2 leakage to USDW or land surface, or (6) an induced or natural seismic event. In the case of one of the listed risks, site personnel, project personnel, and local authorities will be relied upon to implement this ERRP. Tri-State CCS, LLC will communicate to the public any event that requires an emergency response, as described in the ERRP, to ensure that the public understands what happened and whether there are any environmental or safety implications. This will include a detailed description of what happened, any impacts to the environment or other local resources, how the event was investigated, what actions were taken, and the status of the remediation.

If Tri-State CCS, LLC obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, Tri-State CCS, LLC will perform the following actions:

1. Initiate shutdown plan for the injection well(s).
2. Take all steps reasonably necessary to identify and characterize any release.
3. Notify the 24-hour Emergency Contact (Appendix B of the ERRP) followed by the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
4. Implement applicable portions of the approved ERRP.

The emergency contact list in Appendix B of the ERRP will be updated annually at a minimum, and the ERRP will be reviewed at least once every five years following its approval as well as within one year of an AoR reevaluation and following any significant changes to the injection process or the injection facility or an emergency event. Periodic training will be provided, not less than annually, to construction personnel, well operators, project safety personnel, environmental personnel, the operations manager, and corporate communications. The training plan will record that the necessary personnel have been trained and possess the required skills to perform their relevant emergency response activities described in the ERRP.

3.10. Environmental Justice Plan

An Environmental Justice Plan was prepared for the project pursuant to Part III.F of the *Memorandum of Agreement Amended Addendum 1 between WVDEP and U.S. EPA, Region 3* dated October 9, 2024, delegating primacy authority for Class VI UIC well permitting to WVDEP. This plan provides an environmental justice assessment for the AoR identifying minority and low-income populations and describes project benefits and disbenefits. The project's Stakeholder Engagement Strategy is detailed as well as progress to date on implementing the plan.

3.11. Groundwater Protection Plan

The Groundwater Protection Plan (GPP) for the project outlines measures to comply with 47 CSR 58-4 by identifying potential sources of groundwater contamination—such as drilling through USDWs, chemical spills, and wellbore integrity failures—and implementing prevention strategies. These include a closed-loop system, secondary containment with a 20-mil liner, offsite disposal of fluids, cementing casing strings to surface, and numerous safeguards like pressure testing, corrosion monitoring, and injection pressure limits.

3.12. Injection Depth Waiver and Aquifer Exemption Expansion

No injection depth waiver or aquifer exemption expansion is required in this application.

3.13. Additional Project Information [47 CSR 13-13.8.1.u]

Because the project is receiving federal funding under the CarbonSAFE initiative, potential impacts to natural resources will be evaluated through the National Environmental Policy Act (NEPA) process with the U.S. Department of Energy as the Lead Agency. Permanent surface impacts of the project will be limited to about 1 acre at each well site, while temporary surface impacts during construction will be about 4 acres at each well site. No demolition of existing structures is planned for the project at this time.

The following is provided to help with determining other federal laws that may be applicable to development of the project and potential impacts:

- No national wild and scenic rivers protected under the Wild and Scenic Rivers Act are found within the AoR.
- There is one site in the AoR listed or eligible for listing in the National Register of Historic Places under the National Historic Preservation Act of 1966. The site is the David Stewart Farm or Rock Valley Farm in Ohio County, WV, and is approximately 0.3 miles southwest of TR2-IOB-2. No project activity is planned for this site, and any viewshed impacts during construction or operation of the project would be limited due to topography and land cover. Consultation with the State Historic Preservation Office, led by the U.S. Department of Energy, will be documented through the NEPA process to ensure mitigation of any potential project impacts to cultural resources.

- U.S. Fish and Wildlife Service's Information for Planning and Consultation tool indicates that there are two federally listed threatened or endangered species protected under the Endangered Species Act and three proposed listed species that may be present in the AoR: Indiana bat and northern long-eared bat are listed as endangered, tri-colored bat and salamander mussel are proposed as endangered, and monarch butterfly is proposed as threatened. The project will avoid tree clearing to the extent possible and work with U.S. Department of Energy and U.S. Fish and Wildlife Service to mitigate potential impacts to protected bats which will be documented through the NEPA process.
- The AoR is not within a coastal zone protected under the Coastal Zone Management Act.

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Appendix A: Detailed Water Well Completion Records for the Area of Review

#	Record Number	State	County	Total Depth (ft)	Aquifer Formation	Latitude (WGS 84)	Longitude (WGS 84)
1	USGS-395538080395901	West Virginia	Marshall	143	Pennsylvanian aquifers	39.927298	-80.666192
2	USGS-395546080381401	West Virginia	Marshall	75	Pennsylvanian aquifers	39.929520	-80.637024
3	USGS-395603080333301	West Virginia	Marshall	90	Dunkard Group	39.934243	-80.558963
4	USGS-395603080333302	West Virginia	Marshall	91	Dunkard Group	39.934243	-80.558963
5	USGS-395616080325301	West Virginia	Marshall	175	Dunkard Group	39.937854	-80.547852
6	USGS-395620080374101	West Virginia	Marshall	135	Dunkard Group	39.938965	-80.627856
7	USGS-395626080353201	West Virginia	Marshall	90	Pennsylvanian aquifers	39.940631	-80.592021
8	USGS-395632080353301	West Virginia	Marshall	80	Pennsylvanian aquifers	39.942298	-80.592298
9	USGS-395713080363101	West Virginia	Marshall	96	Dunkard Group	39.953687	-80.608410
10	USGS-395731080382601	West Virginia	Marshall	150	Pennsylvanian aquifers	39.958686	-80.640356
11	USGS-395731080390901	West Virginia	Marshall	115	Dunkard Group	39.958686	-80.652301
12	USGS-395734080384101	West Virginia	Marshall	150	Pennsylvanian aquifers	39.959519	-80.644523
13	USGS-395735080384801	West Virginia	Marshall	96	Dunkard Group	39.959797	-80.646468
14	USGS-395736080330601	West Virginia	Marshall	82	Pennsylvanian aquifers	39.960076	-80.551462
15	USGS-395736080384801	West Virginia	Marshall	19.5	Dunkard Group	39.960075	-80.646468
16	USGS-395737080384901	West Virginia	Marshall	23.66	Dunkard Group	39.960353	-80.646745
17	USGS-395737080384902	West Virginia	Marshall	59	Pennsylvanian aquifers	39.960353	-80.646745
18	USGS-395738080390001	West Virginia	Marshall	20	Dunkard Group	39.960630	-80.649801
19	USGS-395745080383701	West Virginia	Marshall	150	Dunkard Group	39.962575	-80.643412
20	USGS-395746080383801	West Virginia	Marshall	35	Dunkard Group	39.962853	-80.643690
21	USGS-395747080311701	West Virginia	Marshall	100	Pennsylvanian aquifers	39.963132	-80.521183
22	USGS-395747080311702	West Virginia	Marshall	55	Pennsylvanian aquifers	39.963132	-80.521183
23	USGS-395800080350801	West Virginia	Marshall	54.92	Pennsylvanian aquifers	39.966742	-80.585353
24	USGS-395805080360801	West Virginia	Marshall	43	Monongahela Formation	39.968131	-80.602021
25	USGS-395807080360201	West Virginia	Marshall	40	Monongahela Formation	39.968686	-80.600354
26	USGS-395828080365601	West Virginia	Marshall	100	Pennsylvanian aquifers	39.974519	-80.615354
27	USGS-395830080395101	West Virginia	Marshall	130	Dunkard Group	39.975074	-80.663968
28	USGS-395832080393001	West Virginia	Marshall	109	Dunkard Group	39.975630	-80.658135
29	USGS-395833080392601	West Virginia	Marshall	139.6	Dunkard Group	39.975908	-80.657023
30	USGS-395834080392701	West Virginia	Marshall	22	Dunkard Group	39.976186	-80.657301
31	USGS-395836080393501	West Virginia	Marshall	130	Dunkard Group	39.976741	-80.659524
32	USGS-395837080392401	West Virginia	Marshall	122.3	Dunkard Group	39.977019	-80.656468

#	Record Number	State	County	Total Depth (ft)	Aquifer Formation	Latitude (WGS 84)	Longitude (WGS 84)
33	USGS-395837080392501	West Virginia	Marshall	120	Dunkard Group	39.977019	-80.656746
34	USGS-395846080385801	West Virginia	Marshall	35	Dunkard Group	39.979519	-80.649245
35	USGS-395847080385801	West Virginia	Marshall	92	Dunkard Group	39.979797	-80.649245
36	USGS-395847080385901	West Virginia	Marshall	92	Dunkard Group	39.979797	-80.649523
37	USGS-395914080385401	West Virginia	Marshall	105	Dunkard Group	39.987297	-80.648134
38	USGS-395921080390901	West Virginia	Marshall	158	Dunkard Group	39.989241	-80.652301
39	USGS-395921080390902	West Virginia	Marshall	100	Dunkard Group	39.989241	-80.652301
40	USGS-395924080400601	West Virginia	Marshall	80	Dunkard Group	39.990074	-80.668135
41	USGS-395925080321801	West Virginia	Marshall	151	Pennsylvanian aquifers	39.990353	-80.538127
42	USGS-395927080381301	West Virginia	Marshall	100	Dunkard Group	39.990908	-80.636744
43	USGS-395938080320701	West Virginia	Marshall	102	Dunkard Group	39.993964	-80.535071
44	USGS-395940080350901	West Virginia	Marshall	117	Pennsylvanian aquifers	39.994519	-80.585630
45	USGS-395940080390401	West Virginia	Marshall	33	Dunkard Group	39.994519	-80.650911
46	USGS-395943080390701	West Virginia	Marshall	114	Dunkard Group	39.995352	-80.651745
47	USGS-395944080393401	West Virginia	Marshall	101	Dunkard Group	39.995630	-80.659245
48	USGS-395944080393901	West Virginia	Marshall	157	Dunkard Group	39.995630	-80.660634
49	USGS-395946080391201	West Virginia	Marshall	143.5	Dunkard Group	39.996185	-80.653134
50	USGS-395946080391202	West Virginia	Marshall	100	Dunkard Group	39.996185	-80.653134
51	USGS-400003080361701	West Virginia	Marshall		Dunkard Group	40.000908	-80.604520
52	USGS-400006080382201	West Virginia	Marshall	56	Pennsylvanian aquifers	40.001741	-80.639244
53	USGS-400021080380501	West Virginia	Marshall	38	Pennsylvanian aquifers	40.005907	-80.634521
54	USGS-400024080380601	West Virginia	Marshall	140.3	Pennsylvanian aquifers	40.006741	-80.634799
55	USGS-400027080383701	West Virginia	Marshall	50	Monongahela Formation	40.007574	-80.643411
56	USGS-400027080383801	West Virginia	Marshall	28	Monongahela Formation	40.007574	-80.643689
57	USGS-400030080381401	West Virginia	Marshall	160	Pennsylvanian aquifers	40.008407	-80.637022
58	USGS-400030080381402	West Virginia	Marshall	50	Pennsylvanian aquifers	40.008407	-80.637022
59	USGS-400031080381501	West Virginia	Marshall	52	Monongahela Formation	40.008685	-80.637299
60	USGS-400031080381701	West Virginia	Marshall	162	Monongahela Formation	40.008685	-80.637855
61	USGS-400031080381702	West Virginia	Marshall	160	Monongahela Formation	40.008685	-80.637855
62	USGS-400032080381301	West Virginia	Marshall	155.6	Pennsylvanian aquifers	40.008963	-80.636744
63	USGS-400032080381302	West Virginia	Marshall	133.8	Pennsylvanian aquifers	40.008963	-80.636744
64	USGS-400032080384701	West Virginia	Marshall	156	Pennsylvanian aquifers	40.008963	-80.646189
65	USGS-400035080381201	West Virginia	Marshall	65	Pennsylvanian aquifers	40.009796	-80.636466
66	USGS-400035080385801	West Virginia	Marshall	50	Pennsylvanian aquifers	40.009796	-80.649244
67	USGS-400038080370701	West Virginia	Ohio		Pennsylvanian aquifers	40.010630	-80.618409
68	USGS-400041080312201	West Virginia	Marshall	75	Pennsylvanian aquifers	40.011464	-80.522570

#	Record Number	State	County	Total Depth (ft)	Aquifer Formation	Latitude (WGS 84)	Longitude (WGS 84)
69	USGS-400043080334101	West Virginia	Marshall	41	Pennsylvanian aquifers	40.012019	-80.561184
70	USGS-400054080374001	West Virginia	Marshall	63.6	Dunkard Group	40.015074	-80.627577
71	USGS-400057080371901	West Virginia	Marshall	83	Dunkard Group	40.015907	-80.621743
72	USGS-400104080370601	West Virginia	Marshall	190	Dunkard Group	40.017852	-80.618132
73	USGS-400104080370602	West Virginia	Marshall	130	Dunkard Group	40.017852	-80.618132
74	USGS-400105080365201	West Virginia	Marshall	26.5	Dunkard Group	40.018130	-80.614242
75	USGS-400116080340401	West Virginia	Ohio	80		40.021185	-80.567573
76	USGS-400116080403701	West Virginia	Marshall	140	Dunkard Group	40.021185	-80.676746
77	USGS-400120080360701	West Virginia	Marshall	45	Dunkard Group	40.022296	-80.601742
78	USGS-400120080364501	West Virginia	Marshall	98	Dunkard Group	40.022296	-80.612298
79	USGS-400124080364401	West Virginia	Marshall	150	Dunkard Group	40.023407	-80.612020
80	USGS-400125080345301	West Virginia	Ohio	105	Dunkard Group	40.023685	-80.581185
81	USGS-400125080364601	West Virginia	Marshall	100	Dunkard Group	40.023685	-80.612576
82	USGS-400128080353201	West Virginia	Ohio	90		40.024518	-80.592019
83	USGS-400128080363601	West Virginia	Ohio	102	Dunkard Group	40.024518	-80.609798
84	USGS-400130080363001	West Virginia	Ohio	96	Dunkard Group	40.025074	-80.608131
85	USGS-400133080363001	West Virginia	Ohio	75		40.025907	-80.608131
86	USGS-400133080363501	West Virginia	Ohio	57	Dunkard Group	40.025907	-80.609520
87	USGS-400147080364701	West Virginia	Ohio	114.8	Dunkard Group	40.029796	-80.612853
88	USGS-400149080391101	West Virginia	Ohio	68	Pennsylvanian aquifers	40.030351	-80.652856
89	USGS-400149080391102	West Virginia	Ohio	25	Pennsylvanian aquifers	40.030351	-80.652856
90	USGS-400150080382201	West Virginia	Ohio	123		40.030629	-80.639244
91	USGS-400158080350801	West Virginia	Ohio	200	Pennsylvanian aquifers	40.032852	-80.585352
92	USGS-400200080315901	West Virginia	Ohio	35		40.033408	-80.532849
93	USGS-400203080354101	West Virginia	Ohio	23	Pennsylvanian aquifers	40.034241	-80.594519
94	USGS-400204080362801	West Virginia	Ohio	56	Pennsylvanian aquifers	40.034518	-80.607575
95	USGS-400204080362802	West Virginia	Ohio	38	Pennsylvanian aquifers	40.034518	-80.607575
96	USGS-400210080363501	West Virginia	Ohio	35	Pennsylvanian aquifers	40.036185	-80.609520
97	USGS-400211080342501	West Virginia	Ohio	30	Pennsylvanian aquifers	40.036463	-80.573407
98	USGS-400211080344701	West Virginia	Ohio	10		40.036463	-80.579518
99	USGS-400213080380501	West Virginia	Ohio	87		40.037018	-80.634521
100	USGS-400213080382501	West Virginia	Ohio	114		40.037018	-80.640077
101	USGS-400213080384401	West Virginia	Ohio	60		40.037018	-80.645355
102	USGS-400226080322401	West Virginia	Ohio	105		40.040630	-80.539794
103	USGS-400227080373201	West Virginia	Ohio	39	Monongahela Formation	40.040907	-80.625354
104	USGS-400229080350501	West Virginia	Ohio	75		40.041463	-80.584518

#	Record Number	State	County	Total Depth (ft)	Aquifer Formation	Latitude (WGS 84)	Longitude (WGS 84)
105	USGS-400232080364401	West Virginia	Ohio	20		40.042296	-80.612020
106	USGS-400235080334301	West Virginia	Ohio	100		40.043129	-80.561739
107	USGS-400235080335501	West Virginia	Ohio	88	Pennsylvanian aquifers	40.043129	-80.565073
108	USGS-400235080374601	West Virginia	Ohio	40	Pennsylvanian aquifers	40.043129	-80.629243
109	USGS-400239080330401	West Virginia	Ohio	30	Dunkard Group	40.044241	-80.550350
110	USGS-400239080330402	West Virginia	Ohio	70	Dunkard Group	40.044518	-80.551183
111	USGS-400239080370001	West Virginia	Ohio	22	Pennsylvanian aquifers	40.044240	-80.616465
112	USGS-400239080371501	West Virginia	Ohio	25	Pennsylvanian aquifers	40.044240	-80.620632
113	USGS-400240080323701	West Virginia	Ohio	46	Pennsylvanian aquifers	40.044518	-80.543405
114	USGS-400240080335001	West Virginia	Ohio	90	Pennsylvanian aquifers	40.044518	-80.563684
115	USGS-400240080361201	West Virginia	Ohio	180		40.044518	-80.603131
116	USGS-400240080375001	West Virginia	Ohio	43	Pennsylvanian aquifers	40.044518	-80.630354
117	USGS-400242080335401	West Virginia	Ohio	120	Dunkard Group	40.045074	-80.564795
118	USGS-400243080334601	West Virginia	Ohio	120	Dunkard Group	40.045352	-80.562573
119	USGS-400248080360001	West Virginia	Ohio	60		40.046740	-80.599797
120	USGS-400249080340401	West Virginia	Ohio	100	Pennsylvanian aquifers	40.047018	-80.567573
121	USGS-400250080375801	West Virginia	Ohio	49	Pennsylvanian aquifers	40.047296	-80.632577
122	USGS-400253080385601	West Virginia	Ohio	147	Pennsylvanian aquifers	40.048129	-80.648689
123	USGS-400255080312101	West Virginia	Ohio	27		40.048685	-80.522293
124	USGS-400255080312102	West Virginia	Ohio	105		40.048685	-80.522293
125	USGS-400256080332001	West Virginia	Ohio	110	Pennsylvanian aquifers	40.048963	-80.555350
126	USGS-400256080335501	West Virginia	Ohio	90	Pennsylvanian aquifers	40.048963	-80.565073
127	USGS-400310080373601	West Virginia	Ohio	12		40.052851	-80.626465
128	USGS-400311080383801	West Virginia	Ohio	125	Pennsylvanian aquifers	40.053129	-80.643688
129	USGS-400317080350201	West Virginia	Ohio	120		40.054796	-80.583685
130	USGS-400317080353601	West Virginia	Ohio	48		40.054796	-80.593130
131	USGS-400324080315501	West Virginia	Ohio	59		40.056741	-80.531738
132	USGS-400336080365401	West Virginia	Ohio	14		40.060073	-80.614798
133	USGS-400347080365901	West Virginia	Ohio		Pennsylvanian aquifers	40.063129	-80.616187
134	PA Well ID: 637940	Pennsylvania	Greene	300		39.961000	-80.518510

Appendix B: Detailed Water Well Geochemistry for the Area of Review

#	County	Collection Date (Year/Month)	Location Type	Latitude (WGS 84)	Longitude (WGS 84)	pH	Water Temperature (°C)	Total Dissolved Solids (mg/L)
1	Marshall	2008/9	Spring	39.914583	-80.592916	7.39		194
2	Marshall	2014/8	Spring	39.914797	-80.654951	7.71	19.71	324
3	Marshall	2015/3	Spring	39.916095	-80.660270	7.8	19.7	282
4	Marshall	2014/8	Spring	39.916095	-80.660272	7.83	21.63	327
5	Marshall	2014/8	Spring	39.916234	-80.655589	6.97	20.48	435
6	Marshall	2015/4	Well	39.916691	-80.596601			242
7	Marshall	2014/7	Spring	39.918113	-80.645597	7.82	19.98	220
8	Marshall	2008/7	Well	39.918556	-80.584832			470
9	Marshall	2014/7	Spring	39.919673	-80.651164	7.88	16.12	349
10	Marshall	2014/9	Spring	39.919797	-80.658348	7.41	21.58	345
11	Marshall	2014/9	Well	39.921371	-80.654731	7.22	13.33	350
12	Marshall	2008/7	Spring	39.921861	-80.581945			48
13	Marshall	2014/9	Spring	39.922414	-80.655022	7.36	17.79	460
14	Marshall	2008/7	Spring	39.924055	-80.577833			218
15	Marshall	2008/7	Spring	39.924138	-80.582000			196
16	Marshall	2008/7	Spring	39.925611	-80.577416			250
17	Marshall	2008/7	Well	39.925972	-80.578666			312
18	Marshall	2008/9	Spring	39.927055	-80.574805	6.89		228
19	Marshall	2014/2	Spring	39.927140	-80.579780			269
20	Marshall	2008/7	Spring	39.927250	-80.579861			216
21	Marshall	2008/9	Well	39.927499	-80.574249	7.11		320
22	Marshall	2008/9	Spring	39.927555	-80.574111	6.94		162
23	Marshall	2017/12	Well	39.938514	-80.549444			498
24	Marshall	2015/4	Spring	39.961369	-80.593366			270
25	Marshall	2015/4	Well	39.961826	-80.592621			314
26	Marshall	2015/3	Well	39.961847	-80.590799			200
27	Marshall	2015/4	Spring	39.962086	-80.595001			242
28	Marshall	2015/3	Well	39.964139	-80.587050			684
29	Marshall	2015/5	Well	39.965462	-80.584616			558
30	Marshall	2008/9	Spring	39.966750	-80.586694	7.61		206
31	Marshall	2015/3	Well	39.967589	-80.610219			221
32	Marshall	2015/3	Well	39.969206	-80.610019			251
33	Marshall	2015/4	Spring	39.970182	-80.610135			86.5

#	County	Collection Date (Year/Month)	Location Type	Latitude (WGS 84)	Longitude (WGS 84)	pH	Water Temperature (°C)	Total Dissolved Solids (mg/L)
34	Marshall	2015/7	Well	39.994434	-80.630142	7.5	23.1	276
35	Marshall	2015/6	Well	39.996360	-80.630854	8.3	23.5	393
36	Marshall	2015/6	Well	39.996861	-80.631353	7.9	23.7	284
37	Marshall	2017/10	Spring	39.997171	-80.618830	7.68		225
38	Marshall	2015/7	Well	39.997289	-80.640441			224
39	Marshall	2017/10	Spring	39.998500	-80.619000	7.85		343
40	Marshall	2017/10	Spring	39.999322	-80.619085	7.73		320
41	Marshall	2018/3	Spring	40.001047	-80.620293	7.52		392
42	Marshall	2017/10	Well	40.001100	-80.618591	8.2		473
43	Marshall	2014/12	Spring	40.001646	-80.582717	7.63	5.28	328
44	Marshall	2014/11	Spring	40.003047	-80.575085			388
45	Marshall	2018/3	Spring	40.003330	-80.620160	8.66		391
46	Marshall	2017/10	Well	40.005694	-80.634492	9.62		634
47	Marshall	2017/10	Spring	40.005725	-80.634266	7.95		388
48	Marshall	2015/6	Well	40.005726	-80.634438	9	21.7	615
49	Marshall	2014/11	Spring	40.006135	-80.576195			306
50	Marshall	2014/11	Spring	40.006308	-80.583676			254
51	Marshall	2017/10	Well	40.006876	-80.638277	6.91		285
52	Marshall	2017/10	Spring	40.007561	-80.633670	8.5		370
53	Ohio	2018/2	Spring	40.008766	-80.551451	8.5	10.2	108
54	Marshall	2018/3	Spring	40.008790	-80.614490	7.64		249
55	Marshall	2017/10	Well	40.010038	-80.636414	7.82		137
56	Ohio	2018/2	Spring	40.010266	-80.548075	7.66	10.14	261
57	Ohio	2018/2	Spring	40.010426	-80.547957	7.62	10.41	264
58	Marshall	2017/10	Spring	40.010510	-80.635965	8.83		677
59	Ohio	2018/2	Spring	40.011045	-80.546317	8.69	4.6	23
60	Ohio	2018/2	Spring	40.011505	-80.547566	7.57	11.92	271
61	Ohio	2018/2	Spring	40.013630	-80.547280	7.43	12.54	365
62	Marshall	2014/10	Well	40.016277	-80.574606			298
63	Marshall	2018/3	Spring	40.017170	-80.614330	7.29		285
64	Marshall	2018/3	Spring	40.017176	-80.612738	7.63		208
65	Marshall	2014/12	Spring	40.017316	-80.580858	7.91	3.3	262
66	Ohio	2017/10	Well	40.017509	-80.532952	7.74	11.06	246
67	Ohio	2018/2	Spring	40.017864	-80.553095	7.36	8.42	237
68	Marshall	2014/12	Spring	40.019287	-80.583269	6.98	7.8	216

#	County	Collection Date (Year/Month)	Location Type	Latitude (WGS 84)	Longitude (WGS 84)	pH	Water Temperature (°C)	Total Dissolved Solids (mg/L)
69	Ohio	2017/10	Well	40.021138	-80.558729	7.43	13.96	545
70	Marshall	2014/10	Spring	40.021743	-80.576310			266
71	Marshall	2014/12	Spring	40.022186	-80.583646	6.56	7.25	130
72	Marshall	2014/10	Well	40.022834	-80.577084			210
73	Ohio	2017/10	Well	40.023211	-80.559437	6.3	14.27	251
74	Ohio	2018/2	Spring	40.023671	-80.538187	7.79	9.15	95
75	Ohio	2018/2	Spring	40.024719	-80.542007	8.48	8.37	36
76	Marshall	2014/10	Spring	40.024987	-80.575338			262
77	Ohio	2018/2	Spring	40.025890	-80.540330	7.7	8.68	41
78	Ohio	2017/9	Well	40.026563	-80.563750	7.99	18.15	329
79	Ohio	2015/12	Spring	40.028351	-80.611728	7.92	9.58	
80	Ohio	2015/10	Spring	40.028777	-80.599874	6.26	13.09	
81	Ohio	2017/10	Well	40.030493	-80.547933	8.35	13.64	216
82	Ohio	2016/10	Well	40.031136	-80.557706	9.26	17.46	448
83	Ohio	2018/2	Well	40.031373	-80.558422	7.43	9.81	222
84	Ohio	2016/10	Spring	40.032938	-80.544754	6.94	12.41	219
85	Ohio	2015/9	Spring	40.033310	-80.614543	7.01	17.27	
86	Ohio	2015/9	Spring	40.033640	-80.614469	8.08	19.65	
87	Ohio	2015/10	Well	40.033948	-80.602197	5.34	12.46	
88	Ohio	2016/10	Well	40.035013	-80.541065	7.5	12.94	294
89	Ohio	2016/11	Spring	40.035419	-80.539408	7.4	14.29	248
90	Ohio	2016/10	Well	40.035708	-80.540955	7.4	13.49	363
91	Ohio	2016/11	Well	40.036729	-80.538547	7.2	17.49	225
92	Ohio	2016/10	Spring	40.036742	-80.555455	7.92	14.51	222
93	Ohio	2016/10	Well	40.040536	-80.551783	7.82	14.17	260
94	Ohio	2016/10	Spring	40.040551	-80.551077	7.93	14.07	275
95	Ohio	2016/11	Well	40.041056	-80.555878	8.27	17.25	138
96	Ohio	2016/10	Well	40.041115	-80.543649	6.77	13.23	263
97	Ohio	2016/10	Spring	40.041481	-80.541122	7.78	16.67	555
98	Ohio	2016/10	Spring	40.043224	-80.539053	6.24	14.59	288
99	Ohio	2016/10	Spring	40.043935	-80.539848	7.85	19.21	289
100	Ohio	2016/10	Spring	40.044216	-80.540094	7.86	18.58	277
101	Ohio	2016/10	Spring	40.044558	-80.541723	7.53	21.05	298
102	Ohio	2016/10	Well	40.044778	-80.543820	7.87	14.99	413
103	Ohio	2016/10	Spring	40.045083	-80.551032	7.78	12.2	237

#	County	Collection Date (Year/Month)	Location Type	Latitude (WGS 84)	Longitude (WGS 84)	pH	Water Temperature (°C)	Total Dissolved Solids (mg/L)
104	Ohio	2016/10	Well	40.045762	-80.545080	7.78	12.88	544
105	Ohio	2016/10	Spring	40.046269	-80.539212	7.96	18.18	230
106	Ohio	2016/11	Well	40.046631	-80.553114	7.19	13.4	242
107	Ohio	2016/11	Spring	40.046929	-80.552089	7.32	14.41	224
108	Ohio	2016/10	Spring	40.047738	-80.543563	6.28	9.8	207
109	Ohio	2016/11	Spring	40.048204	-80.550703	7.22	13.99	183
110	Ohio	2016/10	Spring	40.049341	-80.540592	8.09	18.83	174

Appendix C: Map of the AoR with all Oil and Gas wells and their status. See Appendices A-D in the Area of Review and Corrective Action Plan for specific well information. A larger, higher resolution version is attached separately.