Central Appalachian Basin CarbonSAFE

Integrated Pre-Feasibility Project

Final Technical Report

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List of Acronyms and Abbreviations

2D	two-dimensional
3D	three-dimensional
ADM	Archer Daniels Midland
AEP	American Electric Power
AoR	area of review
BBL/day	barrels per day
bcf	billion cubic feet
BFG	blast furnace gas
BFS	blast furnace stove
BHGE	Baker Hughes General Electric
BOF	basic oxygen furnace
CAB-CS	Central Appalachian Basin CarbonSAFE
CarbonSAFE	Carbon Storage Assurance Facility Enterprise
CCS	carbon capture and storage
CCUS	carbon, capture, utilization and storage
CMG	Computer Modelling Group, Ltd.
CO_2	carbon dioxide
COG	coke oven gas
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
EAF	electric arc furnace
eGRID	Emissions and Generation Resource Integrated Database
EGU	electricity generating unit
EIA	Energy Information Administration
EOR	enhanced oil recovery
EPRI	Electric Power Research Institute
FEED	front-end engineering design
ft	foot
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
gpm	gallon per minute
IAM	Integrated Assessment Model
IEA	International Energy Agency
IFOT	injection fall-off test
IPCC	International Panel on Climate Change
k	permeability
kh	transmissivity
kh_{op}	operational transmissivity
LANL	Los Alamos National Laboratory
LHV	lower heating value
mD	millidarcy
mD-ft	millidarcy-Foot
mg/L	milligrams per liter
mi^2	square mile

MLP	Master Limited Partnerships
MMcf	million standard cubic feet (per day)
MMt	million metric ton
MRCSP	Midwest Regional Carbon Sequestration Partnership
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NGCC	natural gas combined cycle
NGO	nongovernmental organization
NLCD	National Land Cover Database
NMR	nuclear magnetic resonance [wireline log]
NO_x	nitrogen oxide
NRAP	National Risk Assessment Protocol
NRAP-IAM-CS	National Risk Assessment Protocol-Integrated Assessment Model-Carbon Sequestration
OCDO	Ohio Coal Development Office
ODNR	Ohio Department of Natural Resources
OEPA	Ohio Environmental Protection Agency
OhioSeis	Ohio Seismic Network
ppm	part per million
PPA	power purchase agreement
PPS	power plant stack
psi	pounds per square inch
psig	pounds per square inch gauge
psi/ft	pounds per square inch per foot
REV	Reservoir Evaluation and Visualization [NRAP tool]
ROM	reduced-order model
ROWs	rights-of-way
ROZs	residual oil zones
RPSEA	Research Partnership to Secure Energy for America
SCADA	Supervisory Control and Data Acquisition
SCR	Stable Continental Region
SimCCS	Scalable Infrastructure Model for CO_2 Capture and Storage
SO_x	sulfur oxide
SO_2	sulfur dioxide
TDS	total dissolved solids
UIC	Underground Injection Control
USDW	underground source of drinking water
U.S. EPA	United States Environmental Protection Agency
USGS	United States Geological Survey
Vorys	Vorys, Sater, Seymour, and Pease LLP

Executive Summary

The Central Appalachian Basin CarbonSAFE (CAB-CS) Integrated Prefeasibility Project is a part of the U.S. Department of Energy's (DOE's) Carbon Storage Assurance Facility Enterprise (CarbonSAFE) initiative, which seeks to help mitigate carbon dioxide (CO_2) emissions from the burning of fossil fuels. The CarbonSAFE initiative aims to develop an integrated carbon capture and storage (CCS) complex constructed and permitted for operation by 2025 through a series of sequential benchmarks: Integrated CCS Prefeasibility (Phase I), Storage Complex Feasibility (Phase II), Site Characterization and Permitting (Phase III), and Construction (Phase IV). CCS, which is also referred to as CCUS (carbon, capture, utilization and storage), is the method of capturing CO_2 emissions from a large industrial point source and permanently storing it in deep underground rock formations. CCUS is an important option in addressing climate change to prevent warming beyond 2°C while minimizing the disruption to economic development and energy supplies.

This project was the first step in developing a commercial-scale CCUS project. This Phase I project provided an integrated prefeasibility study of the Central Appalachian Basin, focusing on eastern Ohio, where previous efforts funded by the DOE and the Ohio Coal Development Office (OCDO) have defined storage potential in Cambrian-Ordovician age carbonate and clastic formations. Phase I began the process of taking into account all the technical, socio-economic, scientific, and legislative aspects related to implementation of a CCS project in this area. The Central Appalachian Basin is attractive for developing a CarbonSAFE project because the local geology is suited for CCUS and the technology can add value in the regional energy system. CCUS projects can play a role in developing affordable energy, a cleaner environment, and economic opportunities. This region has many large industrial point sources including coal-fired power plants, natural gas processing, refineries, chemical plants, and natural gas power plants.

Results

As described below, the project successfully provided an assessment of the factors that need to be considered for the development of a CCUS project, including suitable sources, suitable geology, project definition, project integration, and team building.

Source suitability was assessed by identifying electricity generation and/or industrial sources large enough to provide CO_2 emissions for a commercial-scale storage project. Because of its importance to Ohio's economy, sources that use coal were a focus of this assessment. A detailed accounting of the sources in the region that are suitable for commercial-scale CCUS projects was achieved, including:

- Facility-wide and unit-scale emissions of existing and proposed large point sources in the region;
- source-sink pipeline routing for 25 of the most promising capture/storage scenarios;
- analysis of carbon capture technology pertinent to the region; and
- in-depth analysis of six promising scenarios for a commercial-scale CCUS project.

Geological suitability was assessed through the identification of geologic areas that can safely and permanently store CO_2 for a commercial-scale CCUS project (i.e., 50 million metric tonnes [MMt] over 30 years). This assessment found sufficient CO_2 storage capacity, high injectivity within the storage zone, presence of a thick and competent geologic seal (caprock), low risk for

tectonic and seismic activity, and low risk posed by existing (legacy) wells that penetrate the storage reservoir or caprock. Results included:

- storage capacity estimates for the primary and secondary selected areas;
- analysis of caprock integrity;
- assessment of geologic hazards like faulting, tectonics, and induced seismicity;
- establishment of an Area of Review (AoR) for the primary and secondary selected areas using site-specific data; and
- initial assessment of the risk posed by existing (legacy) wells using National Risk Assessment Partnership-Integrated Assessment Model for Carbon Storage (NRAP-IAM-CS) for the primary and secondary selected areas.

The project definition, including project dimensions, infrastructure requirements, mineral and property rights, and site screening for a commercial-scale CCUS project, was determined. Results included:

- reservoir modeling to establish CO2 plume migration and pressure fronts;
- accounting for the infrastructure required for a commercial-scale CCS project, including injection wells, monitoring wells, and pipelines;
- assessing the process for acquiring property and mineral rights access; and
- documenting the sensitive areas for the primary and secondary selected areas based on the National Environmental Policy Act (NEPA) assessment criteria.

Project integration factors including economic, regulatory/political/technology issues, permitting, public outreach, and project liability of a commercial-scale CCS project were evaluated. Results included:

- economic analysis and modeling to define the cost of capture, transport, and storage and to present plausible business case scenarios for a commercial-scale CCUS project;
- legal/regulatory analysis completed by legal and policy experts with recommendations for policy that would support a CCUS project in Ohio;
- a permitting plan, including pipelines, monitoring, and Class VI injection well permits;
- an initial social characterization and public outreach plan; and
- an assessment of long-term liability may be defined through policy in Ohio.

Team building involved the creation of a team of experts to provide the necessary expertise to support a successful CCUS project. Team building included the following:

- A project team and technical advisory committee that includes experts in industry, science, legal issues, policy, public outreach, risk assessment, and economics.
- Ongoing discussions with interested stakeholders, including industry, utilities, state government agencies, and environmental groups.

Implications for near Future Commercialization

The CO_2 source assessment showed many diverse CO_2 sources that can be linked to the CAB-CS facility via regional pipeline. The geologic analysis demonstrated significant potential storage capacity both in terms of deep saline reservoirs and depleted oil and gas fields. The project definition analysis supported the feasibility of developing qualified sites within the selected areas for large-scale deployment of CCS. The project integration task used the pre-feasibility results to develop a plan for Phase II (Feasibility Study), which included performing detailed site characterization at a location near a coal-fired power plant.

Project economics illustrate a need for both government and private investment in the absence of a regulatory mandate. Although the project was not selected for Phase II funding, the accomplishments of this project are a significant step forward to implementing a CCUS project in the region. The project team, under the guidance of the technical advisory committee, established the elements of a roadmap needed to implement a CCS project in the 2025 timeframe (Figure ES-1). Technological advances, combined with policy and regulatory clarity and financial support through tax credits and grants, could make the capture technology deployment economical. Ultimately, the Appalachian Basin is a strategic area for early-stage projects to prove out and commercialize the technology due to the region's reliance on fossil fuels for power generation, and heavy presence of chemical manufacturing, petrochemical processing, and steel production.

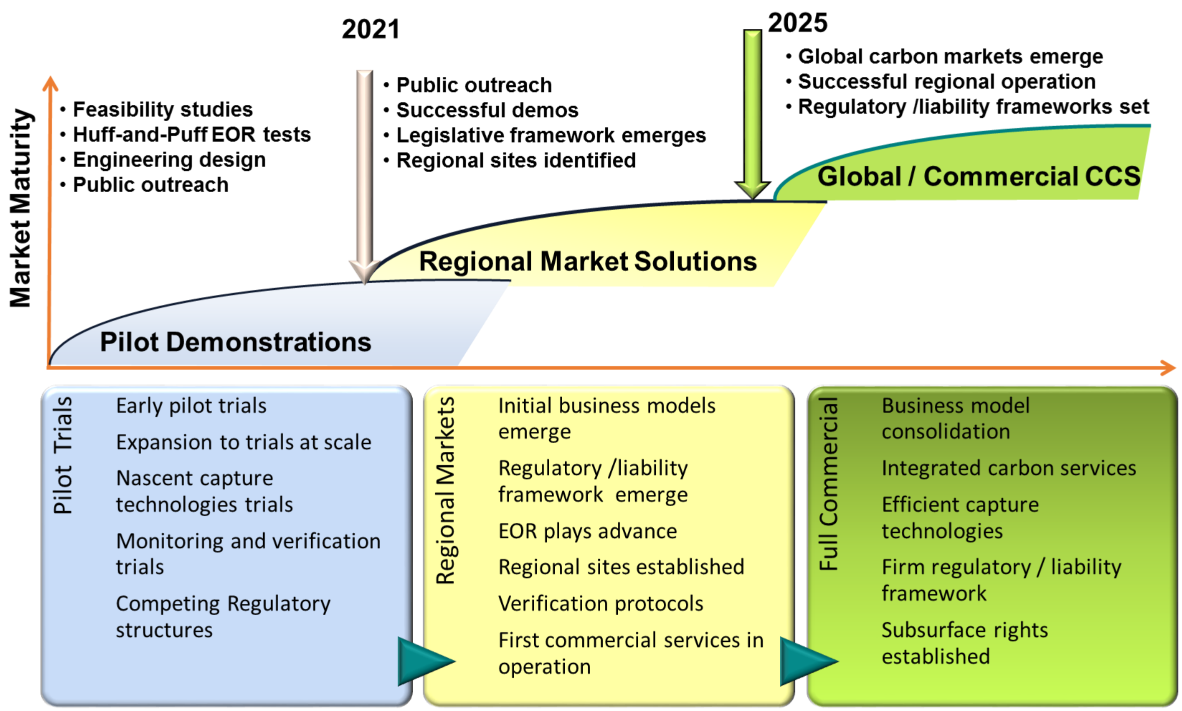

Figure ES-1. Schematic of the expected maturation of the commercial market.

Estimate of Anticipated Capital and Operating Costs for CO_2 Storage Complex

The preliminary cost estimates for the CO_2 storage facility were developed using the DOE/National Energy Technology (NETL) (2017a) FE/NETL CO_2 Saline Storage Cost Model DOE Last Update: Sep 2017 (Version 3). The CO_2 storage cost model integrates information about the CO_2 reservoirs to estimate capital equipment, well drilling and testing, operating and maintenance expenses, monitoring, post-injection site care and site closure, and long-term liability. The NETL CO_2 storage cost model was selected for estimating storage costs because it offers a reasonable and reproducible cost model using publicly available information. For quality assurance, the cost estimates produced by the model were reviewed and substantiated by

Battelle in-house expertise and information from FutureGen 2.0. Anticipated installed capital, operating, and post injection and site closure costs for a 50 MMt storage complex located in Selected Area B are presented in Figure ES-2 (note that costs for Selected Area A are essentially the same). As shown in this figure, the total capital cost for a 50 MMt saline storage complex operating for 30 years is approximately $80 million with an operating cost of approximately $5 million per year.

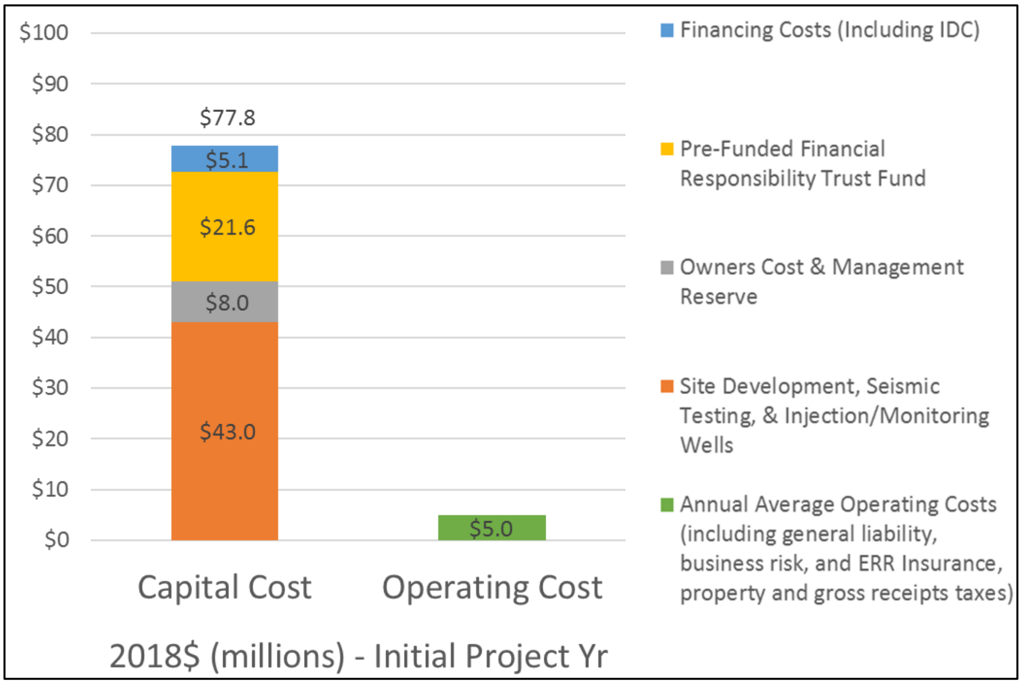

Figure ES-2. Total storage capital and annual average operating costs.

Next Steps

The CAB-CS integrated prefeasibility project has garnered a technical team that can provide insight into what would work in Ohio, including providing input on how to work with lawmakers and the oil and gas industry. A pilot project at the commercial scale would allow legislative and regulatory frameworks to be developed. Existing regulations and legal decisions regarding oil and gas and disposal wells could provide a framework for CO_2 storage. Other states with legislative frameworks dedicated to CCS can be used as a model for what may work in Ohio.

Paths forward and possible opportunities for additional research include the following:

- pursuit of funding opportunity announcements to conduct research projects studying the potential for implementing CCS and CO_2-EOR in the CAB-CS study area;
- leveraging of the existing oil and gas infrastructure in the CAB-CS area and the relationships Battelle has built with industry in this project over the previous 15 years to collect high quality data for geologic characterization. For instance, an existing 7600 ft deep well in this study's primary selected area, currently owned by MFC Drilling, Inc., was investigated to see if it could provide a low cost/low risk piggyback opportunity to address the knowledge gap in the primary selected area of this project. The well appears to be suitable for re-entering for the purposes of conducting a geologic investigation;

- reprocessing and analysis of existing low-cost two- and three-dimensional (2D and 3D) seismic data that have been identified by Battelle. These data can be leveraged to add to the analysis of the geological conditions in the selected areas.

Funding for the advancement to the feasibility study/site selection will come mainly from government sources (NETL, OCDO), and partially from commercial investment (e.g., utilities that operate coal-fired power plants; utilities that operate natural gas combine cycle plants; industry/power merchants; high purity industrial sources; investment groups; and brine disposal industry/oil and gas operators.

1. Introduction

The goal of the U.S. Department of Energy (DOE) National Energy Technology (NETL) Carbon Storage Assurance Facility Enterprise (CarbonSAFE) initiative is to develop an integrated carbon capture and storage (CCS) complex constructed and permitted for operation by 2025 through a series of sequential benchmarks: Integrated CCS Prefeasibility (Phase I), Storage Complex Feasibility (Phase II), Site Characterization and Permitting (Phase III), and Construction (Phase IV). Commercial deployment readiness within the next 5 to 10 years will require accelerated geologic characterization and site certifications. The project goal is to develop a carbon dioxide (CO_2) storage complex in an area with existing coal resources, potential CO_2 enhanced oil recovery (EOR) opportunities, and potential for advanced capture technology integration. In Phase I, the Central Appalachian Basin CarbonSAFE (CAB-CS) Integrated Prefeasibility Project identified several selected areas in the Central Appalachian Basin where the Cambrian-Ordovician age sandstones and carbonates show promising reservoir potential. These selected areas are collocated near depleted oil and gas fields where oil recovery could be improved with CO_2-EOR.

1.1 Introduction to CCUS

CCS, which is also referred to as CCUS (carbon, capture, utilization and storage), is the method of capturing CO_2 emissions from a large industrial point-source and permanently storing it in deep underground rock formations. The largest opportunity for beneficial use is for CO_2-EOR in depleted oil and gas reservoirs. CO_2-EOR is the process of using CO_2 to increase the reservoir pressure and decrease the viscosity of the oil to help the oil flow to the surface. CCUS can be operated in three configurations (Figure 1-1). Collocating saline and oil-bearing reservoirs, referred to as stacked storage, offers several advantages. CO_2-EOR can help to finance the infrastructure necessary to capture CO_2, while saline reservoirs can accept excess CO_2, providing redundant storage resources.

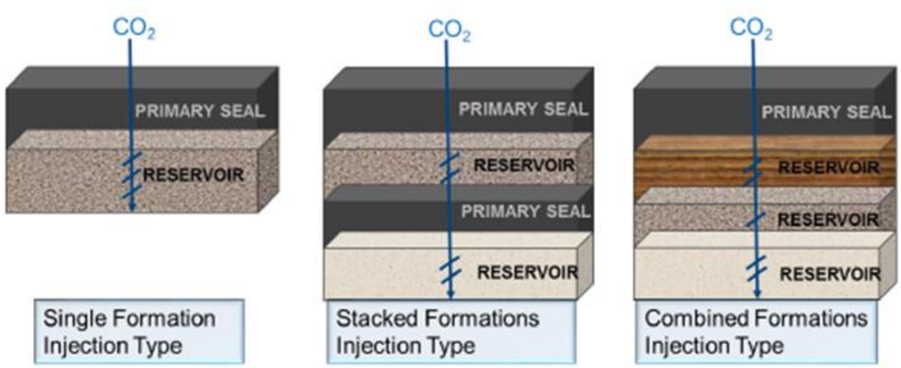

Figure 1-1. Different CCUS configurations, including injection into a single formation, injection into multiple formations separated by one or more seals (stacked storage) and injection into different reservoirs not separated by seals (combined storage).

CCUS is an important factor in addressing climate change to prevent warming beyond 2ºC while limiting disruptions to industry, energy generation, and economic development. The International Panel on Climate Change (IPCC) considers CCUS as an essential technology in climate change mitigation (Global CCS Institute, 2014). In spite of the importance of CCUS for reducing CO_2 emissions from industrial sources and fossil fuels, there are several hurdles in commercial CCUS deployment. Enabling CCUS development in the Central Appalachian Basin will require the establishment of a safe, effective, and economic CO_2 storage complex. The pre-feasibility assessment establishes the groundwork for the feasibility phase and includes an assessment of the following pre-requisites for CCUS project development:

- **Source suitability.** A source or sources of CO_2 should be present near the storage reservoir or within a reasonable distance that a feasible pipeline can connect the two areas. The feasibility of a source can be evaluated based on the size of its unit-based emissions, its expected productive life, the cost of capture, and the distance to a storage location. Additional sources that are nearby or along the pipeline connecting the source and sink can also improve the feasibility of a source because these facilities could offer redundancy in case operations at the primary source(s) unexpectedly cease or are reduced.
- **Geological suitability.** A commercial-scale CCUS program requires the presence of a reservoir or stacked reservoirs with sufficient depth to ensure CO_2 remains in a super critical state (usually around 760 meters [2,500 feet] or greater) and sufficient thickness, porosity, and extent to ensure that 50 million metric tons (MMt) or more of CO_2 can be stored within a reasonable study area. In addition, a regionally extensive, competent geologic seal (cap rock) must be present so that injected CO_2 is effectively sealed from upward migration.
- **Reasonable project definition.** A CCUS project requires a well-defined plan for CO_2 management, site screening and geologic analysis, reservoir modeling, site suitability (i.e., environmental, social, and logistical issues), and project infrastructure (including injection wells, monitoring wells, pipelines, and capture systems). In addition, an assessment of site risks and a plan for monitoring the effectiveness of the CCUS system must also be defined.
- **Mechanisms for addressing nontechnical challenges for integrated CCUS projects.** For a CCUS project to be considered viable, it must be economical, responsive to the needs and concerns of stakeholders, and be implemented in a suitable regulatory framework. Business cases must be developed with investors, stakeholders, and responsible entities clearly defined. A plan for public outreach and education must be developed through social characterization and expertise of local political, business, and community leaders. Finally, a clear analysis of the legal and regulatory issues to implement a CCUS project must be conducted, including, but not limited to, understanding of mineral rights, long-term liability and applying for and receiving permits.
- **Team Development.** CCUS projects require a diverse team, including representatives of CO_2 emitters, geologists, reservoir engineers, oil and gas industry experts, pipeline engineers, environmental scientists and engineers, public relations and outreach experts, risk analysis experts, economic and business advisors, and legal experts.

1.2 CCUS in the Central Appalachian Basin

The pre-feasibility phase is the first step in the development of a commercial-scale CCUS project. Eastern Ohio relies significantly on Ohio coal and coal-fired power plants for much of the region's economic activity (DOE/EIA, 2017a). Numerous studies have concluded that CCUS is one of the key technologies for achieving low-cost, deep decarbonization of the economy by allowing the continued utilization of existing infrastructure (IPCC, 2014; Deng et al., 2017). Therefore, developing CO_2 storage options in this region by identifying and systematically addressing the challenges to CCUS is crucial to protect Ohio's existing economic assets and to create a more sustainable energy portfolio.

Several significant CCUS projects have been completed in the Central Appalachian Basin since 2003. These projects include the American Electric Power (AEP) Mountaineer CCS Product Validation Facility; multiple CO_2 injection tests through the Midwest Regional Carbon

Sequestration Partnership (MRCSP); the Kentucky CCS project; the Ohio CO_2 test well; and various geologic characterization projects funded by the Ohio Coal Development Office (OCDO). In the Midwest, the U.S. Environmental Protection Agency (U.S. EPA) Region 5 Underground Injection Control (UIC) program has permitted the only Class VI CO_2 injection wells in the country. These projects are both in Illinois (FutureGen and the Archer Daniels Midland [ADM] Project); however, lessons learned from these experiences are applicable as Region 5 has regulatory authority for Ohio. Together, these projects and the existing regulatory framework substantiate a supportive environment for CCS.

The Central Appalachian Basin also has good geologic conditions for both saline storage and CO_2-EOR. The area has many potential reservoirs for saline storage, particularly in the Cambro-Ordovician Complex. The storage complex is overlain by competent thick caprock across the entire study area that provides an effective seal. In addition, the risk of natural and induced seismicity is low. There is an untapped potential for CO_2-EOR in the area's many depleted oilfields, particularly those that produce from the Clinton sandstone or Knox Group. The existing oil and gas and industry also can provide the infrastructure, knowledge, and expertise to conduct CCUS projects, although regulatory and legal frameworks need to be further developed to address the unique aspects of carbon storage. Policy and economics are the more serious challenges that CCUS faces, as well as public acceptance challenges.

1.3 Project Objectives

The objective of the CAB-CS Integrated Prefeasibility Project was to complete a pre-feasibility assessment for an integrated commercial CO_2 CCUS project in the Central Appalachian Basin. A commercial scale study is defined in this project as storage of 50 MMt of CO_2 or more over a 30-year period. This pre-feasibility assessment established the basis for the construction of a CO_2 storage facility by completing the following tasks: Task 1 (Project Management and Planning), Task 2 (Carbon Source Review and Assessment), Task 3 (Sub-Basinal Geologic Storage Assessment), Task 4 (Ohio CarbonSAFE Project Definition) Task 5 (CCS Project Integration and Planning), and Task 6 (Team Building Activities).

The following participants comprised the CAB-CS project team (Figure 1-2):

- Battelle—Project lead responsible for overall project coordination, project control, technical activities, schedule, and reporting.
- Pacific National Northwest Laboratory, Los Alamos National Laboratory (LANL), and Lawrence Livermore National Laboratory—Responsible for testing and validating national risk assessment protocol (NRAP) tools to inform permitting plans. LANL also provided technical capabilities for pipeline routing using Scalable Infrastructure Model for CO2 Capture and Storage (SimCCS).
- Wade LLC—Responsible for outreach planning and implementation.
- Vorys, Sater, Seymour, and Pease LLP (Vorys)—Provided advice on how to address legal and regulatory gaps for developing a CO2 storage complex.
- PKM Energy Consulting LLC—Responsible for evaluating economic and financial factors for site development.
- Technical Advisory Committee—Technical and business-focused experts charged with ensuring that the project work completed has meaningful impact by offering insights and knowledge to identify issues and possible solutions. The technical advisors included AEP; Baker Hughes General Electric (BHGE); Buckeye Brine; NGO Development Corp.; and Three Rivers Energy.

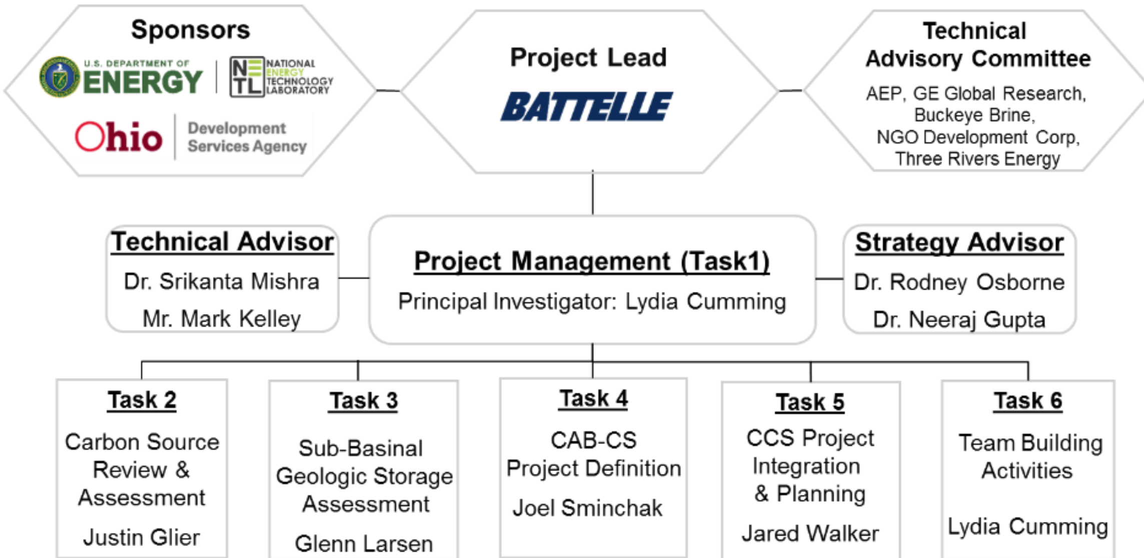

Figure 1-2. Project organization chart.

1.4 Project Outcomes

This final report provides a summary of the accomplishments and results for the pre-feasibility study. The CAB-CS Integrated Prefeasibility Project identified several “Selected Areas” in eastern Ohio where the Cambrian-Ordovician age sandstones and carbonates show promising reservoir potential. These selected areas are collocated near depleted oil and gas fields where oil recovery could be improved with EOR. This region has many large CO_2 point sources that represent a diverse array of industries, including coal-fired power plants, natural gas processing, refineries, chemical plants, and natural gas power. CCUS projects can play a role in developing affordable energy, a cleaner environment, and economic opportunities.

The results and conclusions presented in this document are meant to guide the direction of potential future feasibility assessments. The prefeasibility assessment assumed that the project would entail a 50 MMt storage goal over 30 years with a start date of 2025. Preliminary reservoir simulations were based on regional geotechnical data, ‘piggyback’ characterization wells, and well tests in brine disposal wells. The final site selection, characterization, and storage system design will require a multi-phase, multi-year effort. There is a great deal of uncertainty in the subsurface geologic conditions, as such, development of a certified storage site is crucial for risk management and enabling financing of capital-intensive capture projects.

In addition, the CAB-CS Integrated Pre-Feasibility Project contributed to the larger goal of advancing CCUS development. Specifically, projects at larger scales are valuable “learning by doing” opportunities. This project initiated the site screening and selection process, gathered social characterization data, undertook a legal review, and developed a financial model specific to the region, among other accomplishments. The results will inform the further improvement of the NETL NRAP tools and economic models developed by NETL. Although the project was not selected for Phase II, the results confirm the CAB-CS project has the potential to be adapted to grow new industries that would greatly benefit the region. This report concludes by providing a summary of the opportunities and limitations for CCUS in Ohio to help guide future research and development.

2. Task 2 CO_2 Source Analysis

This section summarizes the characteristics of existing and planned sources in the project area and presents a subset of sources that are most promising for a CAB-CS project. This information was used to support the project definition and project integration efforts (Tasks 4 and 5, respectively). As part of this work, the project team assessed the variety of source scenarios that would be feasible for a 50 MMt commercial-scale project. The source analysis consisted of characterization, carbon capture technology evaluation, and capture and storage integration.

The project team identified prospective CO_2 sources using a semi-formalized process. First, the team identified all large CO_2 sources in the study area that are expected to be operating in the 2024 to 2030 timeframe. This list was then narrowed based on total emissions and proximity to prospective geological storage sites. Finally, the project team examined industry-specific capture costs and operator interest to determine the most suitable candidates for CCUS.

2.1 Carbon Source Characterization

2.1.1 Source Identification

The CAB-CS project team assessed large CO_2 point sources for connecting to a CCUS complex. The primary source of information for identifying CO_2 sources was the U.S. EPA's Greenhouse Gas Reporting Program (GHGRP) (U.S. EPA, 2017a, b), which collects greenhouse gas (GHG) emissions data from larger emitters (i.e., sources with the potential to emit more than 25,000 metric tons of CO_2 per year, per 40 CFR Part 98). The Central Appalachian Basin sub-basinal area has over 200 large CO_2 point sources with total CO_2 emissions of more than 200 MMt CO_2 per year (Figure 2-1). Emissions sources were split into seven categories: power plants, metals/steel, petroleum/gas/refineries, cement/minerals, chemicals, ethanol, and other.

As shown in Figure 2-1, many of the larger point sources in and around Ohio are power plants. However, the latest data from the GHGRP, from the reporting year 2015, at the time of this analysis may not reflect the status of major emissions sources, particularly for coal-fired power plants due to frequent changes in operation, ownership, and fuel source. These changes are the direct result of the region's increasing natural gas production and the subsequent reduction in the commodity price of natural gas and correspondingly the lower price for wholesale electricity. As a result, many of the region's coal-fired power plants have shut down or converted to natural gas since the latest round of GHGRP reporting. The work performed therefore relied on several additional sources of current information, including:

- U.S. EPA Emissions and Generation Resource Integrated Database (eGRID)
- Trade journals and local news reports
- State of Ohio Public Siting Board

More information on each of these data sources and their application to this effort are provided below.

U.S. EPA eGRID. The eGRID is a comprehensive source of data on the environmental characteristics of almost all electric power generated in the United States. Unlike the GHGRP, these data are specific to each electricity generating unit (EGU) rather than aggregated for the entire facility. The environmental characteristics provided by eGRID include: annual CO_2 emissions, net electricity generation, fuel type, annual hours of operation, and last reported EGU status (operational, retired, stand-by, etc.). The added resolution provided by eGRID data allows for more accurate quantification of CO_2 emission potential and capture costs compared to GHGRP data alone. The latest reported data, however, are for 2014, which means that there is still a data deficiency in terms of the current EGU status and ownership.

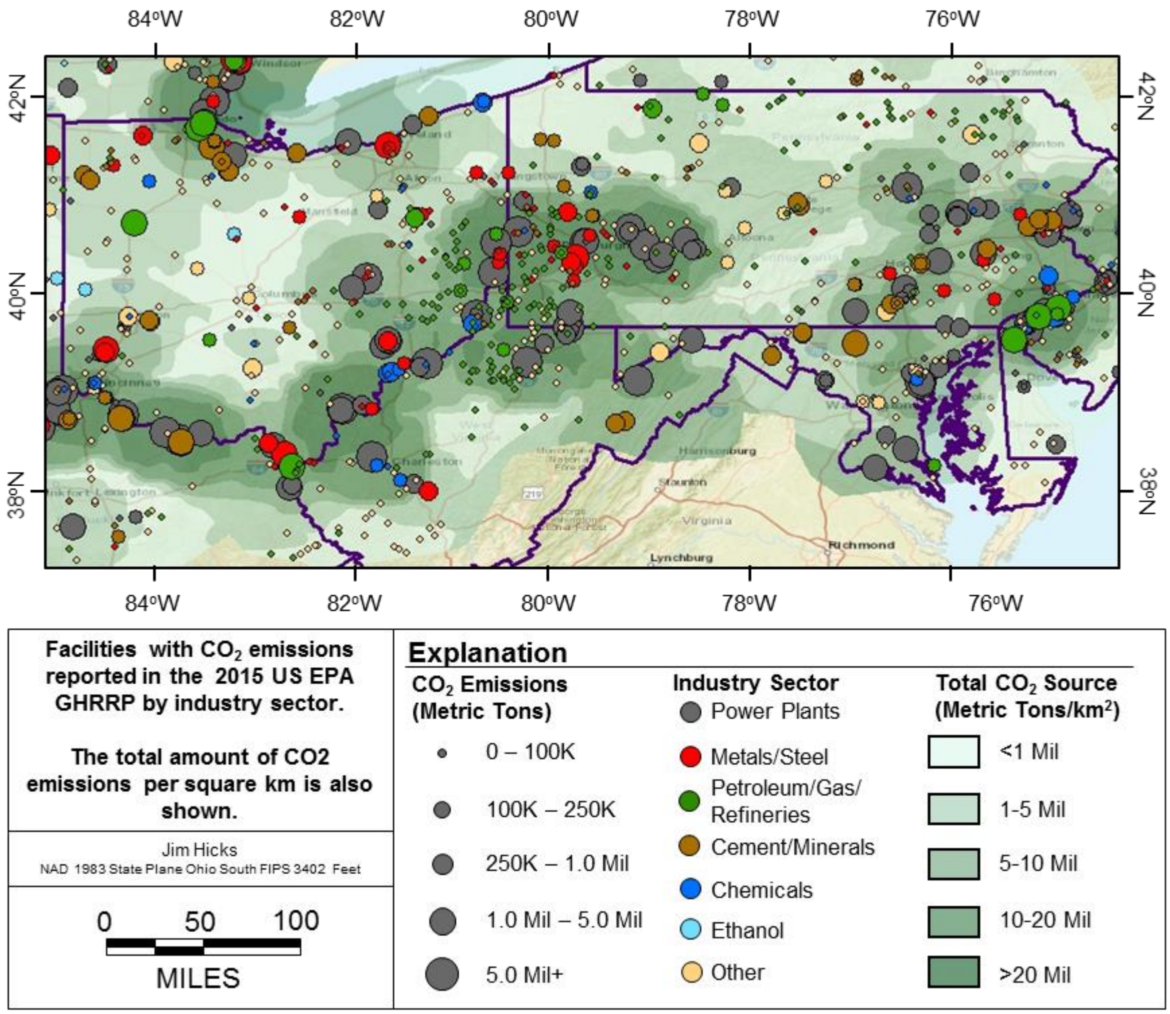

Figure 2-1. Large point CO_2 emissions in the Central Appalachian Basin. Facility type and the amount of CO_2 emissions per square kilometers is also shown (U.S. EPA, 2017a).

Trade Journals and local news reports. These sources provided useful information regarding changes in ownership, generation status, and fuel type for electricity generation in the study area. Events affecting the local community, such as plant closures or plant renovations, have a significant impact on the local economy and are generally well reported. Industry trade journals provide specific information on the type of fuel conversion, affected EGUs, and planned changes in operation.

State of Ohio Public Siting Board. The State of Ohio Public Siting Board is the state agency responsible for permitting of new electricity generation facilities. As of this writing, there are 11 large CO_2 sources (with potential CO_2 emissions calculated to be greater than 300,000 metric tons per year) in various stages of the emissions permitting process. The potential sources range in maturity from having submitted permit applications to the commencement of construction.

Using information collected from these data resources, the project team compiled a comprehensive list of major CO_2 sources in the region that are likely to remain active through 2030. A list of these industrial facilities and a review of CO_2 capture technology applicable to each industry are presented below.

2.1.2 Source Ranking

The CAB-CS project area contains numerous electricity generation facilities for which CO_2 capture technology is available, including 56 coal-fired electricity generation units and eight natural gas combined cycle (NGCC) EGUs. (Note that some power plants employ multiple generation units and often contain a mixture of fuel sources and technologies.) The project team also identified 25 industrial CO_2 sources with potential CO_2 capture compatibility (Appendix A).

The identified CO_2 sources were classified using a tiered system approach based on the facility's maximum single unit CO_2 production rate and location. A facility's total CO_2 emissions is not a strong indication of suitability as a candidate for CO_2 capture. Multiple point sources may be present at a single facility, which would require additional infrastructure (and possibly multiple process trains) to capture, dewater, and compress CO_2. Thus, facilities with larger point sources are most suitable to serve as CO_2 sources. Detailed information about specific point sources within a facility may not be available in all cases, such as with non-utility industrial sources. For these sources, the facility-wide emissions were used to prevent the elimination of potentially attractive sources due to lack of available data.

Criteria for each tier are defined as follows:

Tier 1:

- Facility is located within 50 miles of a selected area (see Section 3); and
- Facility contains at least one point source capable of emitting more than 1.7 MMt of CO_2 per year

Tier 2:

- Facility is located within 50 to 125 miles of a selected area and contains at least one point source capable of emitting more than 1.7 MMt of CO_2 per year; or
- Facility is located within 50 miles of a selected area and contains a point source emitting more than 0.3 but less than 1.7 MMt of CO_2 per year; or
- Facility is located within 125 miles of a selected area and has demonstrated written and financial support in exploring CO_2 capture (i.e., project partners).

Tier 3:

- All other sources
  - Facilities within 50 miles of a selected area that emit less than 0.3 MMt of CO_2 per year;
  - Facilities within 50 to 125 miles of a selected area that emit less than 1.7 MMt of CO_2 per year; or
  - Facilities more than 125 miles away from a selected area, regardless of the amount of CO_2 emitted.

A map of the CO_2 sources based on their tiered designation is shown in Figure 2-2. Sources that are currently undergoing permitting with the State of Ohio Public Siting Board or are currently under construction have also been included as "Pending". A list of Tier 1, Tier 2, Tier 3, and pending sources is provided in Appendix A.

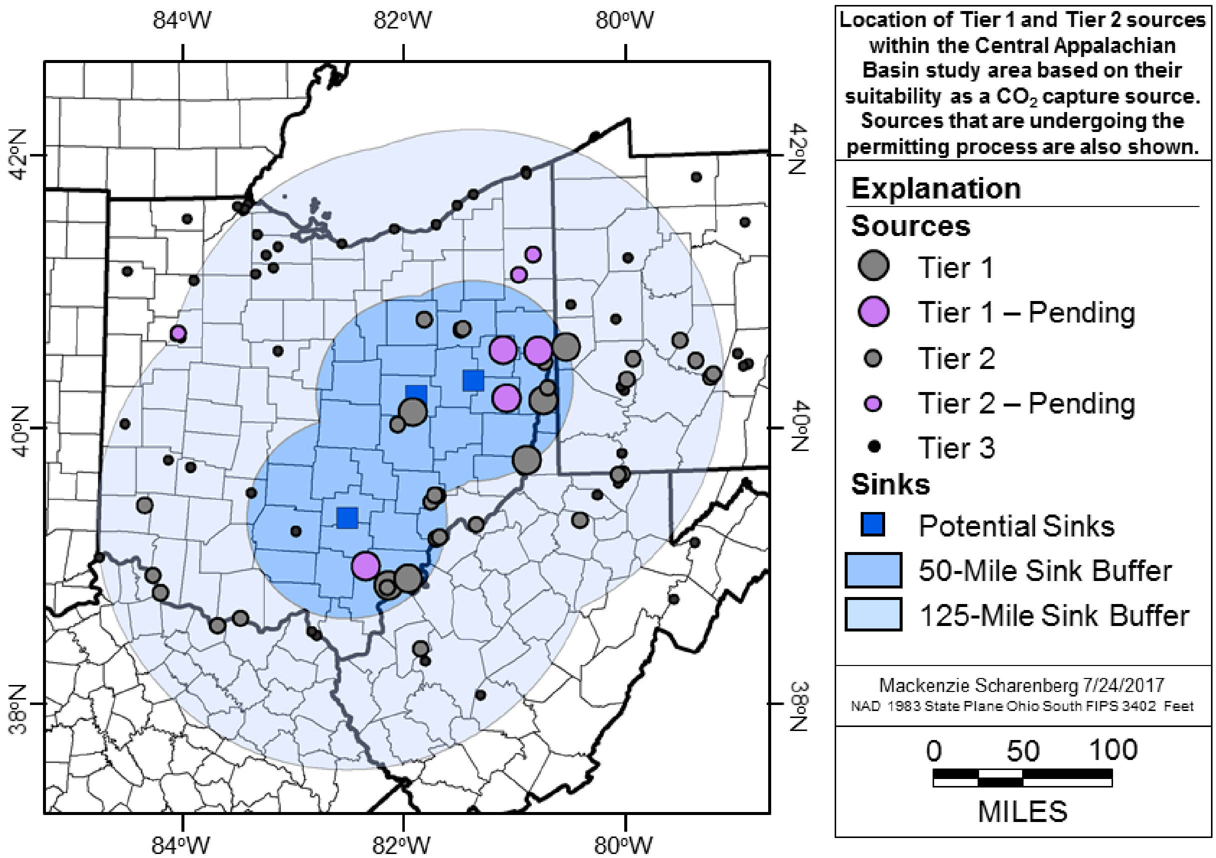

Figure 2-2. Facilities suited for CO_2 capture located within the CAB-CS study area based on their suitability (Tier 1, Tier 2, or Tier 3) as a CO_2 capture source. Sources that are undergoing the permitting process are also shown.

Seventeen larger (Tier 1) point sources at seven locations emit enough CO_2 to provide most, if not all, of the CO_2 needed to meet DOE's project-specific goal of storing 50 MMt of CO_2 over 30 years. These sources are coal-fired EGUs located within a 50-mile radius of the three identified potential sinks (Figure 2-2). An additional 24 facilities are potential candidates for CO_2 capture. These sites span multiple industrial categories including electricity generation, ethanol production, coking facilities, chemical manufacturing, and steel production. The high cost of capture from some industrial sources could make them less attractive as a potential source, despite the suitable location. Moreover, reported CO_2 emissions is a necessary but not exclusive requirement for determining the suitability of an industrial facility for CO_2 capture. In many cases, these data are not available without detailed information from the facility operator. It is also possible that the capture system installation may be preferred only for new sources, where a fully integrated and cost-effective system can be developed as part of initial facility design.

2.2 Source Sink Routing Feasibility

The CAB-CS project has the advantage of being situated in an area with numerous industrial sources of CO_2 and existing oil and gas operations. Because new pipelines are being added in the region to meet Marcellus and Utica-Point Pleasant hydrocarbon production, there are throughways, service companies, and general familiarity with pipeline gas transport requirements. The CO_2 management strategy suggests that there are many suitable CO_2 sources that may be linked to the CAB-CS facility via regional pipeline (>100 miles). These sources may readily provide 1.7 MMt CO_2 per year at suitable conditions for deep well injection. These scenarios generally bracket transport and injection arrangements that would fulfill requirements for a 50 MMt commercial-scale storage complex. Actual well and pipeline locations may differ as the project proceeds to test well drilling, site characterization, and engineering design.

Pipeline routes were generated using SimCCS software, developed by LANL (Middleton and Bielecki, 2009), which uses a four-step process to determine CO_2 pipeline routes. SimCCS is a robust tool that provides least-cost pipeline scenarios. First, the geographic area is rasterized into a weighted-cost surface that multiplies the base cost of building a CO_2 pipeline across a uniform surface to match the corresponding geography of the real world. This base cost is based on published costs for natural gas pipelines. Second, a set of potential origin-destination paths between all source/sink location pairs is calculated using a modified Dijkstra shortest-path algorithm on the weighted-cost surface. Third, a subset of these paths is selected as a candidate network by selecting edges that connect node pairs; these pairs are defined by a Delaunay triangulation of all source/sink locations. And fourth, final routes are selected by a Mixed Integer Linear Program that aims to minimize cost while connecting source/sink locations in a way to ensure a target CO_2 storage amount is met.

The resulting pipeline routes for 25 source sink scenarios for the primary and secondary selected areas (Areas B and A, respectively) as well as existing pipelines (approximated from U.S. Department of Transportation [DOT], 2018]) are provided in Figure 2-3 and Table 2-1. The selected areas are discussed in Section 3.0. Six scenarios are highlighted as scenarios of interest for the capture and storage integration analysis in Section 2.4 and the economic analysis presented in Section 5.1.

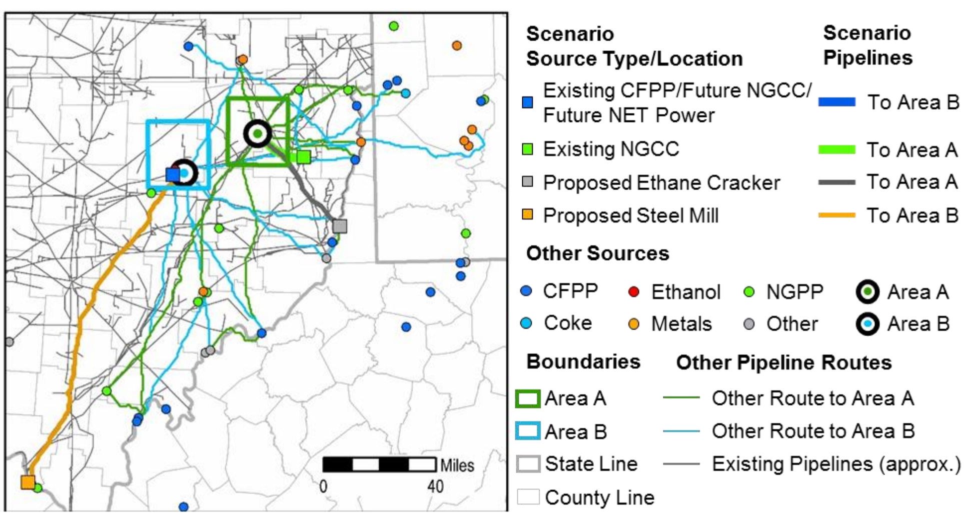

Figure 2-3. Pipeline routes calculated using SimCCS, including selected routes and existing pipelines.

Table 2-1. Scenarios evaluated using SimCCS and resulting pipeline route distances.

Facility	Facility Type	Emissions from Facility Used (MMt/yr)	Sink	Route Distance (miles)
Conesville	CFPP	1.7	B	4.2
Dresden	NGPP	0.6	B	18.0
Conesville	CFPP	1.05		
Three Rivers	Ethanol	0.05		
Waterford	NGPP	0.4	A	74.1
Dynegy Wash. II	NGPP	1.2		
Globe Metallurgical	Metals	0.1		
Gen. JM Gavin	CFPP	1.7	A	120.0
Gen. JM Gavin	CFPP	1.7	B	94.6
Gen. JM Gavin	CFPP	1	B	101.1
Dynegy Wash. II	NGPP	0.7		
Gen. JM Gavin	CFPP	1	A	133.5
Rolling Hills	NGPP (proposed)	0.7		
Mitchell	CFPP	1.7	A	54.1
Axiall Corp.	Chemicals	1.1	B	72.8
Mitchell	CFPP	0.6		
Pleasants	CFPP	1.7	B	67.0
Chemours Wash.	Chemicals	0.2	A	107.2
Kraton Polymers	Chemicals	0.2		
Pleasants	CFPP	1.3		
South Field	NGPP (proposed)	0.6	A	65.3
Carrol Co. Energy	NGPP (proposed)	0.5		
Harrison Co.	NGPP (proposed)	0.6		
South Field	NGPP (proposed)	0.6	B	93.9
Carrol Co. Energy	NGPP (proposed)	0.5		
Harrison PPT	NGPP (proposed)	0.6		
Harrison PPT	NGPP (proposed)	1.7	A	21.4
Harrison PPT	NGPP (proposed)	1.7	B	48.1
Cardinal	CFPP	1.7	A	42.2
Cardinal	CFPP	1	B	69.7
Harrison PPT	NGPP (proposed)	0.7		
Marathon Refinery	Petroleum	0.5	A	51.0
Harrison PPT	NGPP (proposed)	1.2		
Cardinal	CFPP	0.2	B	127.7
Marathon Refinery	Petroleum	0.5		
Orrville	CFPP	1		
US Steel E Thomson	Metals	1.7	B	127
US Steel E Thomson	Metals	1.4	A	97.6
Mountain St Carbon	NGPP	0.3		
Chemours Wash.	Chemicals	0.2	B	70.4
Kraton Polymers	Chemicals	0.2		
Dynegy Wash. II	NGPP	1.3		
Bruce Mansfield	CFPP	1.7	B	91.9
Bruce Mansfield	CFPP	1	A	60.5
South Field	NGPP (proposed)	0.7		
Belmont Co. Ethane Cracker	Ethane Cracker (proposed)	1.7	A	46.9

2.3 Carbon Capture Technology Evaluation

CO_2 capture was investigated for both the electricity producing sources (coal-fired power plants and natural gas power plants) and industrial sources (ethanol plants, steel manufacturing plants, petroleum refineries, and other industrial sources). A distinction is made between “combustion” and “process” CO_2 emissions. Combustion emissions are from burning carbonaceous fuels, such as natural gas, coal, and petroleum, while process emissions account for all other CO_2 released, usually from chemical reactions that are required to produce a desired product (Bains et al., 2017). Reduction of iron ore into iron, limestone into lime, and alcoholic fermentation are examples of such process reactions. In several instances, process and combustion emissions can occur in the same vessel. When process and combustion emissions are mixed, there is the potential for higher purity CO_2 streams. These two types of emissions are discussed in greater detail as each selected industrial source is discussed in terms of the technical requirements for capturing and compressing CO_2.

2.3.1 CO_2 Capture from Electricity Generation

2.3.1.1 Coal-fired Power Plants

A schematic for a pulverized coal-fired power plant using post-combustion CO_2 capture is shown in Figure 2-4. First, coal is pulverized and combusted with air in a furnace (boiler). The heat of combustion is used to make steam at various pressure levels. The highest pressure of the steam relative to the critical point of water determines whether the system is classified as a subcritical or supercritical process. The steam produces mechanical power in steam turbines, which are attached by a shaft. The shaft is attached to a generator, which converts the mechanical power to electric power. A condenser is used to produce liquid water from the turbine exhaust, and then a pump is used to recompress the water to high pressure. The combustion exhaust leaving the furnace typically goes through an ash removal, a nitrogen oxide (NO_x) removal, and a sulfur oxide (SO_x) removal process, and there are various options for each stage. CO_2 is captured from the gas leaving the SO_x removal stage using a solvent-based CO_2 capture process, which removes CO_2 and residual acid gases (nitrogen dioxide and sulfur dioxide [SO_2]). The CO_2 is then recovered for later compression, transport, and storage. The remainder of the flue gases (mostly N_2 and water) are exhausted to the atmosphere. Typical solvents for this purpose include monoethanolamine, diglycolamine, and methyldiethanolamine, among others (Khojasteh et al., 2012; Mudhasakul, et al., 2013; Closmann et al., 2009; Adams II, et al., 2017).

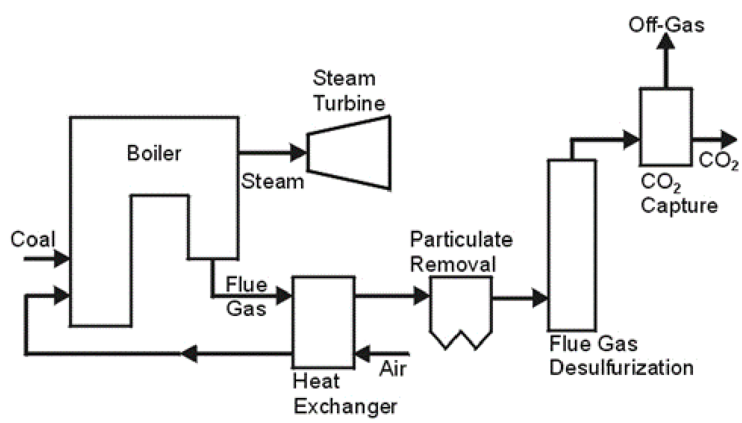

Figure 2-4. Simplified schematic of a coal-fired power plant with a post-combustion CO_2 capture system. Other major air pollutants (e.g., SO_2) are removed from the flue gas prior to CO_2 capture.

Amine-based post-combustion—flue gas treatment downstream from pulverized coal combustion, using chemical absorption—remains the preferred CO_2 capture technology for the short and medium term (around the year 2030). The technology readiness level is between 6 and 7 (i.e., system model or prototype demonstration) (Kanniche et al., 2017). There has been extensive relevant literature in recent years, including detailed CCS design studies published by the DOE (DOE/NETL, 2015), the International Energy Agency (IEA) (IEAGHG, 2014), the Electric Power Research Institute (EPRI, 2013), and others. The commercial-scale CCS project in Canada at Boundary Dam uses amine-based post combustion (Figure 2-5); the coal-fired unit produces 146 MW without capture and 117 MW with capture (Bruce, 2015), representing a 20% power derating or a loss of about 8% efficiency points, consistent with the recent literature range of 7.7 to 11.9% points cited above.

Figure 2-5. The Boundary Dam CO_2 capture facility located in Saskatchewan, Canada. Photo courtesy of SaskPower, Inc.

2.3.1.2 Natural Gas Combined Cycle

A typical NGCC process with post-combustion CO_2 capture is shown in Figure 2-6. In this process, natural gas is combusted with compressed air at high pressure in a gas combustion turbine, producing mechanical power. A generator is typically attached to convert the mechanical power to electric power. The combustion exhaust leaves at high temperature, and a heat exchanger network is used to capture this heat by making high-pressure steam for steam turbines, producing additional electric power. For a NGCC system with CCS, the cooled combustion gases are then subjected to a solvent-based absorption system for CO_2 removal. The solvent-based system typically uses an absorber column to scrub the CO_2 from the gases, with the cleaned gases exhausted to the stack. The loaded solvent is then purified in a stripper, which recovers lean solvent in the bottom and the CO_2 distillate for compression and transport (Adams II, et al., 2017).

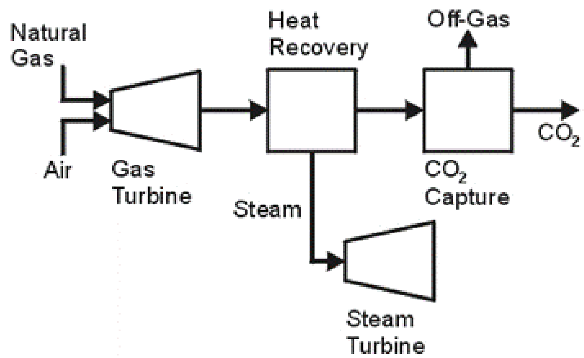

Figure 2-6. Simplified schematic of a NGCC power plant equipped with CO_2 capture.

In the past decade, electric utilities have looked to natural gas as the preferred energy source in response to the bullish outlook for domestic gas supplies from new shale gas production, as well as from new air quality regulations (e.g., New Source Performance Standards [NSPS] and Existing Source Performance Standards [ESPS]) that are accelerating the rate of retirement of many older existing coal plants. Recent studies have reported performance and cost estimates for NGCC power plants with and without CCS. An excellent review of these studies is available in Rubin and Zhai (2012). Most cases presented in the literature assume a “reference case” NGCC plant (without CCS) using General Electric 7FB gas turbines with a net power output of 550 MW for the combined cycle plants. For the cases with CCS, all studies assume an amine-based post-combustion system capturing 90% of the flue gas CO_2.

2.3.1.3 Net Power’s Allam Cycle

So far, the electricity generation technologies described in this section have relied on steam as the working fluid used to spin the turbine and generate electricity. With very few exceptions, these conventional steam-driven turbines are the source of fossil fuel-based electricity throughout the world. However, a new technology is currently being demonstrated at the pilot scale (25 MW_{net}) facility in La Porte Texas which relies on CO_2 as the working fluid. This new technology, called the Allam Cycle after its founder, Rodney John Allam, is a potential groundbreaking technology due to the increases in overall efficiency and lower generation cost. Moreover, this technology produces a high purity stream of compressed CO_2 which creates the real possibility for producing low-carbon electricity from fossil fuel-based sources. The use of CO_2 as the working fluid in the Allam cycle can lead to efficiencies up to about 59 percent (lower heating value [LHV]) for natural gas and 51 to 52 percent (LHV) for gasified coal (Modern Power Systems, 2016). Supercritical CO_2 is very efficient for driving a turbine. In addition, energy losses from phase transitions of water are avoided, allowing plants to recover more energy in their heat exchangers than combined cycle plants can do. Finally, CO_2 capture is already a part of the Allam cycle.

2.3.2 Industrial Sources

2.3.2.1 Iron and Steel Mills

Iron and steel manufacturing remains one of the largest point sources of CO_2 among non-power generation industries (Figure 2-7). Due to the large amount of emissions available for capture, the iron and steel industry has garnered significant attention for CO_2 capture (e.g., Rahman [2016]).One promising development in the iron and steel sector is the ongoing construction of the Al Reyadah steel mill located in Mussafah, Abu Dhabi. This joint venture between the Abu

Dhabi National Oil Company and Masdar Carbon will capture 0.8 million tonnes of CO_2 per year for use in EOR and is the first project to capture CO_2 from this industry (Rahman, 2016).

According to the GHGRP, there are 127 iron and steel mills operating in the U.S., accounting for approximately 70 million tonnes of steel production in 2015 (EPA, 2017b). The American Iron and Steel Institute reports that 80% of these plants are using electric arc furnace (EAF), while the remaining 20% employ the more traditional basic oxygen furnace (BOF) technology shown in Figure 2-8 (American Iron and Steel Institute, 2013). The main difference between the EAF and BOF processes stems from the raw materials used as inputs as well as the furnace design. The resulting steel product from an EAF process typically uses 100% recycled steel, whereas the BOF product contains 25-30% recycled steel on average (Werner Sölken, n.d.). The utilization of scrap steel results in lower CO_2 emissions for an EAF process (0.6 to 0.9 metric tons CO_2 per metric ton steel) versus the BOF process (2.2 metric ton CO_2 per metric ton steel) (Wiley et al., 2011). The combination of generally smaller EAF plants and lower concentration of EAF plant CO_2 emissions results in a high cost of capture from an EAF process.

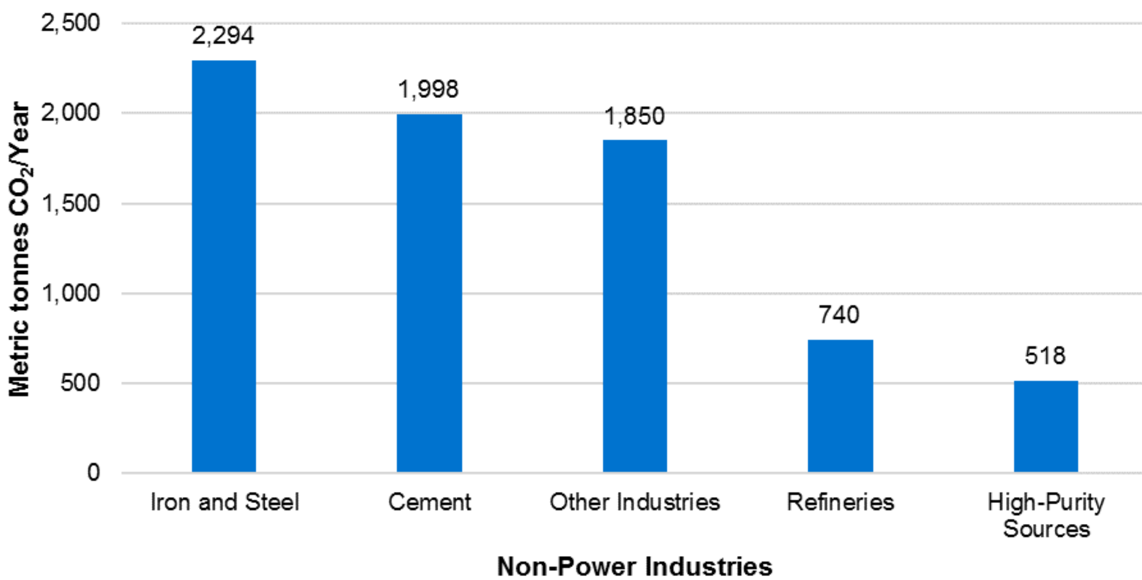

Figure 2-7. Distribution of global CO_2 emissions in 2014 by industrial process (IPCC, 2014).

The configuration of the iron and steel mill has a significant impact on the number of CO_2 point sources and thus the overall cost of capture. A study by Wiley et al. (2011) assessed the opportunities for CO_2 capture in Australian iron and steel mills using stream data from an Australian BOF steel mill, with a specific configuration. For their base plant, the largest source of CO_2 comes from the top gas of the blast furnace, as is typical in an integrated steel mill. The CO_2 is produced in the blast furnace when iron ore is reduced to molten ore. Since the BOF process utilizes a larger amount of iron ore than the EAF process, the BOF process will produce more blast furnace CO_2. However, in this particular mill configuration, the BOF gas stream is not directly vented. Instead, the blast furnace gas (BFG) is cleaned and used in the plant as low-grade fuel. The BFG and the coke oven gas (COG) streams are used in the plant to produce electricity and allow the plant to reduce or eliminate the amount of electricity purchased from the grid (Wiley et al., 2011).

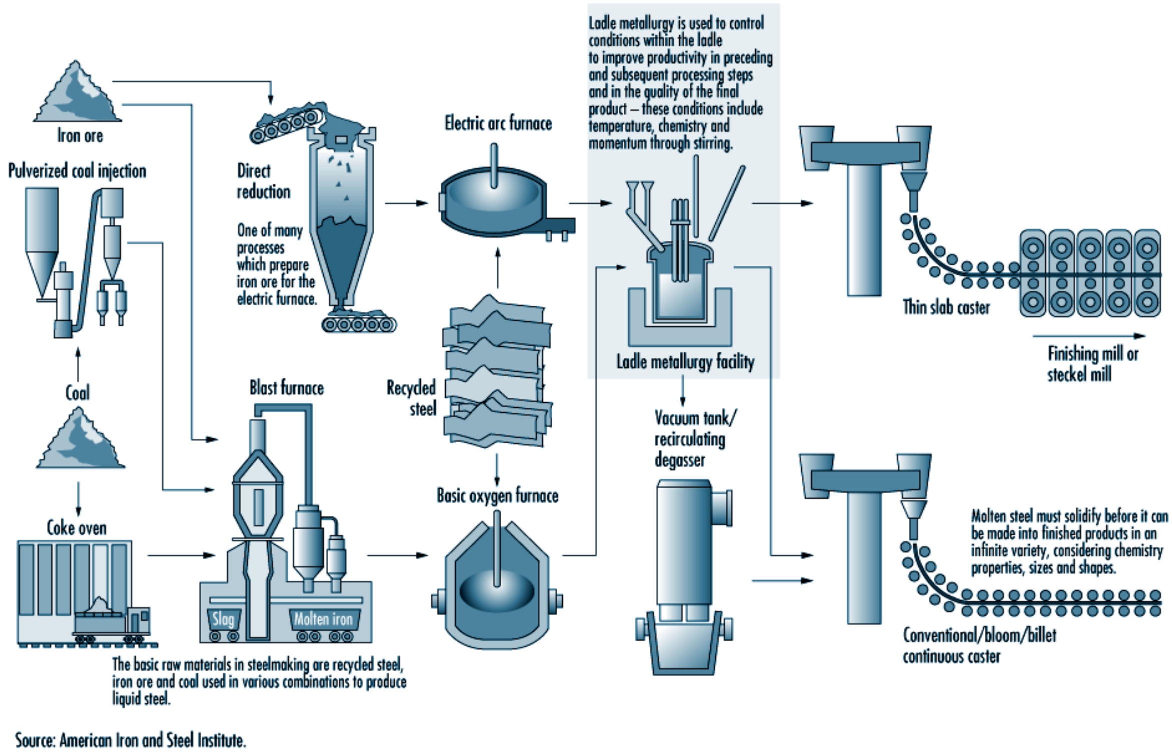

Figure 2-8. Overall proces design of iron and steel making.

Notes: This diagram shows the BOF design, although it is also accurate for the more modern EAF steel process by substituting an EAF unit for the BOF (American Iron and Steel Institute, n.d.).

The relevance of the Wiley et al. (2011) study is that instead of having a high-content CO_2 point source from the BFG, the CO_2 is distributed throughout the plant as smaller CO_2 point sources. This will increase the cost of CO_2 capture in the steel plant. The smaller CO_2 point sources available to be captured include the power plant stack (PPS), COG, blast furnace stove (BFS), sinter stack, blown oxygen steelmaking stack, hot strip mill stack, plate mill stack, and lime kiln for the configuration (Wiley et al., 2011). The three highest CO_2 concentrations from these point sources are the COG at 27 volume percent (vol%), the BFS at 21 vol%, and the PPS at 23 vol%. The relative emission rates and compositions for these sources are shown in Table 2-2. Although the CO_2 emissions are released at multiple point-sources in the facility, a metal plant with emissions around 3.8 MMt/year would provide enough CO_2 for a commercial-scale CCS project (assuming 90% capture from the power plant stack).

Table 2-2. CO_2 concentration and point source composition for a typical blast oven furnace (Wiley et al., 2011).

Description	Power Plant Stack	Coke Oven Gas	Blast Furnace Stack
CO_2 emissions (% of total facility CO_2)	50	23	26
Composition (vol%)			
N_2	67	67	68
CO_2	23	27	21
H_2O	8	5	10
O_2	1	1	1
CO	-	-	-
H_2	-	-	-

2.3.2.2 Petroleum Refining Production

Petroleum refineries produce various fuels and chemical feedstock through the distillation of crude oil followed by reforming and cracking. While there are many sources of GHG emissions at any petroleum refinery, most of the GHG emissions (over 97% CO_2) originate from the combustion of fuels (Det Norske Veritas Ltd., 2010). The four largest sources of CO_2 in a refinery are process heaters, electricity generators, fluid catalytic crackers, and hydrogen production, though a given site may not have all of these units.

On-site electricity and steam generation can account for 20 to 50% of refinery CO_2 emissions. Natural gas and other intermediate refinery products are combusted in air and sent through a gas turbine to create electricity. The exhaust gases may then be sent through heat exchangers to produce steam. The exhaust contains approximately 2 to 5% CO_2 by volume much like the combustion products produced in electricity generation (Det Norske Veritas Ltd., 2010). Four refineries are located in or around the CAB-CS study area.

2.3.2.3 Ethanol Production Plants

In 2013, the U.S. produced 13,321 million gallons of corn-based ethanol, capturing 57% of global production (Renewable Fuels Association, 2015a). The vast majority of U.S. ethanol production uses corn feedstock either from a dry-milling or wet-milling process. The dry-milling process, shown in Figure 2-9, accounts for more than 80% of U.S. production.

Ethanol production produces CO_2 from several sources depending on the process configuration. The majority of (and most easily capturable) CO_2 is emitted during fermentation, which produces CO_2 at purities of 98% to 99% by volume, and almost ambient conditions of 35°C and 1 bar (Bains et al., 2017). At such high CO_2 purity, the cost of capture is low, creating some of the best markets for carbon capture; more than 30% CO_2 captured in the U.S. is from ethanol plants (UNIDO, 2010; Xu et al., 2010; Armstrong, 2013). In the CAB-CS study area, the drawback of ethanol sources for CO_2 capture is the comparatively low volume of CO_2 produced by the facilities, as shown in Table 2-3.

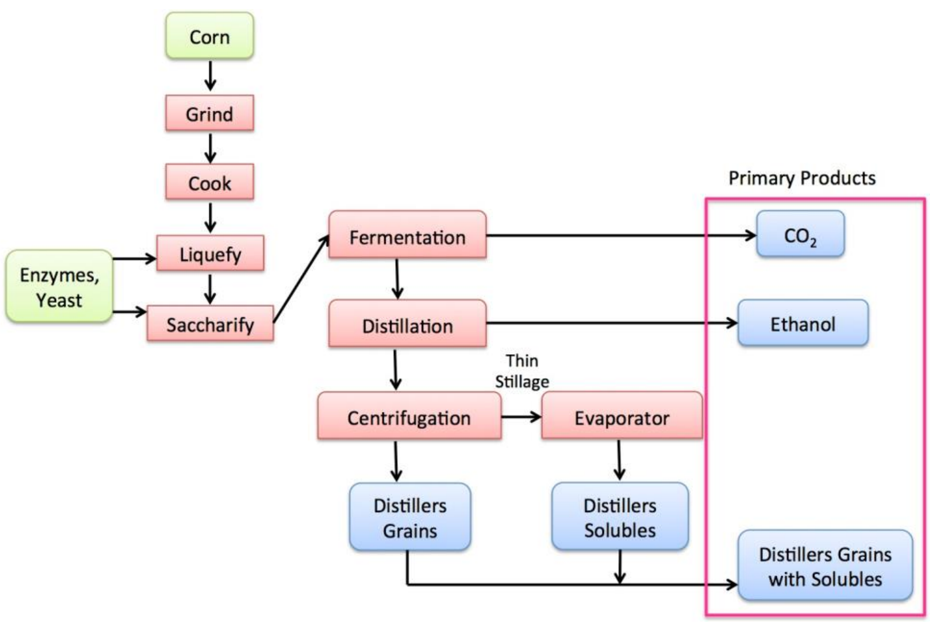

Figure 2-9. Dry-milling ethanol process (from Clifford [2017]).

Table 2-3. Ethanol facilities operating in CAB study area during 2015 (EPA, 2017a).

Name	Ownership	Max. Potential Emissions (metric tons CO_2/yr)	County	State
Three Rivers Energy	Three Rivers Energy	78,703	Coshocton	OH
POET Biorefining - Marion	POET	107,541	Marion	OH
POET Biorefining - Leipsic	POET	103,790	Putnam	OH
POET Biorefining - Fostoria	POET	99,848	Seneca	OH
Guardian Lima	Guardian Lima	87,694	Allen	OH

2.3.3 Capture Costs

The cost of CO_2 separation and compression depends on several important factors including the flue gas composition, pressure, and presence of competitively reactive gas constituents such as SO_2, NO_x and particulate matter. For this initial screening, capture costs for candidate CO_2 sources were taken from two sources published by NETL: DOE/NETL (2015) for electricity generators and DOE/NETL (2014a) for industrial sources. The costs for electricity sources and industrial sources are shown in Tables 2-4 and 2-5, respectively. The cost data collected were used to estimate the cost of CO_2 capture associated with the facilities identified as ideal (Tier 1 and Tier 2) and supplemental (Tier 3) sources for the CAB-CS project. A corresponding capture cost for each Tiered CO_2 source identified in this source assessment exercise is provided in Appendix A.

Table 2-4. Cost estimates for CO_2 separation and compression from coal-fired and natural gas combined cycle electricity generation units (DOE/NETL, 2015).

Technology	Cost ($/tonne of CO_2)
Sub-Critical Coal-Fired	$57
Natural Gas Combined Cycle	$72

Table 2-5. Cost of CO_2 capture from industrial sources (DOE/NETL, 2014a).

Process	Retrofit Cost ($/tonne of CO_2)
High Purity Sources	
Ethanol	$30
Ammonia	$27
Natural Gas Processing	$18
Ethylene Oxide	$25
Low Purity Sources	
Cement	$127
Lime Manufacturing (aggregate processing)*	$127
Refinery Hydrogen	$118
Steel/Iron COG+PPS	$99
Coke manufacturing*	$72

*Inferred values based on similarities in flue gas composition to other processes for which better information is available.

2.4 Capture and Storage Integration

The CAB-CS project team selected six diverse potential source-sink scenarios out of more than 700 facilities analyzed in Ohio, Pennsylvania and West Virginia, capable of supplying CO_2 for geologic storage. These sources, which include a coal-fired power plant (existing retrofit), two NGCC plants (one retrofit and one future source built with CCS), a new steel plant (future source), a hydrocarbon cracker plant (future source), and an innovative power generator NetPower (future source), represent a diverse opportunity for the deployment of established and innovative CO_2 capture technologies. A brief description of these sources is provided below.

***Scenario #1:* Supercritical Pulverized Coal.** This scenario was selected because of Conesville's proximity to Area B (pipeline distance of 4.2 miles), its emissions (40% to 77% of emissions from an individual unit can satisfy the project requirements), its proximity to a project partner (Three Rivers Energy Ethanol Plant), and its reliance on coal as a fuel source.

Located in Coshocton County, Ohio, the Conesville station is a large coal-fired power plant with three operating electricity generation units owned by AEP. The largest of the three coal-burning units has the potential to emit around 6.5 MMt of CO_2 per year at concentrations of 12 to 15%. A CO_2 capture and compression facility could be installed to capture emissions to provide CO_2 to the CAB-CS storage facility from a single source. In addition, on-site packaged or retrofit natural gas-fired electricity generation units may provide heat and power required in the CO_2 capture process, potentially reducing the retrofit capital and operating costs associated with converting the facility for CO_2 capture.

Scenario #2. Natural Gas Combined Cycle Retrofit. This scenario was selected because of Harrison's proximity to Area A (21.4-mile pipeline route), the proposed project plan is relatively close to the construction/commercialization schedule for the CarbonSAFE projects (i.e., construction is scheduled to begin in 2018 and operations are scheduled to begin in 2021), the longevity of the source, the proximity to other nearby sources, and around 50% of expected emissions from a single unit would satisfy project requirements.

Harrison Power, LLC's electricity generation facility is a pending NGCC plant in the permitting and planning phase. Located near Cadiz in Harrison County, Ohio, the facility will contain two gas turbines and two steam turbines producing a combined 1100 megawatts of electricity or an estimated 2.4 MMt of CO_2. A CO_2 capture and compression system applied to both units would produce most of the necessary CO_2 from a single facility and would encourage expansion of the pipeline network using additional CO_2 sources.

Scenario #3. Future NGCC Plant with CCS. This scenario was selected because of the conversion of many power stations in Ohio to natural gas and the benefit of being able to site it anywhere. For demonstration purposes, the potential future system was sited on Conesville property, near Area B (pipeline distance of 4.2 miles).

This scenario involves a new NGCC plant collocated with the existing infrastructure of the Conesville power plant. The location would allow a new CCS facility to take advantage of its proximity to a CO_2 storage site, EOR fields, and existing electrical connections. Moreover, including CO_2 capture in the early development stages allows for less duplicity of project permitting and construction compared to retrofit options. This scenario assumes that a facility will be sized such that a minimum of 1.7 MMt of CO_2 per year would be captured as part of the project.

Scenario #4. Future NetPower with CCS. This scenario was selected because of the expected low cost of capture, the benefit of being able to site it anywhere and NetPower expressed interest in CCS projects. For demonstration purposes, the potential future system was sited on Conesville property, near Area B (pipeline distance of 4.2 miles).

The project team is considering the prospect of a new power plant constructed in Coshocton County. This theoretical new facility would utilize an innovative natural gas-burning power plant capable of producing a highly concentrated, pressurized stream of CO_2 using an emerging technology developed by NetPower, LLC. Currently, a 50 MW pilot-scale facility is undergoing testing in La Porte, Texas, which represents the world's largest attempt to use CO_2 rather than steam to drive a turbine. The project team envisions a facility constructed by a major private utility company using the licensed technology and located along an existing electricity transmission corridor.

Scenario #5. Hydrocarbon Cracker Plant. This scenario was selected to demonstrate an industrial-capture model. In addition, working with an industrial source may help with outreach because there are no obvious "green" alternatives to an ethane cracker facility. The planned source is one of the larger industrial sources that is relatively close to the selected areas (pipeline distance 46.9 miles).

In 2017, PTT Global Chemical signed a memorandum of understanding with JobsOhio regarding a $5 billion ethane cracker plant complex in Belmont County, Ohio. The company has conducted the front-end engineering design (FEED) for the complex to help determine the project's feasibility and is currently performing further engineering work and economic evaluation. Ethane cracking is a chemical process for producing ethylene from the reforming of natural gas (including methane, ethane, and propane). The term is often used to indicate a wider range of natural gas reform processes since ethylene production is a high-volume chemical feedstock used in other chemical industries. CO_2 is a byproduct in the steam reforming (or steam "cracking") of methane (CH_4), the dominant process for H_2 production and a major process step in natural gas reforming. The energy production step (natural gas-based electricity) is the biggest contributor (approximately 85% of the overall environmental impact). For this application, CO_2 typically accounts for 8 to 11% of the produced flue volume. Although the design specifics are not publicly available for this plant at the time of this writing, the cumulative GHG emissions amount to 840 kg CO_2/ton of ethylene produced with additional emissions depending on other industrial processes included in the process (such as ethylene oxide production).

Scenario #6. Proposed Independent Steel Mill. New Steel is currently in the process of permitting and financing an iron and steel works located in Scioto County in southcentral Ohio. The new approximately 20 million ft^2 facility that would be the "greenest facility of its kind anywhere in the world" (Livengood, 2017). The facility will utilize two supercritical coal-fired boilers with an estimated 500 MW generation capacity (approximately 1.5 MMt of CO_2) per unit for steam and electricity generation. While a traditional supercritical boiler has a CO_2 concentration of 14% CO_2, these boilers will be supplemented with process gas from the rotary hearth furnace and will increase the outlet concentration to 18% CO_2 by volume. The higher concentration of CO_2 reduces the capital and operating expenses associated with construction and operation of a CO_2 capture system due to the more favorable thermodynamic conditions associated with CO_2 loading reactions compared to lower concentration systems such as traditional coal-fired boilers. The coal-fired boilers will utilize flue gas scrubbers for NO_x, SO_x, and particulates common among the most recent coal-based electricity generation facilities and result in comparable concentrations prior to entering the proposed CO_2 capture and compression processes. New iron and steel mills are likely to produce a reliable stream of CO_2 because of high utilization rates. Captured CO_2 would be piped through a 150-mile pipeline to the nearest selected area.

For all six scenarios, the pipeline routing analysis confirms that there are suitable rights-of-way for connecting CO_2 sources with the CAB-CS proposed areas (see Section 2.2). In addition, simulations (see Section 4.1.2) suggest that two injection wells would be adequate for the injection rates necessary; these wells could be connected by a relatively short 10-kilometer distribution pipeline.

High-pressure, large-diameter pipelines were designated as the most suitable method for transporting CO_2 from sources to the injection site. These pipelines are designed in a similar fashion to natural gas or hazardous liquid pipelines. The main components of a pipeline include the main pipeline, booster stations, and a Supervisory Control and Data Acquisition (SCADA) monitoring system. Cost factors include pipeline materials, installation costs, right-of-way costs, booster pump electrical costs, labor for operation and maintenance, and maintenance materials.

The CO_2 management strategy assumes that the CO_2 would be supplied at typical 'Kinder Morgan' specification for pipeline quality CO_2. The Task 2 source assessment reviewed sources in the CAB-CS region and determined that many sources will be able to supply a pure stream of CO_2 with no significant impurities. Assumptions for the CO_2 pipeline stream included:

- >95% mole fraction CO_2
- Dry product (<30 pounds water per million standard cubic feet per day [mmcf] vapor phase)
- <5% mole fraction hydrocarbons, <4% mole fraction nitrogen, <20 parts per million (ppm) hydrogen sulfide
- No pressure cycling
- No optimization for cost, distance, elevation, lifespan, etc.
- Minimum acceptable diameter selected for maintenance and required mass transport
- No substation pumps required

Table 2-6 summarizes the general pipeline specifications, assuming purity of greater than 95% CO_2 at pressures of 1,500 to 2,000 pounds per square inch (psi).

Table 2-6. General pipeline specifications.

Item	Specification
Nominal pipe size	8-inch diameter or greater
Material	API 5L X42 carbon steel
Wall thickness	0.277 inch or greater
Max. pressure	2,020 psig
Longitudinal seam type	High Frequency-Electric Resistance Welding

Note: psig = pounds per square inch gauge

Elementary pipeline design may include optimization of economics such that material cost versus pumping power and equipment costs can both be minimized, pipeline routing, accounting for pressure head and friction losses, river and railroad crossings, and development of acceptable corrosion allowance. Elementary facility and pipeline maintenance design will include selection of suitable pumps, metering station, storage tanks, control valves, inline inspection launchers and receivers, cathodic protection, preventive and maintenance plan, and leak detection plan.

Because new pipelines are being constructed in the region to support Marcellus and Utica-Point Pleasant hydrocarbon production, there are existing throughways, service companies and familiarity with pipeline gas transport requirements. There is also awareness of pipeline regulations by landowners, local organizations, and the public.

The Energy Information Administration (EIA) documents 91 hydrocarbon-related pipelines in development in the CAB-CS region since 2010 (largely to support shale gas development), costing more than $35 billion (DOE/EIA, 2017b). The larger new pipelines have capacities of 1.5 to 3.5 billion cubic feet (bcf) gas and 50,000 to 300,000 barrels (bbl)/day natural gas liquids. For comparison, the CAB-CS project would involve pipeline transport of approximately 36,000 bbl/day (or 0.085 bcf) CO_2 in supercritical liquid phase. Main pipelines are mostly 20 to 40 inch diameter, but the projects involve supply and gathering lines similar to the CarbonSAFE hub concept.

Some difficulties related to pipelines still exist. Longer pipelines have experienced some challenges in the permitting process and construction. Many of the best routes for pipelines have been secured for recent natural gas pipelines and pipeline rights-of-way costs may be elevated due to competition for routes. These challenges will be overcome by leveraging relationships with industry partners, public relations, legal and outreach experts. For instance, many of the recently constructed pipelines in the area connect, repurpose, and/or expand upon existing pipelines to minimize costs.

2.5 Conclusions

The work conducted under the pre-feasibility phase has analyzed the nature of large carbon point sources in the Central Appalachian Basin, pipeline routing from sources to a storage complex, carbon capture technologies, and capture and storage integration aspects. Specific conclusions from this task include the following:

- Emissions for commercial scale project (i.e., 1.67 MMt/year) can be obtained from single source or combination of sources throughout the study area. The Central Appalachian Basin project area contains numerous coal and natural gas-fired electricity generation facilities for which CO_2 capture technology is available, including 56 coal-fired electricity generation units and eight NGCC EGUs, and 25 industrial CO_2 sources with potential CO_2 capture compatibility.
- CO_2 capture remains one of the most important factors in developing a CCS project due to the high cost of capture and compression. Selecting a cost-effective method to capture CO_2 requires consideration of the concentration and partial pressure of the CO_2 in the gas stream. To date, amine-based solvents are the commercially established method of separating CO_2 from dilute flue gas streams. DOE/NETL is funding pilot-scale studies for other capture technologies, like sorbents and membranes (DOE/NETL, 2015b); however, these approaches must be improved to be commercially viable. For instance, current adsorption technologies have limited capacity and low CO_2 selectivity and membranes cannot generally achieve high-purity CO_2 separation unless used in tandem with other membranes or other capture technologies (CO_2 Project, 2008). Until these challenges are overcome, amine-based solvents will be a more attractive option for commercial-scale CO_2 separation. Chemical looping is another option for CO_2 capture; however, several DOE-funded studies are currently in the pilot-scale (i.e., 10 MW plants or less) (DOE/NETL, 2018).
- The connection of sources to sinks in the study area were analyzed using the SimCCS tool. Six scenarios representing a diversity of potential integrated CCS projects were selected for detailed economic analysis.

3. Task 3 Sub-basinal Analysis

Since 2003, Battelle, through the MRCSP, has been engaged in assessing the Midwest Region's potential for storing CO_2 in deep geologic reservoirs. From this effort, and from partnerships with the OCDO and the Research Partnership to Secure Energy for America (RPSEA), Battelle has acquired a vast database on and working knowledge of the geologic character of potential storage reservoirs in the central Appalachian region. Since the inception of the partnership, Battelle has participated in numerous deep well studies in collaboration with brine disposal well operators. These types of collaboration wells have been referred to as "piggyback wells" in previous reports. The piggyback well data were an invaluable resource for this pre-feasibility assessment. In addition to the piggyback characterization data, existing wireline logs, hydrologic well tests, seismic data, and core information were incorporated into the geologic assessment. Battelle has also participated in studies addressing potential CO_2 storage in deep saline and depleted hydrocarbon fields for the MRCSP, OCDO, and RPSEA. Table 3-1 lists the sources of studies that provided primary data for this assessment.

Table 3-1. Previous Battelle studies that are the primary data sources for the geologic assessment.

Author, Date	Report Title
Wickstrom et al., 2005	Characterization of geologic sequestration opportunities in the MRCSP region
Wickstrom et al., 2008	Geologic assessment of the Burger Power Plant and surrounding vicinity for potential injection of carbon dioxide
Battelle, 2008	The Ohio River Valley CO_2 storage project, AEP Mountaineer Plant, West Virginia numerical simulation and risk assessment report
Baranoski and Riley, 2010	Preliminary assessment of potential injection strata for carbon dioxide sequestration at New Haven, West Virginia
Battelle, 2011	Appalachian Basin—R.E. Burger Plant geologic CO_2 sequestration field test
Wickstrom et al., 2011	Geologic assessment of the Ohio Geological Survey CO_2 No.1 well in Tuscarawas County and surrounding vicinity
Battelle, 2013	Conducting research to better define the sequestration options in eastern Ohio and the Appalachian Basin
Barclay and Mishra, 2014	Development of a reservoir fluid property prediction toolbox to facilitate estimating CO_2 EOR potential and co-sequestration capacity in Ohio's depleted oilfields
Battelle, 2014	CO_2 utilization for enhanced oil recovery and geologic storage in Ohio. Task #2.1 - Production History Assessment
Battelle, 2015a	Development of the subsurface brine disposal framework in the northern Appalachian Basin
Battelle, 2015b	Systematic assessment of wellbore integrity for geologic carbon storage projects using regulatory and industry information
Battelle, 2015c	CO_2 utilization for enhanced oil recovery and geologic storage in Ohio: Milestone report #3 Task 2 – Reservoir characterization
Battelle, 2016	CO_2 utilization for enhanced oil recovery and geologic storage in Ohio
Hawkins et al., 2017	A revised assessment of the CO_2 storage capacity and enhanced oil recovery potential in the major oil fields of Ohio
Battelle, 2017a	CO_2 storage resources and containment assessment in Cambrian and Ordovician formations of eastern Ohio – Final Report
Battelle, 2017b	CO_2 storage resource and containment assessment in Cambrian and Ordovician formations of eastern Ohio – Geologic mapping topical report.

The analysis of this extensive body of work provides evidence that the assessment region has isolated deep saline formations; potential available pore space in many depleted oil and gas fields; considerable stratigraphic separation between the potential reservoirs and the Underground Sources of Drinking Water (USDWs); a low seismicity (earthquake) hazard; and many large point sources of CO_2 in the surrounding Appalachian Basin region. Battelle has identified three reservoir complexes (selected areas) having geological conditions favorable for CO_2 storage. These areas were selected based on the results from the following analyses: (1) fluid transmissivity of brine injection into deep saline formations from flow-meter and injection fall-off tests; (2) connected pore volume modeling of core and wireline log data of deep saline formations, and (3) available pore volume analysis of depleted miscible hydrocarbon fields. A significant component of this sub-basinal analysis of the Central Appalachian Basin region is to define a deep saline storage complex that has the greatest potential for commercial-scale CO_2 injection (50 MMt or more). This assessment characterized deep saline reservoirs for CO_2 injection, caprocks, trapping mechanisms, and geologic hazards related to the injection process and also identified potentially synergistic depleted hydrocarbon fields. This analysis was used to identify three selected areas, as defined by DOE/NETL (2017a), that are potentially suitable for geologic storage.

The objective of the sub-basinal geologic storage assessment is to produce information necessary to effectively portray the subsurface impact of a CCS complex and related risks. The hypothesis was that viable reservoirs with suitable geologic conditions for a commercial CCS project (i.e., injectivity, storage capacity, etc.) can be found in areas with competent caprock, geologic quiescence, and acceptable risk. This was investigated through a sub-basinal analysis that consisted of reservoir characterization, caprock assessment, geohazards analysis, and risk assessment using NRAP tools.

3.1 Reservoir Characterization

The geologic assessment region is primarily in eastern Ohio but includes portions of western West Virginia and northeastern Kentucky (Figure 3-1). The tectonic setting of region is in the Stable Continental Region (SCR) of North America (Wheeler, 2003; 2009). SCRs are continents or parts of continents that have not undergone geologically recent structural deformation or accompanying metamorphic or igneous processes. The North America SCR, the region east of the Rocky Mountains, experiences infrequent earthquakes (Dart and Hansen, 2008; Wheeler, 2009).

Broad sedimentary basins and arch structures are present in the region, consisting of sequences of mainly Paleozoic-age rock layers overlying Proterozoic-age igneous and metamorphic rocks. The current study region is along the western flank of the Central Appalachian Basin and is bounded by the Rome trough to the south and southeast and the Waverly arch to the west (Figure 3-1). The Rome trough is an Early to Middle Cambrian-age fault-bounded graben related to rifting and spreading of the Iapetus-Theic Ocean (Gao et al., 2000; Baranoski and Riley, 2010; Wickstrom et al., 2005 and 2011). The Rome trough extends from northern Tennessee, through eastern Kentucky and West Virginia, and into southwestern Pennsylvania. The trough is filled with early to late Cambrian strata. The Waverly arch is a north-south-trending paleotectonic feature identified by Woodward (1961) that extends from central-northern Ohio southward to Tennessee (Woodward, 1961; Janssens, 1973; Baranoski et al. 1996; Root and Onasch, 1999). According to stratigraphic correlations by Woodward (1961), Root and Onasch (1999), and Baranoski et al. (2012), the Waverly arch was a positive feature affecting deposition of Cambrian and Ordovician strata from the basal Cambrian sandstone to the Beekmantown dolomite (Figure 3-2). Baranoski et al. (2012) and Babcock and Baranoski (2013) consider the Waverly arch to be a late Mesoproterozoic to Neoproterozoic southward extension of the Laurentian (Algonquin) arch (Figure 3-1).

A carbonate platform began to form along the Waverly arch during the deposition of the Conasauga group and reached maximum development during the deposition of the Knox dolomite. The Knox dolomite and deeper units of the region were deposited on a broad shelf northwest of the Rome trough. The deposits make up a complex transgressive sequence of clastic and carbonate rock units. The sequence overlies the Precambrian unconformity and is truncated at the top by the Knox unconformity (Harris et al., 2004).

Several Cambrian- to Lower Ordovician-age deep, saline reservoirs, related to the deposition along the carbonate platform, have been identified as potential CO_2 storage reservoirs from past MRCSP, OCDO, and RPSEA projects. Three reservoirs are of interest in this study: the Rose Run sandstone, a vugular porosity interval within the lower Copper Ridge dolomite, and a zone of contact where a sandstone facies in the basal portion of the Nolichucky shale overlies vuggy/karsted dolostone of the Maryville formation (Figure 3-2). Also included in the assessment are the overlying depleted oil/gas fields at miscible depths.

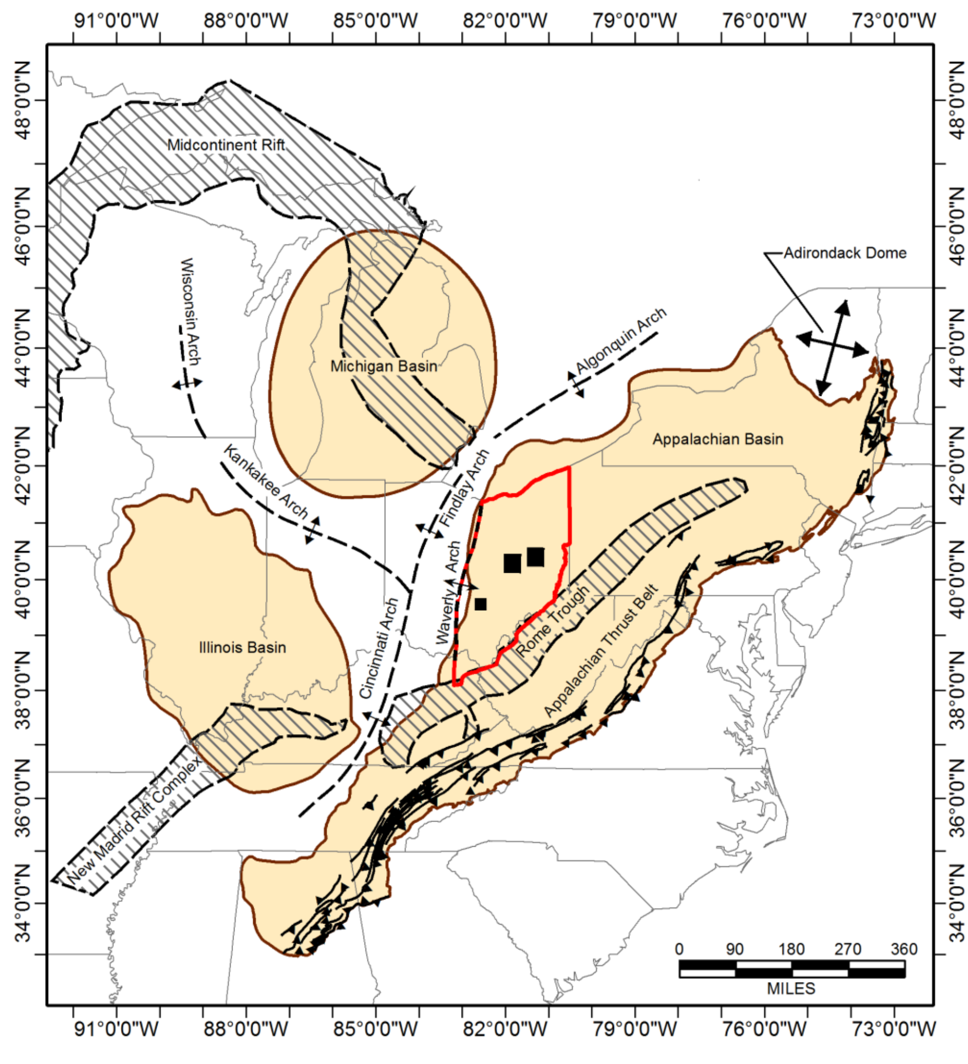

Figure 3-1. Location and regional tectonic setting of the Central Appalachian Basin geologic assessment region (outlined in red).

Notes: Tectonic features bordering the assessment region are the Rome trough on the south and southeast, and the Waverly arch on the west. The three black squares within the assessment region are the three selected areas for pre-feasibility assessment.

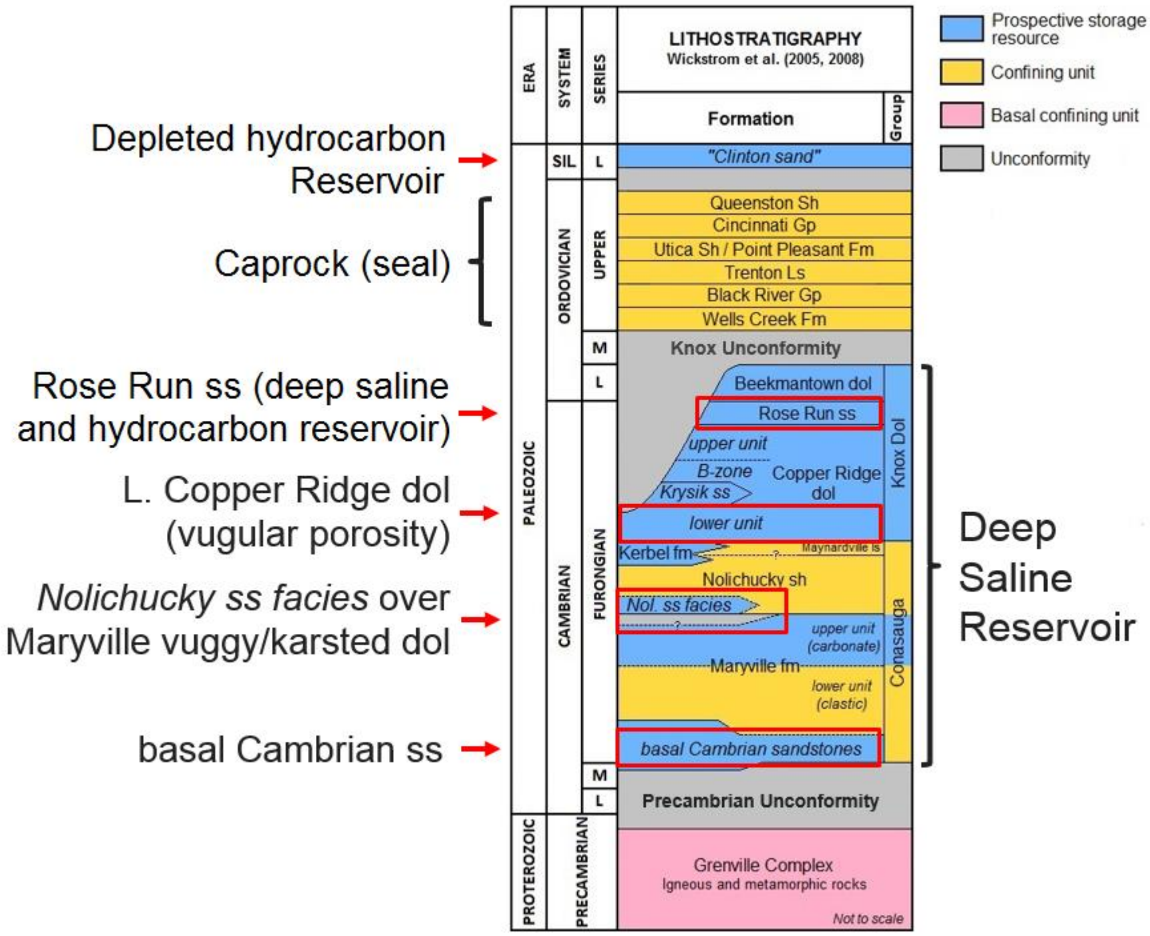

Figure 3-2. Stratigraphic column of the geologic assessment region showing the stratigraphic positions of prospective CO_2 storage reservoir complexes and confining units.

Notes: Stratigraphic terms follow the nomenclature adopted by the MRCSP; see Wickstrom et al. (2005, 2008). The Rose Run sandstone is also a depleted hydrocarbon reservoir in some locations in the study area.

3.1.1 Stratigraphy

A regional conceptual geologic model of the deep, saline reservoir complex from the Knox unconformity surface (top of the Beekmantown dolomite) to the Precambrian unconformity surface (base of the basal Cambrian sandstone) is provided in Figure 3-3. The model illustrates stratigraphic and structural relationships across Ohio, from the Indiana border eastward across the Waverly arch to the Rome trough of West Virginia. The Waverly arch and the Rome trough controlled the development of the carbonate platform and reservoir complex. The Cambrian-lower Ordovician rocks dip, thicken, and become dominated by carbonates eastward toward the Rome trough. Westward toward the Waverly arch, the rocks thin and clastic sediments intermix with the carbonates.

Three selected areas, labeled A, B, and C on Figure 3-3, were identified as potential stacked and combined reservoir complexes (where stacked reservoirs are separated by confining layers and combined reservoirs are vertically connected). The formations comprising the stacked reservoirs are the Rose Run sandstone, vugular lower Copper Ridge dolomite, vugular/paleokarst Maryville formation, and basal Cambrian sandstone. Areas A and B include a combined formation, in the stacked complex, where the Maryville formation is in contact with a sandstone interval at the base of the Nolichucky shale.

Flow-meter testing on several piggyback wells across the assessment region indicate that there are multiple locally to regionally continuous zones of high-permeability rock (Figure 3-4). These flow zones occur in the Rose Run sandstone, in the vugular lower Copper Ridge dolomite, and along the contact of the Maryville formation-Nolichucky shale. The flow zone along the Maryville-Nolichucky contact is of significant interest due to the high transmissivity (*kh*) values measured, up to around 200,000 millidarcy-feet (mD-ft).

The high *kh* of the Maryville-Nolichucky contact is the result of vugs and paleokarst, which led to high secondary porosity and permeability in the upper 100 to 150 feet of the formation (Battelle, 2017a). A study of the Maryville formation in Tennessee has shown that the contact between the Maryville and the overlying Nolichucky is a sequence boundary, an exposure surface and an unconformity that marks a distinct shift in the pattern of sedimentation. Shallow-water carbonate deposition (i.e., the Maryville formation) terminated at the boundary followed by the onlap of deeper-water basinal siliciclastics (i.e., the Nolichucky formation) (Srinivasan and Walker, 1993).

Advanced logs and injection test data Battelle acquired in collaboration with a brine injection operation in Site Area B provided valuable data on the reservoir potential of the Maryville formation. Anecdotal drillers' stories of lost fluid when going through the Maryville formation in the surrounding region of Selected Areas A and B are common (William Rike, personal communication, 20 April 2015). Figure 3-5 outlines the area of reported fluid loss in the upper Maryville formation by drillers, including a well in Selected Area B. Log data from this well supports the anecdotal evidence of high injectivity zones: the pads of the resistivity tool became skewed from their normal orientation and the acoustic image shows a very dark, very low amplitude oblong feature, suggesting borehole enlargement. The zone corresponds with the bulk of the injection shown in the spinner log, the highest anisotropy shown in the well on the acoustic log, a zone of higher relative permeability on the nuclear magnetic resonance (NMR) log and is flagged as pay zone on the triple combo log. The feature is interpreted to be either a karst/collapse feature or an area of highly altered or highly connected vugs. Although a loss of fluid does not necessarily pinpoint the corresponding porosity zone, it is generally considered a reasonable indicator.

A map of the deepest USDWs, defined by the U.S. EPA as water with less than 10,000 ppm total dissolved solids (TDS), is shown in Figure 3-6. The Devonian Berea sandstone, Mississippian Black Hand sandstone (Black Hand member of the Cuyahoga formation) and the Pennsylvanian Sharon sandstone (basal unit of the Pottsville Group) are the primary USDWs in the assessment region (Wickstrom et al., 2006 and 2008; Riley et al., 2012). Deeper rocks are saturated with high-salinity (greater than 100,000 ppm) brine, oil, and gas. Table 3-2 shows the estimated thickness of rock separating the USDW from potential underlying CO_2 storage reservoirs. Estimates were calculated from drilling records of well located near the centers of the areas of interest. These estimates show there is enough rock to isolate the potential reservoirs from any connection with the USDW.

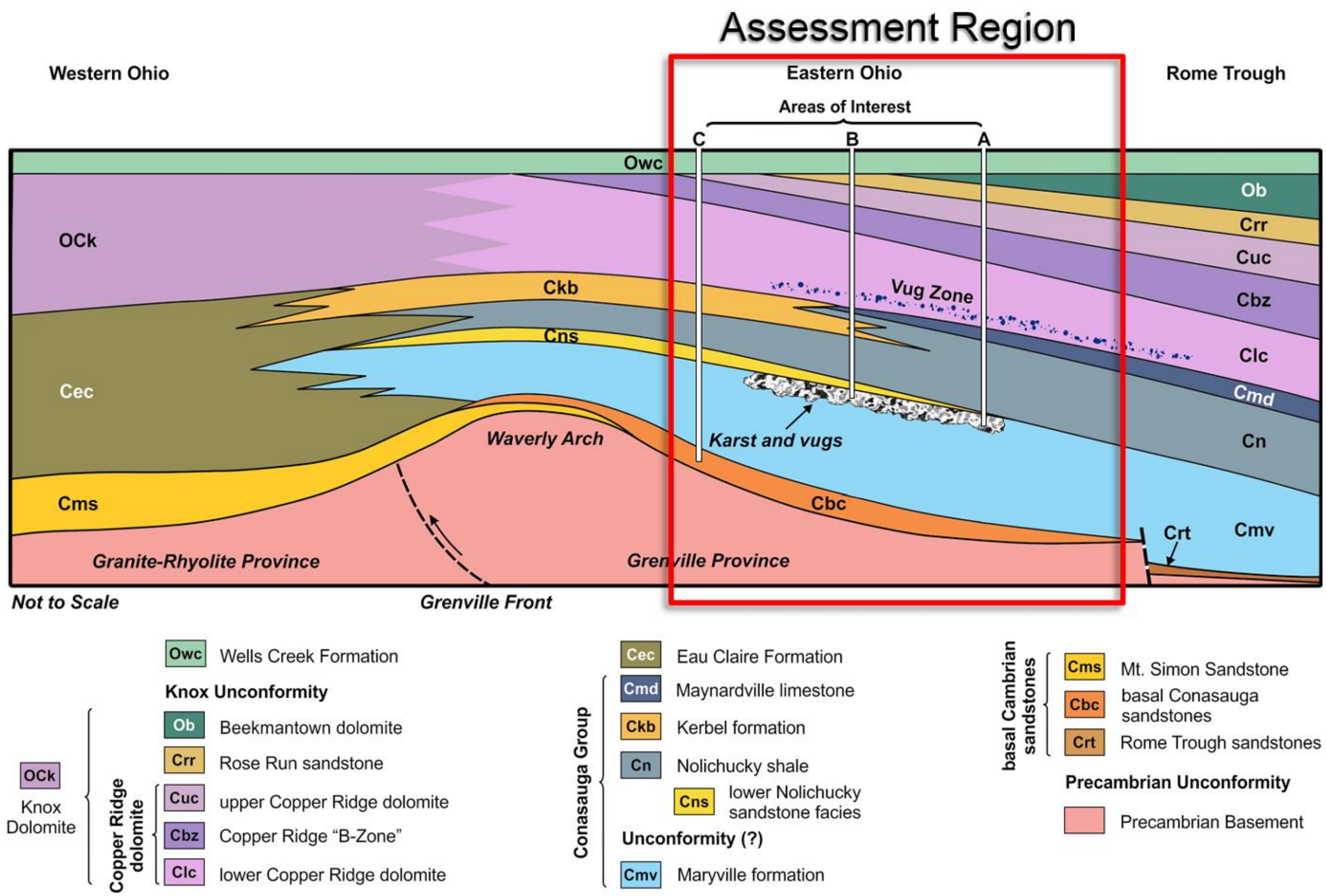

Figure 3-3. Conceptual geologic model of the assessment region.

Notes: The model illustrates stratigraphic and structural relationships across Ohio from its western border eastward across the Waverly arch into the Rome trough of West Virginia. The red square identifies the assessment region and the sub-Knox unconformity stratigraphic sequence containing reservoir rock identified in this study. The Wells Creek formation is the lowest caprock/seal unit overlying the Knox unconformity and reservoir complex.

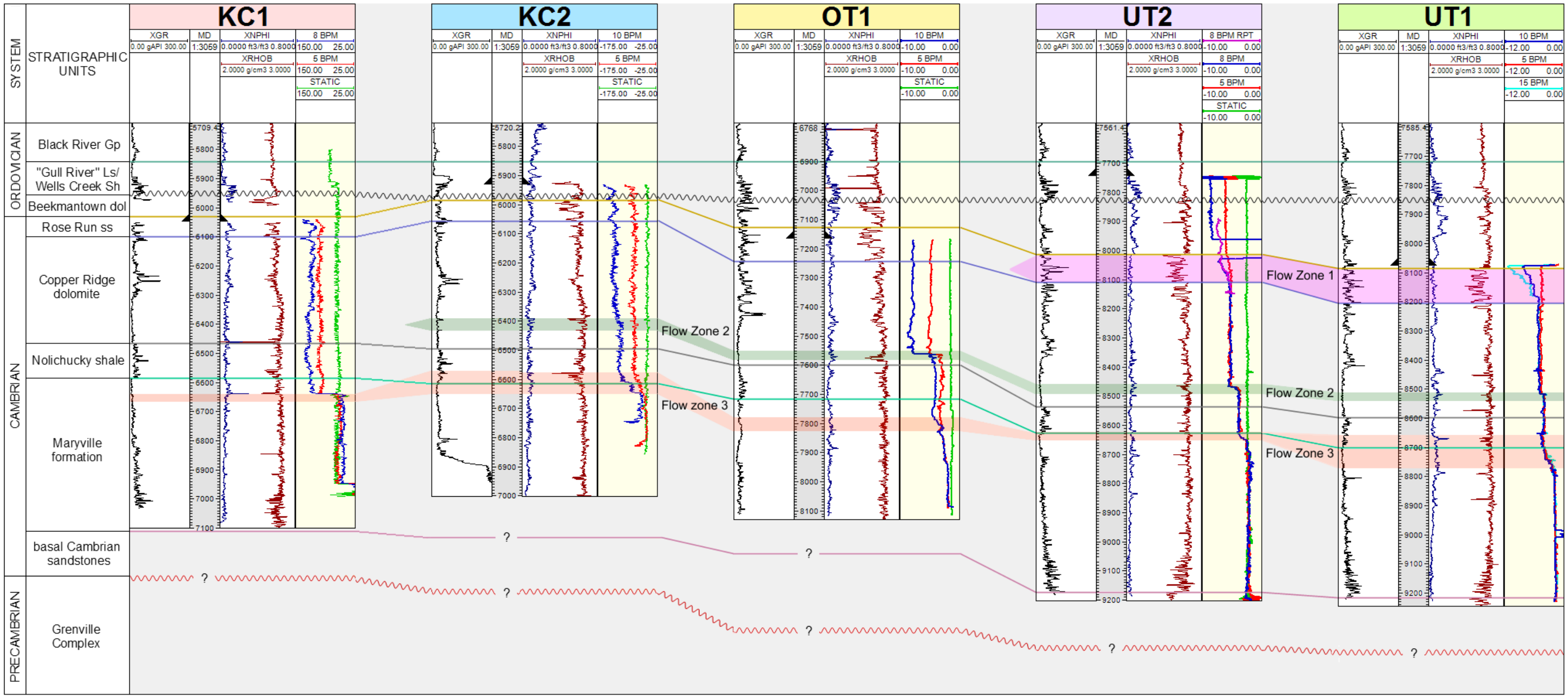

Figure 3-4. Cross section, from areas B to A, of piggyback well logs with hydrologic testing showing the injectate flow zones in the deep, saline reservoir complex.

Notes: Flow zone 1 is in the Rose Run sandstone, flow zone 2 is in the vugular lower Copper dolomite, and flow zone 3 is along the contact of the vugular/paleokarst Maryville and the sandstone facies at the base of the Nolichucky shale. Cross-section location shown in Figure 3-5.

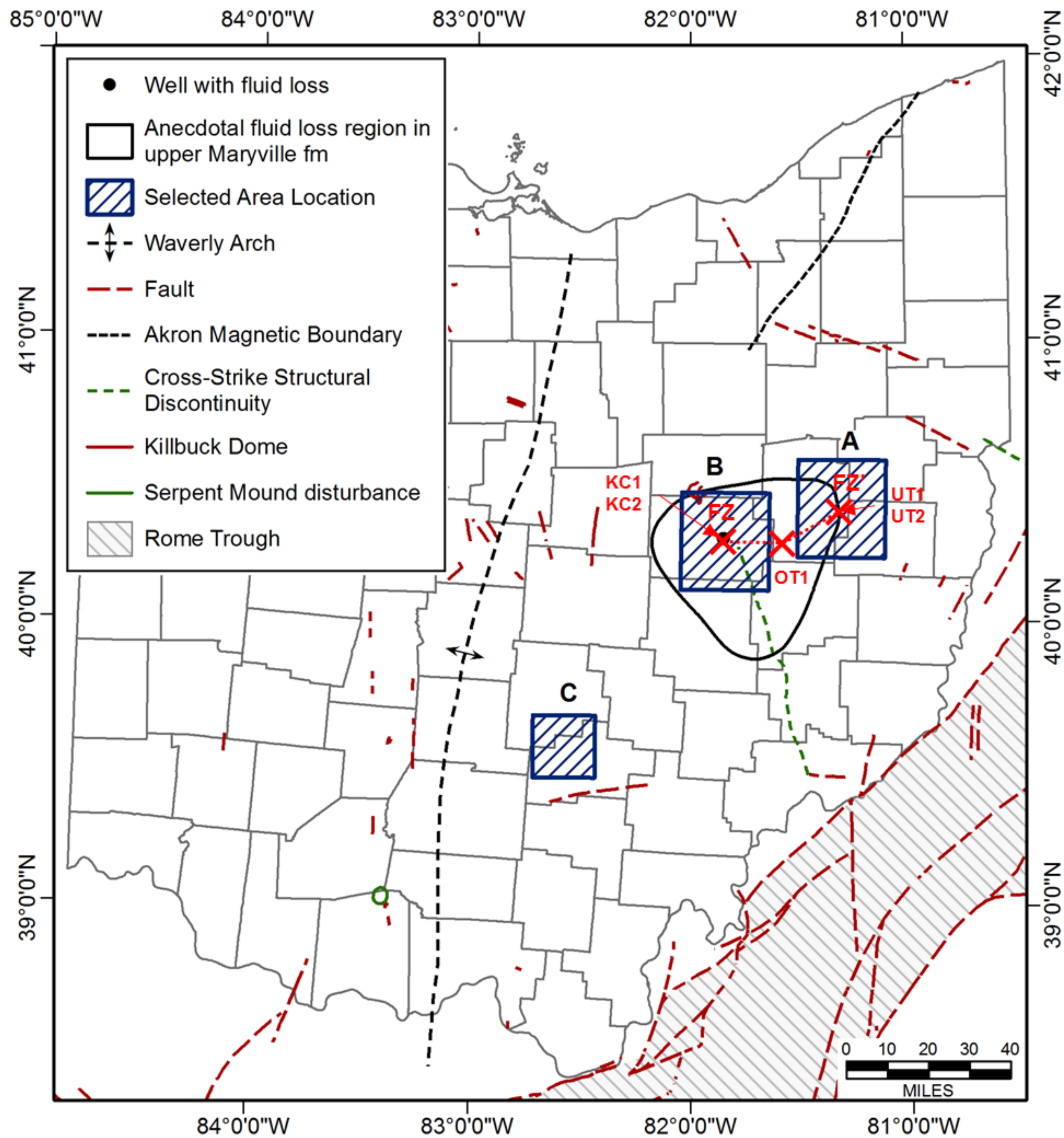

Figure 3-5. Map showing area of reported fluid loss in the upper Maryville formation by drillers (black triangular outline) and well location with fluid loss in Selected Area B. Each cross-section well from Figure 3-4 is marked by a red X. The cross-section line (FZ to FZ') is shown as a red dashed line.

Table 3-2. Estimated interval thickness between deepest USDW and top of potential CO_2 storage reservoir.

USDW-to-Reservoir Interval	Estimated USDW-to-Reservoir Interval Thickness, by Area (ft)[1]		
	Area A	Area B	Area C
USDW to Clinton ss	4,500	3,400	2,400
USDW to Knox dol	7,000	5,700	4,200

1. Thickness estimates from well log data located near center of areas.

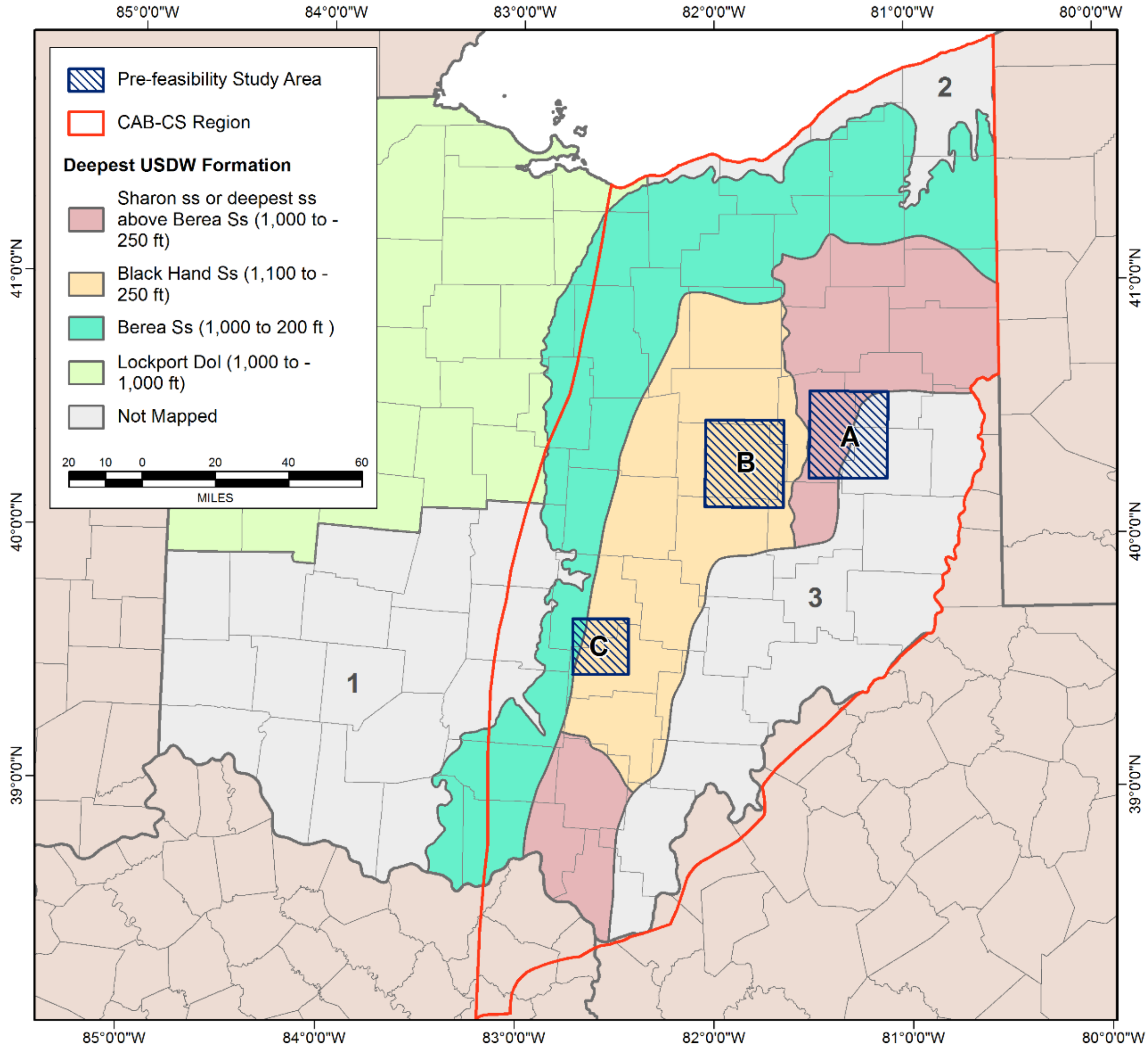

Figure 3-6. Map showing the regional distribution of the deepest USDW formations in Ohio.

Notes: The geologic assessment region is outlined in red; the areas of interest are the blue-lined rectangles labeled A, B, and C. Areas not mapped: (1) the southwest area, where most groundwater sources are within relatively shallow glacial outwash deposits and recent alluvial sediments, (2) the northeast area, where potable water comes from overlying glacial deposits, and (3) the southeast area, underlain by Mississippian and Pennsylvanian sandstone, shale, coal, clay, and limestone. The complexity of these deposits prohibits mapping a USDW across this area (Riley et al., 2012).

3.1.2 Enhanced Oil Recovery (EOR) Fields

Production from Ohio oil and gas reservoirs has led to void pore spaces that can be used as a resource for storing anthropogenic CO_2. CO_2 is considered miscible with residual oil in reservoirs that are greater than 2,500 ft in depth. This miscibility leads to more efficient displacement of in-situ reservoir fluids than immiscible fields. In addition, 2,500 ft is the average depth at which CO_2 injected in a reservoir exists in a supercritical state (Reichle et al., 1999; Beecy et al., 2002).

Fifteen major oil and gas fields of interest in eastern Ohio were evaluated for potential CO_2 storage (Figure 3-7). These fields were selected based on their overall storage capacity, their status as miscible fields, and their importance as historical oil and gas producers. Production data for these fields were previously obtained by Hawkins et al. (2017) from various existing sources. Eight of the fields in the assessment region have a potential storage capacity greater than 10 MMt (Table 3-3, Figure 3-8). The storage estimates reported here are about half of those estimated by previous studies conducted by Battelle (Hawkins et al., 2017; Battelle, 2014) The previous studies considered additional pore space freeing up due to incremental oil recovery from CO_2 injection. The estimates in this study do not account for additional pore space during EOR operations and provides a more conservative estimate based on current production and reservoir conditions. Actual production and storage could be higher due to CO_2-EOR.

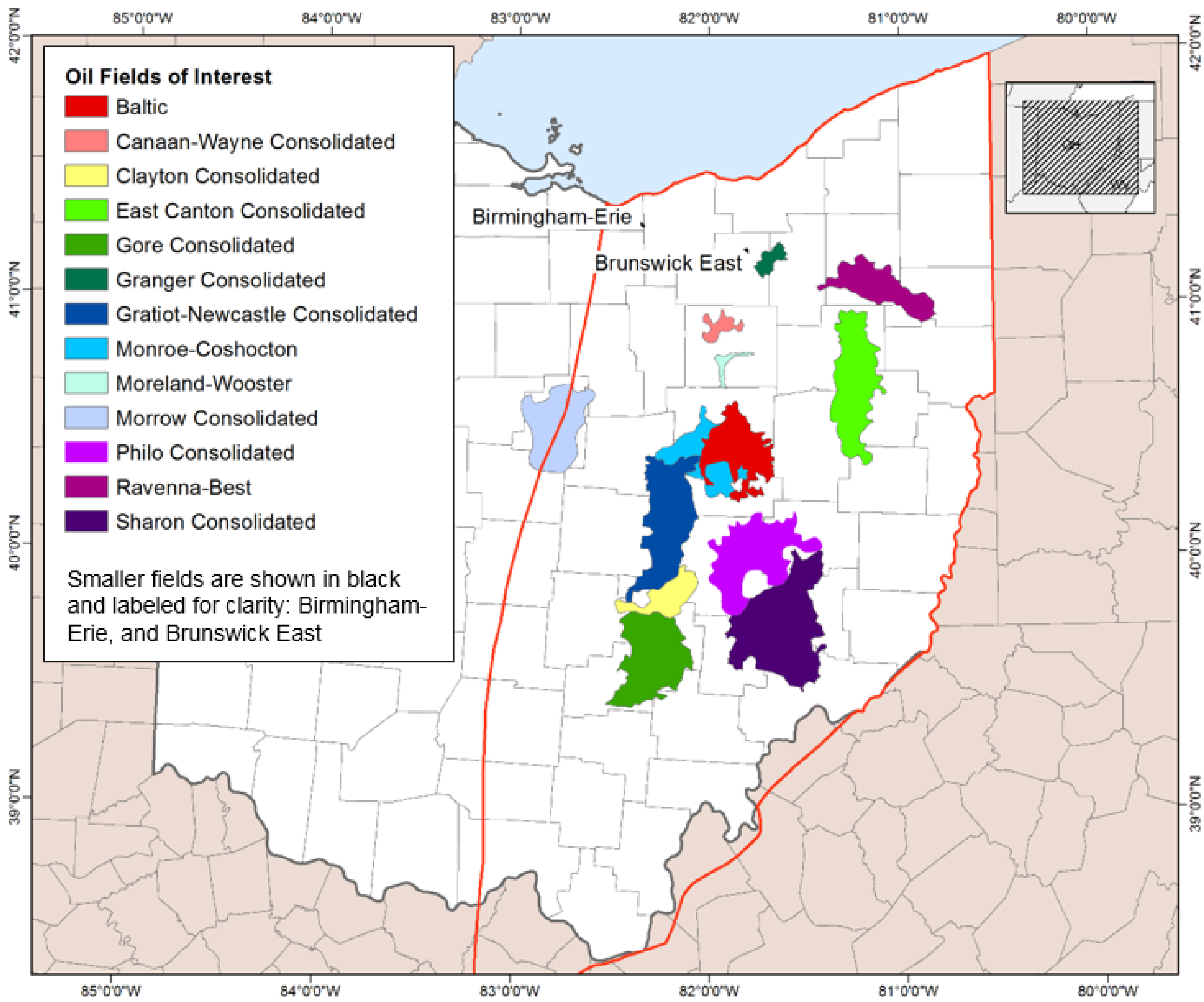

Figure 3-7. Map showing 15 major depleted hydrocarbon fields evaluated in this study.

Twelve depleted oil and gas fields of interest produce from the Silurian-age Clinton sandstone and three fields produce from the Cambrian- and Ordovician-age Knox Group (including one from the Rose Run sandstone, one from the Krysik sandstone, and one from the Copper Ridge dolomite). The Clinton sandstone is an informal drillers term for the sandstones in the Cataract group (Wickstrom et al., 2005). More than 80,000 Clinton wells have been drilled in Ohio

(Battelle, 2015b). The Clinton sandstone has historically been the most prolific oil and gas producer in the state (McCormac et al., 1996). This regional formation can be found in most of eastern Ohio, western Pennsylvania, southwestern New York, western West Virginia, and northeastern Kentucky. It is primarily composed of interbedded sandstones, siltstones, and shales with some carbonates (Laughrey, 1984; Laughrey and Harper, 1986; McCormac et al., 1996).

The Rose Run sandstone in the Baltic field is a 110-ft-thick depleted reservoir consisting of four to five porous sandstone lenses interbedded with nonporous dolomite. Primary production has been from erosional remnants related to regional exposure from the Knox unconformity. The erosional remnants are overlain by the Wells Creek formation or the Black River group. The Rose Run remnants are, on average, 30 to 40 ft in relief (Baranoski et al., 1996; Battelle, 2013).

Table 3-3. Storage capacities for down-selected oilfields.

Field Name	Reservoir Formation	Production-based CO_2 Storage Capacity (MMt)
Baltic	Rose Run ss	10.5
Clayton Consolidated	Clinton sand	35.7
East Canton Consolidated	Clinton sand	49.9
Gore Consolidated	Clinton sand	57.3
Gratiot-Newcastle	Clinton sand	76.9
Monroe-Coshocton Consolidated	Clinton sand	50.4
Philo Consolidated	Clinton sand	47.5
Sharon Consolidated	Clinton sand	25.7

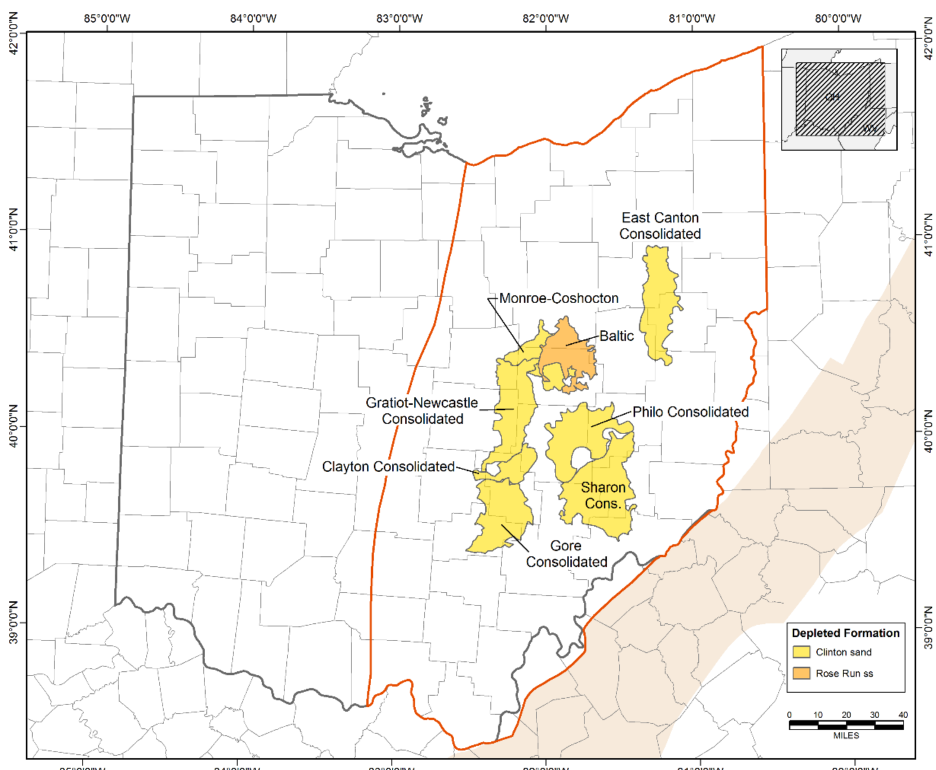

Figure 3-8. Depleted miscible hydrocarbon fields down-selected for site selection.

3.1.3 Selected Areas

Three selected areas (designated A, B, and C) were identified in the sub-basinal geologic assessment. The objectives of sub-surface data analysis of prospective storage resources were to establish the site has the resources to accept and safely store the anticipated quantity of CO_2 at the desired injection rate for a commercial-scale project and to provide input formation data required to predict site performance in terms of pressure change and CO_2 plume evolution. A summary of the geologic framework and formation data for three areas selected for the pre-feasibility study are described below.

3.1.3.1 Process for Identifying Selected Areas

Injection data provided by brine injection well operators through Battelle's piggyback well program have shown proven injection potential in the deep reservoirs in several portions of the assessment region. Subsurface mapping, numerical three-dimensional (3D) static earth models, and capacity estimates of the region have narrowed down candidate storage areas. Feasibility studies emphasized that the stacked reservoir scenario is optimal for commercial-scale storage and that a carefully designed well/field configuration derived from detailed site characterization is key for success. The following describes the approach used to assess the storage potential for both carbonate and sandstone reservoirs

Data from wireline and hydraulic tests were used to determine candidate carbonate reservoirs. The flow-meter wireline test is a reconnaissance technique used to identify the vertical depth distribution of permeable zones capable of taking injected flow. Simultaneously-run temperature logs provided additional information to identify permeable inflow zones and corroborate the flow-meter logging results. Hydraulic tests such as injection fall-off tests (IFOTs), in conjunction with pressure transient and history matching analyses, provided a calculated, open-hole permeability-feet measurement. Both the spinner and temperature logs paired with the hydraulic tests reveal vertical location (i.e., depth/formation and thickness) and permeability-feet of significant permeable zones. Table 3-4 lists the reservoir tests conducted for each well and indicates whether a permeability-feet calculation was possible. Permeability-feet was not calculated for wells ST1 and UT1 due to the lack of an IFOT.

Table 3-4. List of wells, their respective county, reservoir test(s) conducted, and ability to calculate permeability-feet.

Well	County	Hydraulic and Wireline Testing	Permeability-Feet Calculated?
KC1	Coshocton	a, b	Yes
KC2	Coshocton	a, c	Yes
KC3	Coshocton	a, b	Yes
OT1	Tuscarawas	a, b	Yes
UT1	Tuscarawas	a	No
UT2	Tuscarawas	a, b	Yes
ST1	Tuscarawas	a	No

Notes: a: flow-meter logging test; b: injection test; c: surface permeability test.

Tuscarawas and Coshocton Counties have the wells with the highest known open-hole permeability-feet in the assessment region (Figure 3-9). Selected Area A is sited around wells UT1 and UT2 due to their proximity to the prolific East Canton Consolidated Oilfield (Clinton sandstone). These wells also contain the thickest cumulative injection interval (around 180 ft). Formations with highly permeable zones include the Rose Run sandstone, lower Copper Ridge dolomite, Nolichucky sandstone facies, and Maryville formation. Selected Area B is sited around wells KC1, KC2, and KC3 due to their proximity to two oil and gas fields, the Monroe-Coshocton Consolidated (Clinton sandstone) and Baltic (Rose Run sandstone) oilfields. Area B also has the wells with the highest permeability-feet in the region. Each selected area is 506 square miles (mi^2) with its centroid location near the wells mentioned above.

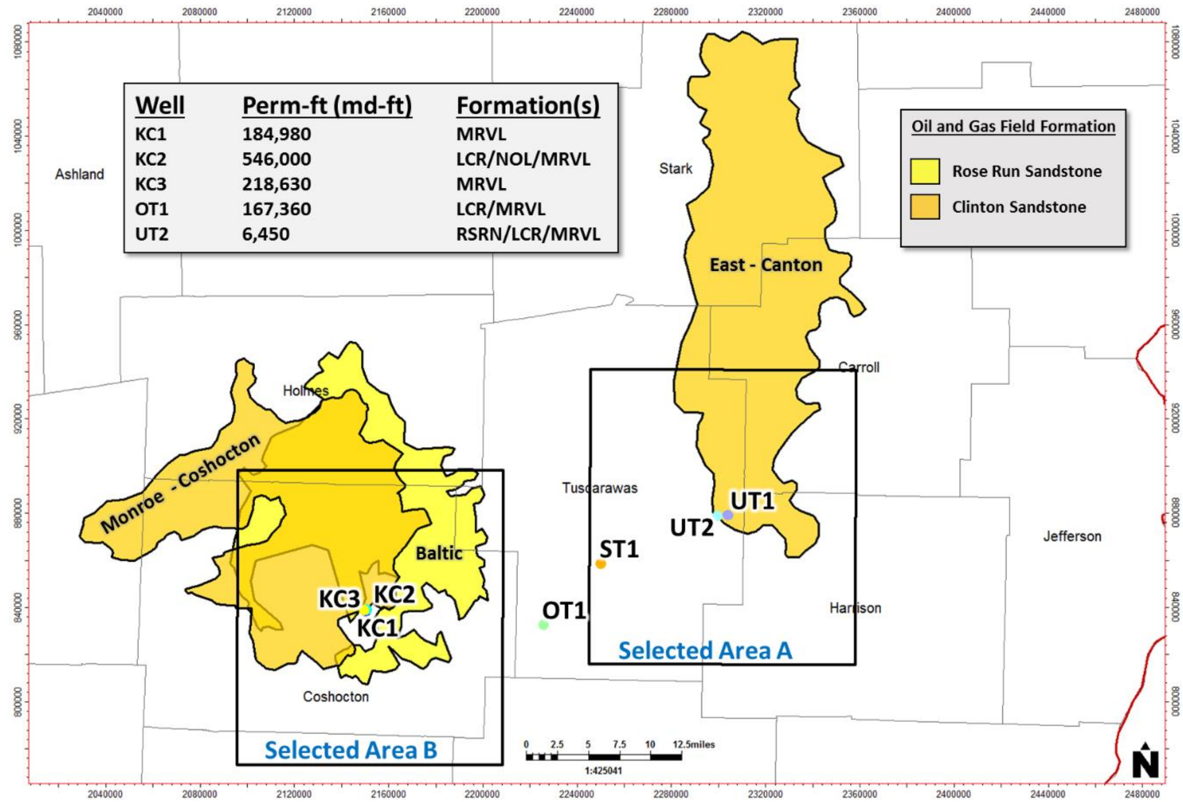

Figure 3-9. Map of Selected Areas A and B with all brine injection wells that have reservoir test data.

Notes: Proximal oil and gas fields, colored by formation, show potential for CCS. A combination of available test data and presence of depleted hydrocarbon fields were used to define selected areas. Rose Run sandstone (RSRN), lower Copper Ridge dolomite (LCR), Nolichucky sandstone facies (NOL), and Maryville formation (MRVL).

A connected volume analysis was performed using the regional static earth model developed by Battelle (2017a) to reveal the extent of potential reservoir-quality rock for CO_2 injection. This model was developed using data from wireline logs, core, and reservoir testing. The permeability distribution in the regional model was screened to capture cells containing a chosen limit of 10 mD or greater, and to identify potential connected reservoir volumes (Figure 3-10). The top 15 connected bulk volumes were then mapped, revealing three areas with three connected volume overlaps (Figure 3-11). For each overlap area, a potential CO_2 resource estimate was found by aggregating each connected volume formation resource estimate map (Battelle, 2017a) within the overlap polygon. For example, Overlap 1 consists of connected volumes in the Rose Run sandstone, Nolichucky, and basal Cambrian sandstone formations. The resource estimate maps for these formations were then clipped to the overlap polygon so only the resource estimate for each formation existed within Overlap 3. Each map's resource was then summed for a total resource estimate for each formation of interest. Overlap 3 contained the largest CO_2 storage resource estimate (99.8 MMt) and was therefore chosen for further analysis. As seen in Figure 3-11, Overlap 3 is juxtaposed against the Clinton sandstone Gore Consolidated oil and gas field (Gore), which is a potential candidate for CCS.

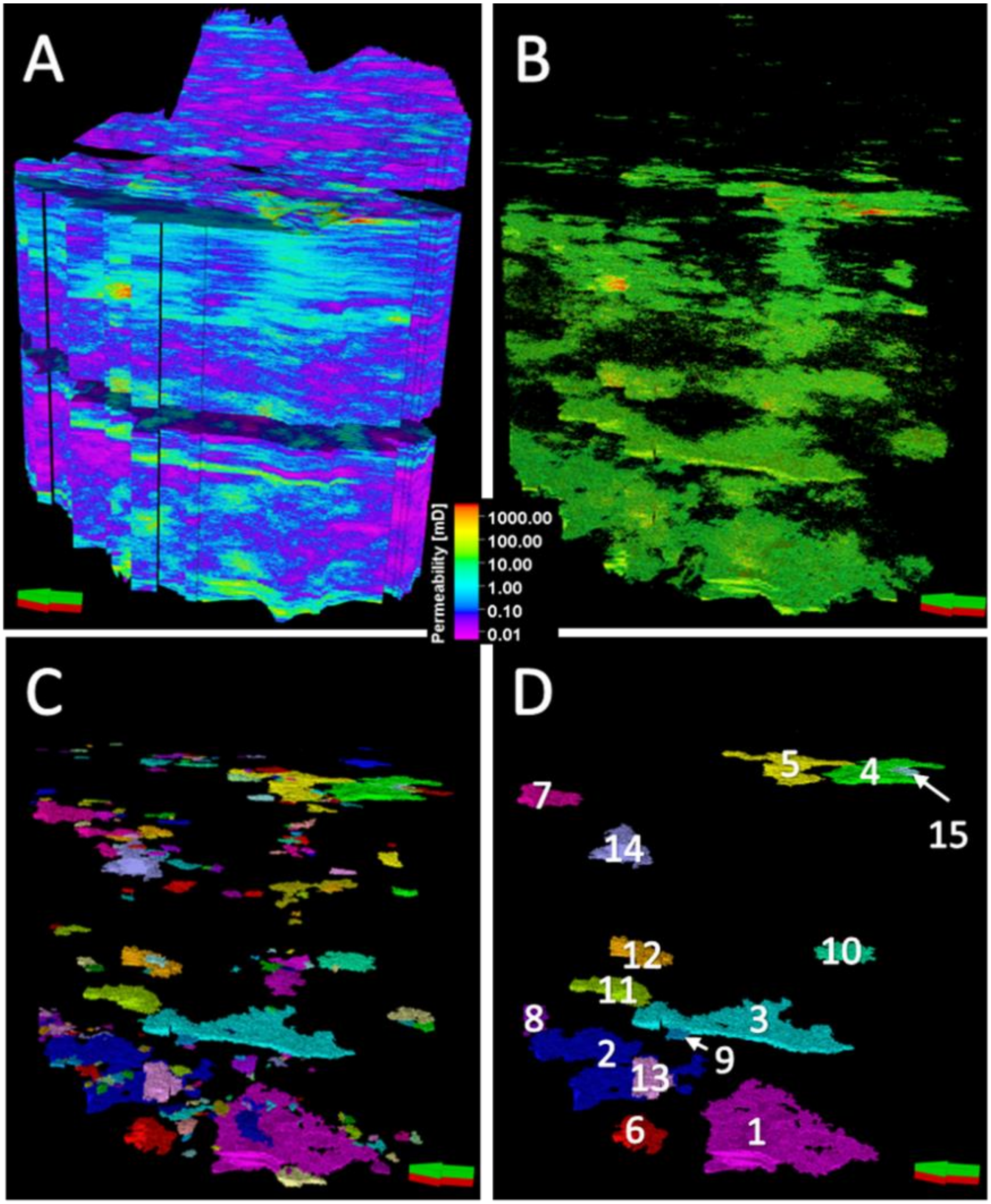

Figure 3-10. Connected volume analysis work flow.

Notes: (A) Permeability static earth model of the Cambro-Ordovician reservoir complex in the assessment region. (B) The filtered permeability cells with 10 mD or greater. (C) The results of the connected volume analysis subjected to screening. (D) The 15 potential volumes of interest resulting from the connected volume analysis and screening.

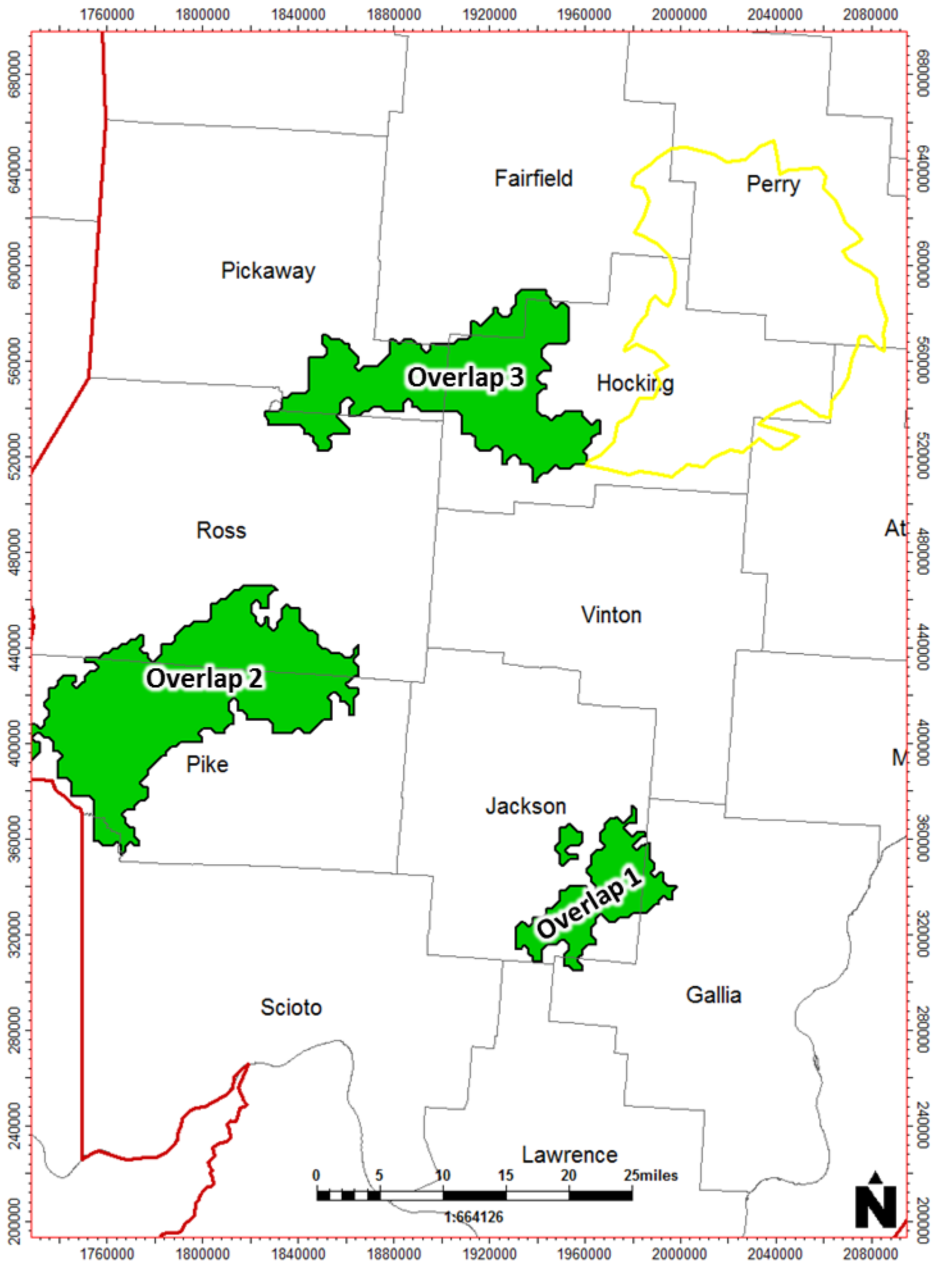

Figure 3-11. Green polygons represent areas where three connected volumes overlap. Yellow polygon is the Gore Consolidated oil and gas field.

Porosity, permeability, thickness, and permeability-feet maps were evaluated to determine the best placement for Selected Area C. All three connected volumes in Overlap 3 were made into cumulative property maps and evaluated to determine the location of Selected Area C placement (Figure 3-12). The cumulative property maps in Figure 3-12 show Selected Area C encompassing the thickest package of rocks with the highest permeability-feet. Area C has an area of 359 mi^2.

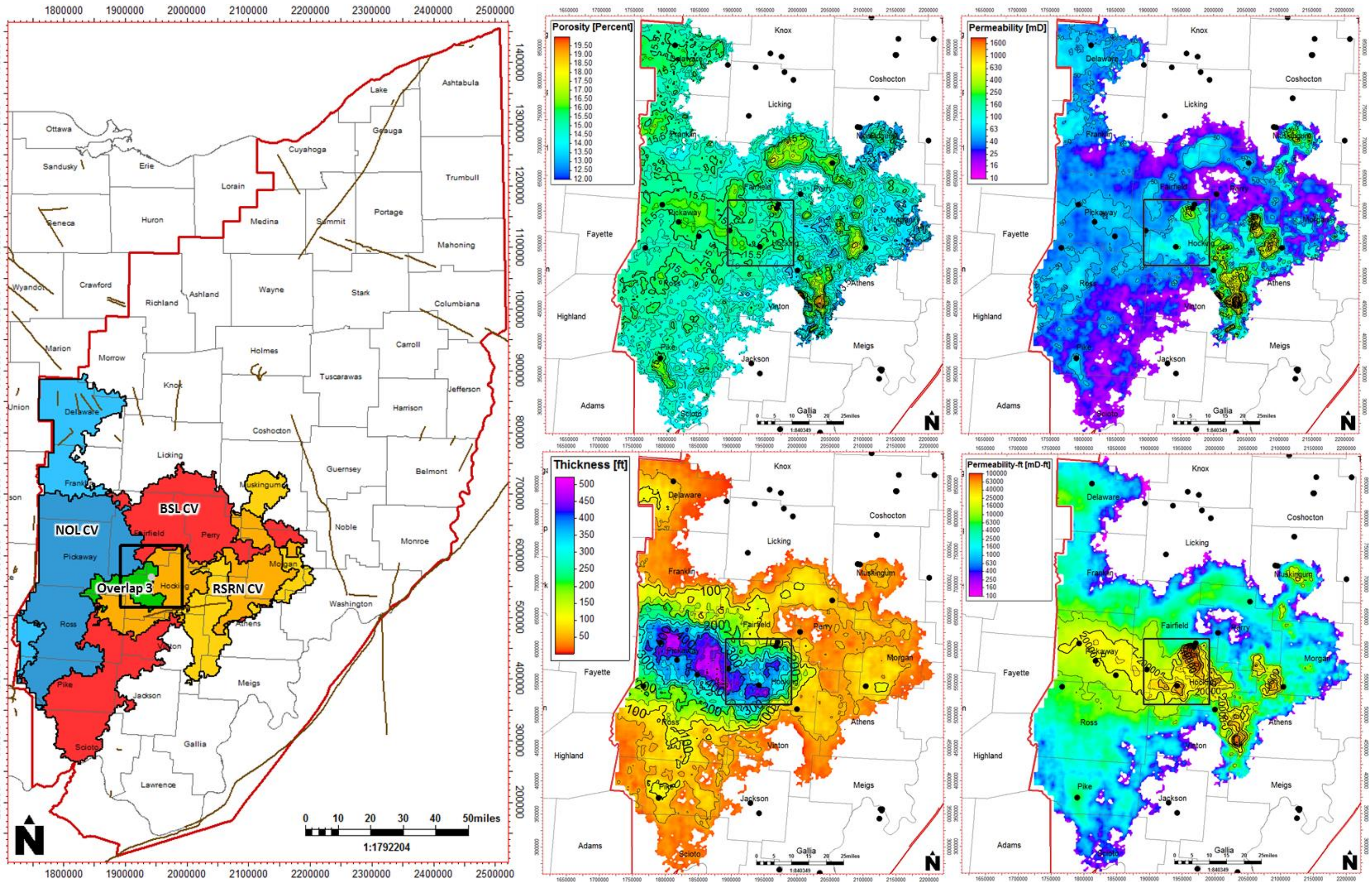

Figure 3-12. Connected volumes of Overlap C (left); cumulative connected volume properties for Overlap 3 (center); selected Area C (black polygon) represents the area that contains the best permeability-feet that is supported by well logs (black circles) (right).

3.1.3.2 Geologic Assessment

The regional 3D geocellular model domains of the selected areas were clipped to contain the Beekmantown formation down to the basal Cambrian sandstone formation for reservoir characterization (Figure 3-13). Each layer was identified as confining unit (caprock), storage reservoir complex (reservoir formation), or deep saline flow zone (high permeability flow zone). High permeability flow zones were identified in vuggy and collapsed karst layers at both Selected Areas A and B. Although these highly permeable zones contain unknown irregular geometries, in absence of site specific data, these zones were modeled using a simple layer-cake geometry. Each formation between major flow zones will contain average formation petrophysical data taken from the clipped model.

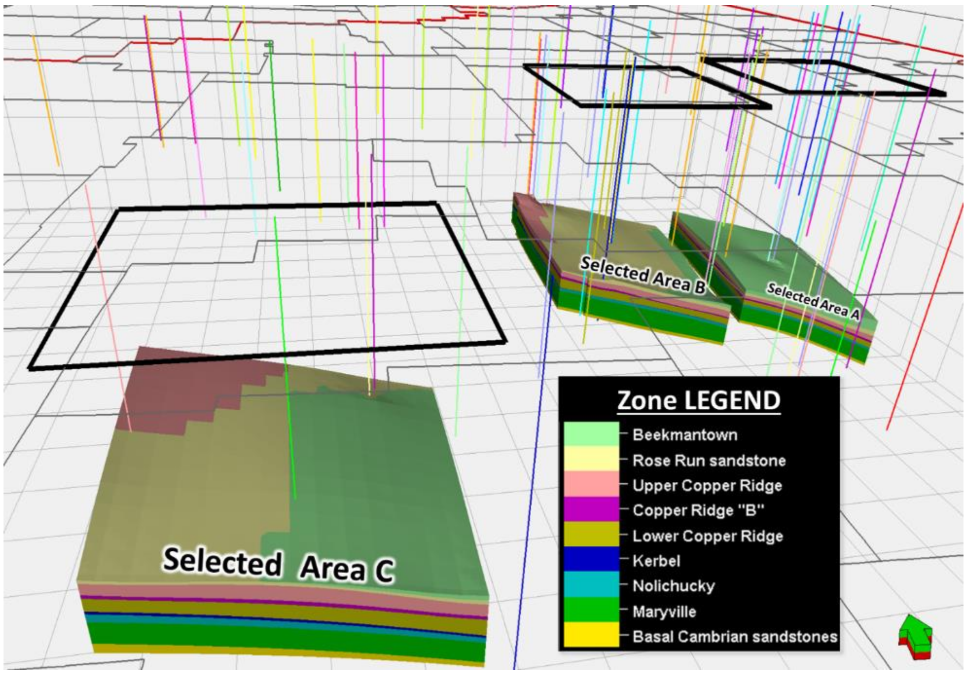

Figure 3-13. 3D view of all three selected areas, colored by formation.

Notes: The vertical colored lines represent wells with porosity logs used to populate the regional 3D geologic model (vertical exaggeration 25x).

For clastic reservoirs in the storage complex, the average porosity curve was sufficient for measuring porosity. However, average porosity logs are not sufficient for the carbonate reservoirs because secondary porosity, which is an important component of carbonate reservoirs, is not observed by commonly acquired neutron- and density-porosity logs. For the formations between the carbonate flow zones, the porosity and permeability were calculated using the clipped static earth model for each site. For reservoirs with carbonates (i.e., Rose Run sandstone with higher carbonate interbeds, lower Copper Ridge, and Maryville) porosity and permeability was derived using available log and core-derived porosity and permeability data. Above these deep saline formations, the Black River group and Wells Creek porosity and permeability were derived from averages from core measurements (Battelle, 2017a).

Selected Area A

Selected Areas A and B are close in proximity and are connected along a string of brine injection wells containing similar flow zone permeability-feet values in the Rose Run sandstone, lower Copper Ridge dolomite, Nolichucky shale, and Maryville formation. Flow zone property data are limited to the cores and the calculated permeability-feet measurements in a few wells. Core and previous studies were used to determine the porosity of each flow zone. Properties for formations and rock between the flow zones were determined with the clipped 3D geologic model. The properties for each flow zone (i.e., thickness, porosity, and permeability) for Selected Areas A and B are the same but vary in depth.

A stratigraphic column denoting flow units with average formation statistics and CO_2 resource estimates for Selected Area A is shown in Table 3-5. The reservoir complex is made up of the formations from the Beekmantown dolomite to the basal Cambrian sandstone overlain by around 50 ft of the Wells Creek formation and close to 600 ft of Black River group caprock. The Wells Creek formations contains interbedded carbonate and shale and is considered a “buffer zone” formation. In this study a “buffer zone” formation is juxtaposed between the reservoir rock and the caprock having the potential for storage.

Flow zone depths and thicknesses were determined using flow-meter log analysis in six wells (Table 3-6). The thickness of each formation flow zone and the total well flow zone thickness were recorded. An average thickness was calculated for each formation by taking the thickness of each formations flow zones divided by the number of flow zones present in the wells.

The permeability of each flow zone was calculated using the permeability-feet values from the IFOTs and an internal permeability analysis using surface gauges for the KC2 well. For each well, the ratio between each individual flow zone and the total thickness of all flow zones in the well was calculated. Each flow zone in the wells with IFOTs was assigned a thickness-weighted permeability-feet value by multiplying the open-hole transmissivity by this ratio. Each transmissivity value was then converted to a permeability dividing the ratio of the transmissivity applied to the zone by thickness of the zone. The permeability of each zone was then averaged for all wells (Table 3-7). The permeability values were scaled down to more realistic values for reservoir simulations (see Section 4.1) using brine injection operational data.

Core porosity measurements for the Rose Run sandstone are from seven wells in and around the county for Selected Area A: Columbiana County, Coshocton County (four wells), Holmes County, Tuscarawas County. Using the Rose Run sandstone (interbedded sandstone and carbonate) porosity measurement distribution, a P90 porosity value of 10.6% was determined. Conventional wireline logs tend to underestimate secondary porosity in carbonates due to complexities of the pore systems of these rocks (Akbar et al., 2000). Given this, using a P90 value is appropriate until further data can be collected. The lower Copper Ridge and Maryville porosity was determined using a porosity/permeability transform. Porosity/permeability transforms are relationships referring porosity, a commonly acquired measurement, to permeability, a measurement that is not commonly acquired. The equation of an exponential regression line fit through a plot where permeability is a variable dependent on porosity can be used to calculate permeability values using porosity. In this case, permeability measurements using the Timur-Coates method were back-calculated using Equation 3-1 to determine an average porosity value for the lower Copper Ridge and the upper 150 ft of the Maryville formation.

$$K = 0.0018e^{0.5052\phi} \qquad \text{(Equation 3-1)}$$

where, K is permeability (mD) and ϕ is porosity (%). The R-squared value for this transform was 0.77, a value indicating good correlation between porosity and permeability. The P90 porosity value is 11.5% for the lower Copper Ridge and 10% for the upper 150 ft of the Maryville. The

Table 3-5. Stratigraphic column of Selected Area A showing the confining units (gray) above and below the reservoir complex (yellow) and the identified flow zones (blue) within the complex.

Stratigraphic Column			Formation Data						
System	Formation Lithologies	Stratigraphy (Colored by Unit Type)	Overburden Thickness (ft)	Elevation (ft MSL)	Thickness (ft)	Porosity (Decimal)	Average Permeability (mD)	NETL P_{10} GCO_2 Resource Estimate (MMt)[a]	NETL P_{90} GCO_2 Resource Estimate (MMt)[a]
Ordovician	LS, DOL	Black River Group	7,187	-6,323	505	0.006	0.003	-	-
	LS		7,692	-6,828	80	0.006	0.003	-	-
	DOL, LS, SH	Wells Creek Formation	7,772	-6,908	54	0.019	0.453	-	-
	DOL	Beekmantown dolomite	7,826	-6,962	188	0.043	0.18	13.3	143.3
Cambrian	SS	Rose Run sandstone	8,014	-7,150	51	0.038	0.8	3.2	34.3
		Rose Run Flow Zone	8,065	-7,201	58	0.106	65[b]	10.1	109
		Rose Run sandstone	8,123	-7,259	35	0.038	0.8	2.2	23.6
	DOL	Upper Copper Ridge dolomite	8,158	-7,294	145	0.031	0.04	7.4	79.7
	DOL, SLT	Copper Ridge B-zone	8,303	-7,439	59	0.035	0.07	3.4	36.6
	DOL	lower Copper Ridge dolomite	8,362	-7,498	105	0.038	0.09	6.6	70.7
		Lower Copper Ridge Flow Zone	8,467	-7,603	43	0.115	1879[b]	8.1	87.6
		lower Copper Ridge dolomite	8,510	-7,646	24	0.038	0.09	1.5	16.2
	DOL, SH	Nolichucky shale	8,534	-7,670	54	0.029	0.05	2.6	27.8
	SS, DOL SS	**Nolichucky Flow Zone**	8,588	-7,724	42	0.15	3900[b]	10.4	111.7
	DOL	**Maryville Flow Zone**	8,630	-7,766	35	0.1	13236[b]	5.8	62.0
		Maryville	8,665	-7,801	398	0.024	0.03	15.7	169.3
	SS	Basal Cambrian sandstone	9,063	-8,199	107	0.042	1.35	7.4	79.7
Precambrian	Igneous and Metamorphic Rocks	Grenville Complex	9,170	-8,306	-	-	-	-	-

[a] Resource estimate computed using volumetric equation for saline formations (DOE/NETL, 2015a). [b] Permeability was scaled down to a more realistic value using brine injection operational data for dynamic modeling.

Unit Type
Confining Unit
Storage Reservoir Complex
Deep Saline Flow Zone

Selected Area A		
ft^2	**mi^2**	**km^2**
14,096,087,000	506	1,310
Surface Elevation (ft)		**Total Depth**
864		9,244

Average formation and flow zone properties are listed to the right. Formation lithologies are as follows: DOL - dolomite; LS - limestone; SH - shale; SS - sandstone; SLT – siltstone

Table 3-6. Wells with identified formation flow zone thickness and total well flow zone thickness.

Well	Flow Zone Thickness (ft)					Open Hole Permeability-feet (mD-ft)
	Rose Run sandstone	Lower Copper Ridge dol	Nolichucky shale	Maryville formation	Total	
UT2	43	30	-	27	100	6,450
KC1	-	-	-	11	11	185,000
KC2	-	40	56	44	140	546,000[a]
KC3	-	-	-	5	5	218,600
OT1	-	60	-	40	100	167,400
UT1	73	-	27	83	183	-

Notes: Open-hole permeability-feet values recorded for reference.

a. Permeability values range from 2,500 to 5,300 mD, median: 3,900 mD. Values determined from an internal pressure transient analysis conducted by Barclay and Mishra (2014).

Table 3-7. Formation flow zones and their thickness-weighted permeability-feet and permeability values.

Well	Rose Run sandstone		Lower Copper Ridge dol.		Nolichucky shale		Maryville formation	
	kh (mD-ft)	k (mD)	kh (mD-ft)	k (mD)	kh (mD-ft)	k (mD)	kh (mD-ft)	k (mD)
UT2	2,774	65	1,935	65	-	-	1,742	65
KC1	-	-	-	-	-	-	185,000	16,820
KC2	-	-	156,000	3,900	218,400	3,900	171,600	3,900
KC3	-	-	-	-	-	-	218,600	43,730
OT1	-	-	100,400	1,674	-	-	66,940	1,674
Average Permeability (mD):	65		1,879		3,900		13,240	
Average Porosity (percent):	10.6		11.5		15		10	

Note: Average permeability and porosity values used for each formation flow zone.

Nolichucky sandstone facies at the base of the Nolichucky shale formation (also referred to as the Conasauga shale) contains porosity values greater than 15% (Gupta et al., 2017), which was used to define the Nolichucky flow zone porosity. The Nolichucky sandstone facies overlies the karsted top of the Maryville formation, which would likely contain porosities like that of a karsted dolomite. Table 3-7 shows the porosity determined for each respective flow zone.

Selected Area B

A stratigraphic column denoting flow units with average formation statistics and CO_2 resource estimates for Selected Area B is shown in Table 3-8. The reservoir complex is made up of the formations from the upper Copper Ridge to the basal Cambrian sandstone overlain by 50 ft of the Wells Creek formation and over 550 ft of Black River group caprock.

KC1 well data were used to identify formation depths and thicknesses. Flow zone thicknesses were found using the same average thicknesses in Table 3-6. The flow-meter log analysis for KC1 revealed one 11-foot flow zone in the Maryville formation. Wells KC2 and KC3 are within 1,500 ft of KC1; they show prominent flow zones in the lower Copper Ridge dolomite and Nolichucky shale. The permeability and porosity of each flow zone were calculated using the same methodology for Selected Area A. The KC3 well contained significant permeability-feet for a small 5-foot zone. Image logs revealed an interpreted large cavity approximately 3 feet thick in the Maryville flow zone. The average log porosity measurements for this zone ranged from 3.9% to 15.2% with an average porosity of 9%.

Table 3-8. Stratigraphic column of Selected Area B showing the confining units (gray) above and below the reservoir complex (yellow) and the identified flow zones (blue) within the complex.

Stratigraphic Column			Formation Data						
System	Formation Lithologies	Stratigraphy (Colored by Unit Type)	Overburden Thickness (ft)	Elevation (ft MSL)	Thickness (ft)	Average Porosity (Decimal)	Average Permeability (mD)	NETL P_{10} GCO_2 Resource Estimate (MMt)[a]	NETL P_{90} GCO_2 Resource Estimate (MMt)[a]
Ordovician	LS, DOL	Black River Group	5,395	-4,620	446	0.00575	0.003	-	-
	LS		5,841	-5,066	109	0	0.003	-	-
	DOL, LS, SH	Wells Creek Formation	5,950	-5,175	50	0.0186	0.453	-	-
Cambrian	SS	**Rose Run sandstone**	6,000	-5,225	78	0.05	12.5	6.3	68.0
	DOL	Upper Copper Ridge dolomite	6,078	-5,303	195	0.055	0.19	17.3	187.1
	DOL, SLT	Copper Ridge B-zone	6,273	-5,498	67	0.061	0.61	6.6	71.3
	DOL	Lower Copper Ridge dolomite	6,340	-5,565	120	0.037	0.18	7.2	77.4
		Lower Copper Ridge Flow Zone	6,460	-5,685	43	0.115	1,879[b]	8.0	86.3
		Lower Copper Ridge dolomite	6,503	-5,728	79	0.037	0.18	4.7	51.0
	SS, DOL, SH	Kerbel sandstone	6,582	-5,807	26	0.037	0.11	1.6	16.8
	DOL, SH	Nolichucky shale	6,608	-5,833	18	0.023	0.06	0.7	7.2
	SS, DOL SS	**Nolichucky Flow Zone**	6,626	-5,851	42	0.15	3,900[b]	10.2	109.9
	DOL	Maryville	6,668	-5,893	82	0.024	0.03	3.2	34.3
		Maryville Flow Zone	6,750	-5,975	35	0.1	13,240[b]	5.7	61.0
		Maryville	6,785	-6,010	400	0.024	0.03	15.5	167.4
	SS	basal Cambrian sandstone	7,185	-6,410	102	0.066	3.15	10.9	117.4
Precambrian	Igneous and Metamorphic Rocks	Grenville Complex	7,287	-6,512	-	-	-	-	-

[a] Resource estimate computed using volumetric equation for saline formations (DOE/NETL, 2015a). [b] Permeability was scaled down to a more realistic value using brine injection operational data for dynamic modeling.

Unit Type
Confining Unit
Storage Reservoir Complex
Deep Saline Flow Zone

Selected Area B		
ft^2	**mi^2**	**km^2**
14,096,087,000	506	1,310
Surface Elevation (ft)		**Total Depth**
775		7,305

The Rose Run sandstone in this area is part of the Baltic oil and gas field. Average formation and flow zone properties are listed to the right. Formation lithologies are as follows: DOL - dolomite; LS - limestone; SH - shale; SS - sandstone; SLT - siltstone.

For the formations between the flow zones, the porosity and permeability were calculated using the clipped static earth model for each site. Above the storage reservoir complex, the Wells Creek formation and the Black River group porosity and permeability were derived from averages from core measurements (Battelle, 2017a).

Selected Area C

A stratigraphic column denoting flow units with average formation statistics and CO_2 resource estimates for Selected Area C is shown in Table 3-9. The 3D geologic model was used to determine all properties for Selected Area C; data indicate that the strata exposed from top to bottom are as follows: Black River group, Wells Creek formation, Beekmantown dolomite, Rose Run sandstone, upper Copper Ridge dolomite, Copper Ridge “B” unit, lower Copper Ridge dolomite, Kerbel sandstone, Nolichucky shale, Maryville formation, basal Cambrian sandstone, and the Grenville basement complex. The reservoir complex is made up of the formations from the Beekmantown dolomite to the basal Cambrian sandstone overlain by 30 ft of the Wells Creek formation “buffer zone” and over 450 ft of Black River group caprock. The injection zone (open hole) covers the interval from the Beekmantown dolomite to the basal Cambrian sandstone. Selected Area C is a potential option for CCS due to its thick total reservoir volume (connected volumes) in the Rose Run sandstone, Nolichucky shale, and basal Cambrian sandstone. The exported 3D static earth model for Selected Area C has an area of around 360 mi^2 and contains more than two million cells. The basal Cambrian sandstone reservoir volume contained the largest storage potential for this area. However, there is uncertainty regarding whether injection into the basal Cambrian sandstone will be permitted due to concern about the induced seismicity events that occurred at the Northstar 1 UIC Class II injection well in Youngstown, Ohio (Ohio Department of Natural Resources [ODNR], 2012).

Average formation and reservoir volume thicknesses were determined using Equation 3-2:

$$h = V_b / A \qquad \text{(Equation 3-2)}$$

where h is formation thickness (ft), V_b is formation bulk volume (ft^3), and A is formation area coverage (ft^2). Formation and reservoir volume average porosity and permeability were determined using the Petrel™ filtering menu to isolate select formations and volumes. Statistics for the formations with reservoir volumes were recorded by isolating the formation cells in Petrel™ and filtering out the cells within the reservoir volume and recording statistics for the remaining cells. Permeability-feet was determined by multiplying the average formation or reservoir volume thickness by average formation or reservoir volume permeability.

Area C is the shallowest of the selected areas, but at 3,525 ft below surface elevation, it is well below the miscibility depth cutoff for injected CO_2 at supercritical pressure and temperature conditions. Structural top surfaces were used to determine the shallowest overburden depth at Selected Area C for the top of the reservoir complex (Knox unconformity surface).

Table 3-9. Stratigraphic column of Selected Area C showing the confining units (gray) above and below the reservoir complex (yellow) and the identified flow zones (blue) within the complex.

Stratigraphic Column			Formation Data					
System	Formations Lithologies	Stratigraphy (Colored by Unit Type)	Average Thickness (ft)	Average Porosity (mD)	Average Permeability (mD)	Permeability-feet (mD-ft)	NETL P_{10} GCO_2 Resource Estimate (MMt)	NETL P_{10} GCO_2 Resource Estimate (MMt)
Ordovician	LS, DOL	Black River Group	355	0.00575	0.003	1.18	-	-
	LS		78	0.001	0.003	0.26	-	-
	DOL, LS, SH	Wells Creek Formation	33	0.0186	0.453	14.94	-	-
	DOL	Beekmantown dolomite	20	0.05	0.2	4	1.1	12.0
Cambrian	SS	Rose Run sandstone Reservoir Volume	22	0.15	285	6,271	3.7	39.9
		Rose Run sandstone	23	0.09	4.8	109	2.3	25.0
	DOL	Upper Copper Ridge dolomite	264	0.08	1.3	352	23.7	255.4
	DOL, SLT	Copper Ridge B-zone	79	0.07	1.4	113	6.2	67.1
	DOL	Lower Copper Ridge dolomite	320	0.06	1.9	618	21.6	232.6
	SS, DOL, SH	Kerbel sandstone	49	0.08	0.9	45	4.4	47.2
	DOL, SH	Nolichucky shale	77	0.06	1.5	119	5.2	55.9
	SS, DOL, SS	Nolichucky Reservoir Volume	6	0.15	39	247	1.1	11.5
	DOL, SH	Nolichucky shale	38	0.06	1.5	60	2.6	27.9
	DOL	Maryville formation	387	0.04	0.3	107	17.4	187.3
	SS	Basal Cambrian sandstone	41	0.09	3.4	139	4.1	44.2
		Basal Cambrian sandstone Reservoir Volume	72	0.16	46	3285	12.9	138.7
		Basal Cambrian sandstone	41	0.09	3.4	139	4.1	44.2
Precambrian	Igneous and Metamorphic Rocks	Grenville Complex	-	-	-	-	-	-

[a] Resource estimate computed using volumetric equation for saline formations (DOE/NETL, 2015a).

Unit Type
Confining Unit
Storage Reservoir Complex
Deep Saline Flow Zone

Selected Area C		
ft^2	mi^2	km^2
10,000,040,000	359	929
Surface Elevation (ft)		Total Depth
1,089		7,305

Average formation and reservoir volume properties are listed to the right. Formation lithologies are as follows: DOL - dolomite; LS - limestone; SH - shale; SS - sandstone; SLT – siltstone.

3.1.3.3 Primary and Secondary Selected Areas

Table 3-10 summarizes the criteria used to evaluate the different selected areas, developed using the DOE/NETL Site Screening Best Practice Manual (DOE/NETL, 2017a). Based on these criteria, Selected Area B was designated the primary selected area, because of the combination of injectivity performance data, geological setting, and CO_2 source strategy. Selected area A was designated as the secondary selected area, with a similar rating but less confidence in injection performance. Selected area C had the lowest rating because there is limited information on deep rock formations and injection wells near the selected area.

Table 3-10. Preliminary selected area evaluation results.

Criteria		Selected Area		
		A	B	C
Subsurface Geological Data	Geologic Setting	+++	+++	+
	Confining Zone	+++	+++	+++
	Trapping Mechanisms	+++	+++	++
	CO_2 Storage Resource	+++	+++	+++
	Injectivity	++	+++	+
Regulatory Requirements	Legacy Wellbores/Corrective Action	++	++	+++
	Monitoring Requirements	++	++	++
	Environmental Factors	++	++	+
	Liability	++	++	++
Model Data	Storage Zone Parameters	++	+++	+
	Storage Zone Subsurface Conditions	++	+++	++
	CO2 Saturation/Pressure Extent	++	++	++
	Existing Seismic	++	++	+
	Boundary Conditions/Uncertainty	++	++	+
Site Data	Source Strategy	+++	+++	+
	Pipeline Routes	++	++	+
	Surface Access/Logistics	++	+++	++
	Infrastructure Requirements	+++	+++	++
	Mineral Rights/Subsurface Access	++	++	++
	CO_2 EOR Options Nearby	+++	++	+
	AoR Requirements	++	++	+
Social Data	Socio-Economic Setting	++	+++	+
	Market Factors	++	++	+++
	Historical Oil & Gas Operations	+++	+++	++
	Other	++	++	+

+ = low rating, ++ = medium, ++ =high rating

3.1.3.4 Other Prospective Storage Resources

The selected areas described above were identified based on the most promising geology using available data. In addition, driller observations (e.g., field observations of lost-circulation zones) suggest the presence of highly permeable zones in wells drilled in the southeastern part of the study area closer to large point sources located along the Ohio River (personal communication William Rike, 10 August 2017). Lost circulation is the reduced or total absence of fluid flow up the annulus when fluid is pumped through the drill string due to natural fissures, fractures, or caverns in a formation, and mud flows into the newly available space. These areas are indicative of high injectivity zones that could be promising targets for CO_2 injection.

Figure 3-14 shows the locations of wells with indicators of high injectivity and vuggy dolostones. Vuggy dolostone in the lower Copper Ridge dolomite was first recognized as a potential reservoir in southeastern Ohio in 2003, in the GM1 well drilled in Mason County, West Virginia (Battelle, 2011 and 2013). Extensively logged, cored, and analyzed, GM1 and subsequent wells provided the initial set of criteria for identifying lower Copper Ridge porosity. Testing with CO_2 injection in the GM1 and GM2 wells has also shown excellent injectivity in this zone. Porosity was subsequently identified in the HG1 and LM3 wells, strongly indicated in the ST1 and WG1 wells, and injection tested in the CG1 well (Battelle, 2013). Vuggy dolostones such as those in the GM1 and GM2 well in Mason County, West Virginia, also occur in core samples from the Aristech Chemical Company's disposal wells in Scioto County, Ohio (Battelle, 2013 and 2017b). These locations could be considered for future studies.

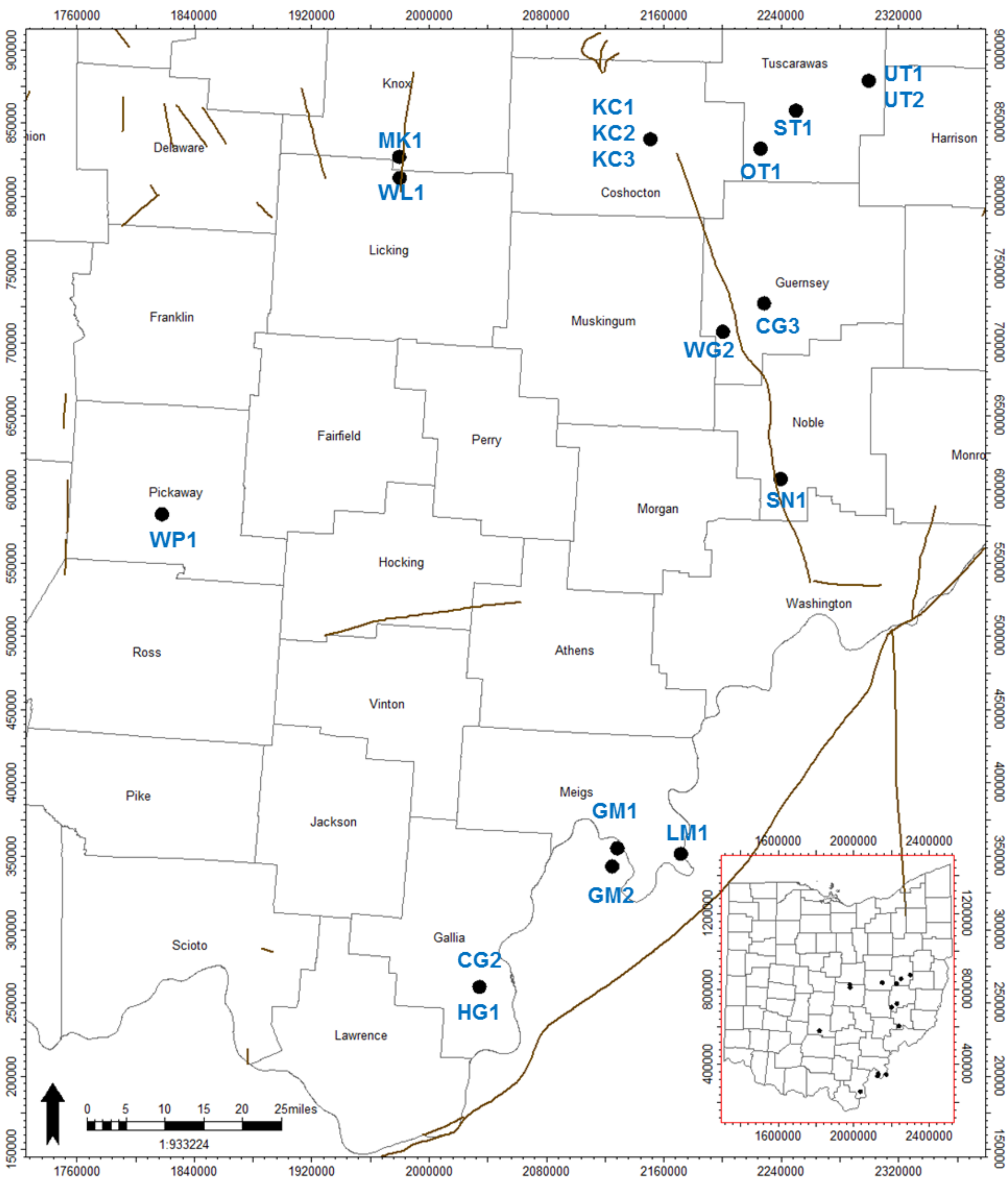

Figure 3-14. Wells with vuggy porosity zones in the Copper Ridge dolomite eastern Ohio. Precambrian fault and structures represented as brown lines. Blue labels indicate piggyback well codes.

3.2 Caprock/Trapping Assessment

Battelle (2017a) assessed the sealing and mechanical integrity effectiveness of the geologic formations that comprise the caprock system for candidate CO_2 storage reservoirs within the Upper Cambrian-Lower Ordovician geologic section in Ohio. The caprock feasibility assessment was the first-of-its-kind study in the region leading to a detailed understanding of the Cambrian-Ordovician caprock systems.

Upper Ordovician units from the top of the Queenston shale to the base of the Wells Creek formation comprise the caprock and seal overlying the deep, saline reservoir complex (Figure 3-2). This interval is 1,700 to 2,400 ft of shale and low-permeability carbonates. The Black River group and the Wells Creek formation, together, make up the primary caprock for the underlying Cambrian-Ordovician strata. Battelle (2017a) evaluated the effectiveness of these units for preventing leakage of injected CO_2 out of the Cambrian-Ordovician system for a commercial-scale CO_2 storage program. To evaluate caprock performance, a series of numerical modeling simulations were conducted to assess (1) leakage potential by direct CO_2 migration and (2) the potential for faulting/fracturing that could lead to CO_2 leakage and/or other consequences.

Results from Battelle (2017a) indicate that the Black River-Wells Creek sequence is a very effective seal for the Cambrian-Ordovician reservoir system; however, the seal could be compromised due to certain conditions (for example, a fracture or fault extends from the top of the reservoir into or through the caprock, or the permeability of the caprock is significantly higher than the laboratory measurements performed on caprock samples). Both conditions are considered low probability, but site-specific investigations would be needed to rule them out.

3.3 Geohazards Assessment

3.3.1 Seismic Hazard

The probable long-term seismic risk for Ohio and the surrounding area, derived from peak ground acceleration (PGA) maps, is provided in Figure 3-15. The assessment region has odds of 1 in 50 (a 2% probability) of undergoing ground shaking greater than 0.04 to 0.06 g's or higher in the next 50 years, indicating a region with a low risk from damaging earthquakes compared to other parts of the United States (Figure 3-16). An acceleration rate of 0.1 g will cause some damage to poorly constructed buildings. With a range of acceleration between 0.04 to 0.06 g's, most people will feel the ground motion, dishes and windows may break, and tall objects may move (Dart and Hansen, 2008; Petersen et al., 2014).

The map in Figure 3-15 also shows the epicenter locations and magnitude of Ohio earthquakes from 1999 to the present, the period since the Ohio Seismic Network (OhioSeis)[1] was established (Hansen and Ruff, 2003).

[1] The Ohio Seismic Network consists of 29 cooperative seismograph stations at colleges, universities, and other institutions across the state of Ohio. The network is maintained and operated by the ODNR, Division of Geological Survey, in cooperation with the Ohio Emergency Management Agency (OhioSeis, 2017).

3.3.2 Induced Seismicity

Because the region is located in a stable tectonic setting, induced seismicity from an injection well is a rare event. A total of 208 located earthquakes have been recorded in Ohio since 1999, ranging in magnitude from 1.8 to 5.0. A survey of UIC Class I and Class II wells indicate most wells do not cause induced seismicity. However, some isolated instances of induced seismicity related to Class I and Class II UIC disposal wells have occurred in northeastern Ohio and northwestern Pennsylvania (Figure 3-15)

Since the 2011-2012 induced seismicity events that occurred at the Northstar 1 UIC Class II injection well in Youngstown (Figure 3-15), the State of Ohio has prohibited drilling injection wells into Precambrian rock as a precautionary measure to prevent induced seismicity (ODNR, 2012; Kim, 2013, Raziperchikolaee and Miller, 2015). It is uncertain whether fluid injection into the overlying basal Cambrian sandstones is also prohibited. Until there is a clear understanding of the revised Ohio regulations, the basal Cambrian sandstones, which is the primary potential storage formation for Selected Area C, may not be a potential storage interval. Because of potential prohibition of injection into the basal Cambrian sandstones, they were not considered as part of the storage complex for Areas A or B as well.

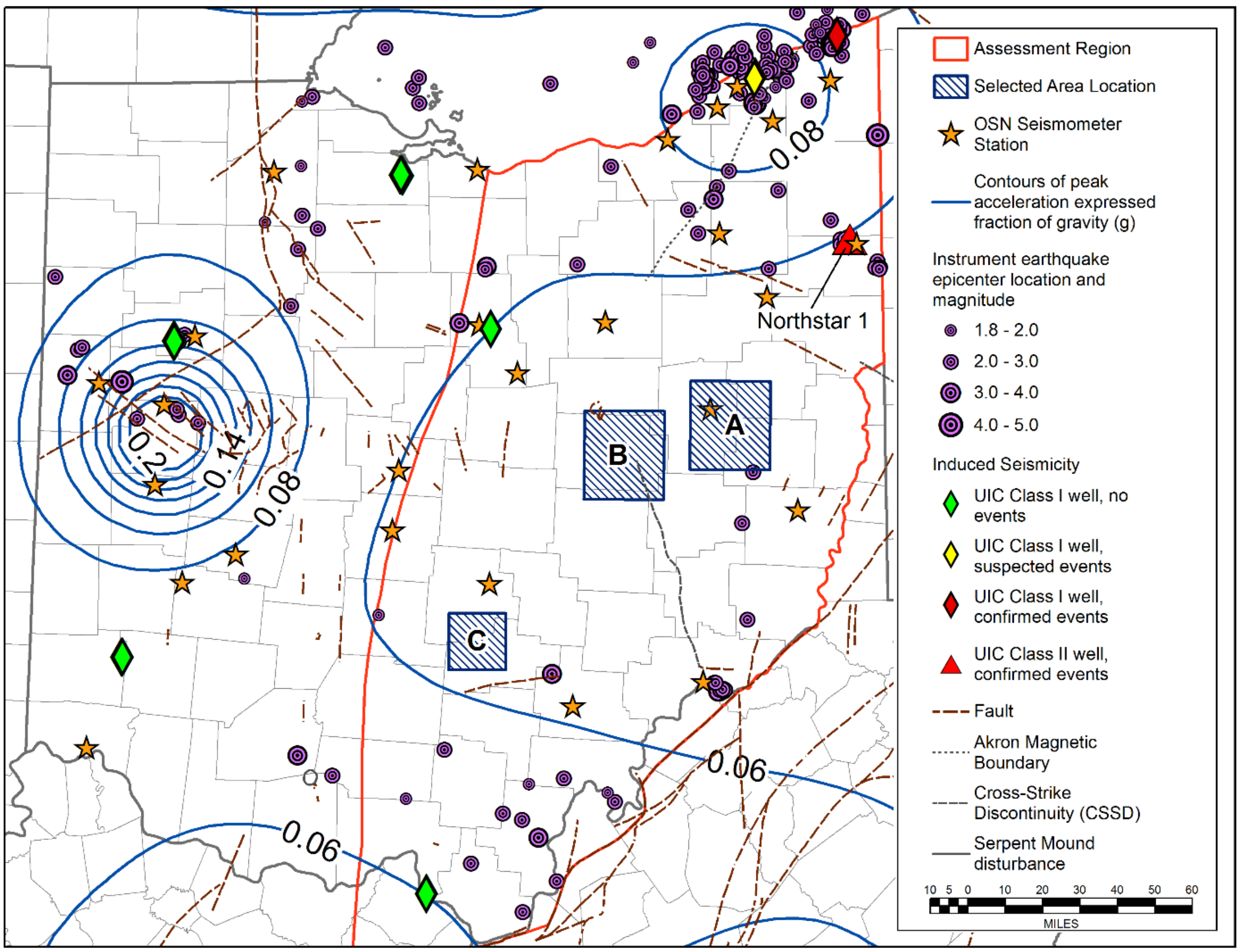

Figure 3-15. Seismic hazard map of the assessment region.

Notes: Map shows fault and earthquake epicenter locations; induced seismicity; and PGA map (2% in 50 years) of Ohio and the surrounding area (Dart and Hansen, 2008; Petersen et al., 2014; OhioSeis, 2017).

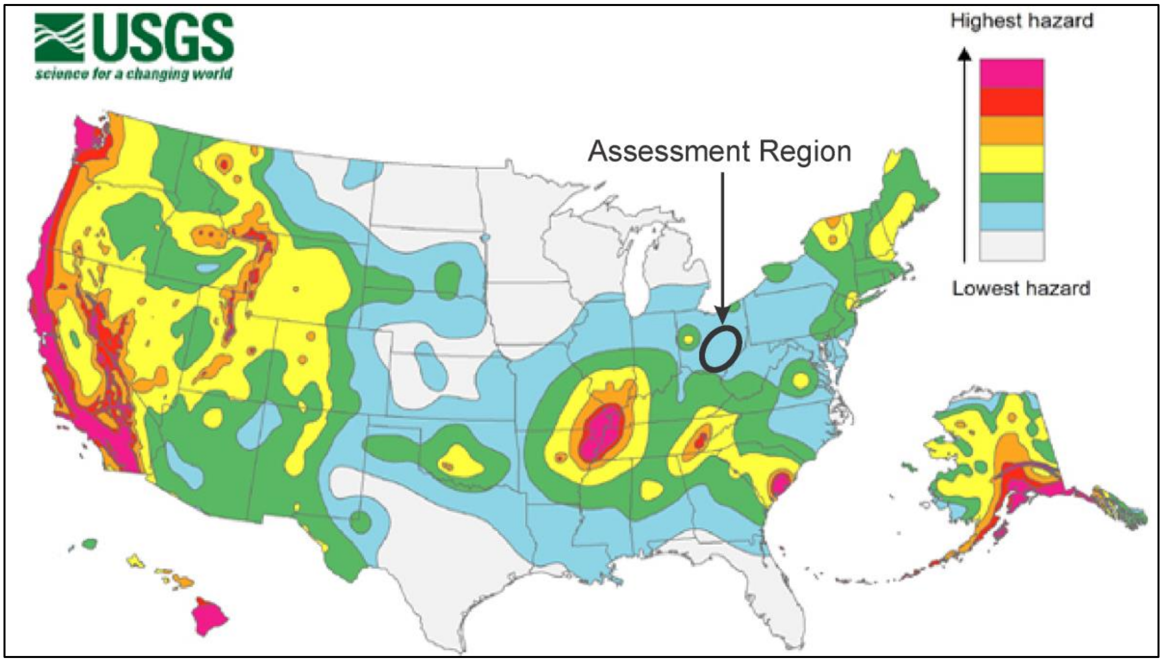

Figure 3-16. Simplified National Seismic Hazard Map (PGA, 2% in 50 years) (USGS, 2014a).

3.4 Risk Assessment Using the NRAP Tools

U.S. EPA's Class VI regulations require owners or operators of carbon storage projects to determine an AoR representative of project risk to USDWs. The AoR is an estimate of the region potentially impacted by the CO_2 injection and is used to develop monitoring plans to ensure protection of USDWs. Estimates of the AoR need to account for the physical and chemical properties of all phases of the injected carbon dioxide stream, are based on available site characterization, monitoring, and operational data, and are to be made with computational models (40 CFR 146.84). Permitting also requires an understanding of the leakage risks from leakage pathways, such as wells and/or faults connecting the storage reservoir with any overlying USDWs. U.S. EPA Class VI Rule requires groundwater geochemistry monitoring above the lowermost confining zone overlying the storage reservoir to detect changes in aqueous geochemistry resulting from fluid leakage out of the injection zone (40CFR 146.90[d]) (U.S. EPA, 2012).

The National Risk Assessment Protocol-Integrated Assessment Model-Carbon Sequestration (NRAP-IAM-CS) is a science-based toolset developed by the DOE for quantitative risk assessment of geologic sequestration of CO_2 (Pawar et al., 2016). The toolset adopts a stochastic approach in which predictions address uncertainties in storage reservoirs, leakage scenarios, and shallow groundwater impacts. It is derived from detailed physics and chemistry simulation results that are used to train more computationally efficient models, referred to here as reduced-order models (ROMs), for each component of the system. These tools can be used to help regulators and operators define the AoR and better understand the expected sizes and longevity of changes in water quality caused by CO_2 and brine leakage from a storage reservoir into drinking water aquifers.

The EPA defines the AoR as the maximum extent of the separate-phase CO_2 plume or the pressure front over the lifetime of the project as measured by numerical model simulations. Generally, the maximum pressure front defines the AoR because it is usually larger than the supercritical CO_2 plume. The AoR is often delineated by the area within which the maximum pressure buildup is above that needed to move the reservoir fluids through an open wellbore (U.S. EPA, 2013a). This approach is conservative and assumes that any leakage will impact USDW quality regardless of the magnitude and duration of the leak.

Wells are high-risk pathways for fluid leakage from geologic CO_2 storage reservoirs because breaches in this engineered system have the potential to connect the reservoir to drinking water resources and the atmosphere. Well integrity is often difficult to measure due to a lack of well data such as permeability of the annular material between the outermost well casing and the borehole wall, a potential avenue for upward fluid migration. For such cases, the NRAP-IAM-CS can be used to evaluate the probability of CO_2 and brine leakage and its impact on drinking water quality from known well locations using default permeability distributions based on oil and gas wells in the Alberta and Gulf Coast basins and the greenfield FutureGen Site.

3.4.1 Model Evaluation

As part of the project, the available NRAP models were evaluated for their capabilities and input data needs. A synopsis of the available models is provided in Table 3-11.

Table 3-11. NRAP model uses and input data needs (D. Bacon, personal communication, 2017).

Model Name	Model Uses	Input Data Needed
NRAP-Integrated Assessment Model-Carbon Storage (NRAP-IAM-CS)[1]	Results in a risk-based AoR. Assesses CO_2 injection, migration and impacts. Incorporates system from storage reservoirs to groundwater aquifers and atmosphere.	Pressure and CO_2 saturation x,y-referenced plumes from GEM with injection well locs.; Reservoir conditions: depth, pressure, temperature, salinity, porosity, and permeability; USDW conditions: depth, thickness, pressure, temperature, salinity, porosity, and permeability; Surface Elevation; Critical pressure estimates
NRAP-IAM-CS Wellbore Leakage Model[1]	Results in leakage potential from actual wellbore locations. Incorporates outputs from the NRAP-IAM-CS model with wellbore locations and user defined cement permeability to estimate leakage potential/rates.	NRAP-IAM-CS output, locational data and depths for known wellbores, option of location-specific cement permeability, permeability distributions or an open wellbore.
DREAM (monitoring design)	Results in an optimal monitoring design that allows for early detection of CO_2 leakage. Leakage signature defined by user based on initial conditions.	Requires pressure, CO_2 saturation, pH, and total dissolved solids output from subsurface leakage simulations.
Short Term Seismic Forecasting	Results in prediction of magnitude of aftershocks from a main seismic event and ongoing seismicity.	Seismic catalog, magnitude vs. time, flow file, surface/downhole flux/pressure vs. time
Ground Motion Prediction applications to potential Induced Seismicity (GMPIS)	Results in peak ground acceleration and peak ground velocity. Appropriate for locations with little or no recorded seismic data. Should be used with care; it is not region-specific.	**Selected event type:** induced, seismic, or both; **Induced event:** x,y,z magnitude, VS30 option, frequency, ground motion fractile; **Tectonic:** x,y, dip, mechanism, magnitude, VS30 option, depth to 2.5 km/sec horizon; **Site response:** location of site(s): x,y, VS30, depth to 2.5 km/sec horizon; **ShakeMap:** input induced and/or tectonic ground motion, output epicenter/ fault data, spectral acceleration data for sites. **Global mapping tools:** topography, roads, cities/names.
NSEALR (seal integrity)	Results in a containment assessment given a set of input parameters about caprock.	Seal permeability, in situ stress and aperture, residual saturation of CO_2/brine, seal thickness

1. Model selected for use in the CAB-CS prefeasibility study.

The NRAP-IAM-CS and Wellbore Leakage models were selected for use in the CAB-CS prefeasibility study because they provided an estimate of an AoR and the leakage potential for actual wellbores, respectively. In addition, input data for the tools is readily available and the results provide information that was most lacking from previous research.

3.4.2 Integrated Assessment Model

The NRAP-IAM-CS toolset, released in 2017, can perform probabilistic assessments that account for the uncertainty of the storage complex. This work represents some of the first applications of the tools to potential CO_2 storage sites. The NRAP-IAM-CS was used to estimate the AoR and the impact of leakage from legacy wells located within the AoR for two illustrative carbon storage sites for the CAB-CS Integrated Prefeasibility Project. The report is provided in Attachment 1. For Illustrative Site A, the risk-based analysis yielded an AoR (234 km^2) that was larger than the AoR calculated using the EPA methods (see Section 4.1.3). Similarly, the results for Illustrative Site B were also larger than those calculated by the EPA methodology.

The following recommendations to the toolset could advance its use for the determination of probabilistic assessments of risk-based AoR and leakage from legacy wells on quality to USDWs.

- The AoR calculations would be more robust if the toolset could sample pressures and CO_2 saturations from many two-dimensional (2D) planes within the reservoir. This is particularly important for stacked storage reservoirs where stratigraphic heterogeneity will control pressure and CO_2 gas saturations. A ROM specific to the site reservoir would further improve a probabilistic assessment of the AoR.
- USDW ROMs need to be calibrated against the high leakage fluxes generated from open wellbores. All USDW ROMs were calculated for cemented wellbores, where leakage is controlled by the permeability of damage zones within the completed wells.
- The NRAP-IAM-CS currently has one option for a USDW ROM, the unconfined carbonate aquifer, where about 10% CO_2 leaks to aquifer return to the atmosphere. NRAP is updating the toolset with a confined alluvium aquifer in which all CO_2 leaked stays within the aquifer system. The alluvium aquifer may be a better match for both sites.

3.4.3 Wellbore Leakage Model

Leakage from tens of legacy wells located within the area of review (AoR) for Site A and Site B should not adversely impact groundwater quality over the 30-year injection period, because the leakage flux and total mass are quite small. Fluxes are lower than the minimum allowable flux used to calibrate the aquifer impact models currently in the NRAP-IAM-CS tool kit. This assessment assumes the cement permeability distributions are suitable for the condition of the legacy wells included in this assessment.

Combining known well locations with permeability distributions is an appropriate method for assessing leakage risk, when considering how little information is available on the integrity of legacy wells. To make more robust probabilistic assessments of leakage it is important to improve computational efficiency of the assessment model for standard laptop computers. For this assessment, 2500 realizations were run for calculations with 31 and 26 wells at the primary and secondary selected areas, respectively. Upward to a million realizations are needed for true probabilistic assessment that samples reservoir, wellbore, and aquifer uncertainty.

Assessment would be better if they were tied to groundwater impacts and if the groundwater module was representative of the site to assess if the small amounts of leaked CO_2 and brine have the potential to change the groundwater chemistry. Such analysis could be used to better define a risk-based AoR constrained by reasonable estimate of well integrity. Currently, the NRAP-IAM-CS only ties leakage to groundwater impacts when there are ten or less legacy wells. It would be useful to calculate and plot volume for each leaking well to better understand how to monitor, in addition to the total volume of impacted groundwater.

3.5 Conclusions

The purpose of the sub-basinal geologic storage assessment of the Central Appalachian Basin region was to define a deep saline storage complex that has the greatest potential for commercial-scale CO_2 injection (50 MMt or more). This storage assessment characterized deep saline reservoirs for CO_2 injection, caprocks, trapping mechanisms, and geologic hazards related to the injection process. This assessment also identified potentially synergistic depleted hydrocarbon fields for three selected areas that are potentially suitable for geologic storage.

The Selected Areas are comprised of a complex of stacked and combined Cambrian to Lower Ordovician deep, saline reservoirs. The primary formations investigated are the Rose Run sandstone, a vugular porosity interval within the lower Copper Ridge dolomite, and a zone of contact where a sandstone facies in the basal portion of the Nolichucky shale overlies vuggy/karsted dolostone of the Maryville formation. Also included in the assessment are three overlying depleted Silurian-age Clinton sandstone hydrocarbon fields and one depleted Cambrian-age Rose Run sandstone hydrocarbon field at miscible depths.

The primary selected area (Area B) in Coshocton County and the secondary selected area (Area A) in Tuscarawas, Harrison, and Carroll counties, Ohio, have the wells with the highest known open-hole permeability-feet in the assessment region. The primary selected area is sited around wells KC1, KC2, and KC3 due to their proximity to two oil and gas fields, the Monroe-Coshocton Consolidated and Baltic oilfields. The wells in the primary selected area also have the highest permeability-feet in the region. The secondary selected area is sited around piggyback wells UT1 and UT2 due to their proximity to the prolific East Canton Consolidated Oilfield. These wells also contain the thickest cumulative injection interval (around 180 ft). Formations with highly permeable zones include the Rose Run sandstone, lower Copper Ridge dolomite, Nolichucky sandstone facies, and Maryville formation. Each selected area is 506 mi^2 with its centroid location near the wells mentioned above.

The tertiary selected area (Area C), in Hocking and Fairfield counties, contains the highest sandstone permeability-feet for the largest connected reservoir volumes found in the static geologic model in eastern Ohio. Caprock above Selected Area C is around 450 ft thick. Stacked formations include the Rose Run sandstone, Nolichucky sandstone facies, and basal Cambrian sandstone, for a total reservoir thickness of 134 ft.

Areas A and B were selected for additional site screening and characterization in Task 4 (Project Definition) based on the most promising geology using available data.

4. Task 4 Project Definition

The objective of Task 4 was to define the surface and subsurface dimensions, infrastructure, and construction requirements for the CAB-CS complex. The task was aimed at providing a real understanding of what this facility would entail, which will allow a better portrayal of the best location for the site. The goal was to find a suitable project location in the primary and/or secondary selected areas, considering the following:

- The plume resulting from the injection of 50 MMt over 30 years will be sufficiently small so that the plume can be monitored during injection and for an additional 50 years after injection has ended and affected pore space owners can be reasonably compensated.
- CO_2 can be delivered from the selected source(s) to the storage area with a reasonably short and technically feasible pipeline.
- Injection rates needed for commercial scale storage can be achieved at low pressures using two injections wells.
- There are no environmental, social, or other features that would preclude project infrastructure, including pipelines, injection wells, and monitoring wells, from being sited at either the primary or secondary selected areas.
- The project definition included modeling project dimensions, defining required infrastructure, analyzing property and mineral rights issues, and site screening.

4.1 Project Dimensions Definition

Reservoir models were developed from the geological data obtained in Task 3 and ported to reservoir simulations to evaluate the feasibility and logistics of injecting 50 MMT CO_2 into the reservoir complex of the primary and secondary selected areas. The Computer Modelling Group, Ltd. (CMG) compositional reservoir simulator, GEM, was used to run the simulations. First, a single-well scenario was examined to determine the mass of CO_2 that can be injected per well under given geological and operational constraints. This analysis informed for a two-well scenario, the most likely injection scenario based on the current assessment of injection sites. The vertical and areal extent of CO_2 plumes and pressure buildup at the well and reservoir level were studied to delineate the AoR to aid economic and logistical analyses. Sections 3.1 through 3.3 summarize the geological and reservoir property inputs of the models and the resulting simulation outputs.

4.1.1 Modeling Parameters

Geological parameters used to build the simulation model are discussed in Section 3.0 and summarized here. Porosity data were based on neutron and density logs. Permeability anisotropy (i.e., ratio of vertical to horizontal permeability) was taken to be 0.1, which is an empirical value because experimental data was not available. Absolute horizontal permeability was estimated using two techniques:

- Porosity-permeability transforms developed for eastern Ohio sandstone and carbonate facies as described in Battelle (2017b)
- Local well test data and operational injection data of brine injection wells close to the selected areas

In the second technique, injection (flow) zone permeabilities were determined using injectivity and flowmeter test data available from wells closest to the sites. Transmissivity values from their well tests and injecting formations are also shown. The formations injected include Maryville formation, Nolichucky formation, Lower Copper Ridge dolomite, and Rose Run sandstone.

Spinner logs, which are a part of flowmeter testing, were used to estimate proportions of flow into individual flow zones and IFOTs were used to determine open-hole transmissivities. Transmissivity for each flow zone in each well was determined by calculating the ratio of the open-hole transmissivity to the proportion of flow into each flow zone.

Operational transmissivity values were obtained by converting the most recent brine injection data available for the wells into CO_2 injectivity (J_{CO2}) data to account for difference in density and viscosity. The resulting injectivity was converted to operational transmissivity (kh_{op}) using the following equation proposed by Mishra et al. (2016) (Equation 1):

$$J_{CO_2} = 0.1 * (kh)_{op} \qquad \text{Eq. 1}$$

The flow test transmissivities ($kh_{flow\text{-}test}$) for KC1, KC2, and KC3 flow zones were anomalously high when compared to operational data and were subsequently adjusted using transmissivity multipliers calculated by Equation 2. These multipliers are shown in Table 4-1.

$$Transmissivity\ Multiplier = \frac{(kh)_{flow-test}}{(kh)_{op}} \qquad \text{Eq. 2}$$

Table 4-1. Transmissivity multipliers for permeability analysis.

Well	IFOT Transmissivity (mD-ft)	Operational Transmissivity (mD-ft)	Mean Transmissivity Multiplier
KC1	184,980	2,517	74
KC2	546,000	9,909	55
KC3	218,630	2,212	99

Note: mD-ft = millidarcy-foot.

The normalized transmissivities at these wells resulted in realistic permeabilities based on actual injection data. The initial (based on log data) and final average flow zone permeabilities (corrected for operational flowmeter tests data) are compared in Table 4-2. The Lower Copper Ridge average permeability value of 661 mD is comparable to the permeability for the vugular Copper Ridge found in core in southern Ohio (Mishra et al., 2013), providing confidence in the permeability input into the models.

Table 4-2. Initial and final permeability values for flow zones.

Flow Zone	Initial Permeability (mD)	Final Permeability (mD)
Rose Run	65	77
Lower Copper Ridge	1,879	661
Nolichucky	3,900	74
Maryville	13,236	289

The resulting geologic parameters for Selected Area B and Selected Area A are shown in Tables 4-3 and 4-4, respectively. Layers 1 through 3 are considered to constitute the caprock for Selected Area B, while layers 1 and 2 constituted caprock for Selected Area A.

Table 4-3. Geologic properties of Selected Area B (primary).

Layer	Formation	Lithology	Zone type	Depth (ft)	Thickness (ft)	Porosity (decimal)	Permeability (mD)
1	Black River Group	LS, DOL	Caprock	5,395	446	0.006	0.003
2	"Gull River ls"	LS	Caprock	5,841	109	0.000	0.003
3	Wells Creek	DOL, LS, SH	Caprock	5,950	50	0.019	0.5
4	Rose Run	SS	Oil/gas, no inj.	6,000	78	0.05	12.5
5	Upper Copper Ridge	DOL	Buffer, no inj.	6,078	195	0.055	0.190
6	Copper Ridge B-zone	DOL, SLT	Storage	6,273	67	0.061	0.610
7	Lower Copper Ridge	DOL	Storage	6,340	120	0.037	0.180
8	**Lower Copper Ridge Flow Zone**	**DOL**	**Storage**	**6,460**	**43**	**0.115**	**661**
9	Lower Copper Ridge	DOL	Storage	6,503	79	0.037	0.180
10	Kerbel	SS, DOL, SH	Storage	6,582	26	0.037	0.110
11	Nolichucky	DOL, SH	Storage	6,608	18	0.023	0.060
12	**Nolichucky Flow Zone**	**DOL, SH**	**Storage**	**6,626**	**42**	**0.150**	**74**
13	Maryville (upper)	DOL	Storage	6,668	82	0.024	0.030
14	**Maryville Flow Zone**	**DOL**	**Storage**	**6,750**	**35**	**0.100**	**289**
15	Maryville (lower)	DOL, SS	Base rock	6,785	400	0.024	0.030
16	Basal Cambrian	SS	Base rock	7,185	102	0.066	3.150

Note: Bold indicates flow zones. Abbreviations: DOL - Dolostone, LS - Limestone, SH - Shale, SLT - Siltstone, SS - sandstone.

Table 4-4. Geologic properties of Selected Area A (secondary).

Layer	Formation	Lithology	Zone type	Depth (ft)	Thickness (ft)	Porosity (decimal)	Permeability (mD)
1	Black River Group + Gull River	LS, DOL	Caprock	7,187	585	0.006	0.003
2	Wells Creek	DOL, LS, SH	Caprock	7,772	54	0.019	0.45
3	Beekmantown	DOL	Buffer, no inj.	7,826	188	0.043	0.18
4	Rose Run	SS	Storage	8,014	51	0.038	0.80
5	**Rose Run Flow Zone**	**SS**	**Storage**	**8,065**	**58**	**0.106**	**77**
6	Rose Run	SS	Storage	8,123	35	0.038	0.80
7	Upper Copper Ridge	DOL	Storage	8,158	145	0.031	0.04
8	Copper Ridge B-zone	DOL, SLT	Storage	8,303	59	0.035	0.07
9	Lower Copper Ridge	DOL	Storage	8,362	105	0.038	0.09
10	**Lower Copper Ridge Flow Zone**	**DOL**	**Storage**	**8,467**	**43**	**0.115**	**661**
11	Lower Copper Ridge	DOL	Storage	8,510	24	0.038	0.09
12	Nolichucky	DOL, SH	Storage	8,534	54	0.029	0.05
13	**Nolichucky Flow Zone**	**SS, DOL SS**	**Storage**	**8,588**	**42**	**0.150**	**74**
14	**Maryville Flow Zone**	**DOL**	**Storage**	**8,630**	**35**	**0.100**	**289**
15	Maryville (lower)	DOL	Base rock	8,665	398	0.024	0.03
16	Basal Cambrian	SS	Base rock	9,063	107	0.042	1.35

Note: Bold indicates flow zones. Abbreviations: DOL - Dolostone, LS - Limestone, SH - Shale, SLT - Siltstone, SS - sandstone.

Layer 4 in Selected Area A corresponds to the Rose Run sandstone which, at this area, houses depleted oil and gas fields. Consequently, injection into this zone was not modeled to avoid gas encroachment into oil- and gas-filled pore space. Layer 5 was chosen to be a buffer zone between injection and oil and gas zones. Selected Area A had no such issues, so injection started from Layer 4. Layers 15 and 16 are considered as base rocks in both cases.

Table 4-5 shows the pore pressure, fracture pressure and temperature gradients, and rock compressibility values used for this study. These data are consistent with the values used in prior studies in eastern Ohio (Battelle, 2017a).

Table 4-5. Geomechanical and geothermal properties of Selected Area A and Selected Area B.

Property	Value
Pore pressure gradient	0.433 psi/ft
Fracture pressure gradient	0.7 psi/ft
Temperature gradient	1°F/100 ft
Rock compressibility	7E-6 psi^{-1}

4.1.1.1 Rock Fluid Properties

Rock fluid properties required for reservoir simulations include relative permeability values for gas-liquid and liquid-liquid systems and capillary pressure values for a gas-liquid system. Corey's correlations were used to compute relative permeabilities, while the Van Genuchten model was used to estimate capillary pressure. The end points for relative permeability curves were taken from a study conducted by Bennion and Bachu (2010) for low-, medium-, and high-permeability regions characterized by the following absolute permeability values:

- Low: < 10 mD
- Medium: 10 to 100 mD
- High: > 100 mD

The resulting gas-liquid relative permeability models are shown in Figures 4-1 through 4-3. These models were used to characterize the rock-fluid interactions for both Selected Area A and Selected Area B.

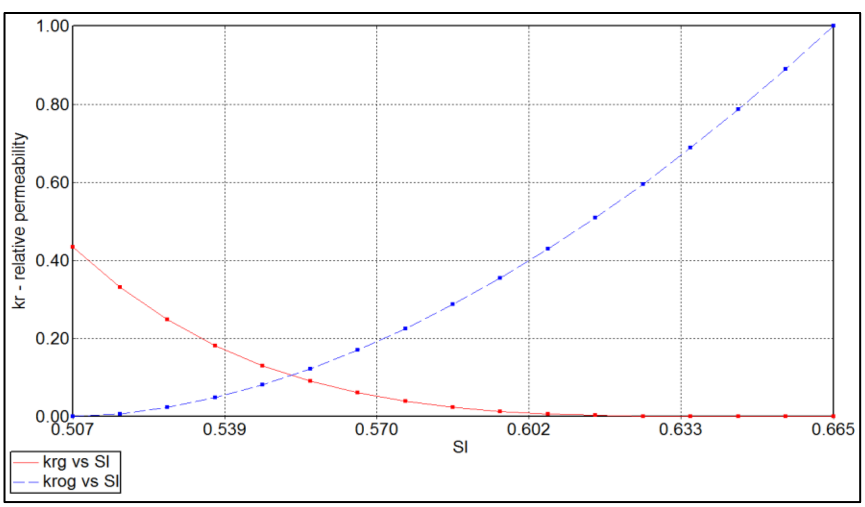

Figure 4-1. Liquid-gas relative permeability for low-permeability formations.

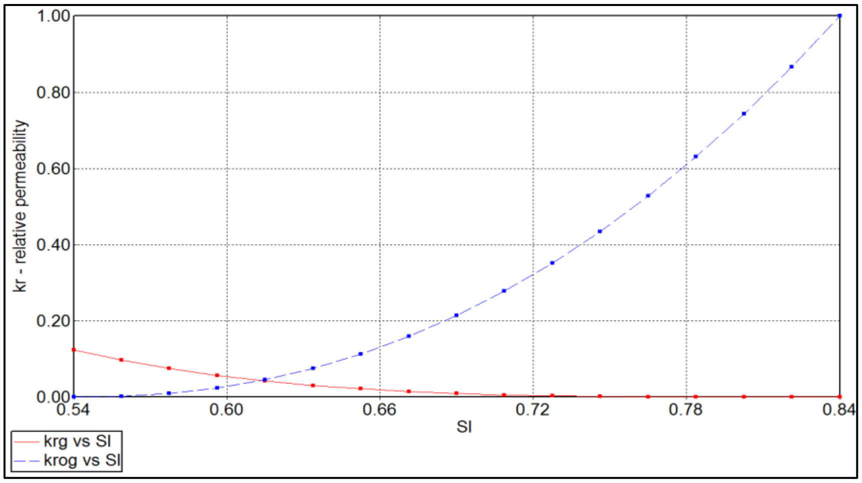

Figure 4-2. Liquid-gas relative permeability for medium-permeability formations.

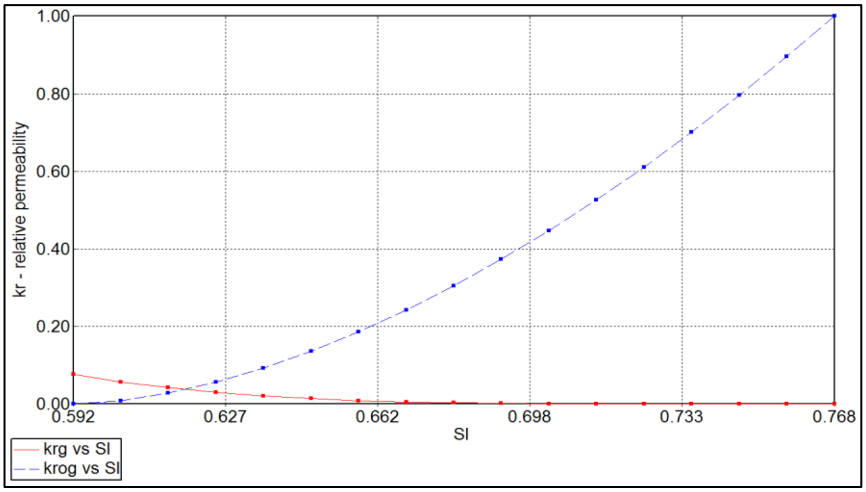

Figure 4-3. Liquid-gas relative permeability for high-permeability formations.

4.1.1.2 Reservoir Model

A 3D Cartesian layer-cake model was built for each area. The model spanned an area of 1,600 mi^2 with 40 miles each in i- and j-directions. Figures 4-4 and 4-5 show the areal and vertical profile of the reservoir models for Selected Area B and Selected Area A, respectively. The grid for Selected Area A was similar to that of Selected Area B except that the grid block lengths varied in the k-direction depending on layer thickness values presented in Tables 4-3 and 4-4. Grid block length in the k-direction is governed by the thickness of the formation to which the block corresponds. The reservoir was modeled to be closed boundary, implying that the pressure front does not diffuse out when it reaches the boundary. Grid refinement has been implemented in a 16-mile x 16-mile region around the center of the grid in layers open to injection; in the following sections, some of the figures show each layer divided into three vertical sublayers and the area of one grid block in the i-j direction further subdivided into four smaller blocks, each 0.2 mile x 0.2 mile.

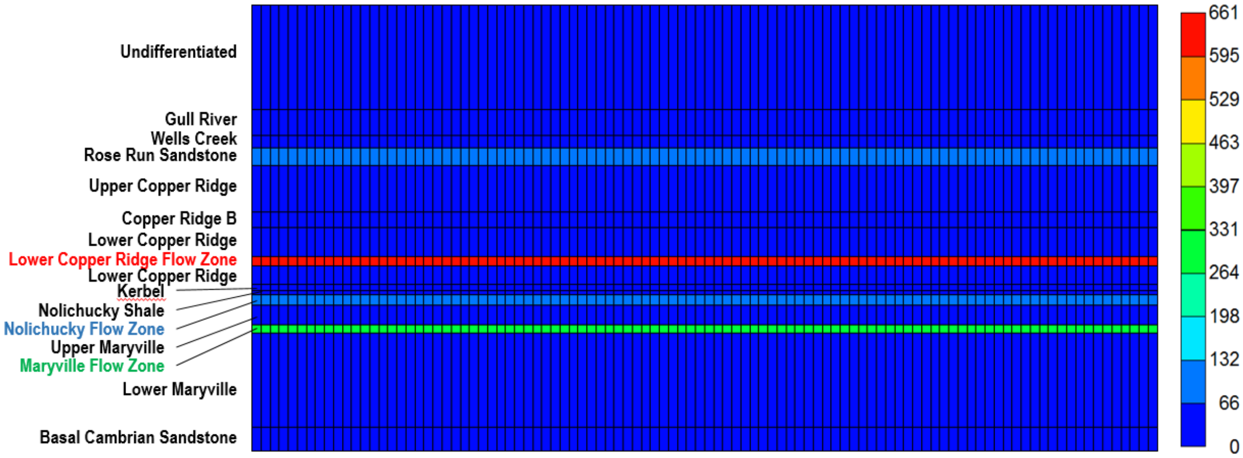

Figure 4-4. Reservoir model geometry for Selected Area B

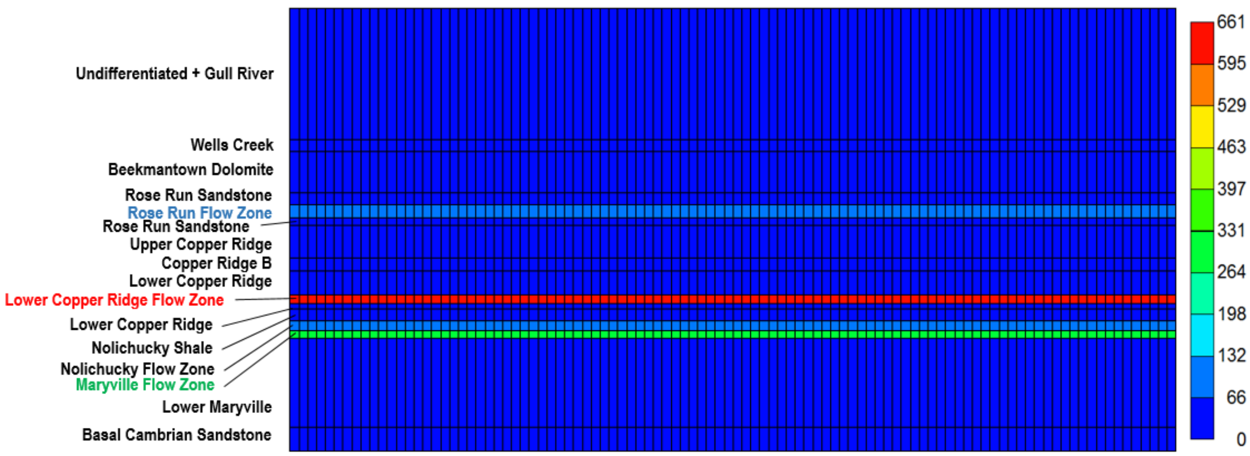

Figure 4-5. Reservoir model geometry for Selected Area A

4.1.1.3 Well Model

Well placement was based on the number of wells used for injection. For a single-well scenario, a well placed in the center of the grid (i = 50, j = 50) served as a starting point for analyses on injection volume and plume migration. Injection volumes were calculated based on the injection target for this study (50 MMt in 30 years) using Equation 3:

$$Gas\ injection\ rate\ \left(\frac{MMscf}{day}\right) = \frac{50*10^6*0.019}{30*365*n} \qquad \text{Eq. 3}$$

Here, ‘n’ denotes the number of wells used for injection. The resulting gas injection rates were found to be 86.93 MMscf/day for one-well scenarios and 43.47 MMscf/day for two-well scenarios. These rates were used to define the primary well constraints for simulations. A secondary constraint was the bottom-hole pressure, which was required to be lower than the fracture pressure of the corresponding formation. As a rule of thumb, the maximum bottom-hole pressure was constrained by 90% of the fracture pressure of the topmost layer of the storage complex. This value was calculated as shown in Equation 4.

$$Pressure\ Constraint\ = 0.9 * (14.7psi +\ 0.7\ psi/ft * depth\ of\ topmost\ storage\ layer) \quad \text{Eq. 4}$$

This value was found to be 3,952 psi for Selected Area B and 5,062 psi for Selected Area A. These values were used to define the secondary simulation constraints. Thus, the simulator proceeded injecting at the target rate set by the primary constraint while constantly checking for violation of the secondary constraint; in the event the secondary constraint was violated, the secondary or bottom-hole pressure constraint acted as the primary constraint and forced the simulation to honor it. All simulation cases included injection for a period of 30 years beginning 01-01-2025 through 01-01-2055, followed by a post-injection monitoring period of 50 years through 01-01-2105.

4.1.2 Simulation Results

Reservoir simulations were completed to evaluate injection scenarios for the CAB-CS facility. CMG's WINPROP was used to generate the fluid model for the reservoir, which consists of brine and gas aquifer to maintain a nominal gas composition in the grid blocks and avoid numerical discontinuity in simulations. Peng-Robinson equation of state was chosen to calculate the phase distribution of reservoir fluid components. Rowe and Chou (1970) correlation was used to calculate the brine density from reservoir pressure and temperature. Similarly, viscosity was calculated from a correlation developed by Kestin et al. (1981). The storage reservoir is assumed to be completely saturated with brine prior to injection.

4.1.2.1 Selected Area B (Primary)

The two-well scenario was evaluated to determine the minimum the plume area while avoiding communication between the CO_2 plumes. The well spacing was found to be 3.2 miles (eight grid blocks), which was narrowed down after a 4-mile (10 grid blocks) spacing yielded encouraging results. Results for both cases were very similar, with the only difference being that the well bottom-hole pressure was higher for the 3.2-mile spacing case. Another case, where the well spacing was reduced to 2.4 miles (six grid blocks), was examined. In this case, the two wells achieved the injection target, but the CO_2 plumes of both the wells communicated. Hence, the lowest well spacing between the two wells to meet the injection target while staying under the pressure limit and ensuring the plumes did not communicate was found to be 3.2 miles. Results presented here represent this case.

Figure 4-6 shows the cumulative injection of CO_2 over 30 years (red) and the average reservoir pressure buildup over the 80-year period. Injection of 50 MMt of CO_2 increased the average reservoir pressure from 2,843 psi to 2,922 psi. This increase of about 80 psi is not significant, which indicates the excellent quality of the storage reservoir at Selected Area B. The reservoir consists of at least two flow zones with high permeability values, which results in high transmissivity and, consequently, low pressure buildup during CO_2 injection.

Figure 4-7 is a plot of the bottom-hole pressure for one of the wells. It is important to note that pressure response is identical in both wells; therefore, only one well was used to analyze pressure data. Figure 4-8 shows that the bottom-hole pressure is well within the imposed pressure constraint of 3,952 psi, suggesting that the two-well scenario is safer compared to the single-well case.

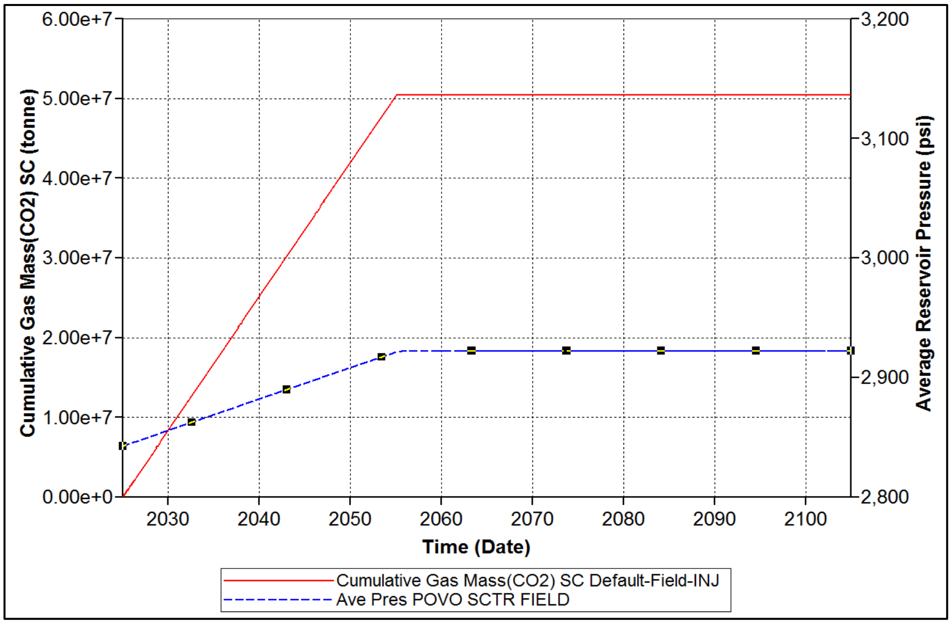

Figure 4-6. Cumulative injection and pressure profile for a two-well scenario at Selected Area B

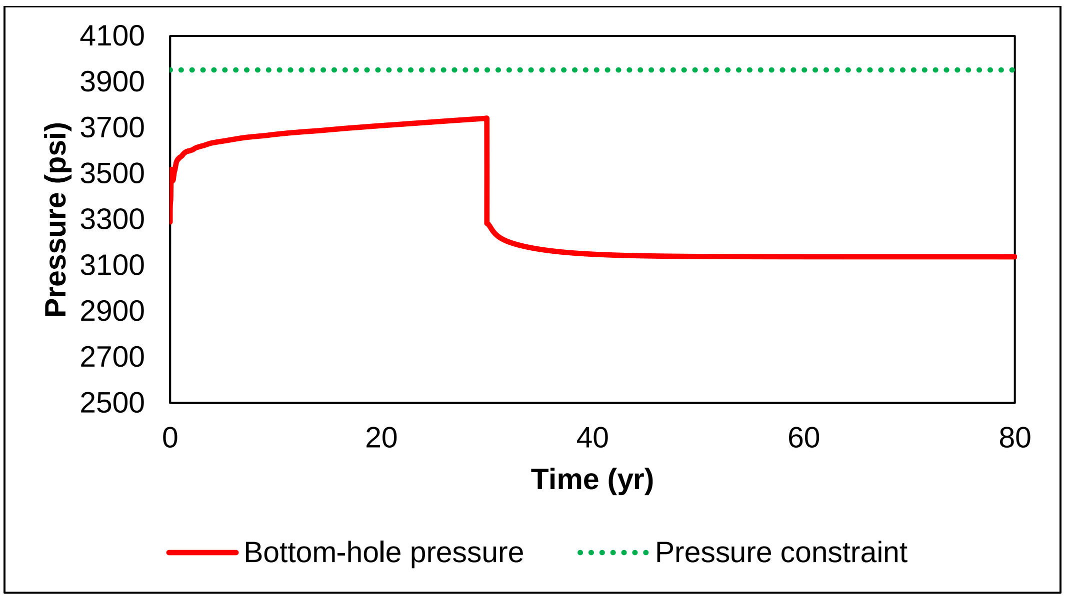

Figure 4-7. Bottom-hole pressure for two-well injection at Selected Area B.

Figures 4-8 and 4-9 show the vertical and areal (layer 8 - Lower Copper Ridge) saturation profiles of the CO_2 plumes, respectively. These figures suggest that the maximum lateral distance of the plume per well is about 1.2 miles from the wellbore, resulting in a pattern area of 16.8 mi^2 (Figure 4-9).

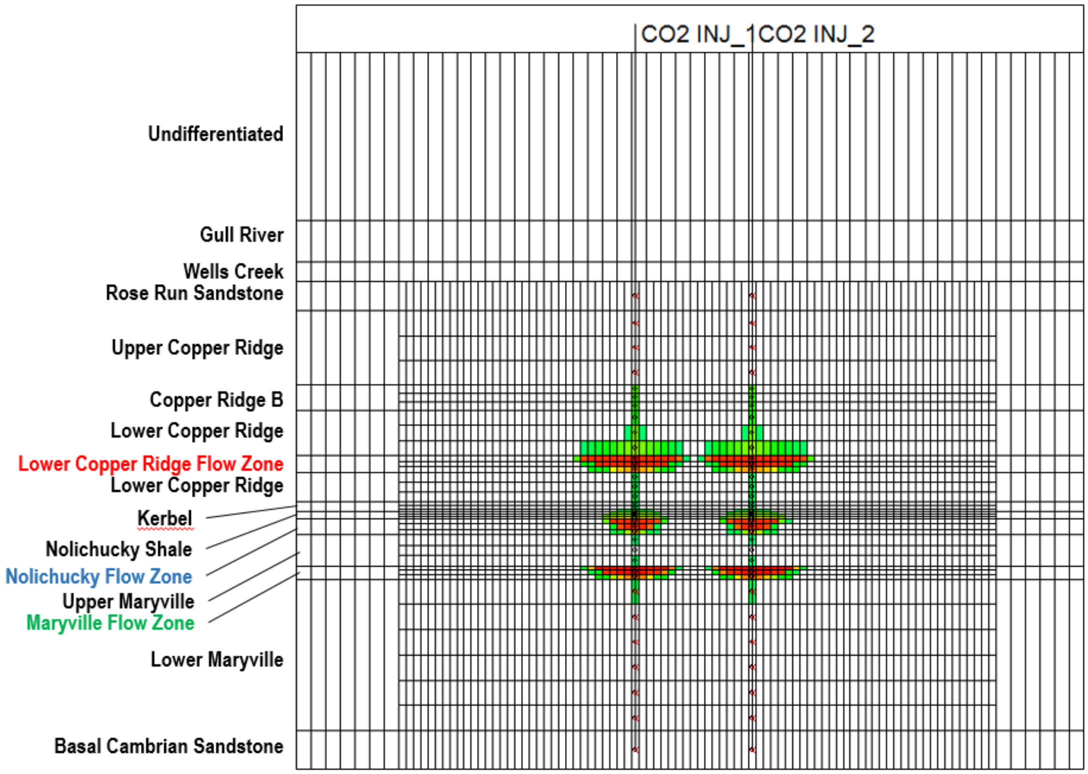

Figure 4-8. Vertical (i-k) CO_2 gas saturation profile for Selected Area B

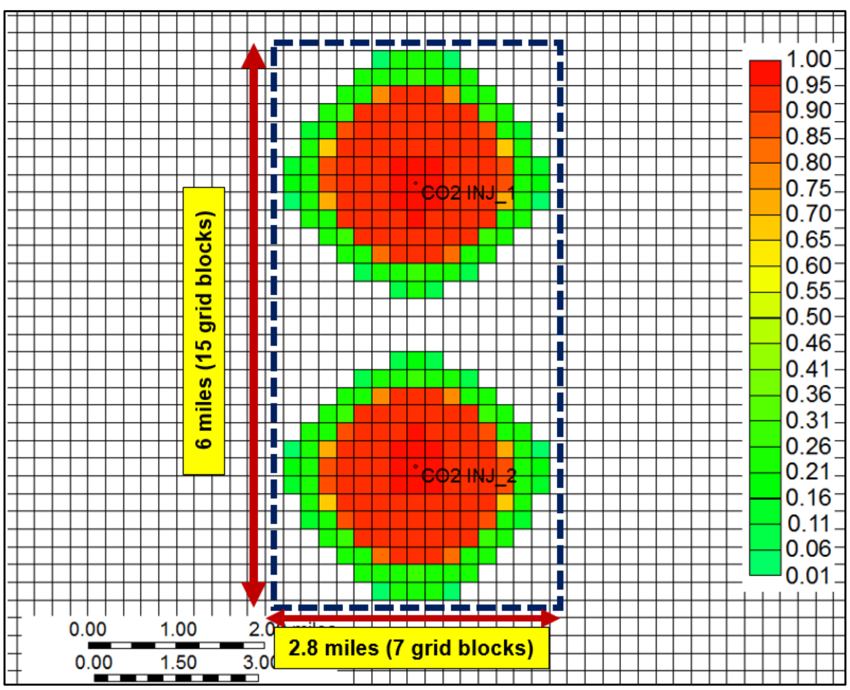

Figure 4-9. Areal (i-k) CO_2 gas saturation profile for Selected Area B (layer 8 – Lower Copper Ridge)

Pressure in the caprock layers was analyzed to observe and evaluate pressure perturbations, if any. Analysis of pressures along a path line from the injection well to the model boundary showed that pressure did not migrate into caprocks. The resulting pressure profiles for caprock layers 1 and 2 are shown in Figure 4-10. Overall, simulation results suggest no pressure migration into the caprocks. Furthermore, the pressure in caprock layers was constant over the whole injection period, implying that there is no pressure communication with the injection layers.

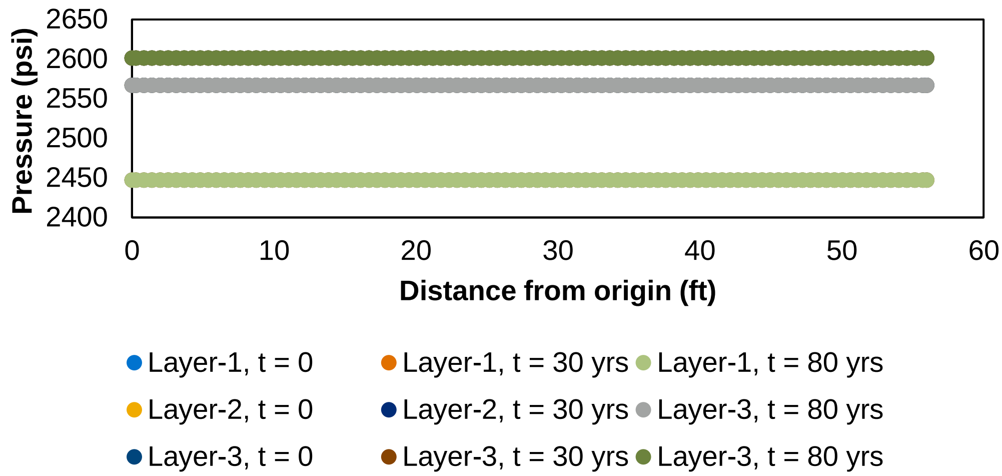

Figure 4-10. Caprock layer pressure profiles at Selected Area B

Figure 4-11 and 4.12 show vertical pressure profiles at start of injection, at 30 years, and at 80 years post-injection. Figure 4-11 shows fracture pressure along the wellbore of one of the injectors, while Figure 4-12 shows fracture pressure at a point midway along the boundary of the grid. The maximum pressure Buildup along the wellbore (Figure 4-11) was around 270 psi during post-injection, while the average final pressure buildup along the wellbore was 70 psi. The average final pressure buildup at the boundary (Figure 4-12) was found to be 70 psi, while the post-injection pressures were similar to the final pressures. None of the layers exhibited vertical pressure levels approaching fracture pressure, which eliminated any possibility of microfractures and induced seismicity.

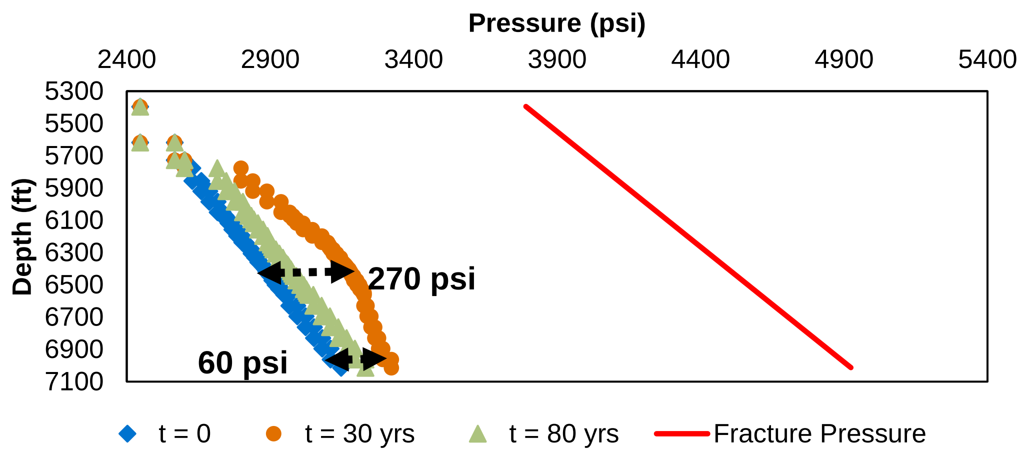

Figure 4-11. Vertical pressure profile near the wellbore of one of the injectors at Selected Area B

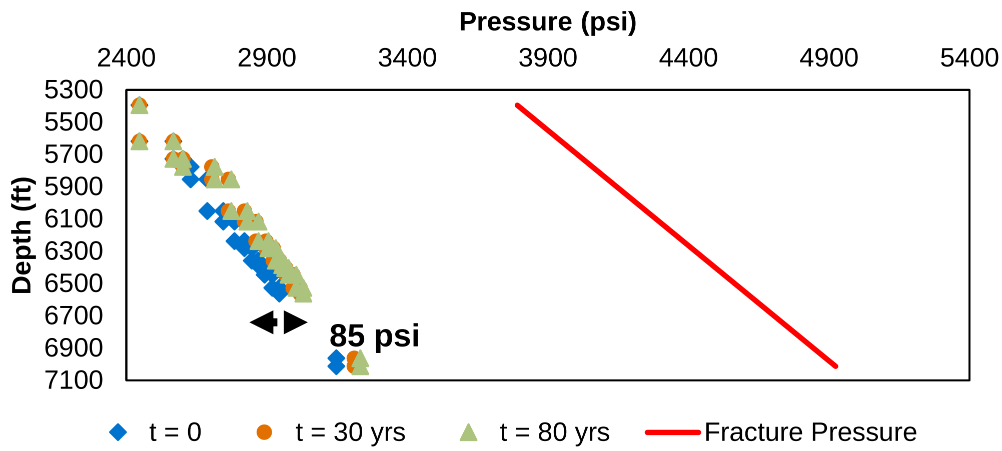

Figure 4-12. Vertical pressure profile at a point on the model boundary in line with the injector at Selected Area B.

Based on the results for a two-well scenario at Selected Area B, it is safe to conclude that 50 MMt of CO_2 can be safely injected over a period of 30 years without exceeding pressure constraints and that the CO_2 can be stored without influencing the caprock layers.

4.1.2.2 Selected Area A (Secondary)

Findings from the analysis of Selected Area B were applied to Selected Area A, as the geology was found to be mostly similar. A two-well injection scenario with well spacing of 3.2 miles was examined; the results are presented below.

Figure 4-13 shows the cumulative injection of CO_2 over 30 years (red) and the average reservoir pressure buildup over the 80-year period. Injection of 50 MMt of CO_2 increased the average reservoir pressure from 3,647 psi to 3,721 psi. As observed at Selected Area B, this increase of about 75 psi is low, which indicates the excellent quality of the storage reservoir at Selected Area A. The reservoir consists of at least three flow zones with high permeability values, which results in high transmissivity and, consequently, low pressure buildup during CO_2 injection.

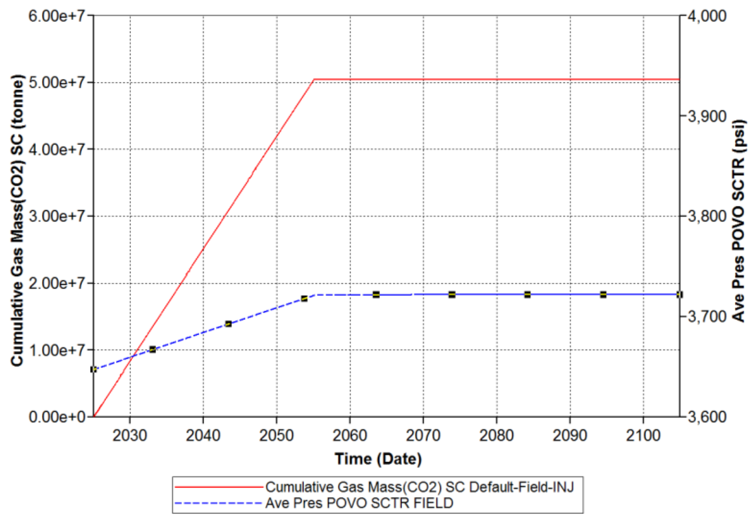

Figure 4-13. Cumulative injection and pressure profile for a two-well scenario at Selected Area A.

Figure 4-14 is a plot of the bottom-hole pressure for one of the wells. It is important to note that pressure response is identical in both wells; therefore, only one well was used to analyze pressure data. Figure 4-14 shows that the bottom-hole pressure is well within the imposed pressure constraint of 5,062 psi, suggesting that the two-well scenario is safer compared to the single-well case.

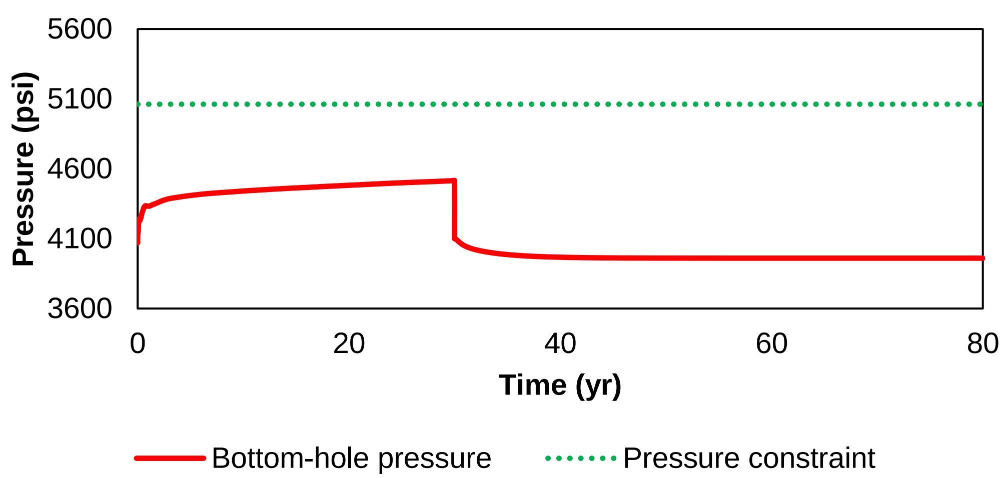

Figure 4-14. Bottom-hole pressure for two-well injection at Selected Area A

Figures 4-15 and 4-16 show the vertical and areal (layer 10 – Lower Copper Ridge) saturation profiles of the CO_2 plumes, respectively. These figures suggest that the maximum lateral distance of the plume per well is about 1.2 miles from the wellbore, resulting in a pattern area of 16.8 mi^2 (Figure 4-16).

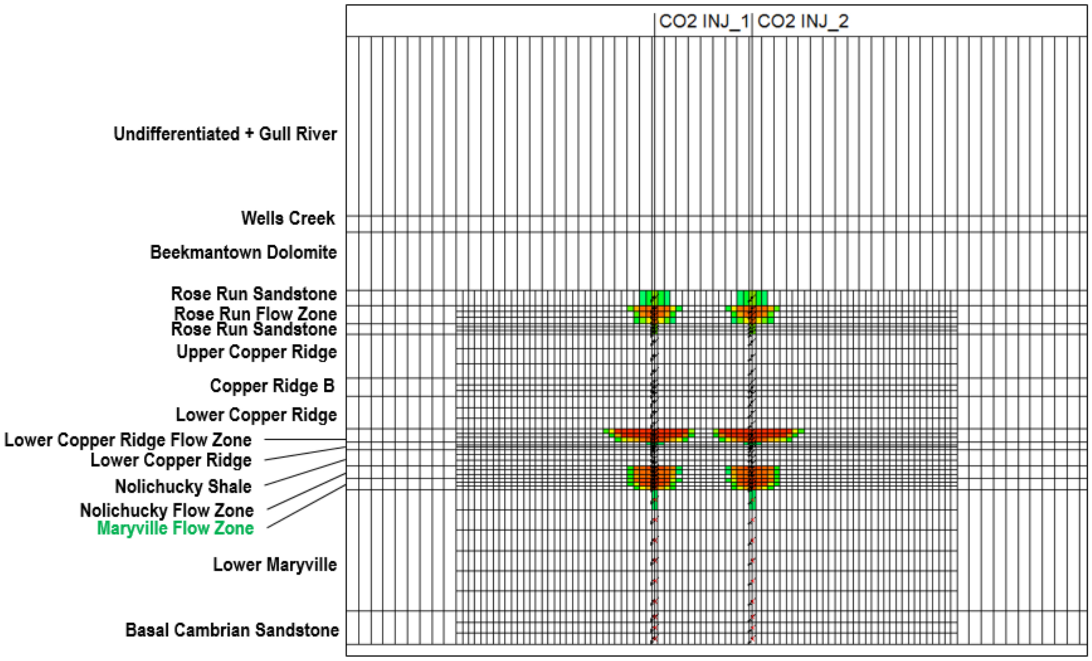

Figure 4-15. Vertical (i-k) CO_2 gas saturation profile for Selected Area A

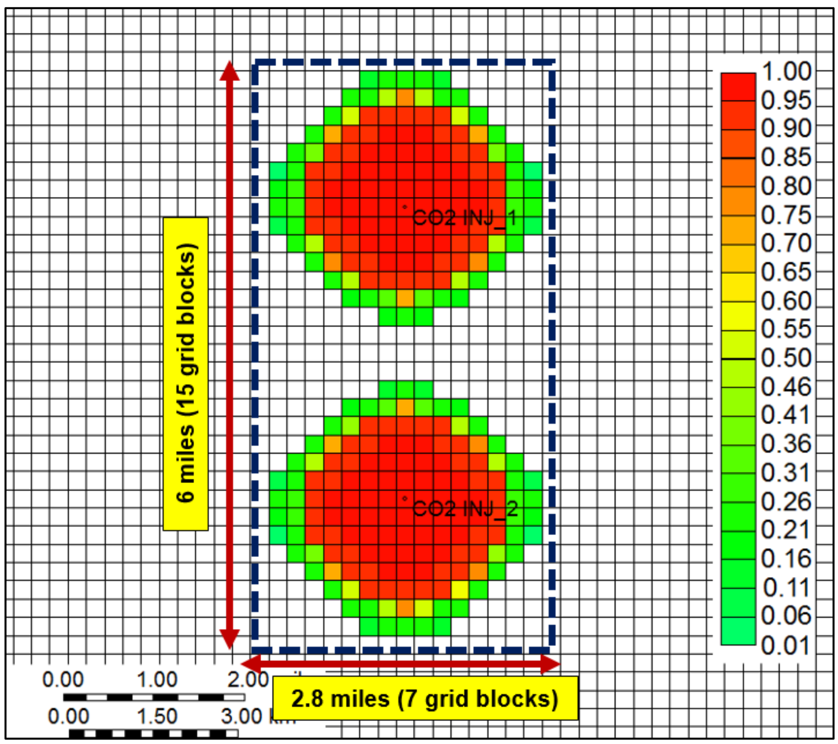

Figure 4-16. Areal (i-k) CO_2 saturation profile for Selected Area A (layer 10 - Lower Copper Ridge)

Pressure in the caprock layers was analyzed as described previously for Selected Area B. The resulting pressure profiles for caprock layers 1 and 2 (Figure 4-17) show that the pressure in the caprock layers was constant over the whole injection period, suggesting that there is no pressure communication with the injection layers.

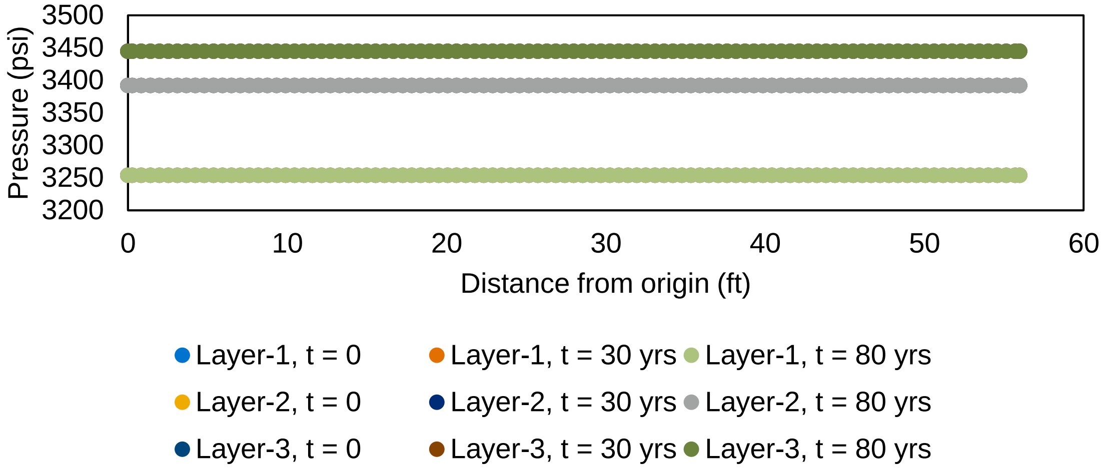

Figure 4-17. Caprock layer pressure profiles at Selected Area A

Figures 4-18 and 4-19 show vertical pressure profiles at start of injection, at 30 years, and at 80 years post-injection. Figure 4-19 shows fracture pressure along the wellbore of one of the injectors, while Figure 4-19 shows fracture pressure at a point midway along the boundary of the grid. The maximum pressure buildup along the wellbore (Figure 4-18) was around 260 psi during post-injection, while the average final pressure buildup along the wellbore was 90 psi. The average final pressure buildup at the boundary (Figure 4-19) was found to be 90 psi, while the post-injection pressures were similar to the final pressures. None of the layers exhibited vertical pressure levels approaching fracture pressure, which eliminated any possibility of microfractures and induced seismicity.

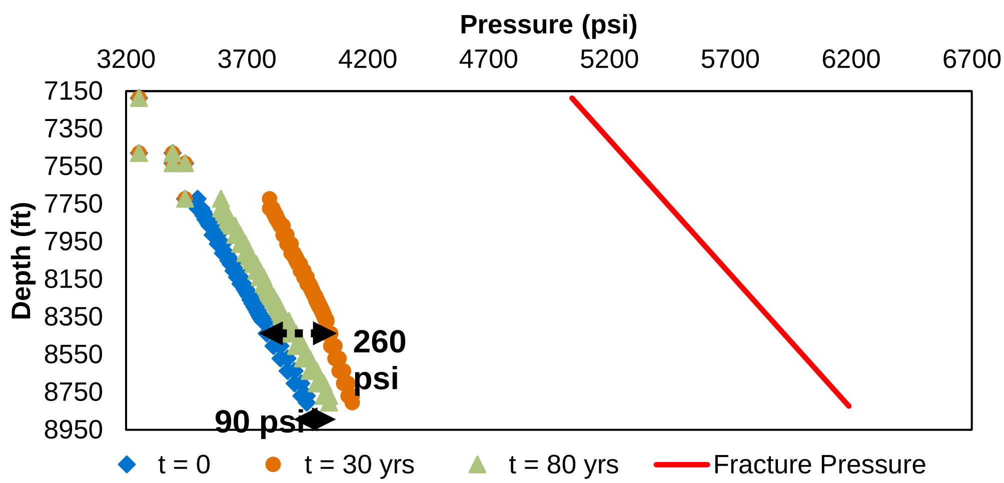

Figure 4-18. Vertical pressure profile along the wellbore of one of the injectors at Selected Area A

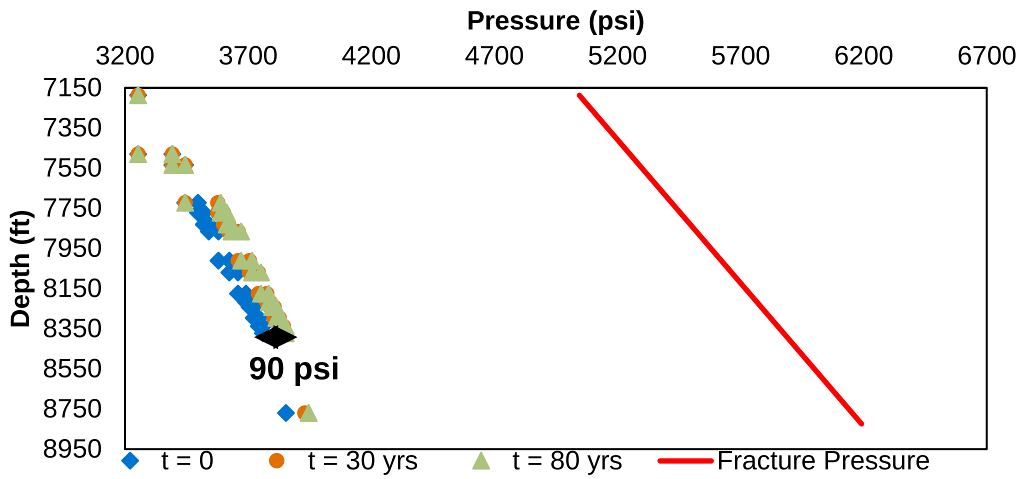

Figure 4-19. Vertical pressure profile at a point on the model boundary in line with the injector at Selected Area A.

4.1.3 Area-of-Review Estimates

The preliminary reservoir simulations, NRAP analysis, and volumetric resource calculations provide an estimate of the AoR for the CAB-CS facility. The AoR is an important part of the project definition, because it will define the area for the Class VI UIC permit, mineral rights, monitoring program, and site characterization. The injection strategy utilizes multiple CO_2 storage zones over a 600- to 700-ft-thick interval. Several high-permeability flow zones within this open-hole interval have been measured with flow-meter tests and well testing in brine disposal wells. Consequently, the CO_2 is distributed across multiple units, resulting in less pressure buildup and CO_2 saturation plume. In general, the flow zones are overlain and underlain by low-permeability rocks that prevent upward migration of the CO_2.

NRAP researchers have provided two methods to calculate preliminary estimates of critical pressure for the CAB-CS project: (1) Birkholzer et al. (2011); and (2) Nicot et al. (2009). Both methods are described in EPA's guidance document as acceptable methods for calculating the pressure increase that can cause fluid leakage through a hypothetical open borehole into an overlying USDW. Under EPA's approach, the project risk is defined as any potential leakage into the lowermost USDW through a hypothetical borehole, and the area representing this risk is delineated by the estimated pressure increase causing this leakage.

The Birkholzer et al. (2011) method (Equation 6) assumes a system in hydrostatic equilibrium, where the initial pressure in the injection zone is larger than the initial pressure in the USDW and the difference is due to the hydrostatic pressure of the initial fluid column between the USDW and the injection formation. The method is developed using a simple mass balance equation assuming that the fluid density in the wellbore after brine intrusion is uniform and equal to the density in the injection formation.

$$\Delta P_{crit} = \int_0^{D_B} \rho_B(z) g dz + P_W - P_B, \qquad \text{Eq. 6}$$

The Nicot et al. (2009) method (Equation 7) presents a static calculation for the critical pressure that is strictly based on lifting brine up an open wellbore to the base of a USDW through an instantaneous pulse, assuming that the system is at a hydrostatic equilibrium, without considering the initial pressure values in the USDW and the injection formation. It is developed based on an assumption of a constant density in the borehole indicating no equilibration of the brine with the borehole surroundings during/after the pulse.

$$\frac{\Delta P}{g} = \left(\int_{zI}^{zV} \rho(z)dz \right)_{\Delta P} - \left(\int_{zI}^{zV} \rho(z)dz \right)_{ini} \quad \text{Eq. 7}$$

Table 4-6 summarizes the critical pressure estimates for Selected Area A and Selected Area B. Based on the estimated values for the uppermost injection zones, the sites would require a relatively large pressure increase to push the brine into the USDW if an open borehole existed. This is mainly due the lowermost USDW being very shallow and the high salinity/density of the brines in the deep rock formations. These high critical pressure values may result in a relatively small area for brine leakage risk. To delineate the potential AoR for the project, this area would need to be compared to the predicted extent of the CO_2 plume. The standard EPA method for critical pressure results in even higher critical pressures—greater than 500 psi for Selected Area A and greater than 350 psi for Selected Area B.

Preliminary AoR estimates were based on geologic mapping, storage interval hydraulic properties, initial reservoir conditions, and reservoir simulation results for two-well injection scenarios. CO_2 resource estimates suggested all three selected areas contained adequate subsurface properties to accommodate 50 million metric tons CO_2. However, these resource estimates did not account for the pressure front and high saturation levels around the injection wells. Consequently, the output from the reservoir models was considered a better indicator of subsurface impact of the CO_2 storage field. Based on the critical pressure estimates, the CO_2 saturation plume was defined as the criterion for AoR designation. Because there are multiple high-permeability zones, pressure buildup from injection is limited.

Table 4-6. Summary of critical pressure estimates.

Parameter		Selected Area A	Selected Area B	Units
Depth at the BASE of the lowermost USDW		280.0	250	m
Initial pressure at the base of the lowermost USDW		432.4	385	psi
Salinity in the lowermost USDW		5,000	5,000	ppm
Temperature in the lowermost USDW		64.2	63.4	°F
Fluid density in the USDW		1,002	987	kg/m^3
Depth of the TOP of the injection zone		2,581	1,970	m
Initial pressure in the injection zone		3,979.5	3,036	psi
Salinity in the injection zone		~270,000	~330,000	ppm
Temperature in the injection zone		139.7	120	°F
Fluid density in the injection zone		1,197.0	1,197	kg/m3
Critical Pressure	***Birkholzer approach***	*370*	*278*	psi
	Nicot approach	*319*	*257*	psi

As described in Section 4.1.2, the reservoir simulations showed a CO_2 saturation plume distributed within an area of 16.8 mi^2. During the 50-year post injection care period, there was no significant additional CO_2 migration. The critical pressure criteria were calculated as 319 psi for Selected Area A and 257 psi for Selected Area B. These pressure criteria are high because there is a large depth separation between the lowermost USDW and the injection zones. In addition, the deep rocks are saturated with highly saline brine with density of 1.1 to 1.2 kg/L. Consequently, the CO_2 saturation was identified as the criteria for the AoR. This area was defined as a 2.8 by 6.0-mile area that encompasses the two injection well saturation fronts. The general pressure front caused by injection was predicted at 75 to 80 psi, which is much lower than the critical pressure criteria. While this pressure-saturation relationship is different than described by guidance on CO_2 AoR methods, the 16.8-mile AoR accounts for both safe levels of CO_2 saturation and pressure in the subsurface.

As defined, the AoR presents a feasible storage zone, given subsurface reservoir extent, surface logistics, and mineral rights for the selected areas. The area is roughly 11,000 acres or 17 sections in a township, which is comparable to other natural gas storage fields and hydrocarbon fields in the region. These analogs suggest it would be manageable to accrue mineral rights and manage injection operations across this extent. In addition, there few surface features that would be obstructions to the facility. The final AoR is unlikely to be as well defined and symmetric as predicted by the reservoir models, and additional site characterization information will aid in defining the actual facility dimensions.

Table 4-7. Summary of area of review estimates.

Parameter	Selected Area A	Selected Area B
CO_2 injected	50 MMt	
Injection duration	30 years	
Injection wells	2	2
Saturation plume radius	1.2 mi (1.9 km)	1.2 mi (1.9 km)
Saturation pattern area	16.8 mi^2 (43.5 km^2)	16.8 mi^2 (43.5 km^2)
Pressure plume radius	<0.6 mi (<1 km) (critical pressure 300 psi)	<0.6 mi (<1 km) (critical pressure 250 psi)
NRAP Integrated Assessment Model	22.5 mi2 (57.6 km^2)	26.2 (68 km^2)

Note: km = kilometer.

It is anticipated that site-specific characterization and testing will allow a more accurate representation of the AoR. NRAP analysis tools were integrated into the project to confirm the AoR. NRAP tools included the IAM, wellbore integrity risk model, and Reservoir Evaluation and Visualization (REV) tool. These tools will provide additional support for determining an appropriate AoR based on additional project performance factors.

This section provides more detail on the CO_2 pipeline, injection wells, monitoring equipment, and support facilities necessary to implement the CAB-CS facility. These items provide the design basis for the equipment and appurtenance for the carbon storage system. Based on reservoir simulations, surficial factors, and existing infrastructure, several CO_2 transport and injection scenarios were developed and analyzed to determine general configuration guidance for development of the CAB-CS facility. These scenarios generally bracket transport and injection arrangements that would fulfill requirements for a 50-MMt storage system. As the project proceeds to test well drilling, site characterization, and engineering design, actual well and pipeline locations may differ.

4.2 Infrastructure Definition

4.2.1 Pipeline Infrastructure

Pipeline infrastructure was reviewed as part of Task 2. Results from this effort are available in Section 2.4 of this report.

4.2.2 Wellhead Equipment

The injection system was specified to meet requirements of the 50-MMt CO_2 storage objective of the CAB-CS facility. Major components of the injection system included two injection wells, injection pumps, wellhead pressure-volume-temperature meters, an inter-annulus monitoring system, and surge tanks. The CO_2 injection modeling and injection simulations concluded that two injection wells would be suitable for the CAB-CS facility. Because there are several Class II brine disposal wells that inject into a similar zone, these wells provide a basis for injection well design and specifications. The injection simulations indicate that the wells would need to be separated by approximately 5 kilometers to prevent pressure and CO_2 plume interaction between the two wells. The wells were designed to facilitate injection into multiple deep saline rock formations at a depth of approximately 6,200 to 7,200 ft. Portions of the Upper Copper Ridge to the Gull River provide intermediate buffer zones. Overlying caprock includes the Trenton-Black River, with a total thickness of 900 ft. Underlying caprock includes a 400-ft-thick portion of the Lower Maryville formation that isolates the CO_2 storage zone from the basal sandstone and Precambrian layers.

4.2.3 Injection well design

Figure 4-20 shows a preliminary injection well diagram for Selected Area B. The well design was based on geologic layers, Class VI UIC requirements, and other Class II UIC brine disposal wells in the region. The well includes 20-inch-diameter surface casing set to approximately 75 ft and cemented to the surface to isolate the well from any unconsolidated sediments and shallow groundwater resources. The 13 3/8-inch shallow casing was specified to a depth of approximately 900 ft to isolate the Berea sandstone and other shallow formations. A 9 5/8-inch intermediate casing was included to a depth of approximately 4,000 ft to isolate the well from the Clinton Sandstone. Finally, a 7-inch casing string to approximately 6,200 ft was specified with an open-hole completion to approximately 7,200 ft. The well was specified with 4-inch injection tubing set with packer in the 7-inch casing. The well will include an inter-annulus monitoring system to monitor pressure of the annulus outside of the injection tubing.

Open-hole completions in the deeper Cambrian carbonate zones are typically recommended in this region to ensure that the injection zones are accessible for injection. These deeper rock formations are highly lithified, so there is less potential for borehole stability problems, sluffing, or bridging. In addition, an open-hole completion ensures that the injection zones are not cemented off or missed in well perforations. Preliminary design includes cementing the deep and intermediate casing strings into the next shallower casing string. This design will allow zonal isolation of the well, prevent problems with multi-stage cement jobs, and allow access to the casing zones. Final well design will be determined based on site characterization, the Class VI permitting process, and discussions with oil and gas regional representatives. However, the well design is not likely to deviate significantly from the general design provided.

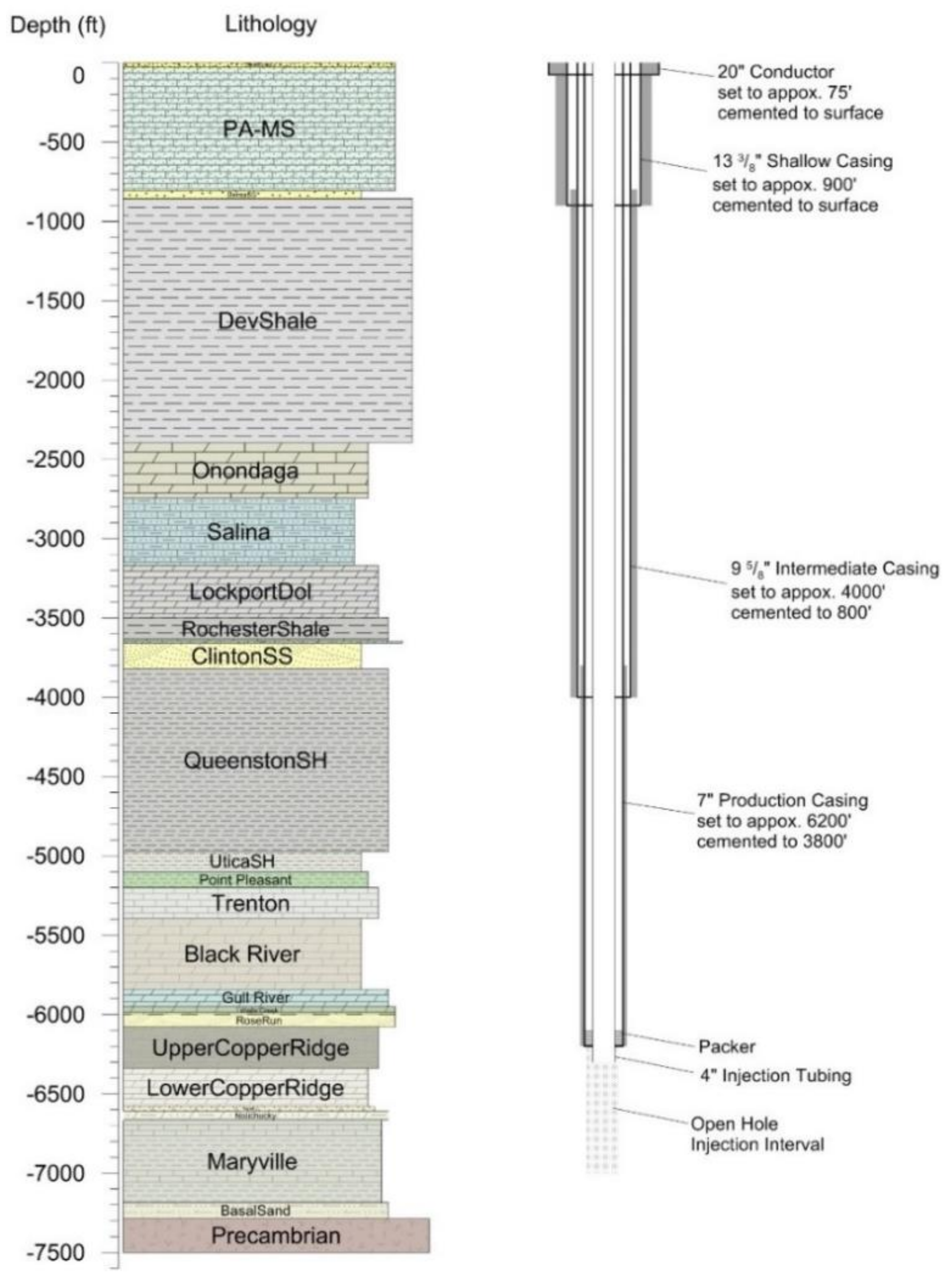

Figure 4-20. Preliminary injection well diagram for Selected Area B.

Given the geologic setting for the CAB-CS facility, well materials were identified for the well construction. There are hundreds of Rose Run wells and thousands of Clinton oil and gas wells in the selected area, so drilling hazards are well defined. There are no major lost circulation zones, geomechanical deformation zones, or salt layers that may necessitate exceptional well design features. Acid gas zones may be present in the 'Big Lime' interval in northeastern Ohio, and could be present potential for long-term well degradation. The conductor, shallow, and intermediate casing zones were specified with standard carbon steel well casing and Portland Class A cement (Table 4-8). Deep reservoir monitoring wells were denoted with similar well design and materials.

The injection zone may experience corrosive conditions due to a mixture of high-salinity brine and supercritical CO_2. Thus, the deep casing string was defined with mostly carbon steel and a stainless-steel tail section in the injection interval. The CO_2 injection zone was specified with acid-resistant cement at the bottom of the well due the pH reduction caused by CO_2 dissolving in the reservoir water. Nickel-plated packers and stainless steel injection tubing tail-end were also defined for the injection wells. Injection wellheads were specified with multiple ports to allow well control, annulus monitoring, well access, and sampling ports.

Table 4-8. Summary of general well materials (Selected Area B).

Well Component	Depth (ft)	Description
Conductor	0-75	20-24 inch pipe b-grade/125.5#
Shallow casing	0-900	13 3/8 inch K55/61# with Class A cement
Intermediate casing	0-4,000	9 5/8 inch N80/40# with Class A cement
Production casing	0-6,200	7 inch N80/29# with 200 ft stainless tail, Class A cement lead and CO_2 resistant tail
Injection tubing	0-6,300	4 ½ inch 12.6# NUE injection tubing with stainless steel tail, nickel plated packers
Open hole	6,200-7,000	Open hole acidized during completion

Periodic operational and maintenance was defined for the injection wells to inspect well materials, perform regulatory testing, and maintain injection performance. Many Class II UIC wells in the region have operated for several decades in the selected area, and these wells provide some practical experience on well maintenance. Some brine disposal wells experience ‘salting out,’ when salt or fines precipitate around the well. This requires periodic acidization of the well. Additional well maintenance included pressure fall-off tests every five years to and annual tests on mechanical well integrity.

CAB-CS support facilities were defined to provide systems control, site access, monitoring, and injection management. The facility was designed to allow continuous monitoring of the injection pressures, flow rates, and temperatures from the pipeline to the wellhead. Based on a 4,500-metric-ton CO_2 per day flow rate, 6,000- to 9,000-ft injection depths, and reservoir simulation results, the system will require wellhead injection pressures of 1,200 to 1,600 ps. Assuming a pipeline supply pressure of 1,800 to 2,000 psi, the injection wells will not need additional pressure boost to ensure adequate injection rates.

To monitor and control the injection system, a control room with a computer-based SCADA system was specified for the CAB-CS facility. The injection wells and a flow control valve were specified to operate under control of the SCADA to match injection well pressure and flow capabilities. The system was specified with two surge tanks at the wellheads to provide buffer capacity between the pipeline supply and injection operations. A well site emergency shutdown valve was specified to provide protection in case of a failure. Pressure, flow, and temperature measuring equipment were included in the pipe to each well injection well to monitor the amount of CO_2 injected and check for upset conditions that may indicate a leak. Speed controls on the injection pump motor and control valves accept signals from the injection site SCADA system to apportion the total system flow to each well. This control valve also was also included for start-up of the injection and to maintain a back pressure for proper operation of the flowmeter. A discharge check valve was specified for safety and to prevent backflow of injected CO_2 out of the well in the event of a sudden pressure loss.

A 4,500-square-foot injection site office building, site electrical supply, perimeter fencing, and access road were included in the project definition. The site office building will provide space for staff, communication systems, the SCADA system, storage of monitoring equipment, and meeting rooms.

4.2.4 Monitoring Plan

Many options are available for monitoring CO_2 storage projects (DOE/NETL, 2012; Benson et al., 2004; Hovorka et al., 2006; Benson and Myer, 2002). However, some monitoring technologies may not be effective for a project given its geologic framework, surface access, size, and other factors. Atmospheric, near-surface, and subsurface techniques each present their own benefits, so a balanced approach is likely the most effective, especially since many of the technologies can be expensive to deploy.

Given the deep, isolated nature of the target storage formations in the CAB-CS area, wellbore integrity and reservoir monitoring options would be most appropriate for the project and were the focus of the monitoring program. Figure 4-21 shows a conceptual diagram of the CAB-CS monitoring system. Major components include two deep monitoring wells, five intermediate-zone monitoring wells, one or more groundwater monitoring wells near each injection well, five shallow/near-surface seismic monitoring stations, and one wellhead flow meter for each injection well. The monitoring program would include one to two years of pre-injection baseline monitoring of reservoir pressure, temperature, geophysical logs, brine sampling, and groundwater sampling. Baseline monitoring of seismic activity with a network of seismic monitoring stations will likely be required.

Operational monitoring was defined to include continuous monitoring of wellhead flow, temperature, and density at the injection wells. Other continuous monitoring included seismic surface stations, intermediate-zone pressure/temperature, and microseismic monitoring of the initial injection period. Additional monitoring may be selected during subsequent project phases as indicated by test well drilling, geophysical logging, seismic surveys, well testing, and other site characterization activities. Many of these monitoring options require feasibility assessment to ensure that they would be suitable for the geologic parameters, injection system, and logistics. Some more advanced monitoring options that may be suitable for the CAB-CS sites include vertical seismic profiles to image the CO_2 saturation front, distributed pressure/temperature sensors in deep monitoring wells, and near-surface tiltmeters.

Table 4-9 summarizes estimated monitoring items, objectives, and schedule defined for the CAB-CS facility. Major monitoring items will include deep reservoir wells, seismic monitoring stations, and microseismic monitoring. The most suitable intermediate zone for monitoring is the ‘Clinton’-Medina sandstone, which has an active oil and gas production in the selected areas at depths of 3,500 to 5,000 feet (ft). Therefore, intermediate monitoring in this zone was based on monitoring existing wells for indicators of CO_2 migration. There are several hundred ‘Clinton’ wells across Selected Area B, and many wells are highly depleted. Consequently, these wells may be monitored for pressure changes and gas composition to ensure that no CO_2 migrates through the caprock layers.

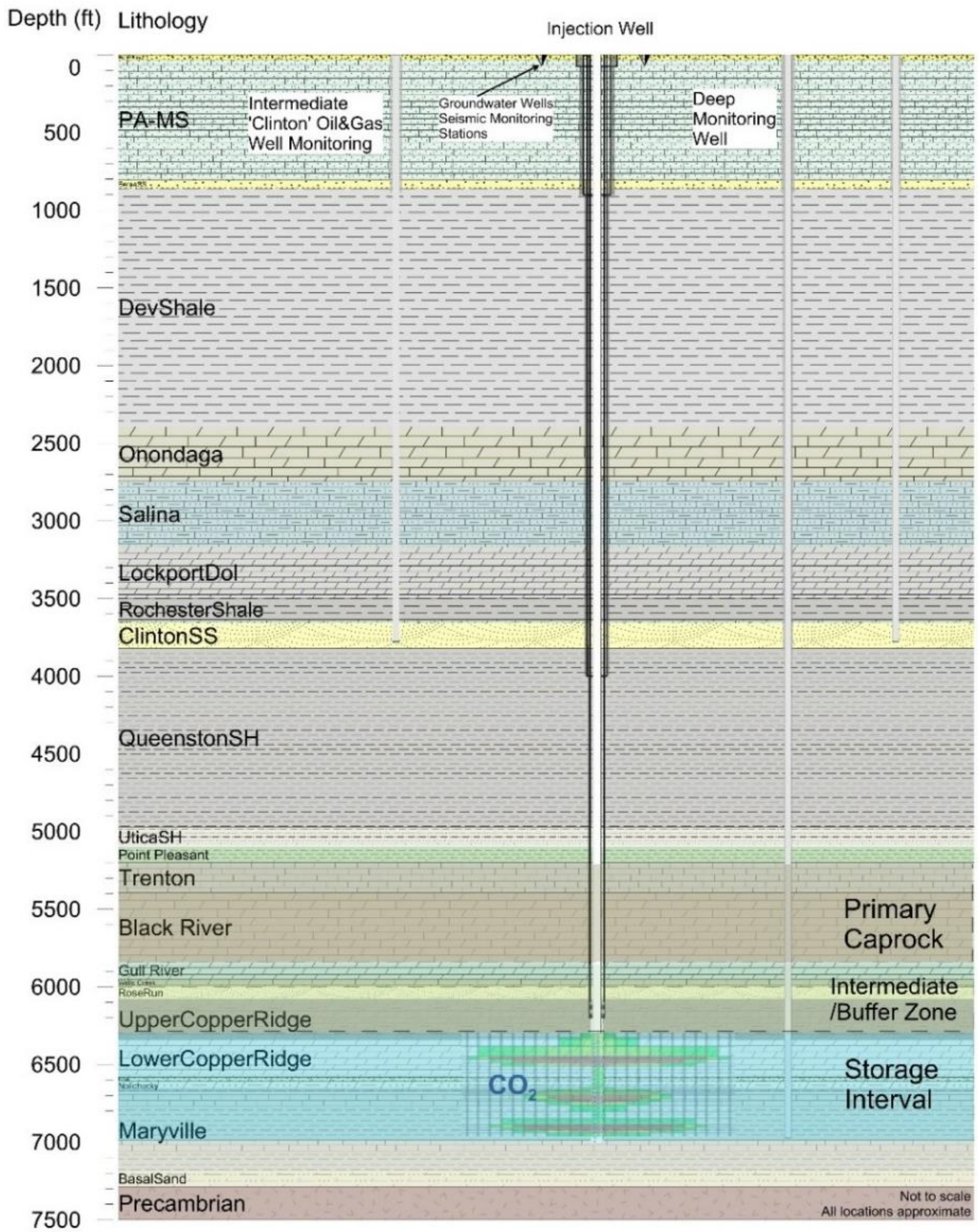

Figure 4-21. Conceptual diagram of CAB-CS monitoring system.

Another key monitoring method is seismic activity monitoring. Microseismic monitoring of the initial injection will be used to determine the geomechanical effects of CO_2 injection, which are most likely to be displayed in the initial injection period. For long-term operations, the site will likely require near-surface seismic monitoring stations for induced seismic activity. While few oil and gas wells penetrate the storage zone or immediate caprock, there is a dense concentration of oil and gas wells in the selected area that may require some degree of wellbore integrity testing and surveillance. In addition, groundwater quality and vadose monitoring of 8 to 15 well sites were included in the monitoring system.

Table 4-9. Proposed monitoring methods and schedule.

Method	Description	#	Monitoring Schedule
Wellhead pressure, flow, temperature	Meter and data logger at wellhead to measure CO_2 injection volumes, pressures, and temperature	2	Continuous
Groundwater wells/vadose zone	Shallow (20-100 ft) groundwater quality monitoring wells near injection wells and/or sampling of domestic wells to ensure CO_2 does not migrate into groundwater resources	8-15	Annual sampling events
Intermediate wells/wellbore integrity	Utilize existing 4,000-4,500 ft deep 'Clinton'-Medina wells for gas & pressure monitoring to ensure CO_2 storage containment. Periodic testing of existing O&G wells to ensure there is no CO_2 migration	5	Continuous downhole pressure and temperature, annual fluid/gas sampling, annual wellbore integrity
Deep/reservoir wells	Deep (6,000-6,500 ft) wells screened in reservoir to monitor pressure, saturation, and CO_2 plume. Periodic geophysical logging to track CO_2 plume saturation	2	Continuous downhole pressure and temperature, annual fluid/gas sampling, annual wellbore integrity
Surface seismic stations	Shallow (40-100 ft) seismic monitoring stations and data logger to ensure there is no buildup of seismic activity	5	Continuous monitoring of surface seismic activity
Microseismic	Initial microseismic monitoring of injection to determine geomechanical impact of CO_2 injection	1	Initial ~12 months of well testing and injection
System safety	Gas, pressure, and atmospheric meters around injection equipment to ensure safety of human health & environment	3	Continuous near injection wells and control facility

Monitoring capital costs include installation of any deep monitoring wells and permanent monitoring equipment. Operational monitoring costs include routine surveys designed to delineate the storage field such as cross-well seismic profiling, wellbore leakage surveys, and surface sampling. These costs can vary widely based on sampling frequency, the number of monitoring points, and extent of the survey. As such, low-level, mid-level, and high-level monitoring programs were identified as a consideration for the economic analysis.

Pressure, flow, and temperature measurements at the injection well are also part of system monitoring. Essentially, measurements taken in system monitoring form the basis for much of the other monitoring methods. Beyond this, many of the system monitoring parameters can be tracked as indicators of changes in reservoir quality, degradation of well materials, and other processes.

Tracking the movement and alteration of the injected CO_2 in the subsurface represents one of the more challenging aspects of a monitoring program. This monitoring is necessary to ensure long-term storage and demonstrate the extent of the CO_2. The CAB-CS project was defined with reservoir pressure-temperature deep wells, intermediate monitoring wells, and geophysical wireline logging to assess the CO_2 saturation plume in the subsurface. As recommended by EPA and DOE/NETL guidance, the monitoring information was combined with multi-phase numerical models to confirm plume behavior in the subsurface.

Several levels of safety monitoring may be integrated into a storage project. Gas, pressure, temperature, and flow monitoring may be used with the capture, transport, and injection to ensure that no accidental releases occur. Likewise, many injection parameters may be monitored with automated systems to ensure the integrity of the monitoring well and immediate storage reservoir. Finally, methods may be used to demonstrate stable conditions of the reservoir and surroundings, such as passive seismic monitoring and well logging.

4.3 Property/Mineral Rights

Because there are large tracts of land owned by single landowners (particularly in the primary selected area), it is feasible that, with strategic placement of the two required injection wells, the estimated 17 mi^2 (10,900 acre) plume area could underlie only a few property owners. Parcel data have been obtained for all counties within the primary selected area and Tuscarawas and Carroll Counties in the secondary selected area (which accounts for around 75 percent of the secondary selected area). Because the exact injection location has not been selected, the analysis sought to determine the entities that are large landowners in each area. Table 4-10 shows acreage of the parcels owned by 10 landowners in each area that own the most land. Because Battelle has only discussed the project with a few organizations, only the State of Ohio and AEP (a project partner) are identified by name in this table. More than 10 percent of the land in the 506 mi^2 primary selected area is owned by either the State of Ohio or AEP, and much of it is near the proposed test well location, which will be on AEP property. Other large landowners include two mineral resources companies, two non-profits, two other private companies, and two privately owned farms. Large landowners in the secondary proposed study area include a nonprofit organization, three mineral resource companies, an oil and gas company, two other private companies, two privately owned farms and the State of Ohio. Landowners affected by pipelines from sources to the primary or secondary selected areas are dependent on the scenario.

Table 4-10. Top ten landowners for the primary and secondary 506 mi^2 selected areas.

Primary Selected Area		Secondary Selected Area[1]	
Owner	Total acreage	Owner	Total acreage
State of Ohio	28,000	Nonprofit Organization #1	11,300
AEP Generation/Ohio Franklin Realty	19,000	Mineral Resources Company #1	8,200
Mineral Resources Company #1	6,900	Oil and Gas Company #1	3,200
Nonprofit Organization #1	5,800	Private Company #3	1,700
Private Owner/Farm #3	1,800	Mineral Resources Company #2	1,500
Mineral Resources Company #2	1,600	Mineral Resources Company #3	1,200
Private Company #1	1,200	Private Company #4	1,100
Private Owner/Farm #4	1,000	Private Owner/Farm #1	1,100
Nonprofit Organization #2	1,000	State of Ohio	1,000
Private Company #2	1,000	Private Owner/Farm #2	800

1. Landowner data not obtained for Harrison County.

Ohio's law regarding groundwater is not based on absolute ownership but rather based on a doctrine of reasonable use which recognizes that groundwater is a common resource, which needs to be shared and managed for the common benefit of all. This requires a proactive role in the courts and in state legislatures addressing comprehensive groundwater-management (Bair and Norris, 1990). There will need to be a great deal of discussion with respect to developing a similar type doctrine for Class VI wells. A memorandum to aid in establishing mineral rights/pore space access for the CAB-CS site was prepared and is presented in Attachment 2.

4.4 Site Screening

Based on requirements for the CAB-CS facility, various environmental, logistical, market, and socioeconomic features near the selected areas were identified and mapped, when applicable, to determine surficial and subsurface risk items related to obtaining a suitable site. The objective of this site screening was to identify significant issues for development of the CAB-CS facility. Data also will be used to define characteristics needed to enable the project to be integrated within a unique natural and human environment.

Sensitive areas were investigated using NEPA Assessment Criteria as a guideline. Spatial datasets (i.e., ArcGIS shape files) and other publicly available information was used to define environmentally sensitive areas, culturally sensitive areas, socioeconomic conditions, and other sensitive features. These features were then classified as barriers (areas where project infrastructure cannot be sited) or obstacles (areas where project infrastructure can be sited with additional contingencies, such as permitting). Maps were generated to create a visualization of potential project locations.

4.4.1 Environmentally Sensitive Areas

Environmentally sensitive features, including air quality, geology/soils, water resources, wetlands, vegetation and wildlife, and land use were investigated using publicly available databases and shapefiles. The results of the analysis and data sources are summarized in Table 4-11. Land cover map of Selected Area A and Selected Area B is presented in Figure 4-22.

Table 4-11. Environmentally sensitive areas in the primary and secondary selected sites.

Criteria	Description/Result	Reference
Air Quality	Selected Areas A and B were designated as "attainment" for all Criteria Pollutants: 8-hour ozone, 1-hour ozone, particulate matter (PM)-2.5, PM-10, SO_2, and lead. Proposed project activities would not require the modification of local, state, or federal air permits and would follow local and state air quality requirements.	U.S. EPA (2017c)
Geology/ Soils	Bedrock surface is comprised of Pennsylvanian Age bedrock in Area A and Pennsylvanian and Mississippian Age bedrock in Area B. Farmland at both sites mostly follows major rivers; these areas will be avoided due to the presence of 100-year floodplains.	USGS (2016a; 2014b; 2005)
Water Resources	Many rivers and streams flow through both Selected Area A and Selected Area B. The main river in Selected Area A is the Tuscarawas River. The three main rivers in Selected Area B, which meet near the city of Coshocton, are the Walhonding River, the Tuscarawas River, and the Muskingum River. The 100-year floodplains follow these rivers and their principal tributaries. The highest yielding aquifers in both areas produce from glacial deposits along major rivers. These aquifers achieve yields of over 500 gallons per minute (gpm). Lower yield wells are drilled into bedrock throughout each selected area. These aquifers typically yield 25 gpm or less and do not exceed 100 gpm.	USGS (2016a; 2014b) ODNR (2015a-g; 2001a-g; 2000a-c)
Wetlands	Wetlands are found in both Selected Area A and Selected Area B, including freshwater emergent wetlands and freshwater woody wetlands. The largest tracts of wetlands in Selected Area A are along the principal tributaries to the Tuscarawas River. The largest tracts of wetlands in Selected Area B are along rivers and streams—namely, the Muskingum River, Wills Creek, and around some of the larger tributaries in the northwestern portion of the area.	USFWS (2017)

Criteria	Description/Result	Reference
Vegetation and Wildlife	Native terrestrial vegetation consists largely of deciduous, hardwood forests, with lesser amounts of emergent and woody wetland and grassland or shrubland. One state protected plant species is found in Area A while eight are found in Area B. Twenty invasive plants species have been identified in Area A and 18 invasive plant species have been identified in Area B. Seven federally protected wildlife species are found in Selected Area A and 10 federally protected wildlife species are found in Selected Area B. Seven of these species are freshwater mussels and one is a giant salamander, all of which are at risk of habitat loss due to sedimentation. The remaining species are bats, which are at risk from commercialization of caves, habitat loss, and disease. An additional 49 wildlife species in Selected Area A and 43 wildlife species in Selected Area B have state-protected status. One invasive insect (Emerald Ash Borer) has been identified in both Areas A and B. The Pine Shoot Beetle has also been identified in Area B. The Soybean Cyst Nematode may also exist in both areas.	OIPC (2017) ODA (n.d.) ODNR (n.d. a, b) U.S. Fish and Wildlife Service (USFWS) (2015)
Land Use	The northwestern corner of Selected Area A is developed. The southwestern and northeastern portions of the area consist largely of cropland and pasture land particularly along the Tuscarawas River and its major tributaries, interspersed with deciduous forests. The southeastern portion of the selected area is largely undeveloped, consisting of deciduous forest, surface water, and wetlands with some pastures and crops. Selected Area B consists largely of farmland (both cultivated crops and land for pasture/hay) and undeveloped deciduous forest interspersed with meandering rivers, some of which are bounded by woody or emergent wetlands (see Figure 4-22). Significant developed areas include the City of Coshocton (in the center of Selected Area B), West Lafayette (in the east-central portion of the area), and smaller communities including Conesville (south of the City of Coshocton), Warsaw (west-northwest of the City of Coshocton), Plainfield (south-southeast of West Lafayette), and Baltic (in the northeast corner of the area).	USGS (2014b)

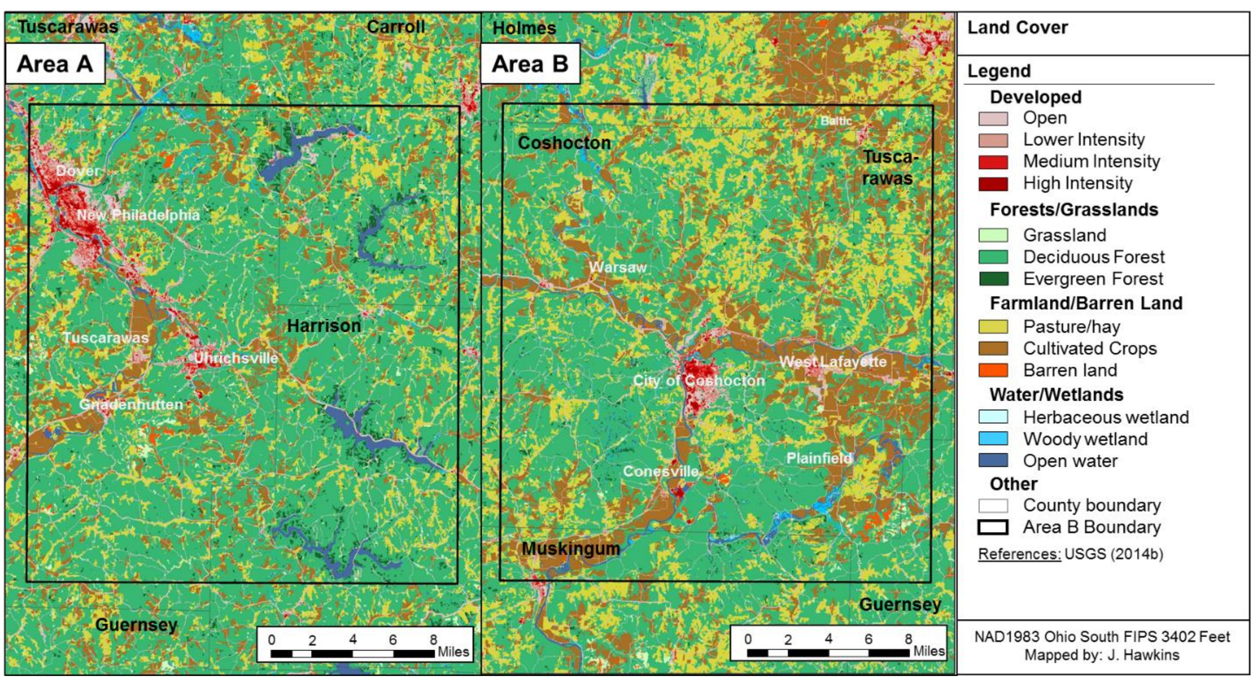

Figure 4-22. Land cover map of Selected Area A and Selected Area B.

4.4.2 Culturally Sensitive Areas and Critical Infrastructure

Culturally sensitive areas and critical infrastructure were investigated using publicly available shapefiles and databases. In Selected Area A, there are some smaller tracts of land owned by the ODNR, Division of Wildlife, mainly in the eastern half of the selected area (Figure 4-23). Other recreational areas in Selected Area A include several designated parks in the urbanized areas and several designated summits and valleys scatted around the area (USGS, 2016b). In addition, 14 buildings and one bridge registered with the National Register of Historic Places are in Selected Area A (National Park Service, 2017).

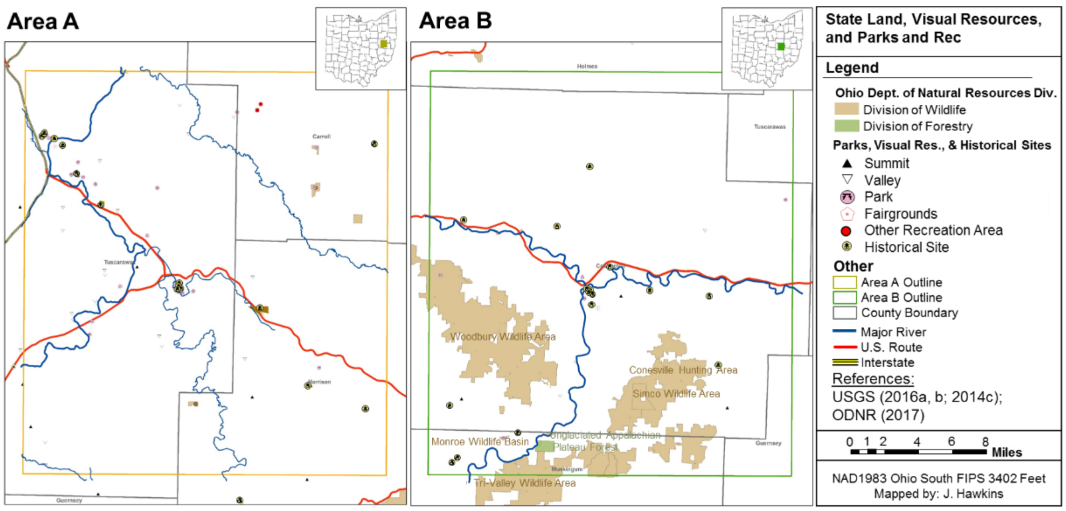

Figure 4-23. Map of state-owned land, visual resources, parks and recreational areas, and historic sites located within Selected Area A (left) and Selected Area B (right).

Several large tracts of land in Selected Area B are owned by the ODNR, Division of Wildlife. These include the Woodbury Wildlife Area and Monroe Wildlife Basin in the southwestern portion of the area; the Conesville Hunting Area and Simco Wildlife Area in the southeastern portion of the area, and the Tri-Valley Wildlife Area just southwest of the area. The ODNR, Division of Forests, owns the Unglaciated Appalachian Plateau Forest in the southwestern portion of the area. Other recreational areas in Selected Area B include Bakersville Community Park in the eastern portion of the area and Lake Park, Stewart Field, and the Coshocton County Fairgrounds in the City of Coshocton. Visual resources include three summits and two valleys. In addition, 17 buildings and two bridges registered with the National Register of Historic Places are located in Selected Area B (National Park Service, 2017).

Several dams can be found on both intermittent and perennial rivers and streams in Selected Area A and there are also a few dozen dams in Selected Area B (Figure 4-24). There have been many underground and surface mining operations in Selected Area A (Figure 4-25). While most of the underground mining operations are inactive or abandoned, there are some active operations in the center of the area. The surface mining operations are largely confined to the western portion of the area. Active oil and gas operations are found throughout the area, indicating that well drilling and mining operations currently coincide in this area. There was some underground mining in Selected Area B; however, most have been abandoned, except for a smaller operation in the southeastern extent of the area (Figure 4-25). There have also been historical surface mining operations in the southern portion of Selected Area B, with some active operations around the eastern and southern border of the area.

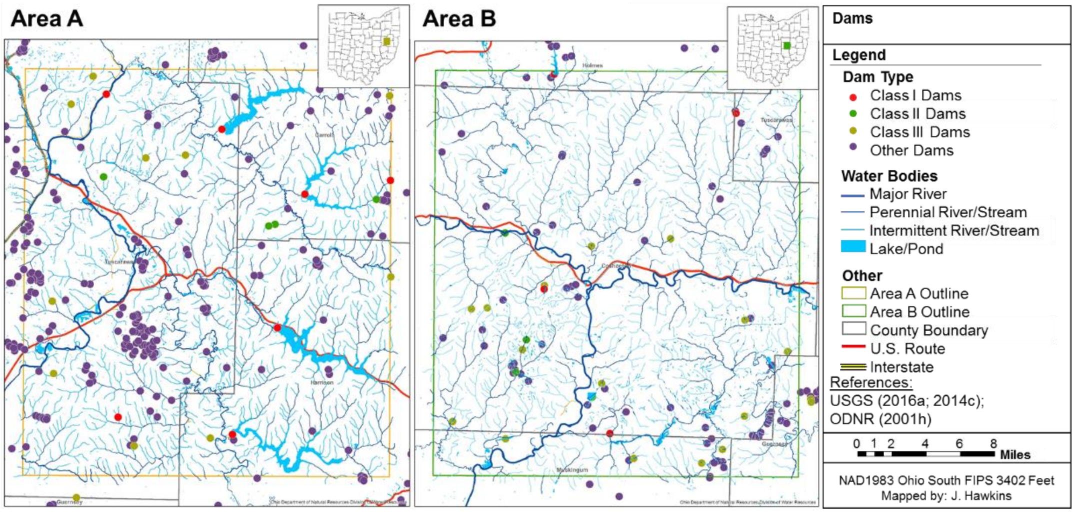

Figure 4-24. Dams in Selected Area A (left) and Selected Area B (right).

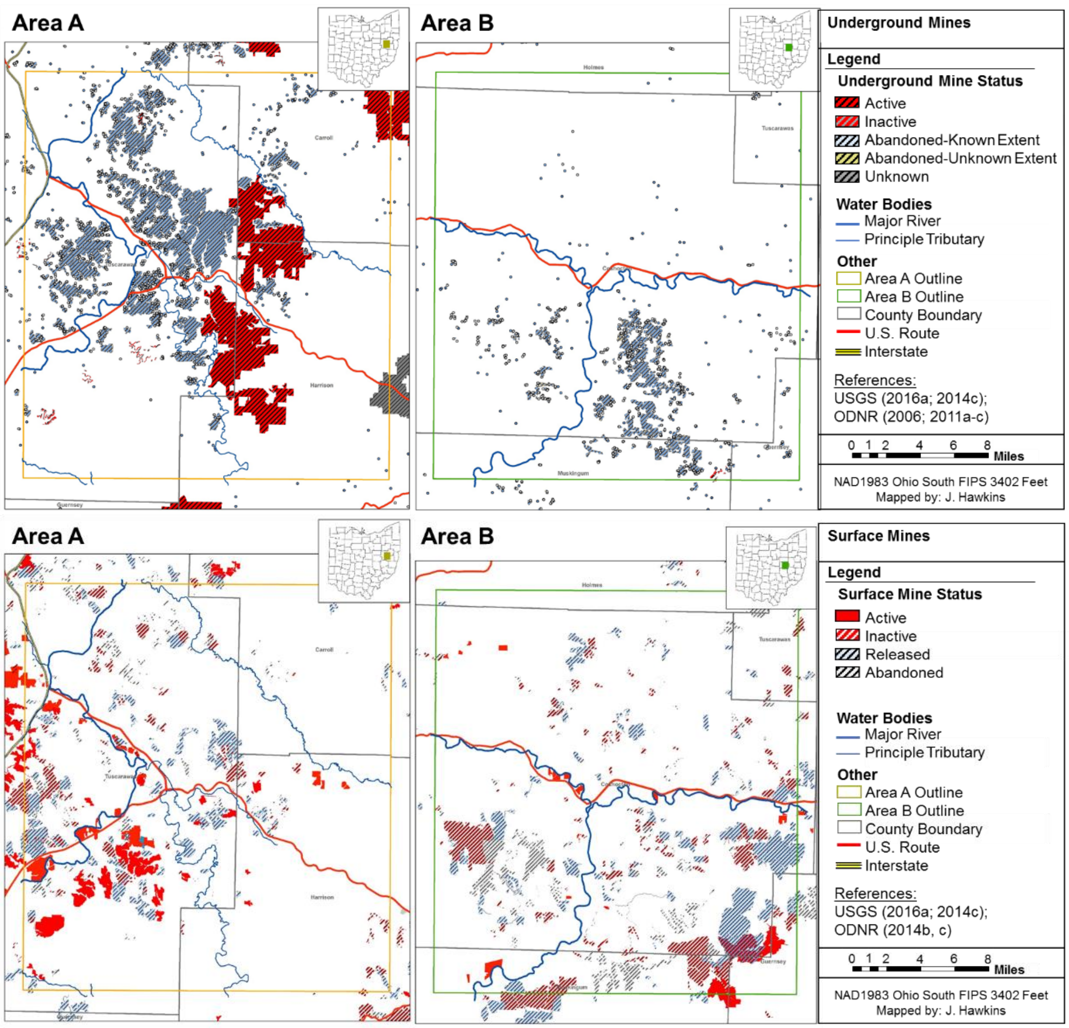

Figure 4-25. Underground mining operations (top) and surface mining operations (bottom) in Selected Area A (left) and Selected Area B (right).

4.4.3 Selected Area Demographics

Population density and socioeconomic resources were investigated using data from the U.S. Census Bureau (U.S. Census Bureau, 2016a, b, c, d). This exercise is intended to address issues of population density and environmental justice. The intent is to avoid citing a project in areas with a large population density. In addition, areas with an inordinate amount of historically underserved populations have often bared the brunt of the adverse consequences of industrial development. Socioeconomic issues in the study areas were analyzed so that environmental justice issues could be considered and to guide the discussion of citing a CCS project with all stakeholders in a selected project area.

4.4.3.1 Selected Area A

Much of Selected Area A is forest or farmland, meaning population density is less than 50 people per mile for around half of the area (Figure 4-26). The areas with low population density could potentially provide project locations that would not adversely affect residents, particularly in areas that are already industrialized. In some areas around the City of New Philadelphia, populations reach more than 5,000 people per square mile, while other incorporated areas have population densities between 500 and 5,000 people per mi^2.

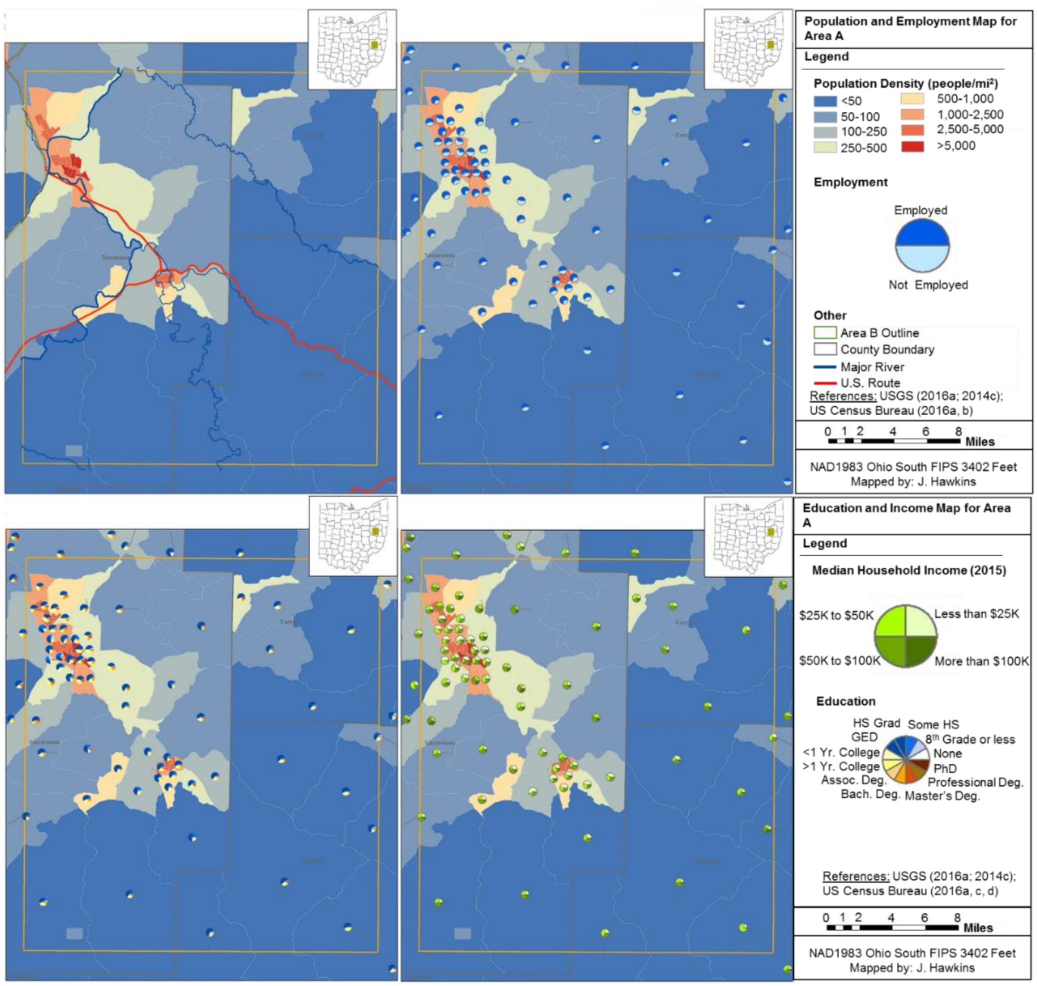

Figure 4-26. Socioeconomic resources and environmental justice maps, by Census Block Group, for Selected Area A (clockwise from top left): population density, employment, median household income, and education.

The percentage of people in Selected Area A who are above the age of 16 and are not employed is shown in Figure 4-26. At least a quarter of the people above the age of 16 in each Census Block Group are not currently employed. Further research would be needed to determine the number of people within this group that are currently looking for work.

The median income of the households in each Census Block of Selected Area A varies from less than $25,000 a year to more than $100,000 a year (Figure 4-26). The percentage of households making less than $25,000 a year is particularly concentrated in the Census Block Groups that make up New Philadelphia and Dover; more than half of the households in some of the Census Block Groups make less than $25,000 a year. In general, less developed areas have the highest percentage of households that make more than $75,000 a year.

Most residents over the age of 25 in Selected Area A have at least a high school diploma (Figure 4-26). The greatest proportion of residents with at least some college live in the suburbs and exurbs of the incorporated areas.

4.4.3.2 Selected Area B

Much of Selected Area B (Coshocton County) is forest or farmland, meaning population density is less than 50 people per mile for around half of the area (Figure 4-27). The areas with low population density could potentially provide project locations that would not adversely affect residents, particularly in areas that are already industrialized. In some areas around the City of Coshocton, populations reach more than 5,000 people per square mile. The towns of West Lafayette and Dresden have population densities of 1,000 to 2,500 people per mi^2 and 500 to 1,000 people per mi^2, respectively.

The percentage of people in Selected Area B who are above the age of 16 and are not employed is shown in Figure 4-27. At least a quarter of the people above the age of 16 in most of the Census Block Groups are not currently employed. Further research would be needed to determine the number of people within this group that are currently looking for work.

The median income of the households in each Census Block of Selected Area B varies from less than $25,000 a year to more than $100,000 a year (Figure 4-27). The percentage of households making less than $25,000 a year is particularly concentrated in the Census Block Groups that make up the City of Coshocton, where more than three-quarters of the households make less than $25,000 a year. In general, the suburbs and exurbs of the City of Coshocton, including West Lafayette, and the more rural areas in the northern half of the Coshocton County have the highest percentage of households that make more than $75,000 a year.

Most residents over the age of 25 in Selected Area B have at least a high school diploma (Figure 4-27). In the Census Block Groups that make up the City of Coshocton, between one-tenth to one-third of the residents have only some high school. Around one-third of the residents in the two Census Block Groups in the northeastern corner of Coshocton County have an eighth-grade education or less. The greatest proportion of residents with at least some college live in the suburbs and exurbs of the City of Coshocton, including West Lafayette.

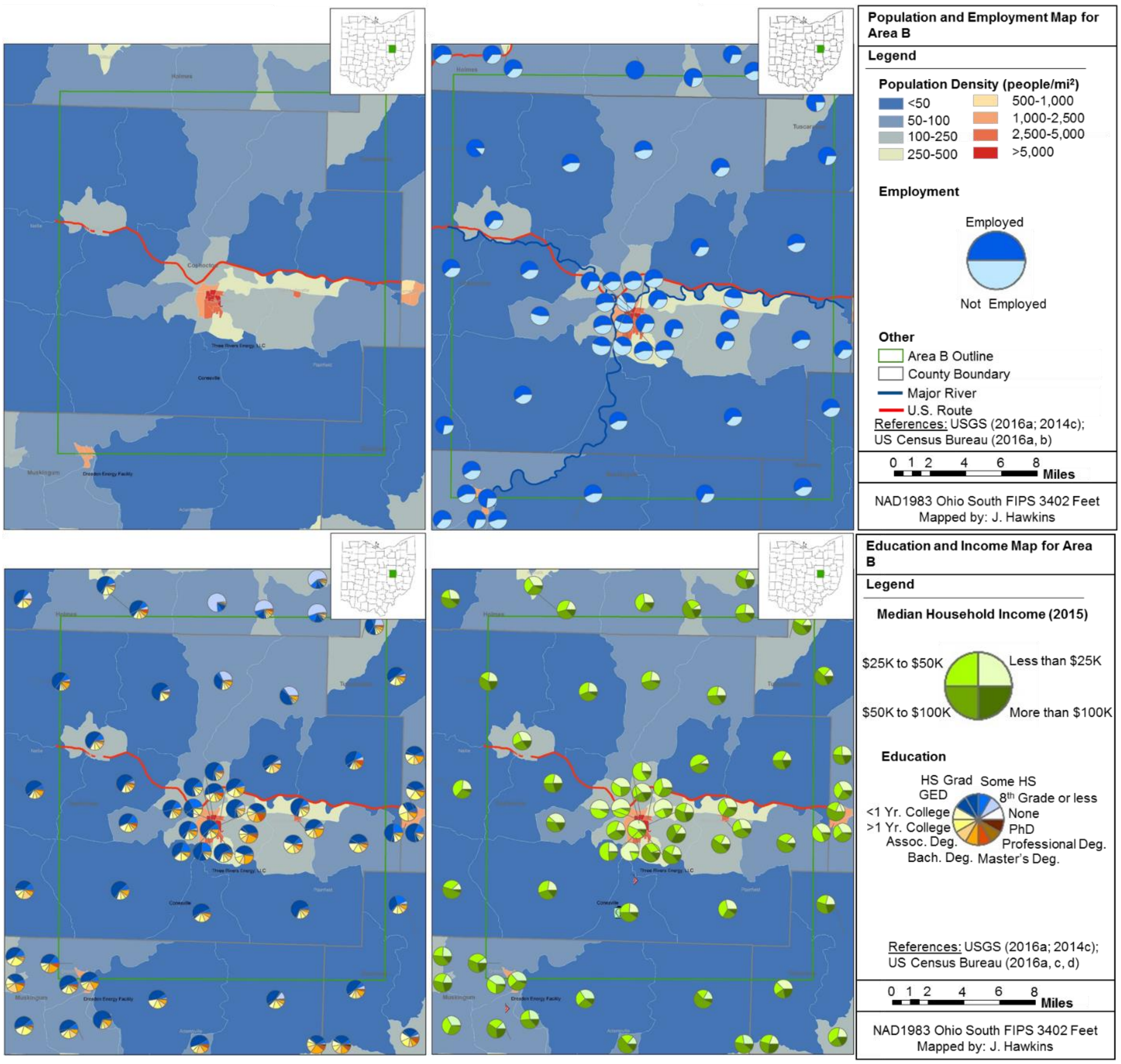

Figure 4-27. Socioeconomic resources and environmental justice maps, by Census Block Group, for Selected Area B (clockwise from top left): population density, employment, median household income, and education.

4.4.4 Site Screening Classifications

Six land designations were created to evaluate the areas available for siting project infrastructure. Two of the designations, open areas and wooded areas, are simplified land covers from the National Land Cover Database (NLCD) (USGS, 2014b) and indicate the level of site preparation required. The remaining four designations–surface barriers, surface obstacles, subsurface barriers, and subsurface obstacles–indicate the accessibility of the land for the proposed project. Simplified land cover maps of Areas A and B using these designations are presented in Figures 4-28 and 4-29, respectively. The details of the six designations follow:

- **Open areas** are NLCD designations of barren land, shrub/scrubland, grassland, pasture/hay, and cropland.
- **Wooded areas** are NLCD designations of deciduous, evergreen, and mixed forests.
- **Surface barriers** indicate areas that cannot be used to site a well, stage surface equipment, or construct a pipeline. Surface barriers include developed areas (NLCD - USGS [2014b]), source water protection areas (Ohio Environmental Protection Agency [OEPA], 2017), culturally significant areas (National Park Service, 2017), active surface mines (ODNR, 2014b, c), and Protected Areas Database of the United States Gap Analysis Areas status #1 (managed for biodiversity, interference allowed) and status #2 (managed for biodiversity, interference not allowed) (USGS, 2016c).
- **Surface obstacles** indicate areas that, with a permit or other consideration, can be used to site a well, stage surface equipment, or construct a pipeline. Surface obstacles are wetlands (USFWS, 2017) and 100-year floodplains (ODNR, 2001a-g). Because using these areas may create difficulties for public acceptance, surface obstacles will not be considered for the siting of a characterization well. For purposes of pipeline construction only, waterbodies (USGS, 2016a) and roadways/railroads (USGS, 2014c) are surface obstacles; wells or other surface infrastructure will not be sited in these areas.
- **Subsurface barriers** are underground features that prohibit the siting of a well but not the staging of surface equipment or the construction of pipeline. These include highly productive alluvial aquifers (ODNR, 2000a) and active underground mines (ODNR, 2006; 2011a-c).
- **Subsurface obstacles** are underground features that require additional considerations when siting a well. Subsurface obstacles include abandoned underground mines (ODNR, 2011a-c). Ohio regulations require a “mine string” casing to be set 50 ft below an abandoned underground mine encountered during drilling and cemented to the surface.

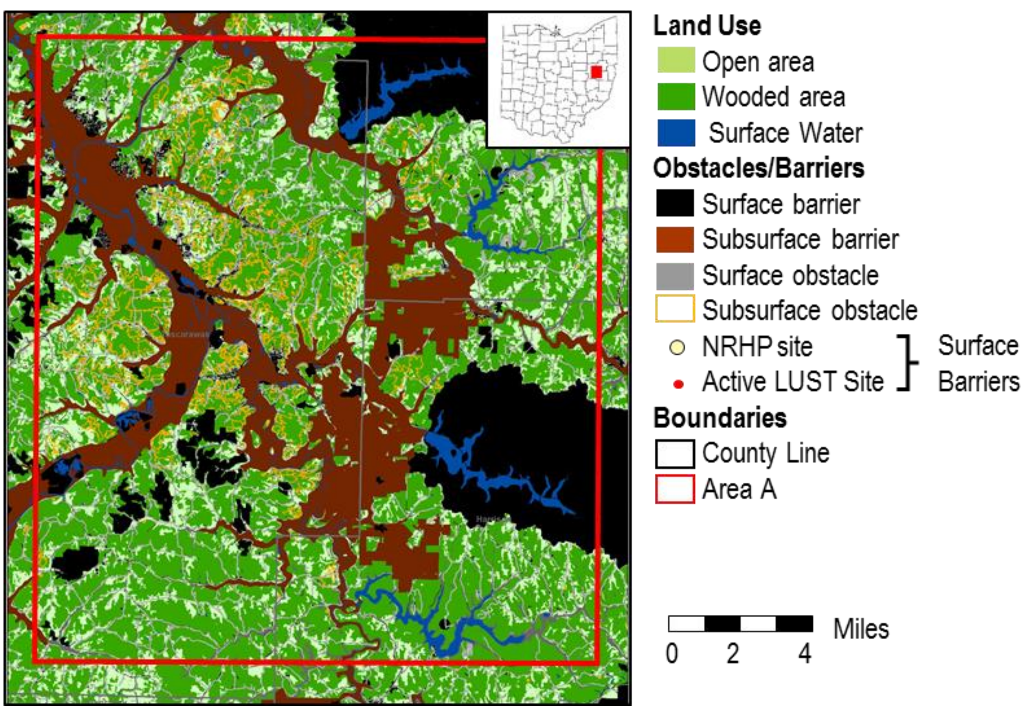

Figure 4-28. Simplified land use map of Area A with project obstacles and barriers

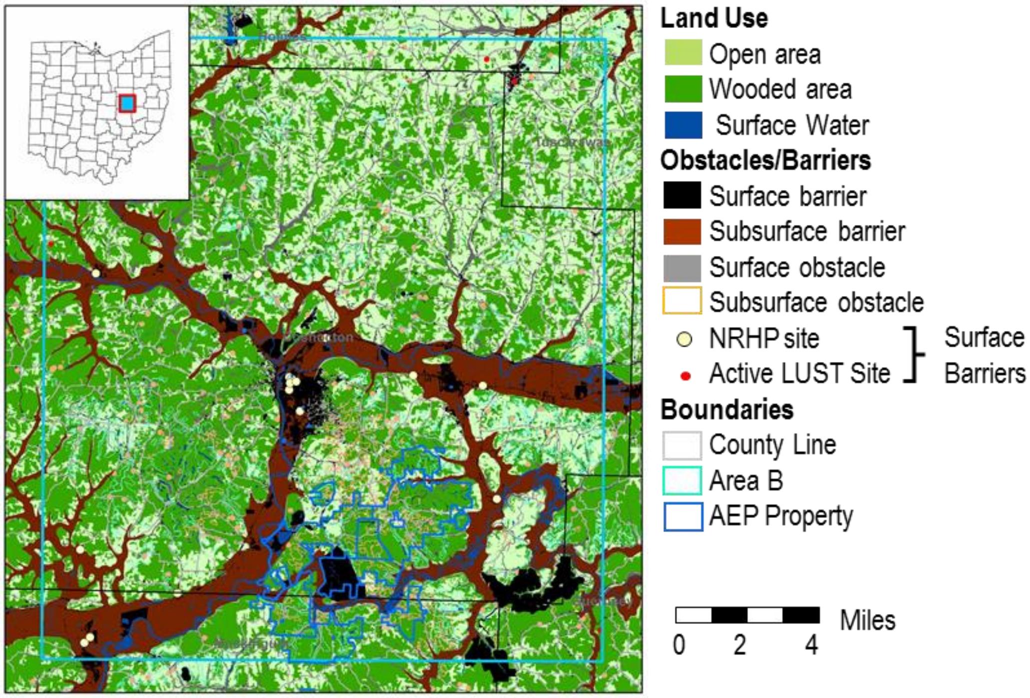

Figure 4-29. Simplified land use map of Area B with project obstacles and barriers.

4.5 Conclusions

The following was found during the project definition task:

- Project has reasonable dimensions
- Only two wells are needed for injection of CO_2
- Property rights and mineral rights are discussed, and scenarios are developed
- The CO_2 management strategy has been outlined in general for source types in the CAB-CS study area.
- Site screening indicates Area B should be considered the primary study area and Area A should be considered the secondary study area.
- Subsurface geology for the primary and secondary study areas is well suited for a CCS project.
- There are no wide-spread sensitive areas (environmental, cultural, or demographical) that would act as show-stoppers that would preclude a CCS project or its associated infrastructure in the primary or secondary study areas.
- Viable pipelines and other infrastructure have been defined for the primary and secondary selected areas.
- Risk defined by the NRAP tools is small
- Defining the mineral rights strategy, which involves purchasing mineral rights in the Rose Run sandstone/Knox Group and deeper for the AoR. Delineation of this area will be important in relation to public acceptance and surface access issues. Site selection would involve a thorough review of the mineral rights in the area, landowners, and existing pipeline/transmission rights-of-way to determine the most suitable location for the project.

5. Task 5 Project Integration

The CO_2 technical analysis showed many diverse CO_2 sources that can be linked to the CAB-CS facility via regional pipeline. The sub-basinal analysis demonstrated significant potential geologic storage capacity both in terms of deep saline reservoirs and depleted oil and gas fields. The project definition analysis supported the feasibility of developing qualified sites within the selected areas for large-scale deployment of CCS. The objective of Task 5 was to integrate various economic, regulatory/political/technology, permitting, stakeholder, and liability aspects into a plan for developing a CarbonSAFE complex in the Central Appalachian Basin.

For a CCS project to be considered viable, it needs to be economical, responsive to the needs and concerns of stakeholders, and be implemented in a suitable regulatory and legislative framework. Business cases must be developed with investors and stakeholders, and responsible entities clearly defined. A plan for public outreach and education must be developed through social characterization and expertise of local political, business, and community leaders. Finally, a clear analysis of the legal and regulatory issues to implement a CCUS project must be conducted, including, but not limited to, understanding of mineral rights/pore space access, long term liability and applying for and receiving permits.

The results of the prefeasibility assessment for project economics, regulatory environment, permitting needs, public outreach planning, and long-term liability follows. The information was used to help develop a potential workplan for the next phase of CAB-CS complex development (Appendix B). Although the Phase II project was not awarded at this time, the results of Task 5 helped to assess commercial readiness and the path forward (discussed in Section 6).

5.1 Economic Assessment

The economic assessment built upon the information gathered in the project definition (dimensions and infrastructure) analysis. A review of capital and operating costs for a 30-year CAB-CS project and financial mechanisms to support and incentivize CCS in the Central Appalachian Basin was conducted. Six possible source types were selected for more detailed evaluation as part of the financial scenario analysis. These business scenarios were developed to compare the cost of the integrated CCS systems for a variety of potential sources. This goal was to help to determine the overall investment by potential project partners and to identify gaps in funding that must be closed by either tax incentives (e.g., 45Q) or commodities (e.g., CO_2-EOR) for the region's diverse sources. A discussion of the results is provided below. The detailed economic analysis including assumptions and limitations is presented in Attachment 3.

5.1.1 Estimate of Anticipated Capital and Operating Costs for CO_2 Storage Complex

The preliminary cost estimates for the CO_2 storage facility were developed using the DOE)/NETL (2017b) FE/NETL CO_2 Saline Storage Cost Model U.S. Department of Energy Last Update: Sep 2017 (Version 3). The CO_2 storage cost model integrates information about the CO_2 reservoirs to estimate capital equipment, well drilling and testing, operating and maintenance expenses, monitoring, post-injection site care and site closure, and long-term liability. The NETL CO_2 storage cost model was selected for estimating storage costs because it offers a reasonable and reproducible cost model using publicly available information. For quality assurance, the cost estimates produced by the model were reviewed and substantiated by Battelle in-house expertise and information from FutureGen 2.0. Anticipated installed capital, operating, and post injection and site closure costs for a 50 MMt storage complex located in Selected Area B are presented in Figure 5-1 (note that costs for Selected Area A are essentially the same). As shown in this figure, the total capital cost for a 50 MMt saline storage complex operating for 30 years is approximately \$80 million with an operating cost of approximately \$5 million per year.

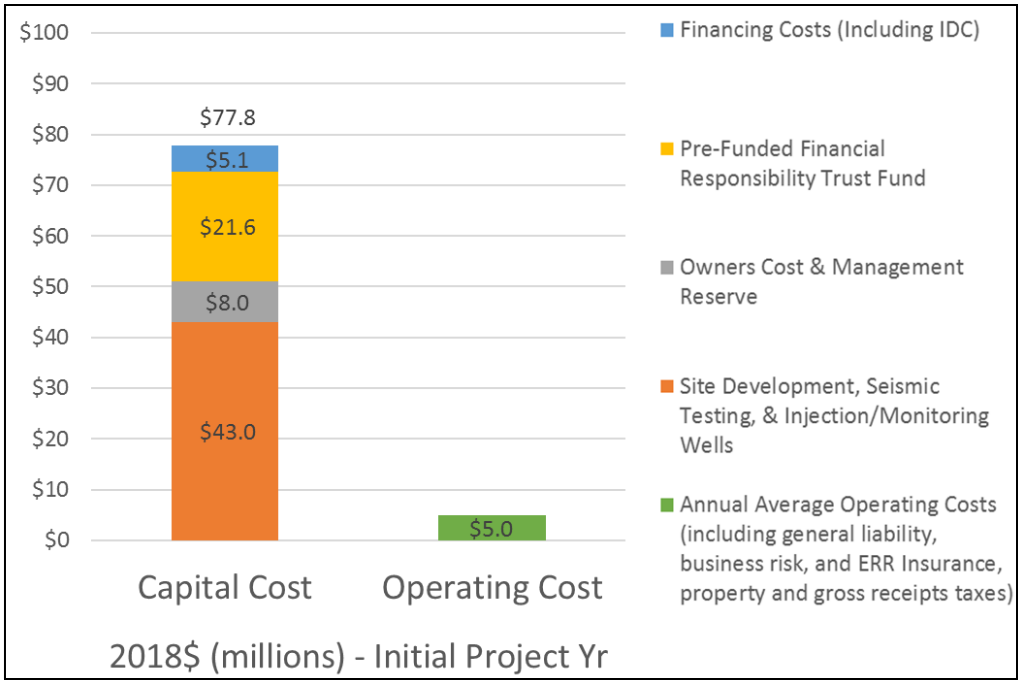

Figure 5-1. Total storage capital and annual average operating costs.

5.1.2 Estimate of Anticipated Capital and Operating Costs for an Integrated CCS Project

The financial analysis used a comprehensive approach to identify total project costs. The starting premise of establishing a regional market for CCS in Central Appalachian Basin is driving down capture costs to make projects economically feasible. Thus, a mix of current and future sources were included for the economic analysis. Six different scenarios were assessed in detail to determine the impact of the source type, business structure, financing scenario, cost recovery mechanisms of total project costs, and whether revenue from sales of CO_2 for EOR would be sufficient to close the remaining revenue gap even after applying federal tax incentives for carbon capture (Table 5-1). The sources used in the scenario analysis are described in more detail in Section 2.

Preliminary capital and operating cost estimates for the capture of CO_2 (Table 5-1) were derived from the following sources:

- NETL's Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3 July 6, 2015 DOE/NETL-2015/1723,
- Cost of Capturing CO_2 from Industrial Sources January 10, 2014 DOE/NETL-2013/1602,
- NETL's Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants; June 22, 2015 - DOE/NETL-2015/172, and
- Post-Combustion Capture Retrofit: Eliminating the Derate; August 21, 2017.

Initial estimates for CO_2 pipeline capital and operating costs were developed using the FE/NETL CO_2 Transport Cost Model (DOE/NETL [2014b]) (Table 5-1). The CO_2 transport cost model is a simplified model that uses the elevation, amount of CO_2 transport, and distance between the source and sink to calculate the cost of a pipeline connecting the two. The capital cost estimates for both the CO_2 storage facility and pipeline were adjusted to include appropriate owner's costs including start-up and commissioning, working capital, builder's risk insurance, financing costs and related fees, and an owner's management reserve. These constant dollar cost estimates were escalated to arrive at an "overnight" estimate at the assumed project start date of January 1, 2018. Interest during construction and escalation were included for the construction period to arrive at an as-spent mixed-year final estimate prior to the commencement of operations on January 1, 2025. Similarly, 30-year operating period costs (CO_2 storage facility and pipeline) were escalated to the appropriate year of operation.

Many assumptions were made to estimate the capital and operating costs for CO_2 capture; however, for the purposes of illustrating differences between various types of sources, this analysis yields insights for anticipating needs and strategies for securing financing. For example, for source types with low capture costs, the CO_2 transportation and storage can be recovered through sales of CO_2 for EOR; sources like coal-fired plants require advancements in capture technologies and additional incentives to implement CCS. All scenarios include the benefits from the recently enacted changes to the Federal tax code and to the Section 45Q tax credits of $50/tonne for saline storage and $35/tonne for EOR. Including Federal tax incentives helps to reduce the overall cost of capital for the scenarios evaluated. EOR sales revenues for either 50 or 100 percent of the CO_2 captured were calculated based on assuming sales at $25/tonne in 2018 dollars.

Table 5-1. Scenarios that describe basic assumptions and results for each source-sink scenario.

Category	Source type	Business structure / Financing scenario / Cost recovery	Pipeline Distance (mi)	Capture Cost (mil. 2018$)	Transport Cost (mil. 2018$)
Electric Generation	Supercritical pulverized coal (SCPC) plant retrofit	Rate Regulated IOU / Corporate Financing / Customer Rates & EOR	<10	940	9
	Natural Gas Combined Cycle (NGCC) Plant Retrofit	Rate Regulated IOU / Corporate Financing / Customer Rates & EOR	<50	674	41
	New NGCC Plant with CCS	Rate Regulated IOU / Corporate Financing /Customer Rates & EOR	<10	645	9
	NET Power with CCS	IPP / Project Financing / Long-Term PPA & EOR	<10	N/A (CO_2 is a byproduct)	9
Industrial	Hydrocarbon Cracker (HC) Plant	Merchant Facility / Project Financing / EOR Sales	50	159	86
	Independent Steel Mill	Merchant Facility / Project Financing / Long-term contract & EOR	100	844	221

The last step for the economic analysis was to develop a 30-year levelized CCS cost and revenue requirements in 2018$/tonne. The business case for each source-sink combination identified by the project team assumed all of three project elements (capture, transport, and storage) were owned and operated by a single entity that had strong financial backing from the project owner. This framework (see Figure 5-2) provides the best opportunity for a project scenario to be successfully developed and financed.

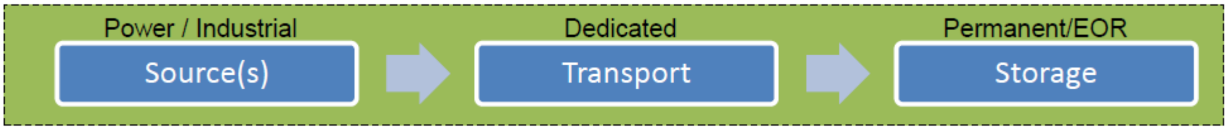

Figure 5-2. Integrated CCS project ownership structure where all elements are owned by a single entity

The scenarios assumed the sale of some (Figure 5-3) or all (Figure 5-4) of the captured 1.67 MMt per annum of CO_2 for EOR. The impact of Section 45Q Tax Credits on levelized revenue requirements was assessed. An example for the SCPC Retrofit is shown in Figure 5-5, which shows the net revenue requirement decreases from $84 per tonne to $46 per tonne (approximately equivalent to $18 per MWh).

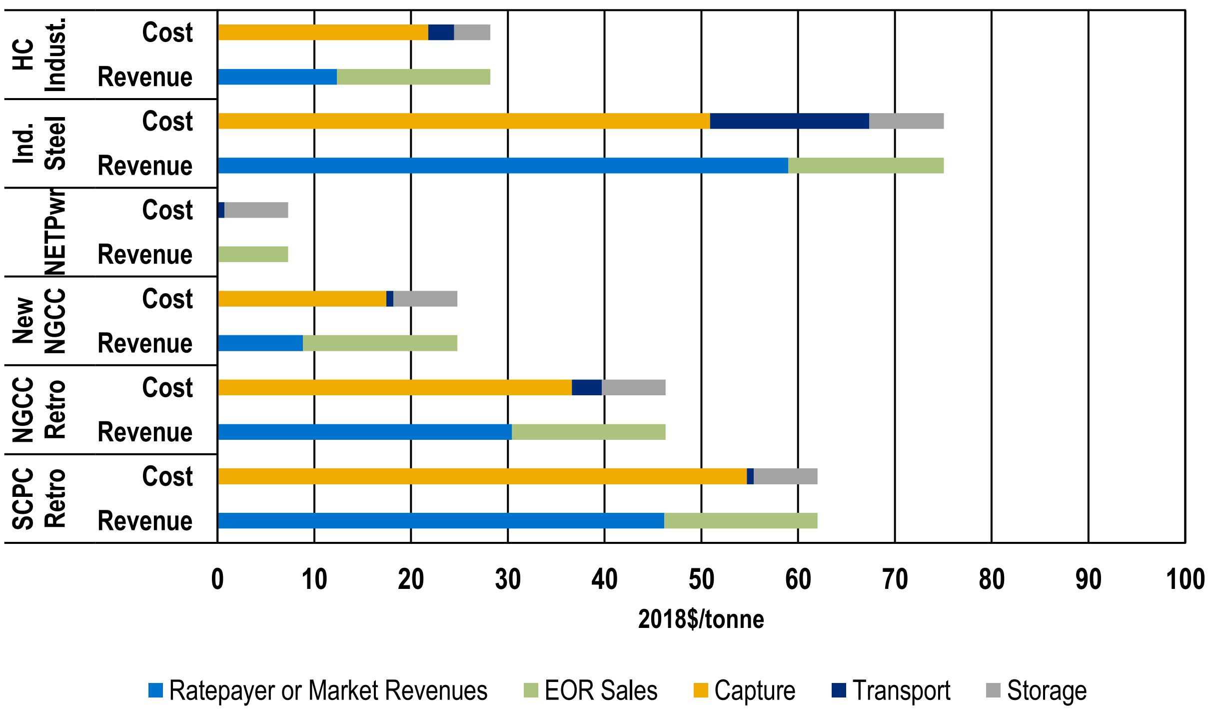

Figure 5-3. 30-Year levelized CCS cost and revenue requirement (50% EOR sales)

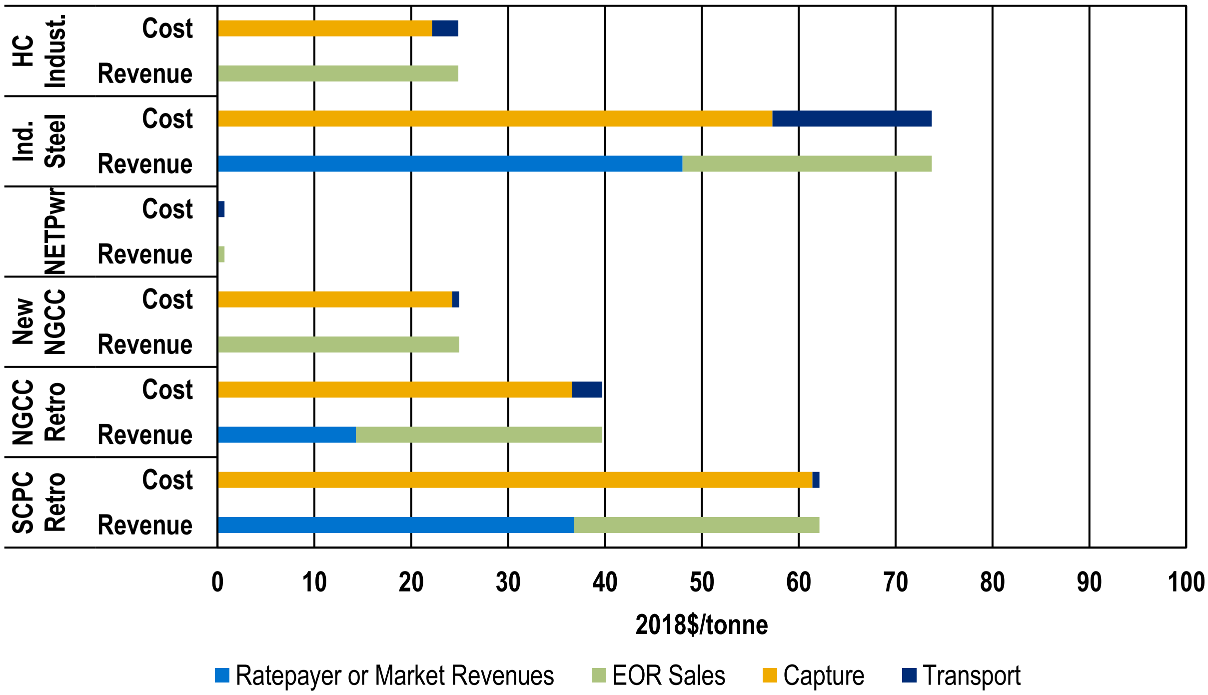

Figure 5-4. 30-Year levelized CCS cost and revenue requirement (100% EOR sales)

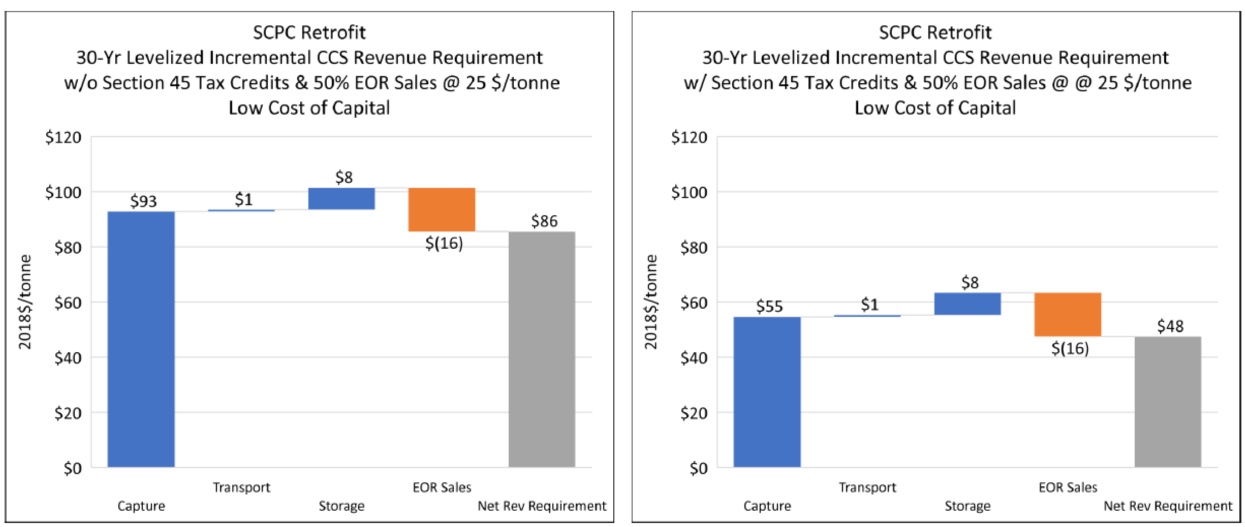

Figure 5-5. Impact of Section 45Q Tax Credits on Levelized Revenue Requirement for SCPC Retrofit

The key findings from the integrated CCS economic analysis include the following:

- The value created by EOR sales significantly reduces the need for other market or ratepayer revenues to cover the costs associated with the capture, transport, and storage components.
- Overall the NET Power scenario is considered the most attractive because this promising next-generation technology requires no additional costs for the capture or compression of the CO_2 produced by that source.
- Addition of capture to hydrocarbon cracker facilities also appear to be viable with EOR sales.

- New conventional NGCC with 100% EOR sales could cover the costs of capture and transport when coupled with Section 45Q tax credits and low cost financing
- Continued reduction in capture costs are necessary for coal and gas retrofit applications even with enhanced Section 45Q tax credits
  - Additional sources of revenue from ratepayers or a long-term power purchase agreement (PPA) are required to support present day CCUS costs
- Full utilization of enhanced Section 45Q tax credits critical to future CCUS opportunities

5.2 Regulatory/Political/Technology Planning

The prefeasibility assessment included a review of the regulatory, political, and technology integration issues in the study area. The task included identification and review of the pertinent regulatory agencies in the study area. In addition, the political environment for CCS was summarized. A review of the current status on sources and energy mix was completed to assess technology adaptation for the study area.

Regulatory Status. There are currently no Federal or State regulatory drivers for CCS. A regulatory framework exists for approving and operating CO_2 injection wells. However, the framework for fully integrated CCS projects are not yet in place. The major contribution of projects under the CarbonSAFE initiative is to progress toward the establishment of a proven, permitted, and market-ready storage complex. This would be done by demonstrating a viable storage complex capable of storing 50 MMt of CO_2, while simultaneously working through the legal and policy barriers that impede the development of a storage complex. Issues of concern include permitting a project (see Section 5.3), access to pore space (see Section 5.4), and assumption of long-term liability (see Section 5.5).

Policy and Incentives. Given the long-term deployment aspects and current uncertainties in policy and climate mitigation technology options, CCS initiatives will need to address a variety of risk factors over a long period of time. To some extent these risks can be shared with project partners, governmental entities, and managed through insurance. Some examples of risk issues include:

- Financial Risks – CCS projects for commercial scale applications will require large capital investments over a period of time. The return on investment is highly dependent on evolving technological and policy framework and is subject to domestic and international arrangements. At an early stage, government subsidies are likely to play a key role in making the project viable for private investors.
- Environmental Risks – These are risks that affect the ability to use a prospective site for storage as well as potential environmental consequences of the CCS project. Detailed due diligence at an early stage and careful environmental impact studies ensure that appropriate mitigation steps are taken in environmentally sensitive areas or alternative sites are selected. The potential risks from CCS deployment, such as possibility of leakage, groundwater impacts, and construction related issues can be mitigated through careful planning and operations.
- Legal – These include challenges to permits, conflicting demands on surface and subsurface rights (tenements), intellectual property ownership, and liability management. Many of these risks can be managed through preparing clear contracts and agreements that address as many potential future issues as possible. These also will rely upon developing a strong partnership with the regulators and government to reduce the uncertainty.

While significant public investment has been made in CCS research and development, incentives, such as tax credits, are recommended for technology deployment. There is a general lack of CO_2 pipelines and storage infrastructure which hinders the development of large capture projects. The use of Federal tax incentives to create a thriving market for development and investment has been demonstrated in the wind and solar energy sector. Policy parity that does not take away from renewables development and deployment is needed for CCS. One recent policy breakthrough was the amendment to the U.S. Federal Section 45Q Tax Credit for CO_2 storage. FUTURE Act (S. 1535) (Furthering carbon capture, utilization, Technology, Underground storage and Reduced Emissions) includes tax credits of $50/metric ton for saline storage and $35/metric ton for utilization for EOR to incentivize CO_2 storage. Features include:

- Removes the cap on total CO_2 amount captured to be eligible for IRS credits
- Increases the tax credit value to $35/metric for utilization and EOR; and $50/metric ton for sequestration over 12 years (construction must begin by January 1, 2024)
- Redefines the eligibility criteria to 100,000 metric tons of CO_2 captured annually to incentivize industrial/smaller projects
- Allows for transfer of credits by capture equipment owner to other entities involved in storage or utilization

Another policy under consideration that further improves the outlook for deployment include the "Utilizing Significant Emissions with Innovative Technologies (USE IT) Act," (S. 2602) that would amend the Clean Air Act and other federal laws to expedite permitting for CO_2 pipelines. Another innovative tax structure that would incentivize CCS deployment is to allow CCS projects to take advantage of the lower cost of capital through Master Limited Partnerships (MLP) and Project Activity Bonds. The MLP structure combines tax benefits of a partnership with the ability to raise capital in the public equity markets. These reforms, coupled with the changes to the Section 45Q program, make it more likely that investors and lenders will be attracted to CCS opportunities.

In addition to Federal policy, state level incentives to promote carbon free power generation are needed. To successfully finance an integrated CCS project from either natural gas or coal-fired electric generating stations, the State of Ohio will most likely need to pass legislation to enable cost recovery by either allowing the signature of long-term power purchase agreements that cover such costs, and/or allowing the Ohio Public Utility Commission to include such costs in consumer electricity rates. These cost recovery mechanisms are critical to the success of any CO_2 capture and storage project in the absence of a value for carbon in wholesale electricity markets or federally mandated carbon reduction, even with the potential for EOR revenues on this project. In addition to legislation that allows for cost recovery, other incentives like exemption from State sales tax during construction, property tax abatement, and the possible reduction in State income taxes should be considered by policy makers to enable the growth of CCS projects.

Technology Integration with the Region. The physical element for deployment of CCS include construction and long-term operation of CO_2 capture, transport, storage, monitoring systems. Most of these objectives can be achieved through industry standard engineering, contracting, and operational practices. However, as discussed in this document, there are additional unique aspects of CCS that require execution of the technical activities within a comprehensive framework of regulation, legislation, systems technology development, risk management, public acceptance and many other issues. Further complexity is added due to the inherent uncertainties in the evolving climate mitigation policy, strategies and unpredictability of future price on CO_2 emissions.

Initially, sequestration takes place in storage sites in close proximity of the CO_2 capture to avoid the cost of a major pipeline infrastructure. Once the large fields have been identified and proven, thus reducing risks, future operations may involve development of centralized CO_2 pipelines that focus geologic storage in pooled regional storage sites (e.g., storage hubs). There are multiple linkage options, as discussed in Section 2.2. The significant time required to develop a storage complex means that site development must be done in parallel with capture technology development and establishment of the legislative and regulatory frameworks.

Learning by doing is critical to address the challenges of implementing commercial-scale projects. The knowledge developed by successful research carried out by the Regional Carbon Sequestration Partnership Program and flagship commercial projects, such as Petra Nova, can help overcome hurdles and advance CCS on a large scale. The location of this project within the Central Appalachian Basin region of Ohio is especially strategic for advancing CCS technologies. This area, historically dependent on the coal industry, will continue to rely upon fossil fuel for electricity production and industrial growth. Therefore, expediting the development of solutions that allow for continued fossil fuel utilization in a carbon-constrained economy is of vital interest to this region.

Stakeholder acceptance and technology adaptation is uncertain. While using CO_2 for EOR is an established practice, saline storage is a relatively new concept; thus, the number of saline storage projects worldwide is limited. The public requires assurance that the storage complex can safely store CO_2. Site specific data need to be collected to refine storage complex models and improve predictability of storage processes and risk (see Appendix B). Strategies for public

State-Level Policy Options for CCS

Direct Financial Assistance: States often structure direct financial assistance to CCS projects and CO_2 pipelines as grants or loans.

Off-Take Agreements: States may require utilities to enter into off-take agreements with power plants with carbon capture technology. This requirement provides a guaranteed buyer for the electricity.

Utility Cost Recovery Mechanism: States may authorize utilities to pass on the costs of carbon capture technology to ratepayers. This provides timely reimbursement of costs incurred during construction and operation through favorable rates of return for regulated utilities' investments.

Clean Energy Standard: When a state declares carbon capture technology eligible toward state electricity generation portfolio standards or voluntary goals, utilities can earn saleable compliance credits by generating electricity at power plants with carbon capture technology. Inclusion of carbon capture in portfolio standards or goals may also facilitate approval of utility cost recovery for carbon capture technology, which may be critical for financing projects in states with regulated electricity markets.

State Assumption of Long-Term Liability: When states assume long-term liability related to geologic storage of CO_2, it may reduce the long-term costs for private project developers.

Tax Incentives: States may provide tax credits for CO_2-EOR and geologic storage. They may reduce corporate income taxes, provide exemptions from property and sales taxes on CO_2-EOR and geologic storage machinery and equipment, and may reduce severance taxes on oil produced through CO_2-EOR using man-made CO_2.

outreach and acceptance, in partnership with local industry and other stakeholders, need to be planned and implemented to address this gap.

Although competition against fossil fuels is increasing, fossil fuels have historically powered much of Ohio's economy and remain a large generator. Newer coal technologies, such as pulverized coal combustion systems, are more efficient and help to reduce emissions. Natural gas and renewables continue to increase; however, coal will continue to have a large share of the energy portfolio because of its abundance and low cost (IER, 2016). Concerns about coal, loss of coal power base, has led to increasing support for developing policies to keep coal in the mix. The future for a diversified energy portfolio includes having access to CCS as a technology option. CCS technologies have the potential to be central elements of an advanced energy technology portfolio because of the capability of delivering significant, cost effective, and sustained emissions reductions. CCS preserves and extends useful life of existing investments in productive assets. As pressure increases over the growing concerns relating to the environmental impacts of unabated CO_2 emission, the addition of CCS to natural gas plants will be needed.

The sale of CO_2 for EOR applications could provide the project with a significant source of revenue, potentially enabling project owners to reduce the amount of capital required to construct the CO_2 storage complex, lower annual operating expenses, and potentially reducing the Financial Responsibility requirements for the Class VI injection permit. While the EOR industry in Ohio is in its infancy, significant CO_2 sales are possible in the areas identified to develop the storage facility (Hawkins et al., 2017). Hawkins et al. (2017) found and estimated recovery potential of 320 million barrels (MMbbls) and associated storage capacity of 880 MMt from 17 of Ohio's major oilfields. The CAB-CS project offers an opportunity to combine saline and associated storage because both reservoir types are co-located. This CAB-CS project area has a long history of oil and gas exploration and continues to attract development, especially in the Utica shale regions. Battelle is working with the OSDA-OCDO to evaluate the potential of using CO_2-EOR in depleted oil and gas fields (OCDO Grant/Agreement OER-CDO-D-15-08). Of the 9 billion barrels of oil present in 30 major Ohio oilfields, only 1.3 billion barrels (or about 14 percent) of oil originally in place has been produced, suggesting oil recovery could be improved through CO_2-EOR.

See Sections 6.3 (Commercialization) and 6.4 (Path Forward) for further discussion on CCS technology development and integration in the region.

5.3 Permitting Plan

A variety of regulations and permits will have to come together for a carbon storage facility to become operational. These regulatory requirements ensure safe, environmentally responsible, and transparent project development. Class VI UIC permits for the injection wells will be the major regulatory permit for subsurface injection and will drive the project schedule, site characterization, facility design, operations, and site closure.

Overall, the regulatory process may take several years to complete. The region benefits from the large amount of characterization data available in the region through prior MRCSP/OCDO projects and piggyback testing in brine disposal wells. A permitting plan that accounts for permitting potential surface construction facility, land access, mineral rights, pipeline, injection wells, and other facilities related to a CCS complex in the Central Appalachian Basin is briefly described below. Major permitting items include stratigraphic well testing, Class VI UIC, pipeline, air permits, and National Environmental Policy Act (NEPA) compliance.

5.3.1 Stratigraphic Test Well(s)

The permit application to drill a stratigraphic test well is a routine process overseen by the ODNR Division of Oil and Gas. The surveyor's plat, restoration plan, plug and abandonment plan, well completion record, well plugging report, road use maintenance affidavit, surface hole additives report, and landowner waiver forms associated with the stratigraphic test well(s) must be obtained. Permits typically take 1 to 2 weeks to prepare and 30 to 60 days for approval.

5.3.2 UIC Permits

Deep well injection in the State of Ohio is regulated by the EPA Region 5 UIC Program. This program has permitted several Class VI UIC wells and other CO_2 test wells. The project will benefit from experience with EPA Region 5, since project participants have worked through permit requirements for other sites. The U.S. EPA has provided several guidance documents on Class VI UIC regulations (U.S. EPA, 2010; 2012; 2013a, b; 2016a, b), and this guidance was used to develop the UIC permit plan along with DOE/NETL Best Practices documents (DOE/NETL, 2017a, c-e). A Class VI permit will be required for each injection well, but much of the material will be the same in each permit. Since Class VI UIC wells are relatively new, few precedents exist for the permitting process, but the permit application appears to take two or more years to complete.

Site Characterization Plan. EPA guidance for site characterization is listed below. In general, the plan includes background on regional geology, description of the injection zone, confining zones, seismic history, groundwater hydrology, baseline geochemistry, regional geophysics, and synthesis of information on the site suitability. The guidance also recommends public notice plan to identify stakeholders in the general AoR. Components of the site characterization plan include:

- Regional Geology, Hydrogeology, and Local Structural Geology
- Detailed Geology and Hydrogeologic Site Characterization
- Maps and Cross Sections of the AoR
- Faults and Fractures in the AoR
- Depth, Areal Extent, and Thickness of the Injection and Confining Zones
- Petrology and Mineralogy of the Injection and Confining Zones
- Porosity, Permeability, and Capillary Pressure of the Injection and Confining Zones
- Geomechanical Characterization
- Seismic History
- Hydrology and Hydrogeology of the AoR
- Baseline Geochemical Characterization
- Fluid Chemistry
- Bulk Solid Phase Chemical Analysis
- Geochemical Calculations and Modeling
- Geophysical Characterization
- Seismic Methods
- Gravity Methods
- Surface Air and Soil Gas Monitoring
- Data Synthesis for Demonstration of Site Suitability
- Demonstration of Storage Capacity
- Demonstration of Confining Zone Integrity

- Public Notice Plan
- Reporting Plan

AoR and Corrective Action Plan. EPA guidance on AoR and corrective action plan is summarized below. The plan includes determination of the AoR with computational models, which may be a large effort to account for supercritical properties of CO_2 and geologic variations in the subsurface. The plan also includes mapping of the AoR, identification of wells in the AoR, surface water features, and groundwater wells. Components of the AoR and Corrective Action Plan include:

- Map of Area of Review, Surface Water Bodies, Artificial Penetrations, and Faults
- AOR Computational Models
- Identifying Artificial Penetrations and Corrective Action Plan

Well Construction Plan. EPA guidance for the well construction plan is listed below. The guidance recommends a plan for drilling, casing, cement, tubing and packer, and down-hole shut-off system (if necessary). Components of the well construction plan include:

- Well Plan and Design
- Casing Plan
- Cement Plan
- Tubing and Packer
- Down-hole Shut-off system

Testing and Monitoring Plan. Items in the EPA Testing and Monitoring Plan are listed below. Much of the plan is related to geophysical logging, core analysis, downhole testing, and mechanical integrity testing of the injection well or stratigraphic test well. Monitoring requirements include operational monitoring, groundwater monitoring, plume and pressure front tracking, and surface air and soil gas monitoring. Since there are many options for monitoring CO_2 storage projects, a feasibility or screening study may be necessary to down-screen monitoring options. Components of the testing and monitoring plan include:

- Well logging
- Core analyses
- Characterization of injection formation fluid chemical and physical properties and downhole conditions
- Fracture pressure of the injection and confining zones
- Hydrogeologic testing
- Pressure fall-off tests
- Injectivity and pump tests
- Mechanical Integrity testing
- Operation testing and monitoring
- Groundwater quality and geochemical monitoring
- Plume and pressure front tracking
- Surface air and soil gas monitoring

Injection Well Plugging Plan and Post-Injection Site Care and Site Closure Plan. EPA Class VI guidance for injection well plugging and post injection site care and site closure is listed below. The plugging plan addresses plugging the injection wells, monitoring wells, and surface equipment associated with the carbon storage project. The post injection site care plan includes post injection monitoring to demonstrate plume stability, verification of computational models, and occasional plan updating. EPA recommends a 50-year post injection monitoring period, but a shorter period may be demonstrated with monitoring evidence. Components of the Well plugging plan include:

- Pipeline and wellhead equipment removal
- Storage zone squeeze job/plugging
- Intermediate zone plugging
- Wellhead/surface monument

Components of the post-injection monitoring plan include:

- Post-injection computational model updates
- Monitoring plan review and maintenance
- Reporting schedule (every 5 years)
- Monitoring wells plugging and abandonment
- Monitoring equipment decommissioning
- Site closure plan

Emergency and Remedial Response Plan. EPA elements for emergency and remedial response plan are listed below. The plan addresses options for wellhead CO_2 release, down-hole auto shut off, well control, and pressure relief wells. The components of the emergency and remedial response plan include:

- Surface wellhead emergency plan
- Well down-hole auto shut off system
- Well control emergency response plan
- Pressure relief wells

Financial Responsibility Plan. Finally, the EPA guidance for financial responsibility is listed below. The plan includes description of the financial mechanism to ensure funding to plug the injection well and corrective action in other deep wells to prevent any CO_2 leakage. The components of the Financial Responsibility Plan include:

- Basis (plugging and abandonment, corrective action)
- Rationale for financial responsibility mechanism
- Financial Responsibility Mechanism (trust fund, letter of credit, surety bond, insurance, escrow, corporate guarantee)
- Reporting plan

Given the initial information gathered for the CAB-CS pre-feasibility study, there are no major obstacles envisioned for obtaining Class VI permits for the injection wells. Based on initial reservoir simulations, the AoR for the project would be manageable and have relatively few surface landowners for public notice. However, it is difficult to predict the outcome of public notice for a project of this type. Most of the site characterization and testing required for the permit is commonly performed for oil and gas operations in the region, with existing regional data available from Class II UIC wells and other deep oil and gas wells. Some issues that may need to be addressed in the permitting plan include the following items:

- Since the 2011-2012 induced seismicity events that occurred at the Northstar 1 UIC Class II injection well in Youngstown, the State of Ohio has prohibited drilling injection wells into Precambrian rock. It is uncertain whether fluid injection into the overlying basal Cambrian sandstones is also prohibited. Until there is a clear understanding of the revised Ohio regulations the basal Cambrian sandstones has uncertain storage potential.
- ODNR Division of Oil and Gas UIC Program has instituted a policy that discourages new Class II injection wells within a 3-mile buffer radius of historical earthquake epicenters and known faults (ODNR, 2014a). While ODNR does not have primacy on Class VI wells, it is likely that USEPA would employ a similar policy, so location of faults and earthquakes should be considered for the project.
- Down-hole shut off valves are not commonly used in the midwestern U.S.; although, shut-off valves were installed in the two CO_2 injection wells at the AEP Mountaineer CCS product validation facility in New Haven, West Virginia.

5.3.3 Pipelines

Several permits will be necessary to implement CO_2 transport (Table 5-2). The U.S. DOT Office of Pipeline Safety and Pipeline and Hazardous Materials Safety Administration administers the national regulatory program to ensure safe transportation of natural gas, petroleum, and other hazardous materials by pipeline. The Natural Gas Pipeline Safety Act of 1968, as amended, authorizes DOT to regulate pipeline transportation of natural (flammable, toxic, or corrosive) gas and other gases as well as the transportation and storage of liquefied natural gas. The Hazardous Liquid Pipeline Safety Act of 1979, as amended, authorizes DOT to regulate pipeline transportation of hazardous liquids (e.g., crude oil, petroleum products, anhydrous ammonia, and CO_2). The Federal Energy Regulation Commission also coordinates National Environmental Policy Act approval of major pipeline construction projects.

Table 5-2. Pipeline regulatory agencies for CAB-CS region.

Category	Location	Regulatory Agency
Pipeline Operations and Safety	Interstate	PHMSA
Pipeline Siting	Interstate	FERC
Pipeline Siting	Intrastate	Ohio Power Siting Board
Pipeline Operations and Safety	Intrastate	PUCO
Compressor Stations Construction & Operation	Intrastate	Ohio EPA Air
Pipeline Construction & Siting	Interstate or Intrastate	Army Corps of Engineers Nationwide 12 Permit
Pipeline Construction & Siting	Local	Muskingum Watershed Conservancy District/County Engineers

In Ohio, the Ohio Power Siting Board certifies the siting of intrastate gas pipelines that operate at higher pressures (>125 psi). The Public Utilities Commission of Ohio regulates operational safety aspects of pipelines in Ohio. These requirements include a pre-construction notice and as-built notice. Additional Nationwide 12 Permit may be required from the Army Corps of Engineers. Pipelines that cross streams, wetlands, and/or rivers require special permits from County agencies. Compressor stations would require Clean Air Act permit from OEPA.

Since 2010, several major pipelines were constructed in Ohio, Pennsylvania, and West Virginia related to shale gas development in the region (Table 5-3). DOE/EIA listed 91 hydrocarbon related pipelines in the process of development in the CAB-CS region since 2010 with total costs of more than $35 billion (DOE/EIA, 2017b). Consequently, there is a general awareness of pipeline regulations by landowners, local organizations, and the public in general. Longer pipelines have experienced 1-3 year permitting process. Many of the best routes for pipelines have been secured by recent natural gas pipelines. In addition, pipeline right of way costs may be elevated due to competition for pipeline routes.

Many of these pipelines connect, repurpose, and/or expand upon existing pipelines to minimize construction costs. The larger new pipelines have capacity of 1.5-3.5 bcf gas and 50,000-300,000 bbl/day natural gas liquids. For comparison, the CAB-CS project would involve pipeline transport of approximately 36,000 bbl/day (or 0.085 bcf) CO_2 in supercritical liquid phase. Main pipelines are mostly 20 to 40-inch diameter, but the projects involve various supply and gathering lines similar to the CarbonSAFE hub concept.

Table 5-3. Summary of Major New Pipelines in the Central Appalachian Basin Region.

Pipeline Name	Approx. Length (miles)	Origin-Destination	Capacity	Cost ($million)	Completion Date
Rover	700	SE OH, SW PA, N. WV→ Ontario, Canada	3.25 bcf/day	$4,300	~2018
Nexus	250	NE OH→SE MI, Ontario, Canada	2.0 bcf/day	$1,200	~2018-2019
Leach Xpress	160	N WV→E OH→S OH→NW WV	1.5 bcf/day	$1,400	2018
ATEX	370	SW PA→S OH→S IN	260,000 bbl/day	$1,200	2013
Mariner West	250	SW PA→N OH→SE MI/Canada	70,000 bbl/day	$600	2014
Mariner East	350	E OH/WV/W PA→E PA	275,000 bbl/day	$2,500	~2018-2019
Utopia East	215	E OH→SW MI/Canada	50,000 bbl/day	$540	~2018
Mountaineer Express	170	N WV→SW WV	2.0 bcf/day	$1,600	~2018-2019

Source: DOE/EIA (2017b). Natural Gas Pipelines Projects from 1996 to Present.

5.3.4 Air Quality

Modifications and construction for carbon capture facilities may require additional air permit for stationary sources of air contaminants, as regulated by the OEPA Division of Air Pollution. These regulations apply to power plants, gas processing facilities, ethanol plants, and any other stationary source of air pollution. Sources considered for CAB-CS would be considered major sources, and larger emitting facilities may have complex to very complex air permitting requirements. Changes to generation capacity may require authorization by the Ohio Power Siting Board and Public Utilities Commission of Ohio. While these regulations are not a direct responsibility of the CAB-CS project, the permits may affect schedule for CO_2 availability.

5.3.5 NEPA Compliance

NEPA requires federal agencies to assess the environmental effects of their proposed actions prior to making decisions. The range of actions covered by NEPA is broad and includes: making decisions on permit applications, adopting federal land management actions, and constructing highways and other publicly-owned facilities.

Using the NEPA process, agencies evaluate the environmental and related social and economic effects of their proposed actions. Agencies also provide opportunities for public review and comment on those evaluations. Features like sensitive environmental areas, national historical preservation act sites, endangered species, and other NEPA items will need to be assessed for proposed sites.

5.4 Public Outreach Review/Planning

A public outreach plan identifying various industry, regulatory, political, subrecipient, local, and policy stakeholders for the Central Appalachian Basin was developed to support CAB-CS facility. A social characterization effort and discussions with the technical advisors and other CCS stakeholders were helpful in determining outreach concerns for establishing a CCS complex in the study area.

5.4.1 Phase I CCS Stakeholder Outreach

A public outreach plan was developed to support the CAB-CS project (Attachment 4). The plan called for a social characterization of the study region; identified various industry, regulatory, political, nongovernmental organization (NGO), local and policy stakeholders for the Central Appalachian Basin; and established the outreach steps to be conducted in Phase I. The project team reached out to those that could have collaborative or opportunistic attitudes towards CCS development for this initial phase. Outreach efforts involved senior staff in the Governor's Office, Cabinet Directors, state agency regulators, congressional staff, regional economic development directors in Appalachia Ohio and leaders in organized labor. Findings included:

- State leaders were briefed through an in-person meeting on January 24, 2018 to help promote a coordinated approach to addressing regulatory issues. The meeting included the Governor's Office, OEPA and the ODNR. OEPA and ODNR are both very knowledgeable about CCS and reaffirmed their commitment to remain engaged as active stakeholders in the development of CCS.
- Outreach and education was conducted with three major labor organizations, all stakeholders, who directly benefit from the successful deployment of CCS. The United Mine Workers of America are particularly interested in remaining active and engaged when it comes to policy issues impacting CCS.
- Regional economic development stakeholders were educated and enthusiastic about the benefits of CCS. These perceptions were based on the economic impact that CCS would have on protecting jobs and extending the use of fossil fuels.

Despite the positive indicators, the project team has identified potential legal/regulatory and public acceptance hurdles. The potential concerns in the legal/regulatory arena are mitigated by several factors. The project benefits from the fact that UIC Class VI permits would be implemented by U.S. EPA Region 5, the only EPA office that has experience issuing UIC Class VI permits to date. The project also benefits from a strong ODNR with authority to implement the UIC Class II permits, which include both EOR and brine disposal operations. A legal review conducted by Vorys indicates that it would be useful to clarify uncertainties relating to the acquisition of pore space rights, the potential use of unitization to facilitate pore space acquisition, and treatment of long-term stewardship of the injected carbon dioxide (Attachment 2; Section 5.5). The legal review examined how other states have addressed some of these issues (e.g., Wyoming, Montana, and North Dakota) and identified potential legislative options to explore in future phases.

In addition to the technical advisors, industry and other CCS stakeholders were engaged to build support for Phase II via meetings and teleconferences. These stakeholders included the Clean Air Task Force; MCF Drilling, Inc.; Ohio Air Quality Development Authority; New Steel, Inc.; Andritz; NetPower, LLC; and Shell. Stakeholder and point of contact information were collected for future discussions.

The Phase I outreach plan serves as the foundation for future outreach efforts. Future phases of the project would involve working with a locally based communications firm to further assess public perceptions of the project, identify potential benefits, and develop an effective strategy for public outreach. The preliminary Outreach Plan includes an initial focus on opinion leaders and stakeholders to help guide potential legal and regulatory frameworks. Environmental NGOs that consider carbon capture an important climate change mitigation strategy for energy production will also be contacted as potential stakeholders. In future phases, this outreach effort will expand to stakeholders directly involved in the project location and continue to increase. This plan is outlined in Attachment 4.

5.4.2 Analysis of Communities near the Storage Site and along the Rights-of-Way (ROWs)

A preliminary social characterization of the counties intersecting the potential sources, sinks and pipeline routes in Eastern Central and Southern Ohio was conducted (Appendix A of Attachment 4). A first step in social characterization is collecting statistics and information that helps to develop an appreciation for the communities in the study area and serves as a foundation for community engagement. The assessment explored economic, social-political, technological, environmental, and legal factors that could indicate or influence public attitudes towards the project.

The stakeholder analysis suggests that the study area appears well suited to host a large-scale project that is integrated with the energy industry in that part of the State. The energy industry serves as a key driver to the State of Ohio’s economy and will continue to serve as an important asset in the future (Michaud et al., 2017). It includes emerging EOR operations (Battelle, 2016), growing shale developments, extensive brine disposal, and coal and natural gas combined-cycle power generation, and discussion of connecting to regional pipelines to move CO_2 into areas where there is greater demand (State CO_2-EOR Deployment Work Group, 2017). The availability of anthropogenic CO_2 via capture technologies could help to invigorate an oil and gas industry that is on the tip of expansion in Ohio. For the coal and natural gas power industry, the geological characterization will provide the foundation for CO_2 storage as a business option in the event of future climate change policy.

Population density is lower compared to other parts of Ohio, and there are higher levels of poverty than in the rest of the state. There are three main economic development groups that have created strong partnerships to build employment and economic vitality in the region (e.g., Appalachian Partnership for Economic Growth, Buckeye Hills and Ohio Mid-Eastern Governments Association). Energy is a key industry in the area but has a complicated impact. On the one hand, shale developments hold the promise of jobs and economic benefits for the region. However, that promise has been tempered by the prevailing shift from coal to natural gas power generation (thereby closing coal power plants, a source of well-paying jobs) and by the slower development of shale units in Ohio as compared to nearby operations in Pennsylvania. The counties in the study area host significant brine disposal operations. All of the counties in the study area are considered to “disadvantaged” in comparison to the average economic indicators for the state of Ohio. Job growth has been modest in the area and CAB-CS jobs would be an attractive opportunity to address CO_2 from coal- or natural gas-fired units and gain experience in subsurface activity (a growing job in the region).

The primary selected area for the feasibility study includes parts of Coshocton, Tuscarawas, Muskingum, Holmes, and Guernsey Counties. The secondary selected area includes parts of Tuscarawas, Harrison, and Carroll Counties. Preliminary modeling suggests a subsurface storage area of less than 17 mi^2 for both selected areas. The social characterization showed no special social issues with regard to the viability of the capture, transportation, or storage aspects of the project in these selected areas. Given the strong presence of energy industry knowledge, the demand for jobs, and the potential role that CO_2 storage could play in the energy industry, one may anticipate the project to be favorably perceived. This has been born out in the positive feedback obtained during initial outreach with economic development and employment groups. These groups are already familiar with CCS and the important role this technology could play in enabling fossil fuel-based power generation in a future low-carbon society. Building on this direct outreach to influential stakeholders in the area will be done in future phases.

5.5 Liability Assessment

The risk for CCS projects is largely dependent on the choice of the site and its geological and environmental features; but well-sited and well-operated projects can be expected to result in a relatively small potential financial risk for damages to human health and the environment compared to both the planned project costs and the benefits of such projects (Price and Wade, 2012; Donlan and Trabucchi, 2011).

Class VI UIC financial responsibility requirements [40 CFR §146.85] cover costs of well plugging and site closure. Per these regulations, the owner or operator of a Class VI injection project is required to provide EPA assurance that the costs for corrective action, injection well plugging, emergency and remedial response, and post-injection site care and site closure are provided for should the owner or operator fail to fulfill their regulatory obligation. These cost assurances can be met through one or more allowed financial instruments. Financial instruments currently recognized in the regulations include self-insurance (corporate guarantee), trust funds, escrow accounts, insurance, surety bonds, and letters of credit.

Ohio does not have a regulatory mechanism to cover the long-term liability of CO_2 storage projects beyond the 30-year injection operations and 50-year post-injection site care period, but it is anticipated that a successful project would not require significant liability coverage beyond this timespan. Additional financial mechanisms may include indemnification, insurance, trust funds, limited liability partnerships, and other methods. Some states have a policy to indemnify long term liability for carbon storage (e.g., Kentucky, Montana, North Dakota, and Texas), which encourages development of new carbon capture and storage projects. Another option is to establish a general fund to cover long-term liability for all carbon storage projects in the state, similar to state “orphan well” funds for abandoned oil and gas wells. This fund may be supplied by a small duty for each ton of CO_2 stored.

A memorandum to aid in establishing liability solution for the CAB-CS site was prepared and is presented in Attachment 2.

5.6 Conclusions

- **Project economics illustrates a need for both government and private investment in the absence of a regulatory mandate.** Technological advances, combined with policy and regulatory clarity and financial support through tax credits and grants, can make the capture technology deployment economical. State level incentives to promote carbon free generation are necessary. In addition to legislation that allows for cost recovery, other incentives like exemption from State sales tax during construction, property tax abatement, and the possible reduction in State income taxes should be considered by policy makers to enable the growth of CCS projects.

- **Although there is no comprehensive policy for long-term liability and subsurface storage rights for carbon storage in Ohio, existing oil, gas, and brine disposal regulations and carbon storage policies from other states can be used as a model to inform CCS deployment in Ohio.** Class VI UIC permits for the injection wells will be the major regulatory permit for subsurface injection. Regulatory frameworks to integrate the CO_2 storage industry within the existing regulatory framework for the oil and gas industry also can be initiated by a real project in the region. This would be done by demonstrating a viable storage complex capable of storing 50 MMt of CO_2, while simultaneously working through the legal and policy barriers that impede the development of a storage complex.
- **While political support within the region exists for the concept of CCS, wide-scale recognition of the importance of CCS to energy production is lacking.** Educational efforts to make economic connections between CCS and coal and other benefits would be helpful in garnering stakeholder support. A strategy for conducting outreach associated with development of a geologic storage site will ensure coordination among the project proponents and building a solid foundation of public support for the proposed storage site.
- **Public acceptance issues should focus on jobs and economic development.** In spite of the importance of CCS mitigating the threat of climate change, stakeholder buy-in and support remain uncertain. CCS should be positioned as complimentary to renewables - deployed at the expense of uncontrolled fossil fuel generation, not renewables. Preliminary public outreach indicates that focus on jobs and economy with environmental benefit as a secondary issue is the best approach. Early public outreach should include business leaders, legislators, and industry experts.
- **Long-term liability remains an unanswered question.** Ohio does not have a regulatory mechanism to cover the long-term liability of CO_2 storage projects beyond the 30-year injection operations and 50-year post-injection site care period, but it is anticipated that a successful project would not require significant liability coverage beyond this timespan. The project risk profile would be very low after the financial responsibility requirements have been fulfilled and that the site has been closed following approval by the U.S. EPA Administrator.

6. Task 6 Team Building

Task 6 included team building activities to establish a CCS coordination team. The project team included scientists, engineers, legal, policy, and financial experts, power generation experts, oil and gas operators, technical field crew, and support staff. The project team evaluated options and provided advice for creating a CAB-CS complex.

6.1 Technical Advisory Meetings and Review

To facilitate project tasks, a series of technical advisory meetings were held with the project team and technical advisors including Battelle; AEP; BHGE, a GE Company; Buckeye Brine; The Energy Cooperative; PKM Energy Consulting; Three Rivers Energy; Vorys; Vorys Advisors, and Wade LLC. The meetings sought to obtain input on aspects related to establishing a CCS complex in the Central Appalachian Basin, including siting, commercialization, and path forward.

The technical advisors met at Battelle Columbus headquarters on April 21, 2017, August 31, 2017 and June 7, 2018 to discuss the project goals and short- and long-term actions items (Figure 6-1). The purpose was to discuss technical activities, briefly walk through the tasks, and to converse on the elements for a successfully integrated project. The topics covered included project management, source identification, sub-basinal geological assessment, project definition, and carbon capture storage project integration planning, as well as economic aspects and outreach planning. Initial steps for the project included identifying and ranking CO_2 sources, collecting and summarizing data, identifying appropriate NRAP tools, and performing social characterization for outreach planning. Technical advisors also reviewed the topical reports and other documents prepared by the project team and provided feedback.

Figure 6-1. Paul Champagne (PKM Energy) presenting an overview of the economic modeling effort during the second meeting of the technical advisors.

6.2 Teaming Planning and Siting Review

This subtask involved identification of roles and responsibilities for commercial complex development. The appropriate organization for the different aspects for a CCS complex was assessed, including permitting, construction, pipeline, capture, injection, operations, monitoring, verification, legal support, and other work. The Phase I project team was viewed as the core team capable of addressing most aspects; however, it was determined that future phases would benefit from additional team members including an engineering/project/ construction management firm to address CO_2 transportation requirements, a local public relation firms to expand on public outreach efforts, and potential future CO_2 sources. The role of private-public partnerships for enabling CCS pointed to the need to engage legislators and economic development groups. An outreach plan was developed and implemented to assist teaming planning, as discussed in Section 5.4.1.

The task also included review of the proposed sites to elicit feedback from the technical advisory group on candidate sites for a CCS complex. In addition to the technical advisor meetings, Battelle reviewed potential locations with AEP and its land management staff to understand AEP's land and mineral rights ownership for the selected areas of interest. Battelle met with AEP to discuss the project definition report and potential locations for a stratigraphic test well and developing plans for logging, coring and testing. The AEP supplied land and mineral rights maps were incorporated into the project's geographic information system database. A list of potential locations suitable for a stratigraphic test well was developed. AEP agreed to provide a location for test well drilling in Phase II, subject to due diligence (e.g., considering the site's current use, environmental and permitting factors, and discussions with mineral lease owners).

Desirable Reservoir Geologic Characteristics
>3,000 ft deep
>10,000 ppm TDS
Saline or depleted O&G reservoirs
Few well penetrations
Existing characterization data
Overlain by low permeability caprock
High storage potential
Amenable to monitoring
Low seismicity, faulting

Desirable Surface Characteristics
Low population density
Outside sensitive areas/USDWs
Proximity to major roads, power
Proximity to oil & gas operators
(Collocated with oil/gas production)
Subsurface rights

To strengthen Ohio's position to leverage future research opportunities, an existing 7600 ft deep well on AEP property owned by MFC Drilling, Inc. was investigated to see if it could provide a low cost/low risk piggyback opportunity to address the knowledge gap. The well appears to be suitable for re-entering for the purposes of conducting a geologic investigation. MFC Drilling, Inc. provided a support letter indicating it would be willing to sell the well at a nominal fee. Battelle believes that re-entering the well as-is (i.e., not drilling a sidetrack borehole) could determine the locations of the injection fairways suggested by the brine disposal wells in central Coshocton County. Re-entering the well as-is would be suitable for lower budget projects and useful information about reservoir properties could be obtained via reservoir testing.

The lowest risk and cost would be to conduct logging and reservoir testing activities through the casing, which ends toward the bottom of the lower Copper Ridge. Additional risk and cost would be incurred for characterization below the casing, which would require the additional tasks, such as drilling out the bottom of the casing to run logs and do testing on the open borehole. Conducting these additional tasks, however, is the only way to characterize the Nolichucky and Maryville. Additional records retained by MFC Drilling, Inc. may help clarify some of the risks associated with the monitoring plan by providing a more complete history of the well.

6.3 Commercialization Plan

A preliminary commercialization plan was completed to support the establishment of the CAB-CS complex. The plan included evaluation of the proper organization for moving forward with a real facility, likely costs for carbon storage, and other economic factors. An assessment of readiness of each of the components were completed. A timeline and future goals and objectives are presented in Section 6.4.

Technology Readiness

There are two likely business models that have been proposed by the IEA for industrial CCS in North America that are applicable for the Central Appalachian Basin. One model is CO_2-EOR. The Central Appalachian Basin has large potential storage capacity in its depleted oil and gas fields. Depleted oilfields producing from the Clinton sandstone and Rose Run sandstone in the primary study area have a potential produce an additional 27.5 million barrels (MMbbls) of oil with up to 60.9 MMt of associated CO_2 storage through this option CO_2-enhanced oil recovery (EOR). A depleted oilfield producing from the Clinton sandstone in the secondary selected area has the potential to produce an additional 96 MMbbls with just under 50 MMt of associated CO_2 storage. This option could be very attractive and expedient if some technical hurdles could be overcome to establish a CO_2-EOR industry in the Appalachian Basin. The second model is a large anchor project that would provide infrastructure for an industrial storage hub system.

The technology readiness level of CCS is a complex question. As of this writing, there are 17 currently operating large-scale CCS projects around the world, defined as at least 800,000 metric tons annually from coal-based power plants or at least 400,000 metric tons for other facilities, including 12 in North America (nine in the United States and three in Canada), two in Europe (both Norway), two in the Middle East (one in Saudi Arabia and one in the United Arab Emirates), and one in South America (Brazil) (Global CCS Institute, 2018). Although 20 additional projects are in various stages of implementation (11 in early development, four in advanced development, and five in construction), the latest IPCC assessment (IPCC, 2014) states that tripling or quadrupling the share of zero- or low-carbon technologies, including CCS, is necessary to prevent more than 2 ^{o}C of warming, the stated goal of the United Nations Framework Convention on Climate Change (UNFCCC). Without a mandate to reduce CO_2 emissions or a price on carbon, CCS is cost prohibitive with a few exceptions. As discussed in Section 5, capital costs for capturing CO_2 is the major cost driver. Furthermore, experience in integrating CO_2 capture with transportation and storage for commercial scale operation is very limited. A discussion of technology readiness for the major components of CCS is presented in Table 6-1. The economic analysis / financial modeling indicated that:

- 45Q is expected to spark interest by private investors but more incentives are needed for CAB region
- Investment in transport and storage infrastructure will be critical
- Commercial relationships between capture, transport, and storage operators need to develop
- Public-private risk-sharing and government involvement are required
- Transport and storage costs would be reasonable on a per metric ton basis

A timeline for the expected maturation of the commercial market is presented in Figure 6-2. This figure presents a high-level view and includes some milestones for parallel technology/socio-economic/policy advancements required to enable carbon capture. The Central Appalachian Basin has large potential storage capacity and site selection for a storage complex has been initiated. The recently completed pre-feasibility phase found that geologic storage can be cost effective with recent policy incentives (i.e., 45Q tax credits) capable of covering the cost of transportation and storage. Additional site characterization is necessary to build confidence that the desired injection rates can be sustained in the target storage formations. Aspects of the regulatory framework for geologic storage projects are in place. Specifically, well drilling, disposal operation, and pipeline construction are managed under current regulations. Questions regarding long-term liability and access to mineral rights/pore space, however, remain to be answered..

Pilot projects are the first steps in the maturation of the commercial market. Pilot projects can reduce risk and costs by providing mechanisms to learn through experience, work through legislative and regulatory issues, develop verification protocols, and determine the best business models. A more detailed discussion for specific milestones for the development of the commercial scale storage complex is presented below.

Table 6-1. Technology readiness in the Central Appalachian Basin

Component	Readiness	Comments
Capture	Medium	Low cost capture technology available for high purity industrial sources such as ethanol plants or hydrocarbon cracker facilities. EOR sales and 45Q tax credits could be used to enable deployment. Largest obstacle to deployment at high purity sources is no characterized or demonstrated saline site or EOR industry in the region. Concerning coal power and NGCC plants and many low purity industrial sources, amine-based post-combustion—flue gas treatment using chemical absorption—remains the preferred CO_2 capture technology for the short and medium term (i.e., 2030). Rate guarantees for power generators are also very important for making the financial case for CCS. Commercial scale projects such as Petra Nova and Boundary Dam are lowering capture costs for coal power plants. Adding CCS to new builds in the early development stages improves economic feasibility compared to retrofit options; however, pending siting permits show power generators are switching from coal to natural gas. Pathway to deployment for CCS in the power sector includes innovative technologies, policy incentives, emission limits, grid reliability, and identified storage sites.
Transport	High	Mature technology with feasible routes to connect sources and sinks in the study area. Policies under consideration to further improve outlook for deployment include the "USE IT Act" that would amend the Clean Air Act and other federal laws to expedite permitting for CO_2 pipelines.
Storage	Medium	Prefeasibility study completed. Site selection initiated. The region has a large potential storage capacity. Storage is relatively cost effective and tax incentives could cover the cost of transportation and storage in the economic models. Questions remained to be answered to complete site selection, obtain permits, develop the site, etc. Pilot tests needed to help develop an EOR industry, which would provide additional incentive to deploy capture technologies.

Note: Because regulations and policy are key components to drive CCS implementation, how these issues affect the readiness levels of the technologies are also discussed in the table.

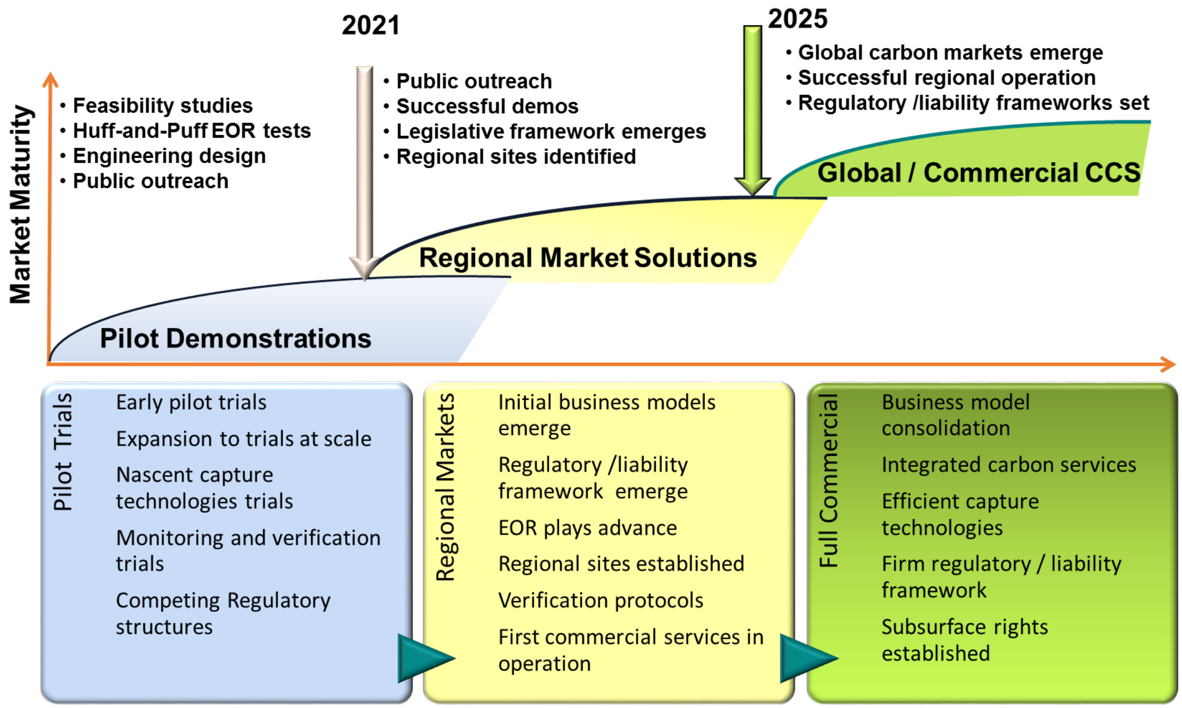

Figure 6-2. Schematic of the expected maturation of the commercial market.

Advancement from prefeasibility to site selection for the storage complex

Additional geological characterization of the selected areas could be accomplished through the installation and monitoring of a new characterization well or through additional characterization of an existing deep well. In addition, 2D and 3D seismic data will be leveraged to add to the analysis. Final site selection will require drilling, sampling, and testing at the candidate CO_2 storage site to confirm injection potential. Testing at the site may consist of drilling, collecting geological samples, and completing a sampling well in the borehole. The borehole may also be used for downhole geophysical, pressure fall-off, hydraulic fracture/pressure shut-in, and various other tests to determine geologic conditions in the area around the borehole and injection rates. The information from testing will be required for the UIC permit application. After completion, the stratigraphic test well may be used for injection or monitoring at the site.

It is expected that funding for the advancement to the feasibility study/site selection will come mainly from government sources, and partially from commercial investment.

- Government sources: NETL, OCDO
- Commercial investment: Utilities that operate coal-fired powerplants; Utilities that operate NGCCs; Industry/Power merchants (e.g., New Steel); High Purity Industrial Sources (e.g., Three Rivers Energy; Shell Cracker Plant, PTTC Cracker Plant); Investment groups (e.g., CB Morris); Brine Disposal Industry/Oil and Gas Operators (e.g., Buckeye Brine, MCF Drilling)

Battelle has recently proposed a project, “Comprehensive Evaluation of Associated CO_2 Storage Potential in Central Appalachian Basin – with a Focus on Utica/Point Pleasant Tight Oil Play”, under Funding Opportunity Announcement 1829. The primary objective of the proposed research is to carry out a comprehensive laboratory experiment, computer modeling and “geo laboratory” field testing-based evaluation of associated CO_2 storage potential in the Central Appalachian Basin – with a focus on the unconventional Utica/Point Pleasant tight oil play. A secondary objective is to perform screening-level assessments of storage associated with CO_2-EOR in residual oil zones (ROZs), stacked reservoirs and fracture-dominated reservoirs in the region. Our focus is on technologies that can help accurately define and characterize associated storage in conjunction with CO_2-EOR, improve model accuracy, understand and interpret reservoir performance, and monitor fate of CO_2 injected within the storage complexes.

Advancement from site selection to pilot demonstration

Site development planning commences. Pilot demonstrations of saline storage and/or EOR are needed to evaluate scaling factors and equipment design. A site or sites will be selected for detailed characterization and site-specific planning, such as siting injection wells, placing above ground equipment and monitoring points, and conducting pipeline routing, will be completed. The economic feasibility of the project will be evaluated.

- A plan for obtaining site access will be finalized. Plans for the detailed characterization phase and the initial development phase will also be finished. The CO_2 capture and transport requirements will be outlined.
- Regulatory and legal issues will continue to be defined, including a permitting plan. Information about preparing UIC permits and other permits will be defined. A legal framework for commercialization will also result from these activities.
- Modeling and risk assessment efforts will work to define site-specific geology, reservoir and plume conditions, and associated risk. A Risk Assessment Mitigation Plan will result from the effort.

At this point in the technology development process, industrial partners interested in operating the technology will be identified. Required funding for these pilots would gradually transition from primarily government sources to commercial partners. As above, it is anticipated that the industrial groups most interested in the storage complex will be oil and gas operators and brine disposal operators; industry looking to leverage tax credits and need a place to put the CO_2; and companies with required targets to reduce their carbon intensity.

Advancement from pilot demonstration to full scale operation

After achieving promising results from the pilot demonstrations, permits will be pursued. At this point, issues of scale-up are expected to be fully resolved. Based on modeling and risk assessment efforts, completion of transport and injection system design, procurement, and construction activities may be initiated. Design of the pipeline transport system will be based on existing codes, standards, and guidelines and includes activities such as conducting pipeline route reconnaissance and determining routes; conducting flow studies and performing calculations to determine pipeline size and pump requirements; preparing permit applications and supporting documents; developing a preliminary construction project schedule; and writing material and equipment specifications for pipe, valves, fittings, flanges, pumps and motors, and the pipeline SCADA system.

Injection system design will draw on experience from CO_2 test wells, brine disposal wells, and CO_2 for EOR (Class II UIC wells). Techniques for drilling, cementing, and completing wells into deep saline reservoirs are well developed in this region. The primary remaining data needs for CO_2 injection relate to methods to characterize the interaction of the CO_2 with the saline reservoir to ensure the confining layer is sufficient to protect USDWs. In addition, the behavior of CO_2 in the reservoir is an important consideration when calculating design parameters, such as achievable injection rate, reservoir capacity, and geomechanical conditions.

Prior to operation, baseline monitoring will be completed to provide a description of pre-injection conditions.

6.4 Path Forward

The CAB-CS project has the potential to be adapted to grow new industries that would greatly benefit the region. Two Selected Areas have been identified for locating potential storage sites near large, diverse group of CO_2 sources in an important industrial area. High purity sources such as ethanol plants could leverage federal tax incentives to deploy CCS either in saline or depleted oil and gas fields. On one hand, there isn't currently infrastructure to transport large amounts of CO_2. On the other hand, Ohio has an oil and gas industry with the resources and knowledge to drill for, produce, and transport oil and gas. Ohio has poor primary and secondary recovery in many of its major oilfields, leaving much original oil in place to be produced via tertiary recovery methods. Ohio could be primed for a viable market for CO_2 for EOR. In summer 2018, Battelle will conduct CO_2 Huff 'n' Puff tests on wells drilled in two major Ohio oilfields, the East Canton Consolidated (produces from the Clinton sandstone in eastern Ohio) and the Morrow Consolidated (produced from the Copper Ridge dolomite in central Ohio), working with Northwood Energy and GeoPetro, respectively. It is expected that these tests will demonstrated the viability of conducting CO_2-EOR in these reservoirs.

The CAB-CS integrated prefeasibility project has garnered a technical team that can provide insight into what would work in Ohio, including providing input on how to work with lawmakers and the oil and gas industry. An anchor CCS project could help build the infrastructure to kickstart a CO_2-EOR industry or CCS storage hub in the Central Appalachian Region. A pilot project at the commercial scale would allow legislative and regulatory frameworks to be developed. Existing regulations and legal decisions regarding oil and gas and disposal wells could provide a framework for CO_2 storage. Other states with legislative frameworks dedicated to CCS can be used as a model for what may work in Ohio. The Ohio EPA also could consider pursuing Class VI primacy in order to streamline the permitting process, provide more local control, and shorten the lead time for facility startup.

A plan for delivering a commercial storage complex by 2025 is presented in Table 6-2. However, because Phase II was not awarded, the focus for the path forward is on research priorities that need to be tackled. At the last meeting of the technical advisors, the following recommendations were discussed:

- In addition to technology innovation, policy innovation is certainly needed. More efforts to educate state legislative leaders on CCS and ensure storage/EOR information is not lost in the noise would be useful, especially considering there will be a new administration. A mechanism for long-term engagement and strategic thinking would be appreciated by legislators. MRCSP could be vehicle for this education. Additional stakeholders to reach out to include the Appalachian Regional Commission, the U.S. Department of Agriculture Rural Development, and the Nature Conservancy.
- A roadmap for the Appalachian Basin is needed. The Appalachian Basin is critical for serious emissions reductions and has untapped potential for increased domestic oil production.
  - To be able to use the 45Q tax credits, 2024 is the deadline to break ground. This means that in a year to a year-and-a-half, an engineering design must be started and site characterization should be done for early adopters.
  - Beyond 45Q, ongoing capture research programs enabling potential gamechangers make it likely that long-term energy sources will come into play once storage is confirmed.

- Storage certainty is needed. Ohio can make use of existing oil and gas data to move forward. The energy industry is still operating under the assumption it will eventually have to capture carbon – even on natural gas if coal is not competitive.
  - One of the large challenges for geocharacterization is geometry of the storage reservoir. Using the large set of available 3-D seismic data and testing in existing deep wells is a good way to get cost-effective data that will provide information to prove storage areas.
  - Testing in the deep (7600 ft) well owned by MFC located at the AEP Conesville Plant would provide vital information on storage flow zones (see Section 6.2).

In addition to the items discussed above, educating the industry and potential CO_2 supply partners about the current state of CCS/CCUS and government incentives such as 45Q tax credits is crucial to securing industry buy-in. As the economic evaluation suggests, the proposed tax credit system can help offset capture costs by about a half in commercial scale coal-fired power plants. This is an even more attractive proposition for chemical and steel companies that produce purer streams of CO_2. This opportunity can also be leveraged to build industry partnerships that can foster innovation in capture technologies which would focus on reducing capture costs.

Table 6-2. Timeline, Milestones, and Performance Targets for a Storage Complex Built for Operation in 2025

<table>
<tr><th>Year</th><th>Storage Complex Milestones</th><th>Performance Targets</th><th>Parallel technology/socio-economic/policy advancements</th></tr>
<tr><td>2018</td><td>Prefeasibility study</td><td>Assessment of technical, socio-economic, scientific, and legislative aspects related to implementation of a CCUS project show proposed project is ready for next phase.</td><td rowspan="7">CCS becomes broadly recognized at the State and local level as beneficial to the economy and environment.
Additional policy incentives for capture are established.
Pre-requisites for CCS deployment in the energy sector are in place*.
National DOE carbon capture program and first-of-a-kind integrated CCS projects continue to lower technical and economic barriers.</td></tr>
<tr><td>2020</td><td>Detailed site characterization</td><td>Sites selected. Outreach program in place</td></tr>
<tr><td>2021</td><td>Execute pilot tests</td><td>Saline and EOR potential validated.
Storage capacity estimates completed.
Industrial partners interested in operating the technology identified.
Class VI permit application submitted.</td></tr>
<tr><td>2023</td><td>Permits for saline storage obtained</td><td>Site ready for development.</td></tr>
<tr><td>2024</td><td>Begin construction of capture component</td><td>Qualify for 45Q tax credit.</td></tr>
<tr><td>2025</td><td>Commercial unit demo.</td><td>Technology commercial start-up.</td></tr>
<tr><td>2025+</td><td>Long-term commercial operating system</td><td>CCS industry is fully kickstarted with new projects following suit.</td></tr>
</table>

*CCS in the energy sector faces additional challenges compared to smaller high purity industrial sources because of the high capture cost - available technologies, emission limits, grid reliability, and proven storage are key enablers.

7. Conclusions

Power generation and industrial processes emit nearly 40 billion metric tons of CO_2 into the global atmosphere each year. DOE's CarbonSAFE initiative, announced in 2016, provides funding for cost-shared projects to determine the feasibility of onshore and offshore carbon storage and identify safe storage locations. Identifying commercial ready storage sites are critical for deployment of advanced capture technologies under development in the U.S. and world-wide. The ultimate objective is to develop commercial-scale geologic storage sites capable of cumulatively storing more than 50 million metric tons of CO_2. The DOE has set a goal of having these sites constructed and permitted by 2025 in time for use by the next generation of cost-effective carbon capture technologies.

Rising CO_2 emissions from power generation and other industrial sources have been implicated as a major driver of climate change. CCS, which has been successfully deployed in a small number of locations, is seen as a promising solution that could help the energy industry slow or halt the rise of CO_2 in the atmosphere.

CCS involves capturing CO_2 generated from combustion of fossil fuels at the source—such as a coal-fired power plant—before it escapes into the atmosphere. CO_2 is then transported to a geologic storage site where it can be used for enhanced oil recovery in depleted oil fields or injected deep into the ground for permanent storage. These methods could reduce CO_2 emissions from power plants and other industrial sources by up to 90%, allow for more oil to be extracted from existing oil fields and make continued use of fossil fuels significantly more sustainable world-side. In a carbon constrained future, commercial carbon storage could become mainstream. However, to have CCS as an option for addressing CO_2 emissions, work needs to be done to identify potential storage sites, characterize the risks of deep geologic injection, and evaluate emerging capture technologies.

7.1 Significance of the Work

The CAB-CS Integrated Prefeasibility Project focused on the identification of early technical and non-technical challenges at potential carbon storage sites, including the formation of a team of industry partners and technical experts to identify and address knowledge gaps. This initiative builds on previous field pilots in the region with the MRCSP and the AEP Mountaineer CCS Product Validation Facility, as well as several research studies for understanding the subsurface storage potential. The project had the following major accomplishments:

- **Learning by doing.** The project team selected primary and secondary sites, conducted social characterization, completed a legal review, and evaluated business cases for CCS deployment, among many other activities.
- **Adding to NETL best practices and tools.** This project team employed recommended best practices, tested the NRAP tools for risk assessment, and used the economic models to developed by NETL to estimate capital and operating costs. Feedback on the tools and models were provided to researchers at NETL and national laboratories as the project worked through the models to identify future improvements.
- **Building the elements of the CCS road map for the Central Appalachian Basin.** While project was not selected for Phase II, the project helped to define future research needs and the results confirm the project would greatly benefit the region. The CO_2 technical analysis showed many diverse CO_2 sources that can be linked via regional pipeline. The sub-basinal analysis demonstrated significant potential geologic storage capacity both in terms of deep saline reservoirs and depleted oil and gas fields. The project definition analysis supported the

feasibility of developing qualified sites within the selected areas for large-scale deployment of CCS. The various economic, regulatory/political/technology, permitting, stakeholder, and liability aspects were incorporated into a plan for developing a CarbonSAFE complex in the Central Appalachian Basin.

7.2 Opportunities and Limitations

Although competition against fossil fuels is increasing, fossil fuels have historically powered much of Ohio's economy and remain a large generator. Coal technologies are also becoming more efficient and clean, such as pulverized coal combustion systems. Natural gas and renewables continue to increase; however, coal will continue to have a large share of the energy portfolio because of its abundance and low cost. As pressure increases over the growing concerns relating to the environmental impacts of unabated CO_2 emissions, the addition of CCS to natural gas plants could be needed. The future for a diversified energy portfolio includes having access to CCS as a technology option. Industrial sources in the CAB-CS study area also have interest in low-carbon solutions.

The commercial market for CCS is emerging and being shaped concurrently within developing technological and socioeconomic frameworks. Much work must be done in a number of spheres - social, political, technical, regulatory, economic and corporate - to realize a future in which CCS technologies are accepted, trusted, and economic technologies. Recent changes to the Federal Tax code could incentivize industry with high purity CO_2 emissions and to jumpstart achievements in the development of a storage complex or associated CO_2 storage with EOR.

The following opportunities and limitations were identified for commercial development:

- **Storage:** Two candidate sites for a carbon storage hub with significant storage potential, evidence of high injectivity, and co-located near depleted oil and gas fields were identified close to a large, diverse group of CO_2 sources. However, site-specific characterization data are needed to determine the extent of high injectivity flow zones. This can be overcome by drilling a characterization well in conjunction with leasing existing 2-D and 3-D seismic data. Characterizing these sites will be applicable to other locations within eastern Ohio, a region that has been extensively drilled but scarcely characterized.
- **Utilization:** Existing oil and gas infrastructure in eastern Ohio can be leveraged to build integrated CCUS projects to reduce capital costs. Ohio could be primed for a viable market for CO_2 for EOR; however, there isn't currently infrastructure to transport large amounts of CO_2 to the oilfields for CO_2-EOR. A project like this could help build the infrastructure by providing a steady supply of CO_2 and financial support.
- **Capture:** Capture costs are a significant limiting factor. The cost of amine scrubber-based technologies to isolate CO_2 from low purity exhaust streams such as those from coal-fired power plants is a major cost driver. This provides an opportunity for research on improved and cheaper techniques for carbon capture, which requires synergy between the government and industry to test and implement new technologies such as membrane-based capture.
- **Regulatory Environment:** The regulatory regime governing CCS projects is not well defined in Ohio. Existing regulations and legal decisions regarding oil and gas and disposal wells could provide a framework for CO_2 storage. Other states can be used as a model for what may work in Ohio in terms of long term liability, economic mechanisms and regulations. Ohio EPA also could consider obtaining UIC Class VI primacy to help streamline the process.

7.3 Recommendations

The CAB-CS Integrated Pre-Feasibility Project initiated the site screening and selection process, gathered social characterization data, undertook a legal review, and developed a financial model specific to the region. The results support the feasibility for development of an integrated CCUS project in the region. Because Phase II of the project- which would have completed the feasibility study and selected potential sites- was not awarded, it will be necessary to pursue other research and development pathways. The following items are recommendations for near term action:

- Take steps to address the research needs identified in Section 6.4 (Path Forward). The CAB-CS project has formed a network of industrial and other CCS stakeholders that can provide insight into what would work in Ohio to assist future efforts such as:
  - Innovative policy development
  - Data collection and analysis to demonstrate storage certainty.
  - DOE/NETL road map development for the Appalachian Basin
- Leverage current R&D efforts funded by the State of Ohio for EOR development (Section 6.4) to help build business cases for CCUS.
- Leverage future R&D efforts. Should the proposal "Comprehensive Evaluation of Associated CO_2 Storage Potential in Central Appalachian Basin – with a Focus on Utica/Point Pleasant Tight Oil Play" under FOA 1829 be awarded (Section 6.3.2), not only would the knowledge gained from the study greatly benefit the region and contribute to any road mapping efforts, the project could be used to enable the pursuit of future OCDO opportunities.
- Include results of these efforts in stakeholder outreach and education activities conducted under the MRCSP.

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Appendix A. Identified Sources (Tiers 1 through 3)

Table A-1. Tier 1 Existing CO_2 point sources in the Central Appalachian Basin. Additional CO_2 sources that are co-located with qualifying sources are also included in this table since they represent additional site-specific opportunities for CO_2 capture. Note that multiple entries for a plant represent different electricity generation units.

Name	Capture Cost ($/tonne of CO_2)	Max. Source Emissions (tonne of CO_2/y)	Facility Type	Ownership	County	State
Bruce Mansfield	$57	6,788,958	Coal	First Energy	Beaver	PA
Bruce Mansfield	$57	6,492,423	Coal	First Energy	Beaver	PA
Bruce Mansfield	$57	6,405,772	Coal	First Energy	Beaver	OH
Cardinal	$57	4,709,901	Coal	Buckeye Power, AEP	Jefferson	OH
Cardinal	$57	4,631,668	Coal	Buckeye Power, AEP	Jefferson	OH
Cardinal	$57	5,005,452	Coal	Buckeye Power, AEP	Jefferson	PA
Conesville	$57	6,471,913	Coal	AEP	Coshocton	PA
Conesville	$57	3,176,778	Coal	AEP	Coshocton	PA
Conesville	$57	2,398,167	Coal	AEP	Coshocton	PA
Gen J M Gavin	$57	10,380,980	Coal	Lightstone Generation	Gallia	PA
Gen J M Gavin	$57	10,692,324	Coal	Lightstone Generation	Gallia	PA
Mitchell	$57	5,476,850	Coal	Appalachian Power	Marshall	OH
Mitchell	$57	5,709,006	Coal	Appalachian Power	Marshall	OH
Mountaineer	$57	8,267,644	Coal	Appalachian Power	Mason	OH
W H Sammis	$57	1,774,108	Coal	First Energy	Jefferson	OH
W H Sammis	$57	4,663,701	Coal	First Energy	Jefferson	OH
W H Sammis	$57	4,721,126	Coal	First Energy	Jefferson	OH

Table A-2. Tier 2 existing CO_2 point sources in the Central Appalachian Basin. Like the Tier 1 sources, additional CO_2 sources that are co-located with qualifying sources are also included in this table since they represent additional site-specific opportunities for CO_2 capture. Note that multiple entries for a plant represent different electricity generation units.

Name	Capture Cost ($/tonne of CO_2)	Max. Source Emissions (tonne of CO_2/y)	Facility Type	Ownership	County	State
Washington Works	$25	374,204	Chemicals	Chemours	Wood	WV
Cheswick	$57	4,036,545	Coal	NRG Energy	Allegheny	PA
Conemaugh	$57	6,406,182	Coal	Public Service Enterprise, NRG Energy, Talen Energy, UGI, Arcllight Energy	Indiana	PA
Conemaugh	$57	6,381,309	Coal	Public Service Enterprise, NRG Energy, Talen Energy, UGI, Arcllight Energy	Indiana	PA
Dresden	$72	827,698	NGCC	AEP	Muskingum	OH
Dresden	$72	829,743	NGCC	AEP	Muskingum	OH
Dynegy Washington II	$72	1,034,585	NGCC	Dynegy	Washington	OH
Dynegy Washington II	$72	1,028,026	NGCC	Dynegy	Washington	OH
Fort Martin	$57	4,029,595	Coal	First Energy	Monongalia	WV
Fort Martin	$57	4,005,464	Coal	First Energy	Monongalia	WV
Globe Metallurgical	$57	354,388	Metal	Globe Specialty Metals	Washington	OH
Harrison	$57	5,265,263	Coal	First Energy	Harrison	WV
Harrison	$57	4,770,784	Coal	First Energy	Harrison	WV
Harrison	$57	4,534,801	Coal	First Energy	Harrison	WV
Homer City	$57	4,934,067	Coal	Homer City Holdings	Indiana	PA
Homer City	$57	4,499,293	Coal	Homer City Holdings	Indiana	PA

Table A-2 (continued). Tier 2 existing CO_2 point sources in the Central Appalachian Basin. Like the Tier 1 sources, additional CO_2 sources that are co-located with qualifying sources are also included in this table since they represent additional site-specific opportunities for CO_2 capture. Note that multiple entries for a plant represent different electricity generation units.

Name	Capture Cost ($/tonne of CO_2)	Max. Source Emissions (tonne of CO_2/y)	Facility Type	Ownership	County	State
Homer City	$57	4,469,923	Coal	Homer City Holdings	Indiana	PA
John E Amos	$57	8,365,026	Coal	Appalachian Power	Putnam	WV
John E Amos	$57	5,853,064	Coal	Appalachian Power	Putnam	WV
John E Amos	$57	5,811,157	Coal	Appalachian Power	Putnam	WV
Keystone	$57	6,706,622	Coal	Public Service Enterprise Group, NRG Energy, Arclight Energy Partners, Talen Energy	Armstrong	PA
Keystone	$57	6,578,680	Coal	Public Service Enterprise Group, NRG Energy, Arclight Energy Partners, Talen Energy	Armstrong	PA
Kraton Polymers	$25	332,309	Other	Kraton Polymers US	Washington	OH
Kraton Polymers	$25	332,309	Other	Kraton Polymers US	Washington	OH
Kyger Creek	$57	1,589,594	NGCC	Ohio Valley Electric	Gallia	OH
Kyger Creek	$57	1,525,259	NGCC	Ohio Valley Electric	Gallia	OH
Kyger Creek	$57	1,500,590	NGCC	Ohio Valley Electric	Gallia	OH
Kyger Creek	$57	1,501,525	NGCC	Ohio Valley Electric	Gallia	OH
Kyger Creek	$57	1,578,095	NGCC	Ohio Valley Electric	Gallia	OH
Longview Power	$57	3,749,813	Coal	Longview Intermediate Holdings	Monongalia	WV
Canton Refinery	$118	556,018	Petroleum	Marathon Petroleum	Stark	OH
Miami Fort	$57	4,236,032	Coal	Dynegy; Dayton Power and Light	Hamilton	OH

Table A-2 (continued). Tier 2 existing CO_2 point sources in the Central Appalachian Basin. Like the Tier 1 sources, additional CO_2 sources that are co-located with qualifying sources are also included in this table since they represent additional site-specific opportunities for CO_2 capture. Note that multiple entries for a plant represent different electricity generation units.

Name	Capture Cost ($/tonne of CO_2)	Max. Source Emissions (tonne of CO_2/y)	Facility Type	Ownership	County	State
Miami Fort	$57	3,783,073	Coal	Dynegy; Dayton Power and Light	Hamilton	OH
Middletown Works	$99	5,263,690	Steel	AK Steel	Butler	OH
Mountain State Carbon	$72	429,069	Coke	Mountain State Carbon	Brooke	WV
Orrville	$57	483,393	Coal	City of Orrville	Wayne	OH
Orrville	$57	8,692	Coal	City of Orrville	Wayne	OH
Orrville	$57	180,564	Coal	City of Orrville	Wayne	OH
Orrville	$57	202,246	Coal	City of Orrville	Wayne	OH
P H Glatfelter Co. - Chillicothe Facility	$57	277,122	Paper	PH Glatfelter	Ross	OH
P H Glatfelter Co. - Chillicothe Facility	$57	445,495	Paper	PH Glatfelter	Ross	OH
Pleasants	$57	5,000,270	Coal	First Energy	Pleasants	WV
Pleasants	$57	4,957,717	Coal	First Energy	Pleasants	WV
Seward	$57	3,754,529	Coal	Seward Generation	Indiana	PA
Three Rivers Energy	$30	78,703	Ethanol	Three Rivers Energy	Coshocton	OH
Timken, Canton	$99	431,435	Steel	Timken	Stark	OH
Edgar Thomson	$99	3,641,738	Steel	US Steel Corp.	Allegheny	PA
W H Zimmer	$57	9,671,912	Coal	Dayton Power and Light; Dynegy	Clermont	OH
Waterford Plant	$72	858,276	NGCC	Lightstone Gen	Washington	OH
Waterford Plant	$72	861,522	NGCC	Lightstone Gen	Washington	OH
Waterford Plant	$72	865,797	NGCC	Lightstone Gen	Washington	OH

Table A-3. Tier 3 existing CO_2 point sources in the Central Appalachian Basin.

Name	Capture Cost ($/tonne of CO_2)	Max. Source Emissions (tonne of CO_2/y)	Ownership	County	State
AK Steel Butler	$99	314,191	AK Steel Corp.	Butler	PA
Ashtabula	$57	980,644	First Energy	Ashtabula	OH
Avon Lake	$57	551,809	NRG Energy	Lorain	OH
Axiall Corporation Natrium Plant	$27	977,974	Axiall Corp.	Marshall	WV
Carmeuse	$127	494,247	Carmeuse Lime	Lake	OH
Carmeuse Lime and Stone	$127	560,820	Carmeuse Lime	Seneca	OH
Carmeuse Lime and Stone	$127	323,392	Carmeuse Lime	Sandusky	OH
Eastlake	$57	691,685	First Energy	Lake	OH
Fremont	$72	832,803	American Municipal Power	Sandusky	OH
Grant Town Power Plant	$57	945,618	American Bituminous Power Partners	Marion	WV
Guardian Lima	$30	87,694	Guardian Lima	Allen	OH
Haverhill North Coke	$118	1,086,647	SunCoke Energy	Scioto	OH
Huron Lime	$127	381,142	Mississippi Lime	Erie	OH
Lake Shore	$57	878,310	First Energy	Cuyahoga	OH
Martin Marietta Lime and Stone	$127	1,447,273	Martin Marietta Materials	Sandusky	OH
Middletown Operations	$118	409,110	SunCoke Energy	Butler	OH
Morgantown	$57	626,244	RCM Morgantown Power Ltd (35%); EIF Morgantown Holdings (50%); Calypso Energy Holdings (15%);	Monongalia	WV
POET Biorefining - Leipsic	$30	103,790	Poet	Putnam	OH
POET Biorefining - Fostoria	$30	99,848	Poet (50%);	Seneca	OH
POET Biorefining - Marion	$30	107,541	Poet (50%);	Marion	OH

Table A-3 (continued). Tier 3 existing CO_2 point sources in the Central Appalachian Basin.

Name	Capture Cost ($/tonne of CO_2)	Max. Source Emissions (tonne of CO_2/y)	Ownership	County	State
Praxair	$118	444,338	Bayer Group	Kanawha	WV
Scrubgrass	$57	1,013,447	Calypso Energy Holdings (70%); Aspen Scrubgrass Participant/Olympus Power (30%);	Venango	PA
Clairton Coke	$99	684,288	Us Steel Corp.	Allegheny	PA
Irvin Works	$99	374,306	US Steel Corp.	Allegheny	PA
Bloomingburg	$30	171,233	Valero Energy Corp	Fayette	OH
WVA Manufacturing	$99	514,612	Dow Corning (49%); Globe Specialty Metals (51%);	Fayette	WV

Table A-4. Potential emission sources in Ohio for facilities with large potential emissions (greater than 300,000 tonnes of CO_2 per year) that are currently engaged in the permitting process with the State of Ohio Public Siting Board.

Facility Name	Capture Cost ($/tonne of CO_2)	Potential CO_2 Emissions (tpy))	Electrical Output (MW_{Net})	Technology	Permitting Status	County
Tier 1						
Harrison	$72	3,504,891	1100	NGCC	Submitted	Harrison
Carroll	$72	2,230,385	700	NGCC	Under construction	Carroll
Guernsey	$72	5,273,268	1655	NGCC	Pending	Guernsey
South Field	$72	3,504,891	1100	NGCC	Approved	Columbiana
Rolling Hills Conversion Project	$72	4,505,378	1414	NGCC	Under construction	Vinton
Tier 2						
Trumbull	$72	2,995,089	940	NGCC	Pending	Trumbull
Clean Energy Future-Lordstown	$72	2,549,012	800	NGCC	Approved	Trumbull
Lima Energy IGCC*	$108	2,469,355	775	IGCC	Construction activities on hold	Allen
Tier 3						
Oregon	$72	3,042,883	955	NGCC	Pending	Lucas
Middletown	$72	1,624,995	510	NGCC	Under construction	Butler
FDS Coke Plant	$72	1,700,001	--	Coking Plant	Under construction	Lucas

*Cost of CO_2 capture was derived from the Integrated Environmental Assessment Model v9.5.

Appendix B. Task 5 Milestone on the Central Appalachian Basin CarbonSAFE Integrated Pre-Feasibility Project: Workplan for the next Phase of CAB-CS Complex Development

This file has been prepared to describe the plan for the next phase of CAB-CS complex development (Phase II). The main components for Phase II are listed below to help guide planning for future activities.

1.0 – Project Management and Planning

Project management and planning includes the necessary activities to ensure coordination and planning of the project with DOE/NETL and other project participants. These activities include, but are not limited to, the monitoring and controlling of project scope, cost, schedule, and risk, and the submission and approval of required National Environmental Policy Act (NEPA) documentation. The Data Management Plan will be updated and maintained.

1.1 - Update Project Management Plan. The project management plan and data management plan will be revised and updated as needed in Phase II.

1.2 - Project Management. The management will provide oversight of schedule, budget, milestones, issues, and interactions with project managers and sponsors. The project manager will coordinate team meeting and technical advisory committee meetings. Specific roles and responsibilities for team members will be defined and tracked.

1.3 - Progress Reporting. The project manager will ensure all technical reports are submitted on a timely basis and will oversee contracting procedures and mechanisms required for acquiring the services of all entities involved in the project. This will include quarterly progress reports, continuation applications, and informal updates to DOE project manager.

2.0 - Storage Complex Subsurface Characterization

The objective is to perform initial characterization of the storage complex, including drilling of a stratigraphic test well, and develop comprehensive datasets of formation characteristics to determine the suitability of the potential geologic storage sites. Subsurface mapping, numerical three-dimensional (3D) static earth models, and capacity estimates of the region performed in Phase I have narrowed down potential storage areas (Battelle, 2017a). A conceptual geologic model of the deep, saline reservoir complex from the Knox unconformity surface (top of the Beekmantown dolomite) to the Precambrian unconformity surface (base of the basal Cambrian sandstone) was developed using existing data. In Phase II, additional data will be collected and analyzed for potential stacked and combined reservoir complexes including the Rose Run sandstone, vugular lower Copper Ridge dolomite, vugular/paleokarst Maryville formation, and basal Cambrian sandstone within selected areas. Land use and land and mineral rights ownership are the key criteria for selecting the stratigraphic test well location within the selected areas; well location is being determined in Phase I.

2.1 - Identify and evaluate existing data. Additional existing data not collected under Phase I of this project that can be used to refine the site analyses will be identified, acquired, and evaluated to support site development activities in Phase II. Data may include, but is not limited to, existing 2-D and 3-D seismic data, Ohio Seismic Network (OhioSeis) data, advanced wireline logs collected at future piggyback wells conducted under the MRCSP program, produced water chemistry data from oil and gas production wells, and groundwater monitoring data from AEP. A characterization workplan for drilling the stratigraphic test well, data collection, and analysis will be completed based on the results of this evaluation.

2.2 - Drill and characterize test well. New datasets will be obtained to characterize the storage complex and to validate existing data. This shall encompass all activities required to permit, drill and characterize the stratigraphic test well (the exact location is being determined in Phase I). With a depth of up to approximately 9,200 feet, the stratigraphic test well will target the Cambrian-Ordovician storage complex and overlying Ordovician caprock will be drilled to the Precambrian Basement as part of Phase II. The wellbore will be used to facilitate the investigation of site-specific into geologic, geophysical, geochemical and geomechanical parameters. Methods of investigation will include mudlogging, gas detection, basic wireline logging, and sonic logging (to tie in leased 2-D and 3-D seismic data) over the entire interval, advanced wireline logging (including borehole imaging and nuclear magnetic resonance logging) over the interval of interest (i.e., the primary caprock through storage complex), flow-meter testing to identify flow zones within the storage complex, reservoir testing and fluid sampling, and performing a vertical seismic profile (VSP) survey. Whole core and sidewall cores will also be collected from reservoir and caprock formations. Core and other geologic materials will be provided to the NETL core repository. Data collected will be used in sequent tasks for additional geological characterization of geological and reservoir parameters needed to define storage conditions.

2.3 - Analyze data sets. Datasets will be analyzed and processed for use in sequent tasks, including 3.0 (Storage Complex Modeling), 6.0 (Conduct Risk Assessment and Provide Mitigation Strategies), 7.0 (Frame the Site Development Plan), and 8.0 (Evaluate Economic Feasibility). The results of this subsurface data analysis will be summarized into a report and used to define viable storage candidates.

2.4 - Update Databases. Project databases used to describe the reservoir framework will be updated with the raw and processed datasets resulting from this and sequent tasks according to the process outlined in the Data Management Plan. This will include uploading of all non-confidential raw and processed datasets to the DOE's Energy Data Exchange (EDX) system.

3.0 - Storage Complex Modeling

The objective is to refine storage complex models and improve simulation's predictability of storage processes and risk. Reservoir models were developed from the geological data obtained in Phase I and ported to reservoir simulations to evaluate the feasibility and logistics of injecting 50 million metric tons CO_2 into the reservoir zones of Selected Area B and Selected Area A (Battelle, 2017b). The Computer Modelling Group, Ltd. (CMG) compositional reservoir simulator GEM was used to run the simulations, which provided insights on the mass of CO_2 that can be injected per well under given constraints. The models will be updated with and calibrated to match the information obtained in Task 2 to assess the lateral and areal extent of CO_2 plumes and pressure buildup and delineate the area of review (AoR). The model outputs will also be inputs for risk analysis using NRAP tools.

3.1 - Refine Static Model. The static earth model (SEM) of the study area, created by Battelle as part of Phase I of this project and previous efforts, will be updated as needed. The SEM is a model of the geologic conditions of the reservoir and associated caprock formations. The seismic data leased as part of Task 2.1 as well as the information gathered from the stratigraphic test well program will be used to refine the SEM.

3.2 - Refine Dynamic Model. The dynamic model, created by Battelle as part of Phase I of this project, will be updated using data collected under 2.0. The dynamic model provides the basis for evaluating plume size and development during the injection program, and includes the resulting pressure and CO_2 concentrations over time. Field specific data gathered under 2.0 will be used to update the reservoir model (structural features, porosity/permeability distribution, distinct geological features, geo-mechanical properties, fluid saturations, relative permeability and fractional flow curves, capillary pressure, pressure and temperature gradients), the fluid model (oil-water and gas-oil contacts, brine density and composition), and the well model (well placement, perforation depths, injection schedule, tubing, and casing data). The dynamic model will provide information needed for sequent tasks including 6.0 (assess risk and develop mitigation strategies), 7.0 (complete site selection and determine pore space requirements), and 8.0 (evaluate economic feasibility). A topical report encompassing the static and dynamic modeling efforts will be prepared.

3.3 - Provide Outputs for National Risk Assessment Protocol (NRAP) Tools Validation. The outputs of the static earth model and dynamic model will be provided to the contracted National Laboratories (Federally Funded Research and Development Centers [FFRDCs]) for validating NRAP tools as well as delineating AoR. During Phase I of the project, the NRAP models were used to define an AoR using the Integrated Assessment Model (IAM) and to determine potential leakage risks at existing wellbores using the Wellbore Leakage Model. Phase II will include a more specific application of the NRAP tools to help define an effective monitoring program, apply a specific permeability value to wellbore integrity ratings, determine the applicability of the tools to the permitting process, and outline a workflow for future phases.

4.0 - Public Outreach

The objective is to support the successful implementation of the proposed CCS project through good/effective working relationships with the involved communities. The Phase I outreach objectives include: developing insights to characterize the identified communities, identifying initial stakeholders, identifying the preliminary public perceptions of CCS, identifying and articulating potential project benefits for the identified communities, reviewing potential legal, regulatory, and other non-technical hurdles for the project and implement initial outreach actions to address them. The preliminary social characterization and public outreach plan completed for Phase I will be used a starting point for the Phase II public outreach program. The next phase of the project will further characterize the short list of identified communities with regards to natural resources, economic drivers, historic environmental and industrial development, and other characteristics; plan the initial outreach to support key events such as site screening, selection, and characterization, permitting; and develop a Phase III outreach plan.

4.1 - Define goals and activities. The goals and activities of the public outreach plan for the project developed in Phase I will be updated under this task. This will result in a list of entities that will need to be engaged on the Outreach Team (4.2), will provide the information needed to assess stakeholders and social climate (4.3), and will provide the goals needed as a basis for updating the Public Outreach Plan (4.4).

4.2 - Establish Outreach Team. The public outreach team that will engage affected communities to foster project acceptance will be established under this task. Similar to Phase I, the public outreach team will be led by Battelle, Wade, LLC, and Vorys Advisors, and will engage project partners and the technical advisory committee for input. The will build on the public outreach planning conducted as part of Phase I and will involve garnering the support of potential CO_2 sources, pipeline entities and corridors, community leaders (e.g., state and local representatives, local business leaders, etc.), and other entities associated with the storage site(s).

4.3 - Assess Stakeholders and Social Climate. Building on Phase I analysis, a more detailed analysis of the stakeholders and their perceptions of the CAB-CS project will be conducted. As the specific information of key elements (e.g., CO_2 sources, transportation corridors, and storage sites) are determined, this analysis will consider policy, community benefits, and consultation opportunities to help build stakeholder acceptance for the project. Ultimately, this will lead to development of a Public Outreach Plan under 4.4.

4.4 - Update Public Outreach Plan. The Public Outreach Plan will be updated and the Outreach Program will be implemented under this task. The details of the Outreach Program will be developed under Tasks 4.1 through 4.3 and will likely involve the development of fact sheets and other communication materials, engagement with stakeholders, convening of meetings that include stakeholders and technical experts from the project team, and other communications and engagement activities. This will also include initial planning for the steps that would need to be taken as part of Phase III of the Project.

5.0 - Regulatory Issues Analysis

The objective is to define regulatory requirements that may affect siting of the CAB-CS facility. The list of permits that may be required for the CAB-CS project was developed under Phase I. The main permit associated with the facility will be a Class VI UIC injection permit. The evaluation will focus on well classification, corrective action, injection pressure, containment mechanisms and liability. The project will benefit from a large amount of characterization performed in the region by MRCSP/Ohio Coal Development Office and piggyback testing in brine disposal wells. Additional existing regulations on oil and gas drilling, pipelines, and construction would apply to the project. Many permits require significant background information, testing, modeling, and design. Regulatory entities will be contacted regarding data needs and steps involved in the permitting process. Overall, the regulatory process may take several years to complete so it will require coordination with other project activities.

5.1 - Identify application regulations and permits. All appropriate regulations and permits required for an Underground Injection Control (UIC) Class VI Permit in Ohio will be identified under this task. This work will include identifying all federal, state, and (if applicable) local permits required for a Class VI injection well as well as other federal, state, and local permits required for implementing a CCS project.

5.2 - Develop plan to obtain UIC permits. A plan to obtain all Class VI permits identified in 5.1 will be developed under this task. A framework that will include permit application forms, permitting organization contacts, processing requirements and timing, associated fees, and a summary of information needed for a successful application will be a deliverable for this task.

5.3 - Develop plans to obtain other permits. A plan to obtain all other permits identified in 5.1 will be developed under this task. A framework that will include permit application forms, permitting organization contacts, processing requirements and timing, associated fees, and a summary of information needed for a successful application will be a deliverable for this task.

6.0 - Risk Assessment and Mitigation Strategies

The objective is to conduct a risk assessment to identify potential technical and non-technical (e.g., legal and public acceptance) constraints that would prevent potential candidate storage reservoirs with the storage complex from serving as commercial sites and to provide a mitigation plan. In Phase I, Battelle is creating a Risk Assessment and Management Plan (RAMP) that encompasses both technical and non-technical risks for a commercial-scale storage site in the 2025-time frame. The RAMP will be revised using new inputs from the risk identification, characterization and ranking performed in Phase II. NRAP tools will be used to assist in evaluating the subsurface containment system. Future phases also will examine possible solutions for gaining legal clarity and addressing public acceptance, by building on existing statutes and regulations, as well as relevant Supreme Court of Ohio cases.

6.1 - Address Physical Risks / NRAP Tool Validation. During Phase I of the project, the NRAP models were used to define an AoR using the Integrated Assessment Model (IAM) and to determine potential leakage risks at existing wellbores using the Wellbore Leakage Model. Phase II will include a more specific application of the NRAP tools to help define an effective monitoring program, apply a specific permeability value to wellbore integrity ratings, determine the applicability of the tools to the permitting process, and outline a workflow to use the NRAP tools in future phases.

6.2 - Address challenges in legal/regulatory frameworks for commercialization. Any gaps in regulations or permitting requirements that, if addressed, would lead to a more viable CCS project in the study area(s) will be identified under this task. This will involve refining the understanding of existing state and federal regulations and legal requirements for the selected site(s). A Legal and Regulatory Analysis Report will be prepared in two parts: Part 1- Legislative Approaches to liability and addressing property rights for geologic storage: Model Laws and Other State Approaches; and Part II - Recommendations for Legislation to Promote and Regulate CCS: Regulatory mechanisms.

6.3 - Finalize approach to address liability. A final approach to address legal liability will be addressed under this task. This will involve example language for a comprehensive new sequestration statute (and/or amendments to existing statutes) to address legal and regulatory gaps. This will be sample statutes based on research of similar options provided in the other states.

7.0 - Site Development Plan

The objective is to create an initial site development plan by completing the site suitability analysis initiated in Phase I, incorporating the results of Tasks 1-6 and 8, and prioritizing potential sites for detailed site characterization. This will entail looking at infrastructure needs, AoR requirements, surface access, and pore space ownership and the development of plans needed to advance the project into the next Phase. The task will build on the project team established in Phase I.

7.1 - Complete Site Selection. The selection of storage site(s) will be completed under this task. Phase I identified two selected areas within the larger regional CAB-CS study area using existing data and analyses. Phase II will complete the selection process by identifying and characterizing a specific storage site, including locations for the injections wells and monitoring points. Site surface mapping will be finalized and maps identifying environmental factors and other sensitive areas will be finalized under this task.

7.2 - Obtain landowner agreements for site access and pore space use. A plan for obtaining landowner agreements for site access and pore space use will be developed under this task. Landowner agreements for site access will be obtained for locations where planned injection wells or monitoring points will be installed. Landowner agreements to acquire pore space usage rights will be obtained for the entire area covered by the modeled plume area as determined by the refined dynamic model developed under 3.2.

7.3 - Prepare Initial Development Phase Plan. An initial Development Phase Project Plan will be developed under this task. Under this task, the selected site(s) will also be evaluated for continuation to additional phases, per DOE/NETL (2017). This evaluation will demonstrate whether the selected site(s) has (1) an effective public outreach plan, (2) a plan for wells that meets all regulatory and permitting requirements, (3) a viable storage reservoir, (4) modeling results that suggest a viable storage site, and (5) an effective site development plan. This will include updated information about storage resource calculations, risk assessments, initial injection scenarios, infrastructure needs, monitoring and verification plans, operational and mitigation plans, and the Public Outreach Plan. The will also include an accounting of the additional information required to advance the site to development.

7.4 - Prepare Detailed Characterization Phase Plan. A detailed Characterization Phase Project Plan will be developed for implementation in Phase III. Per DOE/NETL (2017), the plan will include the following:

- Detailed processes for updating the public outreach plan with specific information about citizens' concerns about the effects of project activities, additional stakeholder interest, and incorporating permitting, installation/construction, and CO_2 injection into the Public Outreach Plan.
- Acquiring, analyzing, and integrating new characterization data, including newly acquired 2-D and 3-D seismic data, geophysical data from test wells, and data to establish reservoir conditions prior to injection.
- Updating reservoir models with data collected during the Detailed Characterization Phase.
- Gathering site characterization data needed to support permitting activities.

8.0 - Economic Feasibility

The objective is to evaluate the economic feasibility of the CAB-CS complex. The CAB-CS conceptual model involves two injection wells, each capable of injecting approximately 900,000 metric tons CO_2 per year (1.8 million metric tons CO_2 per year combined) at full capacity (Battelle, 2017b). This will also include development of a CO_2 management strategy to ensure the reliability of the CO_2 source. This will build on the Phase I economic assessment, CO_2 source assessment, and CO_2 management strategy for potential CO_2 sources, volumes, and transportation methods in relation to the subsurface CO_2 injection and monitoring system. Candidate sites with the most favorable economics will be prioritized for detailed site characterization (Battelle, 2017b; 2017c). Phase I is developing a commercialization plan for delivering a commercial CCS complex by 2025, including construction, permitting, land acquisition, carbon capture, and other aspects, as well as the timeline and major milestones. The commercialization plan will be updated using Phase II research results.

8.1 - CO_2 Capture Planning (Source & Transportation Requirements). When the specific site(s) and source(s) are identified, CO_2 source capture requirements will be investigated, and a capture plan will be finalized. In addition, the SimCCS pipeline routing software developed by Los Alamos National Laboratory (LANL) will be used to finalize CO_2 transportation (pipeline) requirements. The Phase I model will be refined by LANL (working with Battelle) to account for site specific factors like environmentally sensitive areas and other sensitive areas. A CO_2 pipeline feasibility study for the proposed regional CO_2 storage facility and associated pipeline will be completed, including:

development of a pipeline route selection methodology; evaluation of potential pipeline routes to proposed storage locations within the Central Appalachian Basin based on publicly available information and industry knowledge; identification of all major permit and regulatory requirements and regulatory gaps relevant to the constriction, ownership, and operation of the pipeline system; identification of major environmental considerations for the potential pipeline routes to potential storage areas within the Central Appalachian Basin; development of a preliminary design basis for the pipeline system configuration; development of a capital and operating cost methodology to be used in evaluating each of the pipeline system routes; and development of a preliminary capital and operating cost model to estimate the net present value economics of the potential pipeline system routes based on the CO_2 specification provided.

8.2 - Update Preliminary Cost Estimates for CCS complex. More accurate costs for developing a CCS complex in the CAB-CS region under this task. Phase I of this project involved using the DOE/NETL saline storage model to provide a general basis for costs of a CCS project. Phase II will refine this analysis with site-specific data that consider more detailed economic information. In addition, the effect of CO_2-enhanced oil recovery (CO_2-EOR) in helping to pay for infrastructure needed for the CCS project will also be investigated. Results from the Phase 2 OCDO funded *CO_2 Utilization for EOR and Geologic Storage in Ohio* study (period of performance of June 2016 through February 2019) that includes field injectivity testing and economic studies, will be used for the analysis.

8.3 - Update Commercialization Plan. The Commercialization Plan that provides updated information about the path to commercialization by 2025 will be updated at the conclusion of Phase II. In addition, additional revenue from beneficial use of CO_2 for CO_2-EOR will be accounted for in this task.

References

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Battelle. (2017b). Central Appalachian Basin CarbonSAFE Integrated Pre-Feasibility Project Task 4: Project Definition Report under OCDO Grant/Agreement D-17-02 and DOE Project DE-FE0029466, 89 p. December.

Battelle. (2017c). Central Appalachian Basin CarbonSAFE Integrated Pre-Feasibility Project Task 2: CO_2 Source Assessment Topical Report under OCDO Grant/Agreement D-17-02 and DOE Project DE-FE0029466, 38 p. October.

DOE/NETL. (2017). Best Practices: Site Screening, Site Selection, and Site Characterization for Geologic Storage Projects, DOE/NETL-2017/1844.

Central Appalachian Basin CarbonSAFE Integrated Pre-Feasibility Project

Attachment 1 - National Risk Assessment Partnership (NRAP) Assessment

Assessment of the Area of Review and Leakage Impact using the NRAP-IAM-CS, Central Appalachian Basin CarbonSAFE Integrated Prefeasibility Project

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Overview

1.0 Organization
2.0 Risk-Based Approach for Determining the Area of Review (AoR)
3.0 Critical Pressure Based AoR
4.0 Assessment of Leakage Impacts from Known Legacy Well Locations
5.0 Summary and Conclusions
6.0 Recommendations

Background

U.S. Environmental Protection Agency's (EPA's) Class VI regulations require owners or operators of carbon storage projects to determine an Area of Review (AoR) representative of project risk to underground sources of drinking water (USDWs). The AoR is an estimate of the region potentially impacted by the carbon dioxide (CO_2) injection and is used to develop monitoring plans to ensure protection of USDWs. Estimates of the AoR need to account for the physical and chemical properties of all phases of the injected carbon dioxide stream, are based on available site characterization, monitoring, and operational data, and are to be made with computational models (40 CFR 146.84). Permitting also requires an understanding of the leakage risks from leakage pathways, such as wells and/or faults connecting the storage reservoir with any overlying underground sources of drinking water (USDWs). EPA's Class VI Rule requires groundwater geochemistry monitoring above the lowermost confining zone overlying the storage reservoir to detect changes in aqueous geochemistry resulting from fluid leakage out of the injection zone [40CFR 146.90(d)] (EPA, 2012).

The NRAP-IAM-CS is a science-based toolset developed by the U.S. Department of Energy (DOE) for quantitative risk assessment of geologic sequestration of CO_2 (Pawar et al., 2016). The toolset adopts a stochastic approach in which predictions address uncertainties in storage reservoirs, leakage scenarios, and shallow groundwater impacts. It is derived from detailed physics and chemistry simulation results that are used to train more computationally efficient models, referred to here as reduced-order models (ROMs), for each component of the system. These tools can be used to help regulators and operators define the AoR and better understand the expected sizes and longevity of changes in water quality caused by CO_2 and brine leakage from a storage reservoir into drinking water aquifers.

The EPA defines the AoR as the maximum extent of the separate-phase CO_2 plume or the pressure front over the lifetime of the project as measured by numerical model simulations. Generally, the maximum pressure front defines the AoR because it is larger than the supercritical CO_2 plume. The AoR is often delineated by the area within which the maximum pressure buildup is above that needed to move the reservoir fluids through an open wellbore (U.S. EPA, 2013). This approach is conservative and assumes that any leakage will impact USDW quality regardless of the magnitude and duration of the leak.

Wells are considered to be high-risk pathways for fluid leakage from geologic CO_2 storage reservoirs because breaches in this engineered system have the potential to connect the reservoir to drinking water resources and the atmosphere. Well integrity is often difficult to measure due to a lack of well data such as permeability of the annular material between the outermost well casing and the borehole wall, a potential avenue for upward fluid migration. For such cases, the NRAP-IAM-CS can be used to evaluate the probability of CO_2 and brine leakage and its impact on drinking water quality from known well locations using default permeability distributions based on oil and gas wells in the Alberta and Gulf Coast basins and the greenfield FutureGen Site.

One objective of the Central Appalachian Basin CarbonSAFE Integrated Prefeasibility Project is to test and validate NRAP tools using real-world data to improve future iterations of these tools. The results of the modeling efforts for this project found minimal risks of CO_2 leakage for illustrative sites in both the primary selected area (Area B) and the secondary selected area (Area A). The reader should note that slight differences in the results are not significant enough to distinguish the two sites in terms of site safety, and there are a number of other factors are considered for site selection. Ultimately, the main takeaway from this effort is that both the primary and secondary selected areas have a low risk of leakage of CO_2 from legacy wellbores. The following factors should also be considered:

- In this effort, an open wellbore model is used for the NRAP-IAM-CS to define the AoR. Once the AoR was defined, cemented wellbores were used to quantify risk.
- So far, the NRAP-IAM-CS only allows for the modeling of unconfined carbonate aquifers while the primary aquifers at the storage sites are either clastic bedrock aquifers or alluvial aquifers.
- Cement permeability values for the wellbore leakage models are based on permeability distributions from other models, not site-specific data.
- Legacy wellbores plotted for both areas include wells known to penetrate the caprock and/or storage reservoir and wells with unknown depths. Most legacy wellbores at both the primary and secondary selected sites have unknown depths and are likely much shallower than the caprock or storage reservoir based on the age of the well, meaning the actual risk posed by these wells could be further reduced in future phases with additional site investigation.

1.0 Organization

This section discusses the use of the NRAP-IAM-CS model to estimate the AoR and the impact of leakage through legacy wells to overlying drinking waters for Sites A and B, two illustrative saline reservoir storage sites evaluated as part of the Central Appalachian Basin CarbonSAFE Integrated Prefeasibility Project. The report is organized into the following sections:

- Section 2.0 presents a risk-based AoR calculated using the NRAP-IAM-CS tool based on leakage impacts to groundwater quality in a shallow drinking water aquifer overlying the storage reservoir from hypothetical open wells;
- Section 3.0 presents an AoR calculated using the U.S. EPA suggested critical pressure method;
- Section 4.0 presents an assessment of leakage impacts to groundwater quality in a shallow drinking water aquifer overlying the storage reservoir from known legacy wells in the AoR calculated using the NRAP-IAM-CS tool;
- Section 5.0 summarizes the results and conclusions; and
- Section 6.0 provides recommendations for future iterations of the NRAP tools.

2.0 Risk-Based Approach for Determining the Area of Review (AoR)

The risk-based AoR calculated using the NRAP-IAM-CS is the area where CO_2 or brine leakage from a hypothetical open (i.e., uncemented) well connecting the storage reservoir to the shallow drinking water aquifer would cause drinking water quality to change outside “no-net degradation” thresholds. For both sites, the “no-net-degradation” thresholds are pH = 6.6 and total dissolved solids (TDS) = 420 ppm (i.e., pH not less than 6.6 and TDS not greater than 420 ppm). The boundaries of the AoR were calculated by calculating pH and TDS in the shallow drinking water aquifer at hypothetical open wells located at increasing distances to the east, west, north, and south of the injection wells until no impact to the aquifer was observed. CO_2 or brine leakage at a location beyond the AoR boundary is possible, but the leaked mass is too small to cause pH or TDS to change outside their threshold values

2.1 Description of NRAP-IAM-CS and Assumptions

The NRAP-IAM-CS is an integrated system model developed by DOE for use in performance and quantitative risk assessment of geologic sequestration of CO_2 (Pawar et al., 2016). The model components include a primary CO_2 injection reservoir, potential leakage pathways, and receptors such as shallow aquifers. The model is designed to perform probabilistic simulations related to the long-term fate of a CO_2 sequestration operation. A stochastic framework at the system level allows NRAP-IAM-CS to be used to explore complex interactions among large numbers of uncertain variables and helps evaluate the likely performance of potential sequestration sites. The model samples values for each uncertain parameter from probability distributions, leading to estimates of global uncertainty that accumulate as the coupled processes interact during a simulation. NRAP-IAM-CS is designed to link together many different processes (e.g., subsurface injection of CO_2, CO_2 migration, leakage, and shallow aquifer impacts) required in the analysis of long-term CO_2 storage in geologic reservoirs. The underlying processes can be simulated using reduced-order models (ROMs) developed for the components in the IAM. Details of the NRAP-IAM-CS are provided in the manual (Stauffer, et al., 2016). The risk-based AoR for Sites A and B was calculated using spatial and temporal distributions of CO_2 saturations and pressures within the storage reservoir from a multi-phase numerical reservoir flow simulator (Computer Modeling Group-Generalized Equation of State

Model [CMG-GEM] that was used to predict CO_2 plume boundaries as input to a site-specific open wellbore ROM and a shallow groundwater ROM developed with NRAP-IAM-CS:

1. **CMG-GEM:** 3-D reservoir simulation
2. **RROM-Gen:** Reformats model output
3. **Reservoir Lookup Table Model:** Pressures and saturations mapped to 100x100 grid
4. **Open Wellbore Model:** Lookup table of CO_2 and brine leakage rates based on the drift-flux approach
5. **Carbonate Aquifer Model:** Predicts the size of “impact plumes” according to selected water quality metrics
6. **Risk-based AoR:** Define area where groundwater concentrations exceed no-impact threshold.

The ***open wellbore model*** (used to calculate CO_2 and brine leakage rates into a shallow aquifer and to the atmosphere) (Pan et al., 2011) is a multiphase and non-isothermal model that couples wellbore and reservoir flow of CO_2 and variable salinity brine. The model allows for the phase transition of CO_2 from supercritical phase to gaseous phase and accompanying Joule-Thompson cooling and exsolution of CO_2 from the brine phase. The model simulates CO_2 and/or brine leakage from the storage reservoir using inputs of pressure and CO_2 saturations from the RROM-GEN generated look-up tables. The CO_2 and brine fluxes from the open wellbore Reduced-Order Model (ROM) used to calculate groundwater impacts are qualitative, because leakage rates from the open wellbore ROM may exceed the range of values to which the carbonate aquifer ROM was calibrated (Table 1). Additional parameters needed for the wellbore leakage and aquifer impact calculations are shown in Table 2.

It is very important to note that ***open wellbore model*** assumes that the wellbore is completely open – meaning that the annular space outside the casing is completely devoid of cement or other material. The assumption of a completely open borehole that penetrates the storage reservoir and connects it to the shallow drinking water aquifer can lead to unrealistically high leakage rates (flux of brine and CO_2) and aquifer impacts (resulting from chemical constituent concentrations in the shallow drinking water aquifer). However, this assumption is consistent with EPA’s guidance for calculating the Area of Review.

The ***unconfined carbonate aquifer ROM*** (used to estimate the impacts of CO_2 and brine leaks to the drinking water aquifer) (Keating et al., 2016a) predicts the impacted volume of shallow drinking water using nine water quality parameters. The unconfined carbonate aquifer ROM is the only USDW ROM available in NRAP-IAM-CS. NRAP is currently adding a confined alluvium aquifer ROM. In this analysis two of the nine parameters (pH and TDS) were used. pH and TDS plume volumes below the no-impact threshold were assumed to be consistent with EPA guidelines for no-net degradation. More information on how the threshold values were determined can be found in Last et al. (2016). Adjustable input parameters, including permeability mean, variance, correlation length and anisotropy, aquifer thickness and horizontal hydraulic gradient were based on site characterization data where possible.

For the reservoir component, the Reservoir Reduced-Order Model – Generator (RROM-Gen) (King, 2016) was used to create NRAP-IAM-CS reservoir ROM look-up tables from the 3D reservoir simulations performed with the CMG GEM code. Simulated CO_2 saturations and pressures for 30-years of CO_2 injection and 50 years post-injection with a total injection of 50 MMT CO_2 were converted to a format acceptable to the NRAP-IAM-CS via two steps:

1. The results are translated onto a specified grid (100x100 cells), and
2. The gridded data are written into the appropriate file format.

RROM-Gen automates both of these steps. The tool defines a new grid based on user input options, then uses piecewise bi-linear interpolation to convert the reservoir data from the original grid to the new grid. The gridded results are then written to the specified file format reservoir lookup tables. Only one horizontal plane is extracted from the reservoir simulation results for use in the NRAP-IAM-CS calculations. For this application, reservoir pressures and gas saturations for all nodes of the GEM model at yearly time steps from 0 to 30 years, and 5-year times steps from 35 years to 80 years were used. Values from the Lower Copper Ridge were used at both sites (the Lower Copper Ridge is Layer 10 and Layer 8 of the CMG-GEM model at Site A and B, respectively). These layers were selected because they had the highest pressure (gradient) and largest CO_2 plume for their respective Sites. The top of the reservoir was defined to be at an elevation of -2324.4 m (-7617 ft) for Site A and -1648 m (-5407 ft) for Site B relative to Mean Sea Level (MSL).

Table 1. Carbonate Aquifer ROM wellbore leakage parameter maximum values

Parameter	Maximum Value	Unit
CO_2 leak rate	500	gram/s
Brine leak rate	75	gram/s
Cumulative CO_2 mass leaked	500	kTon
Cumulative Brine mass leaked	100	kTon

Table 2. NRAP-IAM-CS Input Parameters for Illustrative Sites A and B

Parameter	Illustrative Site A	Illustrative Site B
Surface elevation	850 ft AMSL [259.1 m]	1,053 ft AMSL [321.0 m]
Depth to top of the USDW[a]	100 ft [30.5 m]	100 ft [30.5 m]
Thickness of the USDW[a]	400 ft [122 m]	400 ft [122 m]
Pressure in the USDW[b]	61.7 psia [0.425 MPa]	61.7 psia [0.425 MPa]
Temperature in the USDW[c]	52.7 ^oF [11.5 ^oC]	52.7 ^oF [11.5 ^oC]
Permeability in the USDW[d]	100 mD [9.87e-14 m^2]	100 mD [9.87e-14 m^2]
Porosity in the USDW[d]	0.1	0.1
Salinity in the USDW[c]	340 ppm	340 ppm
Depth to the top of the Reservoir[e]	8,467 ft [2,581 m]	6460 ft [1,969 m]
Initial Pressure of the Reservoir[e]	3994 psia [27.5 MPa]	3050.7 psia [21.0 MPa]
Temperature of the reservoir[e]	127 ^oF [52.8 ^oC]	108 ^oF [42.2 ^oC]
Permeability of the reservoir[e]	661 mD [6.524e-13 m^2]	661 mD [6.524e-13 m^2]
Porosity of the reservoir[e]	0.115	0.115
Salinity of the reservoir[f]	270,000 ppm	330,000 ppm

Notes: [a] ODNR Sources; [b] Used top of USDW and gradient of 0.47 psi/ft + 14.7 psi; [c] From USGS (1983) - Median of middle aquifer, post-mining data; [d] Battelle estimate for typical limestone aquifer; [e] From GEM Model; [f] From Critical Pressure calculations

The initial pressures in the model domain were assigned the values shown in Table 2. The initial gas saturation over the entire model domain was 0. Figures 2-5 show the interpolated pressures and CO_2 saturations at 30 years (the end of the injection period) and 80 years (the end of the post-injection period) for Site A. Pressures and saturations for the same times for Site B are shown in Figures 6-9. Note that the pressure and saturation pattern is similar for both sites. This is because the same model parameters were used for the GEM model for both sites with the exception of the reservoir depth. Therefore, the absolute pressure values differ, but the overall pressure distribution is similar.

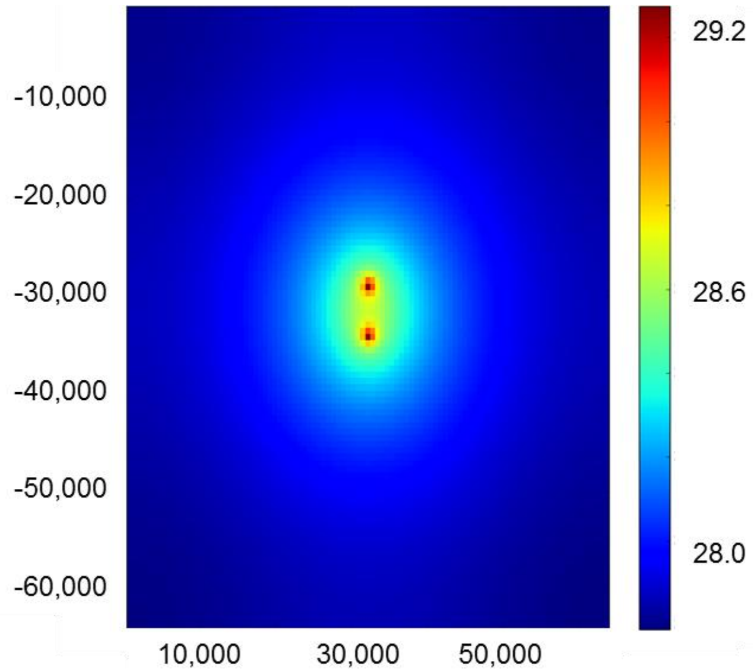


Figure 2. Pressure distribution in MPa for the Lower Copper Ridge, CMG-GEM Model Layer 10 (see Table 4-4 in main text of Final Report), for Site A at time 30 years interpolated to a 100x100 grid (the location of the two injection well locations can be seen in the center of grid). The grid has units of meters.

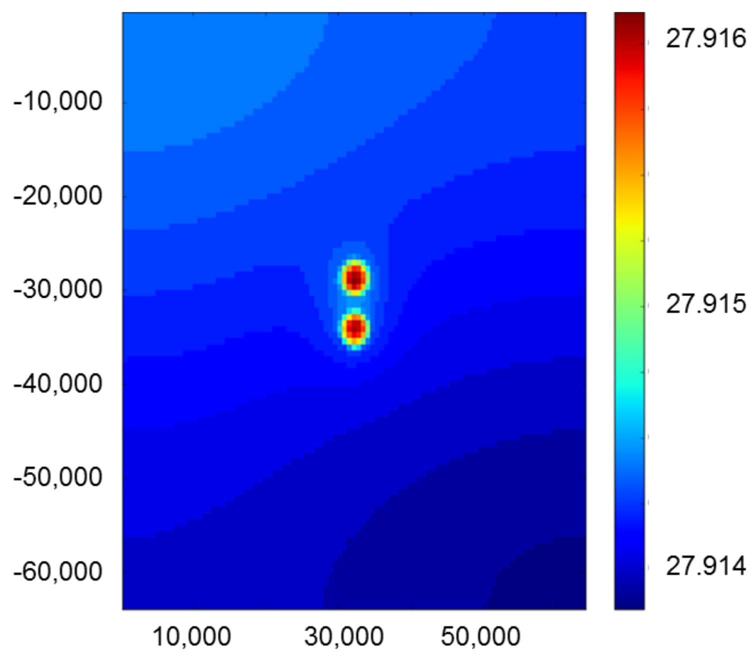


Figure 3. Pressure distribution in MPa for the Lower Copper Ridge, CMG-GEM Model Layer 10 (see Table 4-4 in main text of Final Report), for Site A at time 80 years interpolated to a 100x100 grid (the location of the two injection well locations can be seen in the center of grid). The grid has units of meters. Note the gradient in the background is an artifact in the model due to the very small changes in values and not a true pressure gradient.

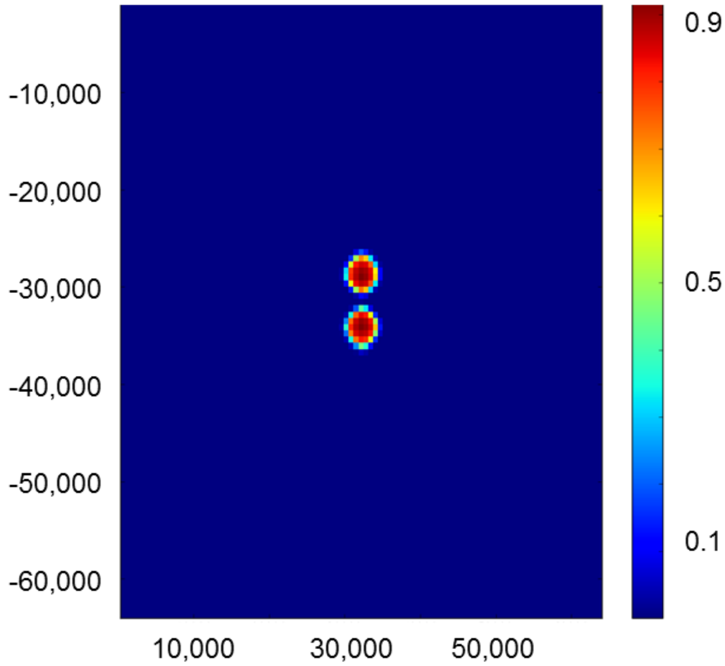


Figure 4. CO_2 gas saturation distribution for the Lower Copper Ridge, CMG-GEM Model Layer 10 (see Table 4-4 in main text of Final Report), for Site A at time 30 years interpolated to a 100x100 grid (the location of the two injection well locations can be seen in the center of grid). The grid has units of meters.

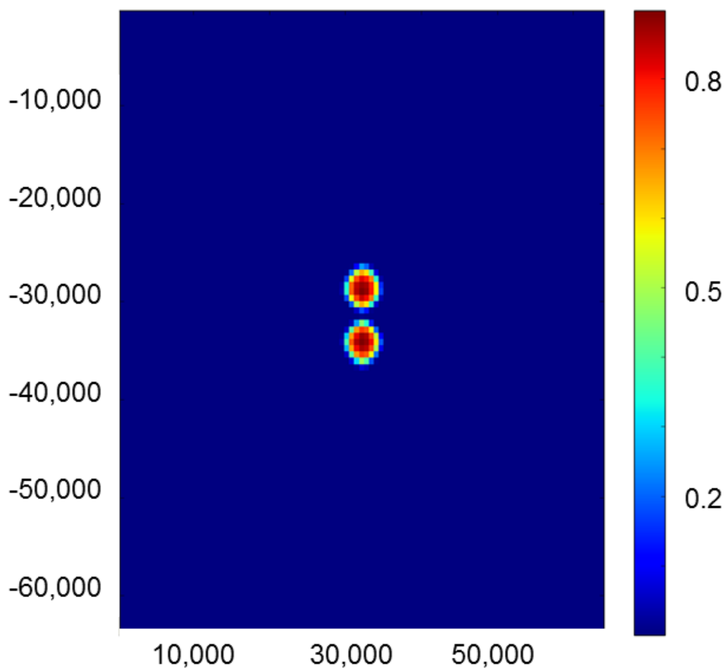


Figure 5. CO_2 gas saturation distribution for the Lower Copper Ridge, CMG-GEM Model Layer 10 (see Table 4-4 in main text of Final Report), for Site A at time 80 years interpolated to a 100x100 grid (the location of the two injection well locations can be seen in the center of grid). The grid has units of meters.

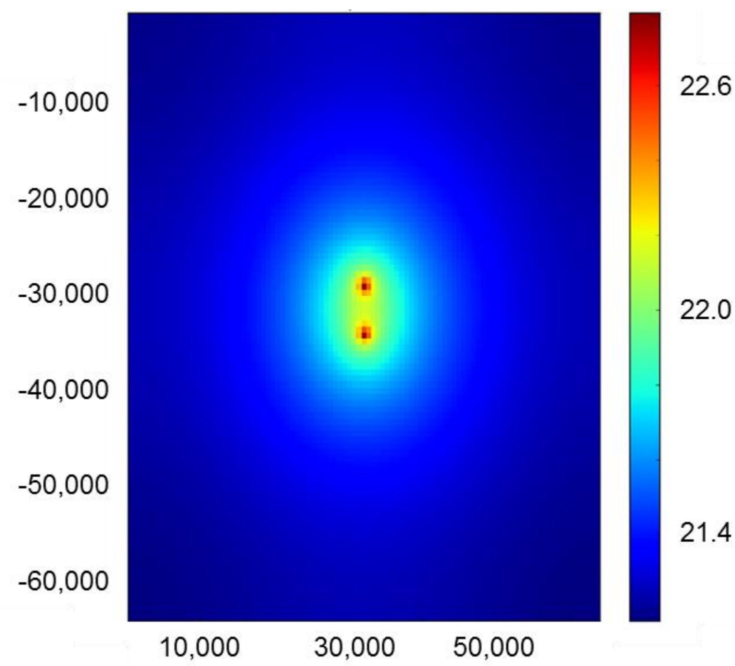


Figure 6. Pressure distribution in MPa for the Lower Copper Ridge, CMG-GEM Model Layer 8 (see Table 4-3 in main text of Final Report), for Site B at time 30 years interpolated to a 100x100 grid (the location of the two injection well locations can be seen in the center of grid). The grid has units of meters.

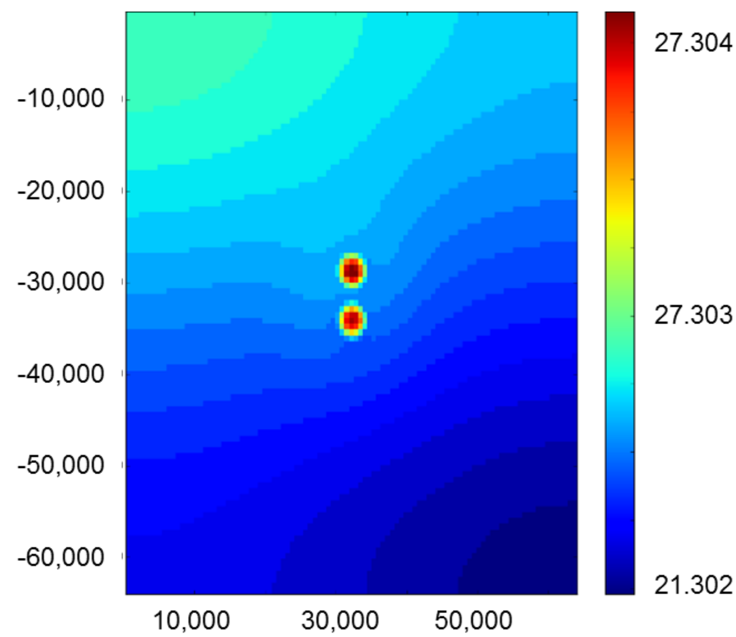


Figure 7. Pressure distribution in MPa for the Lower Copper Ridge, CMG-GEM Model Layer 8 (see Table 4-3 in main text of Final Report), for Site B at time 80 years interpolated to a 100x100 grid (the location of the two injection well locations can be seen in the center of grid). The grid has units of meters. Note the gradient in the background is an artifact in the model due to the very small changes in values and not a true pressure gradient.

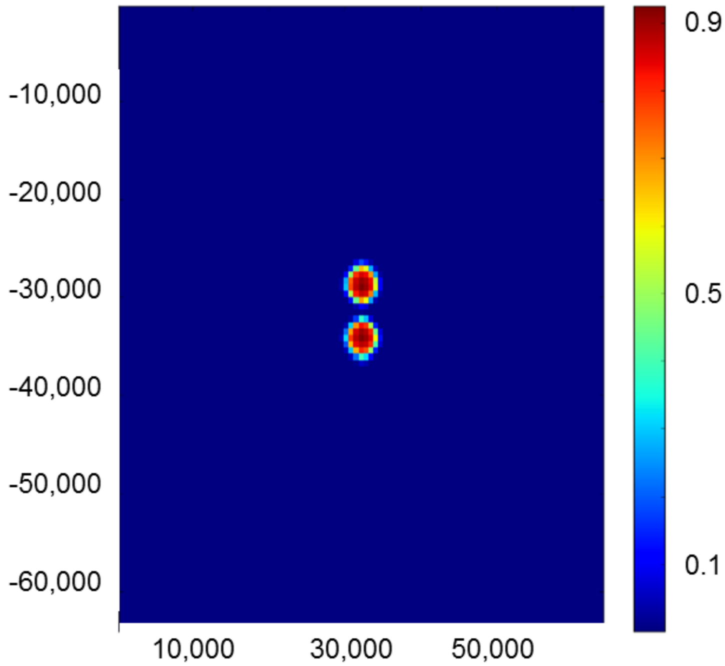


Figure 8. CO_2 gas saturation distribution for the Lower Copper Ridge, CMG-GEM Model Layer 8 (see Table 4-3 in main text of Final Report), for Site B at time 30 years interpolated to a 100x100 grid (the location of the two injection well locations can be seen in the center of grid). The grid has units of meters.

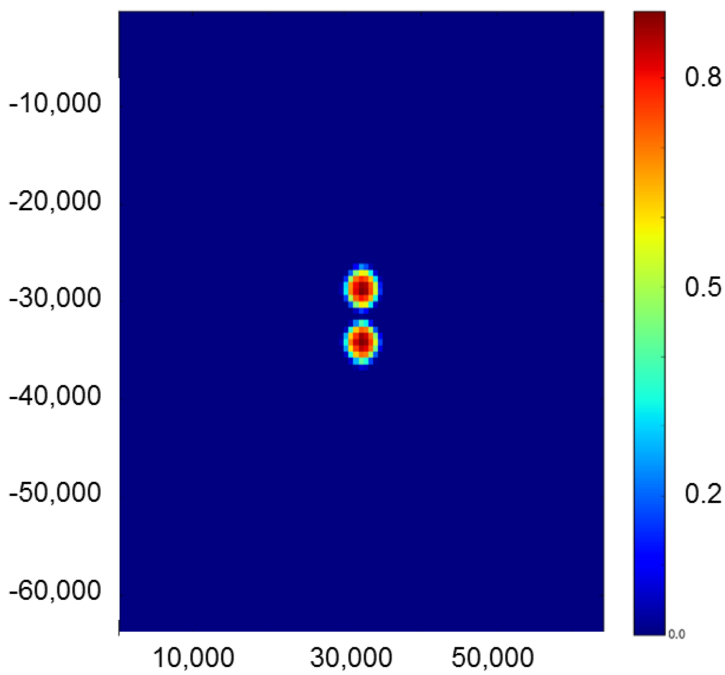


Figure 9. CO_2 gas saturation distribution for the Lower Copper Ridge, CMG-GEM Model Layer 8 (see Table 4-3 in main text of Final Report), for Site B at time 80 years interpolated to a 100x100 grid (the location of the two injection well locations can be seen in the center of grid). The grid has units of meters.

2.2 Risk-Based AoR Results for Site A

For Site A, five locations at distances increasing by 1 km from injection well #1 in the northern direction were chosen to calculate the aquifer impact from a hypothetical open wellbore (Figure 10). Table 3 shows the locations of the wells and their respective distances from injection well #1. Note that the location of well 1 corresponds directly to the injection well #1 location. The modeled reservoir pressure and CO_2 gas saturation vs. time for each of the five hypothetical well locations are shown in Figures 11 and 12. These values were used to calculate the CO_2 and brine leakage fluxes with time at each location. Wells 1, 2, 3, and 4 are located within the CO_2 plume and Well 5 is just on the outside edge of the CO_2 plume. Pressure buildup varies from approximately 2.0 MPa (290 psi) at the injection well to about 1.1 MPa (160 psi) at the northern plume boundary.

CO_2 leakage to the USDW occurs at Wells 1 through 4 and changes the shallow groundwater pH to below 6.6 (Figures 13 and 14). Well 5 is outside that plume footprint and hence does not result in any leakage or impact to the groundwater. Impacts to groundwater are used only to define the AoR; a full quantitative analysis would require updating the groundwater ROMs to handle large fluxes created by flow through an open wellbore. Qualitatively, the magnitude of the impact to groundwater decreases with distance from the injection center; and, the timing of the onset of impact increases in time with distance. Potential brine leakage to the USDW also occurs at Wells 1-4, although the rates are small and the magnitude of impact decreases with increasing distance from the center of injection (Figure 15).

The ellipse in Figure 16 defines the risk-based AoR for Site A. Table 4 specifies the boundary points for the AoR and Figure 17 shows the pressure buildup over the 80-year simulation period. There is no CO_2 or brine leakage at the AoR boundary point locations. The estimated AoR has a radius from 3115 m (10220 ft) to 5885 m (19308 ft), measured from the center of the injection area. This corresponds to an AoR with an approximate area of about 57.6 km^2 (22.2 mi^2).

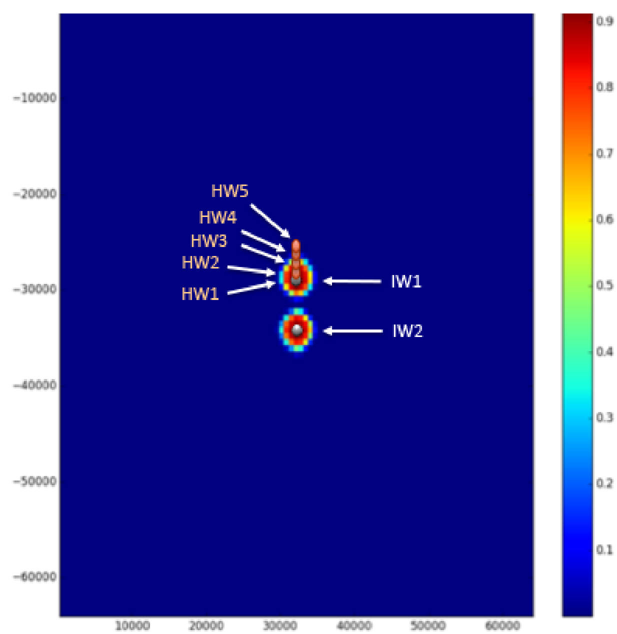


Figure 10. Locations of hypothetical wells used for Site A superimposed on the gas saturation contour plot for year 30. The grid has units of meters.

Table 3. Locations of hypothetical open wells for Site A and their respective distances from injection well #1

Hypothetical well Locations			Distance from Injection Well #1
Well	x(m)	y(m)	km
Well 1	31865	-29290	0
Well 2	31865	-28290	1
Well 3	31865	-27290	2
Well 4	31865	-26290	3
Well 5	31865	-25290	4

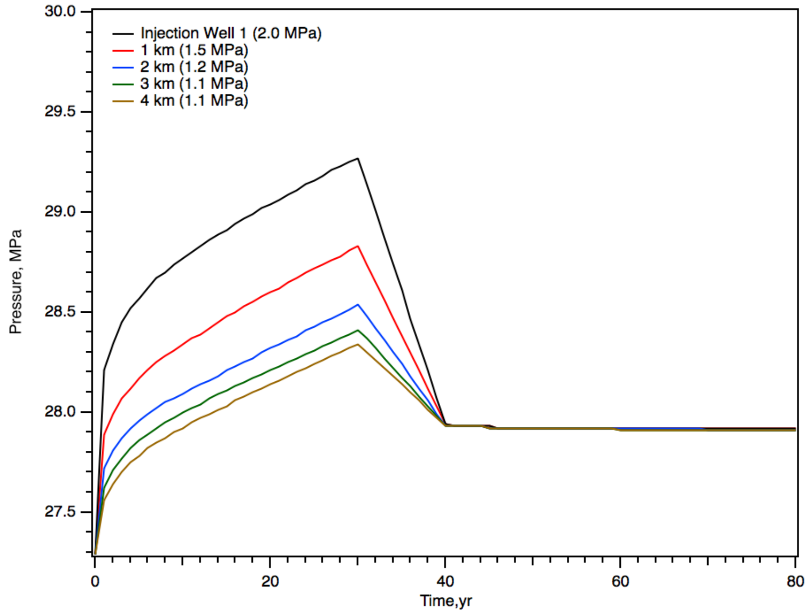


Figure 11. Pressure vs. time at each hypothetical well location for Site A. The maximum pressure difference is shown in parenthesis for each well.

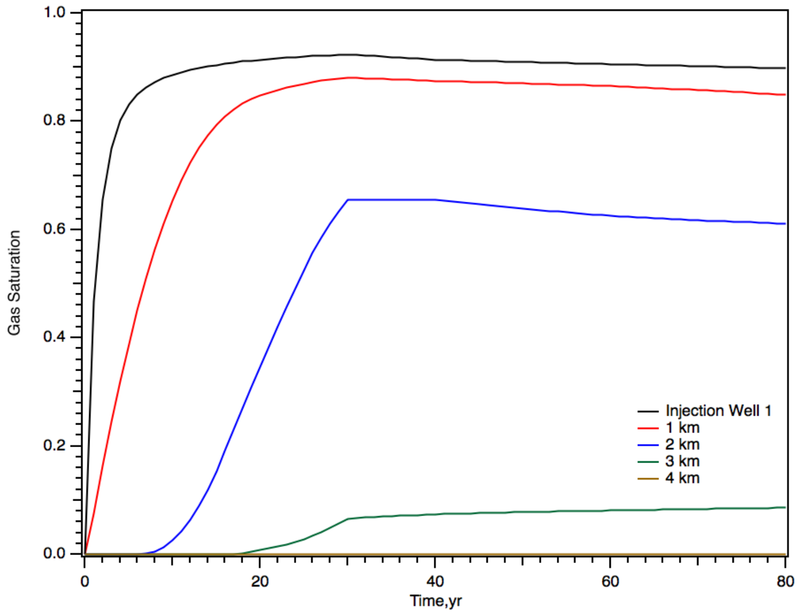


Figure 12. Gas saturation vs. time at each hypothetical well location for Site A.

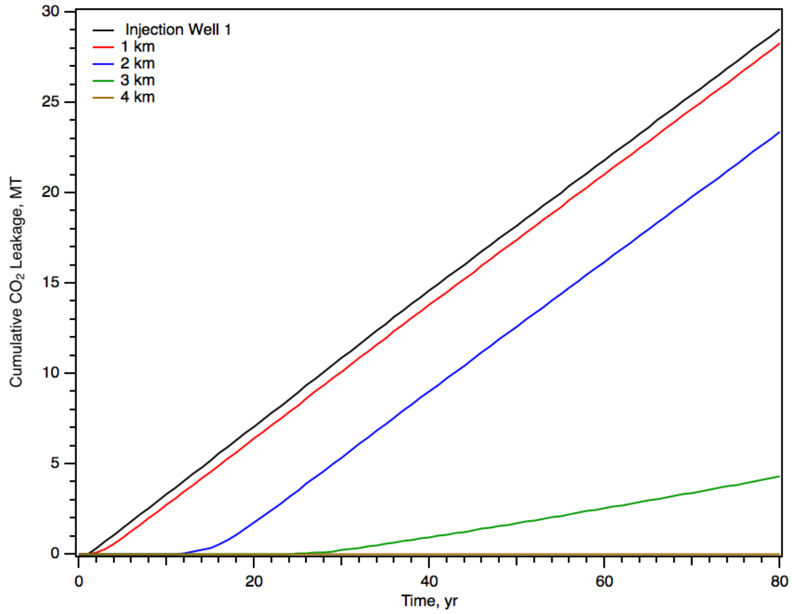


Figure 13. Cumulative mass of CO_2 leakage (MT) over time at hypothetical well locations for Site A. Note that wells 1, 2, 3, and 4 are located within the CO_2 plume footprint while well 5 is located at 4km from the injection well and outside the CO_2 plume footprint and hence has no leakage

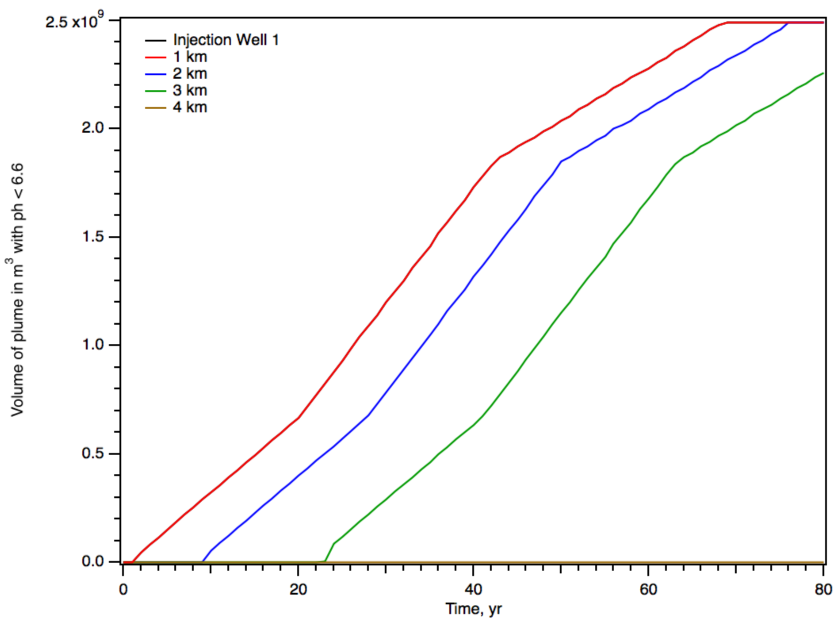


Figure 14. Impact to the USDW in terms of pH changes at hypothetical well locations for Site A

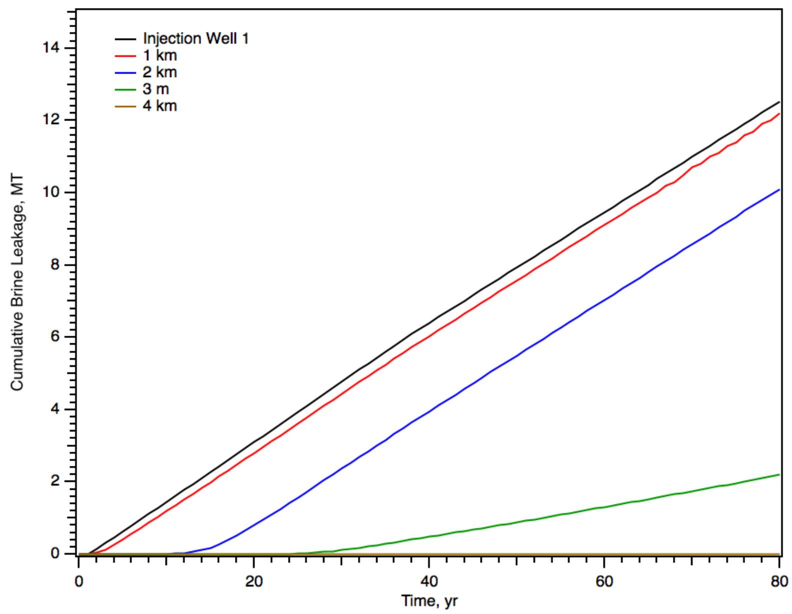


Figure 15. Cumulative mass (MT) of brine leakage over time at hypothetical well locations for Site A

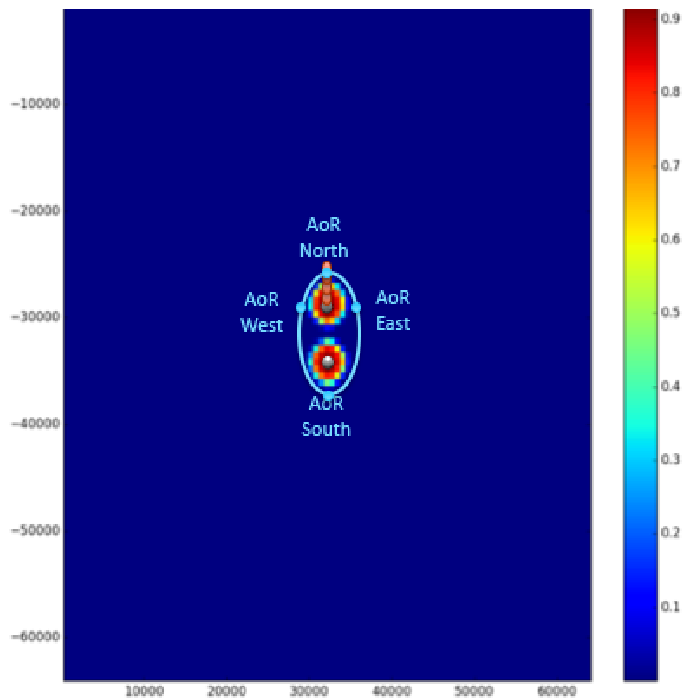


Figure 16. Area of Review for Site A as determined by the area outside which there is no impact to the USDW from CO_2 or brine leakage. CO_2 plume is shown with colored contours of gas saturation. The grid has units of meters.

Table 4. Locations of hypothetical wells for Site A where there was no impact to the USDW

AoR Boundary Points			Directional Distance from Injection Well #1
Direction	x(m)	y(m)	km
North	31865	-26000	3.23
East	35500	-29290	3.6
South	31865	-37750	8.5
West	28750	-29290	3.1

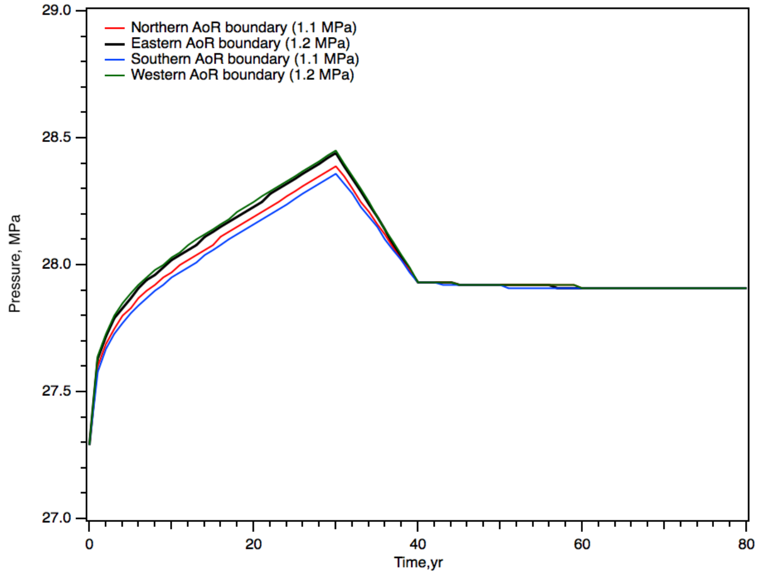


Figure 17. Pressure vs. time at points representing the northern, eastern, southern, and western limits of the Area of Review for Site A as determined by estimated zero risk to the USDW. Maximum pressure buildup is indicated in parenthesis for each locatio

2.3 Risk-Based AoR Results for Site B

A similar approach was used to determine the AoR for Site B. However, in this case, multiple distinct hypothetical open well locations were selected for analysis with the NRAP-IAM-CS. Table 5 shows the locations of the injection well and some of the hypothetical wells. The wells shown in blue are those that were used to generate the plots described below. The modeled reservoir pressure and CO_2 gas saturation vs. time for each of the four hypothetical well locations shown in blue in Table 5 are shown in Figures 18 and 19. These values were used to calculate the CO_2 and brine leakage fluxes with time at each location. Wells 1, 2, and 3 (corresponding to 1, 2, and 3 km east of injection well 2) are located within the CO_2 plume and Well 4 (corresponding to 4km east of injection well2) is outside the CO_2 plume footprint.

CO_2 leakage to the USDW occurs at Wells 1 through 3 and changes the shallow groundwater pH to below 6.6 (Figures 20 and 21). Well 4 is outside that plume footprint and hence does not result in any leakage or impact to the groundwater. Impacts to groundwater are used only to define the AoR; a full quantitative analysis would require updating the groundwater ROMs to handle large fluxes created by flow through an open wellbore. Qualitatively, the magnitude of the impact to groundwater decreases with distance from the injection center; and, the timing of the onset of impact increases in time with distance. Potential brine leakage to the USDW also occurs at Wells 1-3, although the rates are small and the magnitude of impact decreases with increasing distance from the center of injection (Figure 22).

Table 5. Locations of wells used to determine AoR for Site B

Well Locations	X (m)	Y(m)
Injection Well 1 (IW1)	31865	-29290
Injection Well 2 (IW2)	31865	-34440
Hypothetical Open Well Location 1 (1km west of IW2)	30865	-34440
Hypothetical Open Well Location 2 (2km west of IW2)	29865	-34440
Hypothetical Open Well Location 3 (3km west of IW2)	28865	-34440
Hypothetical Open Well Location 4 (3.25km west of IW2)	28615	-34440
Hypothetical Open Well Location 5 (4km west of IW2)	27865	-34440
Hypothetical Open Well Location 6 (1km east of IW2)	32865	-34440
Hypothetical Open Well Location 7 (2km east of IW2)	33865	-34440
Hypothetical Open Well Location 8 (3km east of IW2)	34865	-34440
Hypothetical Open Well Location 8 (4km east of IW2)	35865	-34440
Hypothetical Open Well Location 9 (1km west of IW1)	30865	-29290
Hypothetical Open Well Location 10 (2km west of IW1)	29865	-29290
Hypothetical Open Well Location 11 (4km west of IW1)	27865	-29290
Hypothetical Open Well Location 12 (1km east of IW1)	32865	-29290
Hypothetical Open Well Location 13 (2km east of IW1)	33865	-29290
Hypothetical Open Well Location 14 (4km east of IW1)	35865	-29290
Hypothetical Open Well Location 15 (1km north of IW1)	31865	-28290
Hypothetical Open Well Location 16 (2km north of IW1)	31865	-27290
Hypothetical Open Well Location 17 (4km north of IW1)	31865	-25290
Hypothetical Open Well Location 18 (1km south of IW2)	31865	-35440
Hypothetical Open Well Location 19 (2km south of IW2)	31865	-36440
Hypothetical Open Well Location 20 (4km south of IW2)	31865	-38440

Figure 23 shows the risk-based AoR for Site B. Table 6 specifies the boundaries for the AoR. There is no no impact to groundwater beyond the AoR boundary locations. The AoR is drawn as two connected circular shaped areas surrounding the two injection wells for site B. Each area surrounding one of the injection wells has a short radius of 2.6 km in between the two injection wells, and a long radius of 3.3 km from the nearest injection well in the north, south, east and west directions as listed in the Table 6. The size of AoR is about 68 km^2 (26 mi^2), conservatively estimated using the long radius of 3.3 km. Table 6 also lists the domain boundary and AoR boundary point coordinates for site B.

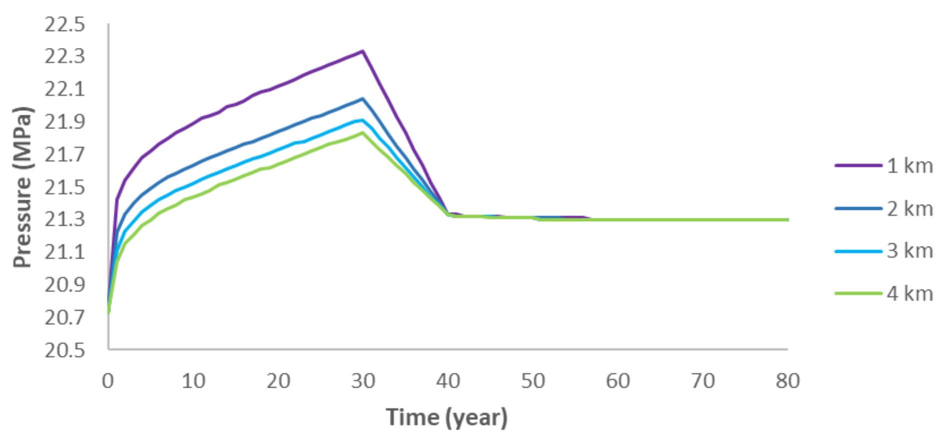


Figure 18. Pressure vs. time at each hypothetical well location for Site B

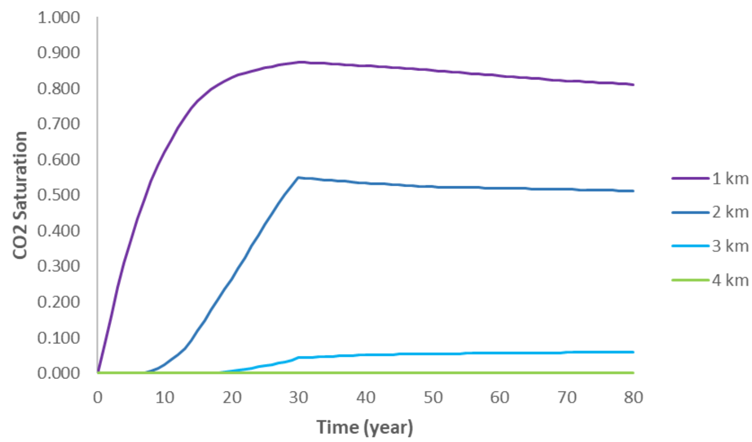


Figure 19. Gas saturation vs. time at each hypothetical well location for Site B

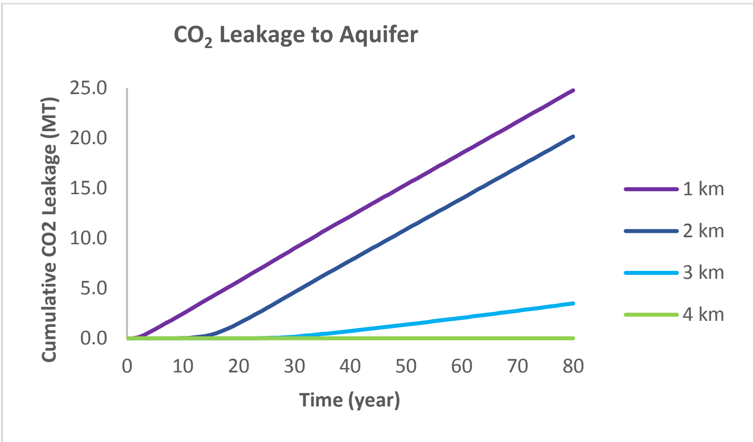


Figure 20. Cumulative mass of CO_2 leakage (MT) over time at hypothetical well locations for Site B. Note that wells 1, 2, 3, and 4 are located within the CO_2 plume footprint while well 5 is located at 4km from the injection well and outside the CO_2 plume footprint and hence has no leakage

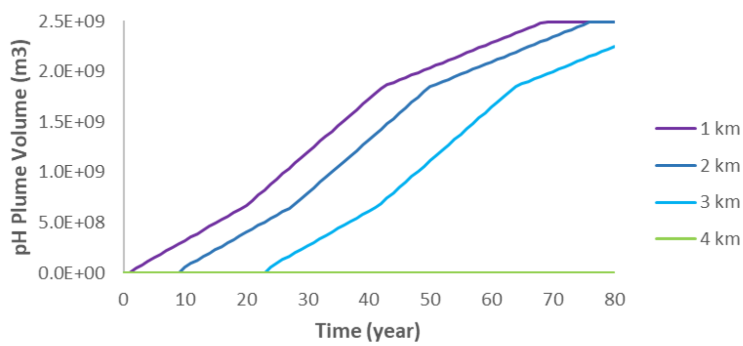


Figure 21. Impact to the USDW in terms of pH changes at hypothetical well locations for Site B

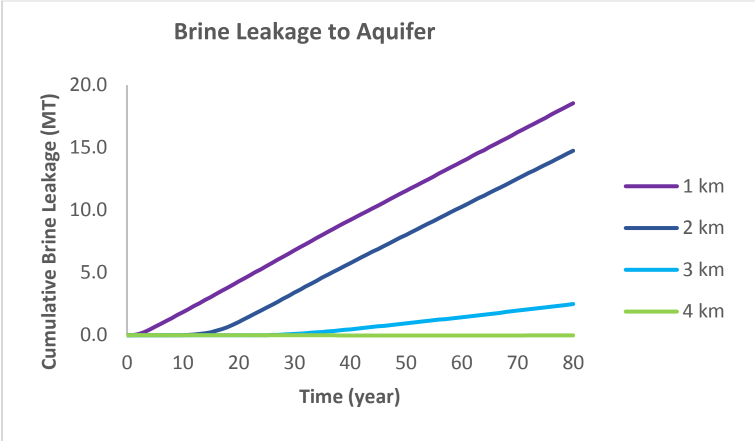


Figure 22. Cumulative mass (MT) of brine leakage over time at hypothetical well locations for Site B

Table 6. Locations of AoR boundary points for Site B beyond which there was no impact to the USDW

Location	x(m)	y(m)
Model Domain (min)	321	-64051
Model Domain (max)	64051	-321
AoR boundary point Location 1	31865	-26040
AoR boundary point Location 2	31865	-37690
AoR boundary point Location 3	28615	-29290
AoR boundary point Location 4	28615	-34440
AoR boundary point Location 5	35115	-29290
AoR boundary point Location 6	35115	-34440
AoR boundary point Location 7	31615	-31865
AoR boundary point Location 8	32115	-31865
AoR boundary point Location 9	30000	-36500
AoR boundary point Location 10	30000	-32500
AoR boundary point Location 11	33800	-32500
AoR boundary point Location 12	33800	-36600
AoR boundary point Location 13	30000	-26900
AoR boundary point Location 14	34000	-26800
AoR boundary point Location 15	30000	-31250
AoR boundary point Location 16	34100	-31250

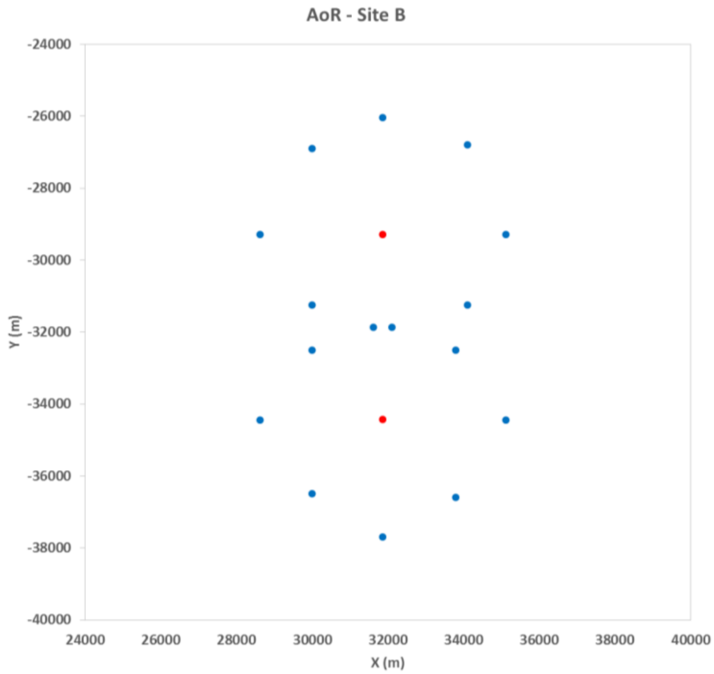


Figure 23. Area of Review for Site B as determined by the area outside which there is no impact to the USDW from CO_2 or brine leakage. The AoR boundary is shown by the blue dots and the two red dots are the injection well locations The grid has units of meters.

3.0 Critical Pressure Based AoR

Currently, the EPA provides guidance to operators of CO_2 storage sites for approaches to determining the critical pressure that should be used to define the pressure front that is considered in the AoR delineation (U.S. EPA, 2012). Comparison of the risk-based and critical pressure approaches yielded very similar AoR to that of both sites. The following approach was taken to determine a critical pressure for each site.

The critical pressure corresponds to the critical (minimal) pressure needed to move fluids from the reservoir into a USDW through a hypothetical open conduit, such as an uncemented well (U.S. EPA, 2012). The first step is to use a method that is applicable to reservoirs that are hydrostatic or underpressurized prior to the injection of CO_2 (Birkholzer et al., 2011). This method assumes that the density of the fluid in the wellbore is uniform and equal to the density in the injection zone. Equation 1 can be used to calculate the necessary increase in pressure in the reservoir to equalize the hydraulic head between the injection zone and the USDW.

$$\Delta P_{if} = P_u + \rho_i g \cdot (z_u - z_i) - P_i \qquad \text{(Equation 1)}$$

where:

P_u is the initial pressure in the USDW (Pa= kg·m^{-1}·s^{-2}),
ρ_i is the density of the injection zone fluid (kg/m^3),
g is the acceleration of gravity (m/s^2),
z_u is the depth to the base of the lowermost USDW (m),

z_i is the depth to the top of the injection zone (m), and
P_i is the initial pressure in the injection zone (Pa)

A positive value of $\Delta P_{i,f}$ (Equation 1) corresponds to an injection reservoir that is under-pressurized relative to the USDW (i.e., a downward hydraulic gradient exists between the USDW and the injection zone). The reservoir overpressure would need to increase to values equal to or above $\Delta P_{i,f}$ to move reservoir brine into the drinking water aquifer. A $\Delta P_{i,f}$ value of zero corresponds to the hydrostatic case. A negative value of $\Delta P_{i,f}$ indicates an over-pressurized injection zone where reservoir brine has the potential to migrate to the drinking water aquifer prior to any CO_2 injection.

Using Equation 1 and the parameters shown in Table 7, a critical pressure of 1.49 MPa (217 psi) was calculated for Site A and 2.01 MPa (292 psi) for Site B. Figures These values can be used to delineate the AoR from the GEM multiphase simulation results. However, the AoR is defined as the maximum extent of the separate-phase CO_2 plume or the pressure front footprint and for both sites the plume footprint is larger than the area defined by the critical pressure (ie. Pressure front footprint). Therefore the resulting AoR for both sites is based on the CO_2 plume footprint with an area of 43.4 km^2 (16.8 mi^2) as shown in Figures 24 and 25.

Table 7. Inputs for Critical Pressure Calculation

Input Parameter	Site A	Site B
Depth to top of injection zone (m)	2,581	1,969
Depth at base of the lowermost USDW (m)	152.5	152.5
Initial Pressure in Injection Zone (MPa)	27.4	21.0
Initial Pressure at the base of the lowermost USDW (MPa)	0.43	0.43
Fluid Density in the Injection Zone (kg/m^3)	1,197	1.270
Fluid Density in the USDW (kg/m^3)	1,000	1,000
Critical Pressure from Equation 1 (MPa)	1.49	2.01

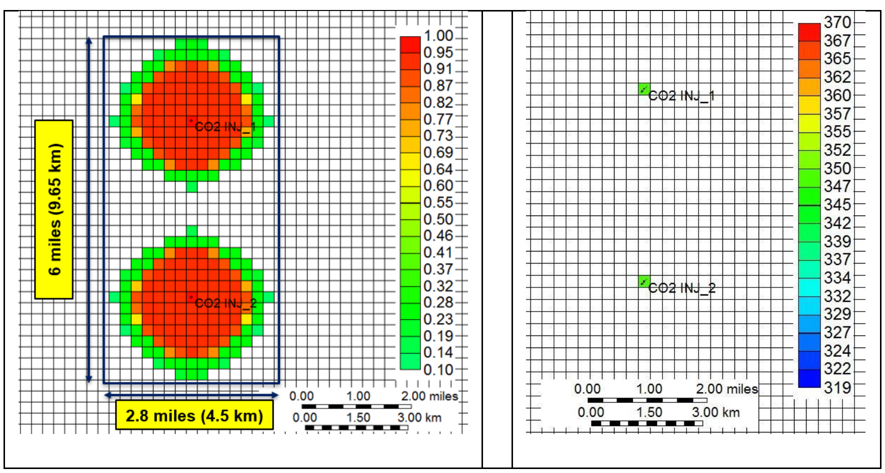


Figure 24. Area of Review for Site A corresponds with the saturation plumes (Area =43.4 km^2) (left), which is the larger area compared to the critical pressure calculated using the analytical approaches [1.49 MPa (217 psi)]

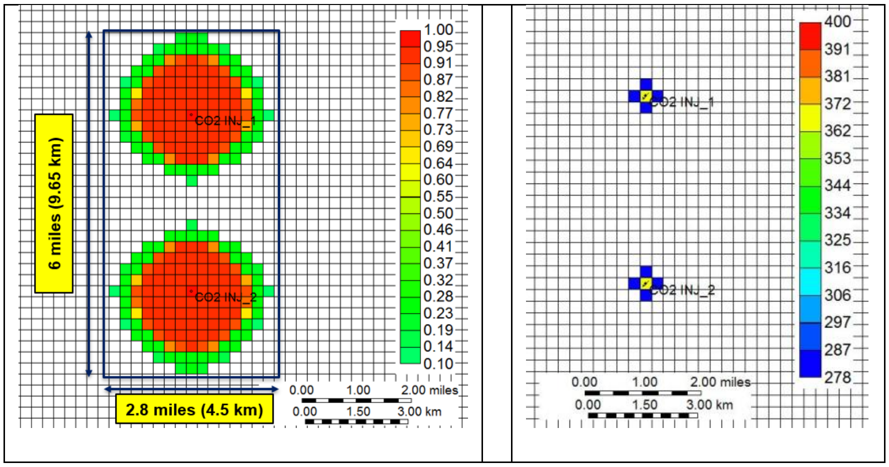


Figure 25. Area of Review for Site B corresponds with the saturation plumes (Area =43.4 km2), which is the larger area compared to the critical pressure calculated using the analytical approaches [2.01 MPa (292 psi)]

4.0 Assessment of Leakage Impacts from Known Legacy Well Locations

The NRAP-IAM-CS was also used to evaluate the probability and impacts of CO_2 and brine leakage from known well locations at Illustrative Sites A and B. Groundwater impacts through cemented wellbores and known well locations were calculated using the same approach used to calculate the risk-based AoR; however, the open wellbore assumption was replaced with permeability data representative of cemented wellbores.

Locations of legacy wells known to penetrate the CO_2 storage reservoirs and drilled to an unknown depth are included in the analysis and are shown in Figure 26 and Tables 8 and 9. Most of these wells are of an unknown depth, so the actual risk could be much lower, depending on the depths at which these wells are completed. The storage reservoir at Site A is the deeper of the two sites, where the top of the reservoir is 2194 meters (~7197 feet) depth. No wells are known to penetrate the CO_2 storage reservoir and 26 wells were drilled to an unknown depth within the area of review. The storage reservoir at Site B is shallower than at Site A, where the top of the reservoir is at 1644 meters depth (5395 feet). There are 9 legacy wells known to penetrate the CO_2 storage reservoir in the Knox formation and 22 legacy wells of unknown depth within the area of review.

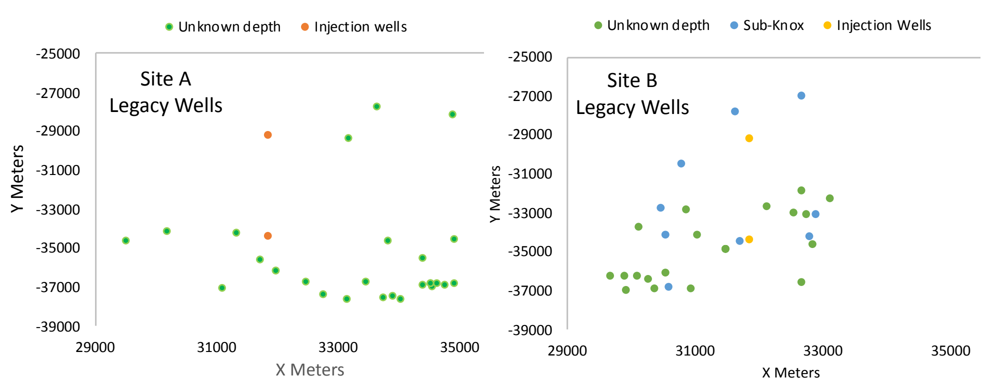


Figure 26. There are 26 legacy wells at Site A of unknown depth (Top). There are 9 legacy wells known to penetrate the CO_2 storage reservoir in the Knox formation and 22 legacy wells of unknown depth within the Area of Review at Site B (Bottom).

Table 8. Site A legacy wells considered in the NRAP-IAM-CS CO_2 and brine leakage assessment

API Well No.	Longitude	Latitude	X-meters	Y-meters
34157247670000	-81.28622	40.389784	33174	-37712
34157601940000	-81.33767	40.390032	28811	-37684
34157603860000	-81.27599	40.390056	34041	-37681
34157603970000	-81.279159	40.390708	33772	-37609
34157603990000	-81.277475	40.391521	33915	-37519
34157224860000	-81.290914	40.392098	32776	-37455
34157603810000	-81.310421	40.395246	31122	-37105
34067610820000	-81.269823	40.396057	34564	-37015
34067610810000	-81.267441	40.39633	34766	-36985
34157605620000	-81.271732	40.396497	34402	-36967
34067610800000	-81.268795	40.397091	34651	-36901
34067022820000	-81.270211	40.397205	34531	-36888
34067622830000	-81.270211	40.397205	34531	-36888
34067610790000	-81.265439	40.397574	34936	-36847

API Well No.	Longitude	Latitude	X-meters	Y-meters
34157603830000	-81.294196	40.397813	32497	-36820
34157215660000	-81.282727	40.398051	33470	-36794
34157603820000	-81.300231	40.402859	31986	-36260
34157603840000	-81.303227	40.407986	31732	-35691
34157603880000	-81.271493	40.408669	34422	-35616
34157215430000	-81.278436	40.416672	33834	-34727
34157603910000	-81.329234	40.417221	29527	-34666
34067610740000	-81.265534	40.417661	34928	-34618
34157603890000	-81.307635	40.420347	31358	-34319
34157603920000	-81.321384	40.421604	30192	-34180
34157224900000	-81.286002	40.464656	33192	-29402
34019209910000	-81.265675	40.475419	34916	-28207
34157224690000	-81.280533	40.478735	33656	-27839

Table 9. Site B legacy wells considered in the NRAP-IAM-CS CO_2 and brine leakage assessment

Unknown Depth				
API Well No.	**Longitude**	**Latitude**	**X-meters**	**Y-meters**
34031266200000	-81.792442	40.186104	30873	-32925
34031271760000	-81.768630	40.191599	31485	-34952
34031271760100	-81.768481	40.191671	31493	-34965
34031271890000	-81.768600	40.191680	31494	-34955
34031271890100	-81.768458	40.191753	31502	-34967
34031603040000	-81.749133	40.202300	32675	-36612
34031603050000	-81.771293	40.203948	32858	-34725
34031603060000	-81.790198	40.202997	32752	-33116
34031603070000	-81.790305	40.201350	32569	-33107
34031603080000	-81.799569	40.206483	33140	-32318
34031603090000	-81.803886	40.202414	32688	-31950
34031603100000	-81.794989	40.197427	32133	-32708
34031603110000	-81.776999	40.187764	31058	-34240
34031603120000	-81.754543	40.183269	30558	-36151
34031603140000	-81.745116	40.186780	30949	-36954
34031603260000	-81.782495	40.179512	30140	-33772
34031603280000	-81.752159	40.179209	30107	-36354
34031603290000	-81.752270	40.177540	29921	-36345
34031603300000	-81.752491	40.175440	29687	-36326
34031603310000	-81.744614	40.181767	30391	-36997
34031603320000	-81.744413	40.177725	29941	-37014
34031603500000	-81.751189	40.180768	30280	-36437

Depth within the Knox Formation				
API Well No.	**Longitude**	**Latitude**	**X-meters**	**Y-meters**
34031234620000	-81.852162	40.193130	31655	-27840
34031245480000	-81.861237	40.202377	32683	-27068
34031261920000	-81.776308	40.203598	32819	-34298
34031261930000	-81.789430	40.204350	32903	-33181
34031263050000	-81.777531	40.183238	30555	-34194
34031263060000	-81.773658	40.193782	31727	-34524
34031263540000	-81.745560	40.183600	30595	-36916
34031265810000	-81.793901	40.182553	30478	-32801
34031265830000	-81.820519	40.185444	30800	-30534

Leakage risk was calculated using simulated pressures and CO_2 and brine saturations for the storage reservoir to estimate possible ranges of CO_2 and brine mass over an 80-year period. The reservoir CO_2, brine, and pressure distributions are based on a single simulation of the injection of 50 million tons CO_2 over 30 years, followed by an additional 50 years with no injection.

The IAM contains four well cement permeability distributions (Figure 27). All four were used in our assessment. The FutureGen permeability models assume a log normal distribution. The FutureGenLow model assumes 10% of the wells have a permeability of 10^{-15} to 10^{-17} m^2 and 90% of the wells have a much lower permeability of 10^{-20} m^2. The FutureGen High model assumes that 10% of the wells have a higher permeability of 10^{-13} to 10^{-15} m^2 and 90% of the wells a lower permeability between 10^{-18} to 10^{-20} m^2. The Alberta model assumes a uniform distribution with permeability between 10^{-12} to 10^{-13} m^2 for 0.2% of the wells, 10^{-14} to 10^{-17} m^2 for 4.4 % of the wells, and 10^{-20} m^2 for 95.4% of the wells. The Gulf of Mexico model assumes a uniform distribution with permeability between 10^{-12} to 10^{-13} m^2 for 0.6% of the wells, 10^{-14} to 10^{-17} m^2 for 11.4 % of the wells, and 10^{-20} m^2 for 88% of the wells.

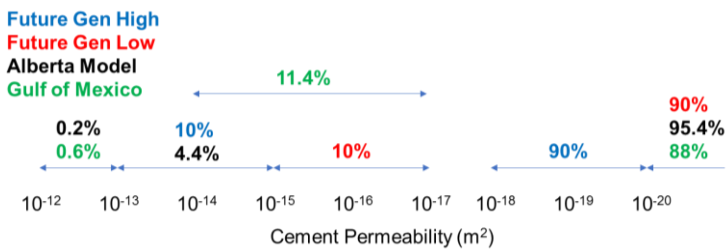


Figure 27. Cement permeability distributions used in the assessment.

Figure 28 compares the mean mass of CO_2 and brine forecast to leak after 80 years using the four different permeability distributions for legacy wells based on 2500 realizations for Site A and B. The assessment that was made using permeability distributions based on the oil and gas wells from fields in Alberta or the Gulf of Mexico yielded CO_2 and brine leakage that is 5 to 10 times smaller than leakage based on the FutureGen permeability model. Most of the CO_2 leaked goes to the USDW aquifer, with only 10% going to the atmosphere. The amount of brine leaked is about 100 times smaller than the mass of CO_2 leaked.

The mean mass of CO_2 leaked at 80 years ranged from 1.0 e-6 and 1.3 e-5 MMt (1.0 and 13 metric tons) brine after 80 years and between 2.0e-4 and 1.7e-3 Mt (i.e., between 200 and 1,700 metric tons) for CO_2. The CO_2 represents 0.0004% to 0.0034% of the total CO_2 injected. The mass leak depends on the number of legacy wells immediately surrounding the injection well and the depth of the injection zone. Longer leakage pathways require larger overpressures and saturations to drive the same amount of fluids to the underground drinking water resources.

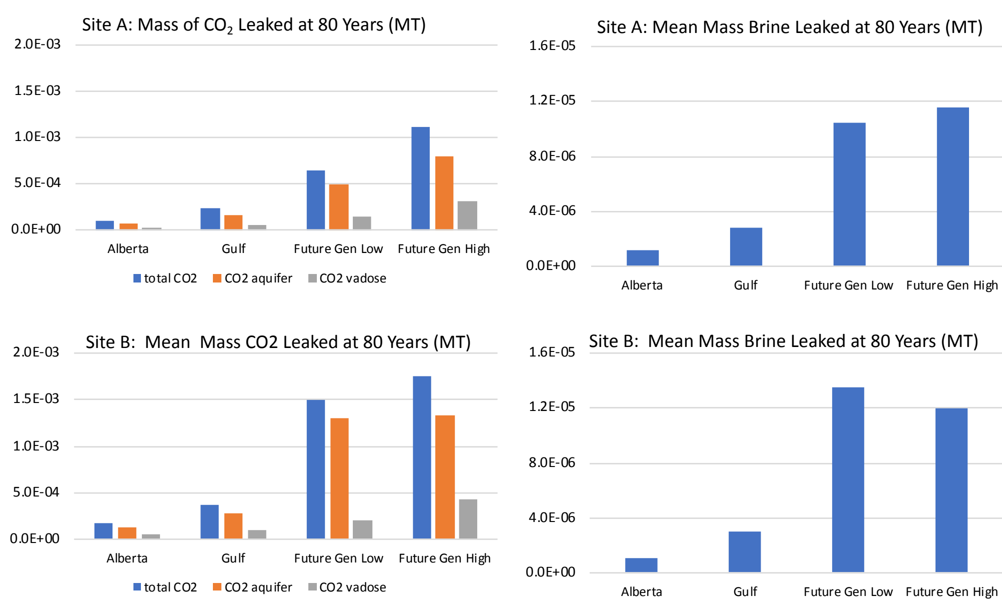
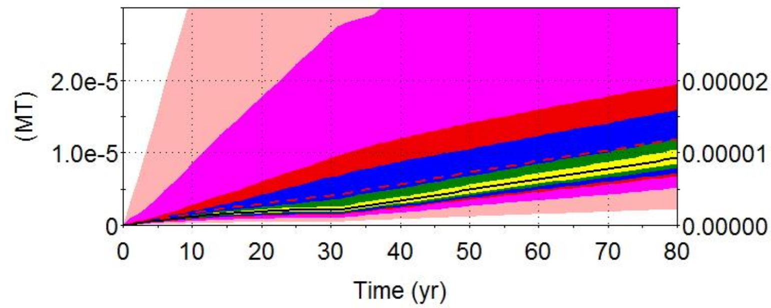


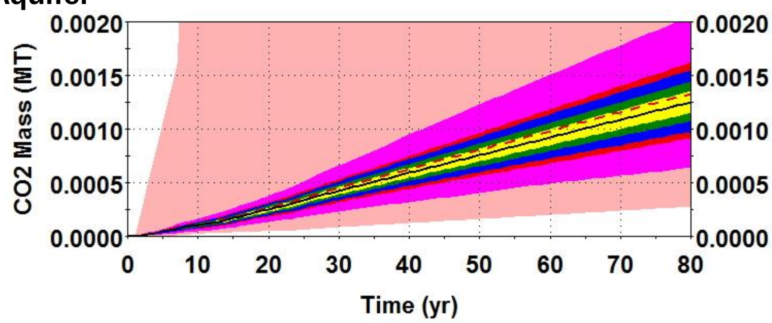
Figure 28. Mean mass of CO_2 and brine leaked after 80 years from the four distributions available in the NRAP-IAM-CS. Figures summarize the results of 2500 realizations for all wells listed in Tables 8 and 9.

Figure 29 shows the mass of brine and CO_2 leaked over the 80-year simulation period for legacy wells within the Site B area of review estimated with the FutureGen High permeability distribution. The time series is shown as an example of the type of information provided by the assessment (NRAP-IAM-CS produces similar plots for each permeability distribution and each site). The probabilities can be useful in terms of framing the risk and developing monitoring plans that allow the operator to detect leaks that have the potential to negatively impact the aquifer system. Leakage into the shallow aquifers are low but persist over the 30-year injection until the end of the 80-year simulation (Figure 30). The fluxes are currently below those used to train the unconfined carbonate aquifer ROM included in the NRAP-IAM-CS, suggesting any groundwater impacts would be negligible or quite small.

Brine Leaked to Aquifer



CO_2 Leaked to Aquifer



CO_2 Leaked to Vadose Zone

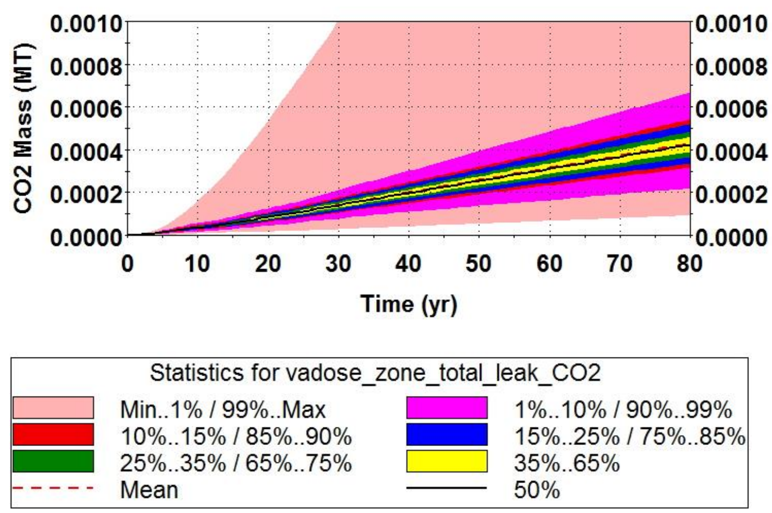


Figure 29. Probability of brine and CO_2 leakage from 31 wells within the Area of Review for Site B, plotted as the mass leaked over 80 years. Figures summarize the results of 2500 realizations sampling permeability from the FutureGen High distributions.

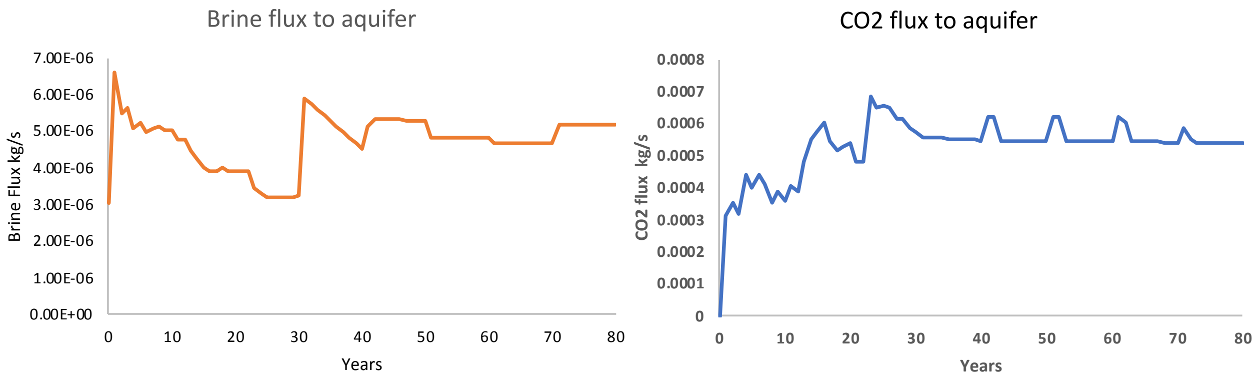


Figure 30. Mean brine and CO2 flux from 31 wells within the Area of Review for Site B, plotted as kg/s leaked over 80 years based on 2500 realizations sampling permeability from the FutureGen High distributions. Leakage into the shallow aquifers are low but persist over the 30-year injection until the end of the 80-year simulation. Note the slight fluxes after year 30 are an artifact due to the small size of the fluxes which approaches the lower limit of the model.

Leakage from tens of legacy wells located within the Area of Review for Site A and Site B should not adversely impact groundwater quality over the 30-year injection period, because the leakage flux and total mass are quite small. Fluxes are lower than the minimum allowable flux used to calibrate the aquifer impact models currently in the NRAP-IAM-CS tool kit. This assessment assumes permeability distributions are suitable for the condition of the legacy wells included in this assessment.

Combining known well locations with permeability distributions is an appropriate method for assessing leakage risk, when one considers how little is known about the integrity of legacy wells. To make more robust probabilistic assessments of leakage it is important to improve computational efficiency of the assessment model for standard laptop computers. We ran 2500 realizations with 26 and 31 wells to assess leakage risk. Upward to a million realizations are needed for true probabilistic assessment that sample reservoir, wellbore, and aquifer uncertainty.

The assessment would be better if it was tied to groundwater impacts and if the groundwater module assessed small amounts of CO_2 and brine to change the groundwater chemistry. Such analysis could be used to better define a risk-based Area of Review constrained by a reasonable estimate of well integrity. Currently the NRAP-IAM-CS only ties leakage to groundwater impacts when there are ten or less legacy wells. It would be useful to calculate and plot the volume for each leaking well to better understand how to monitor, in addition to the total volume of impacted groundwater.

Our calculations were made with the unconfined carbonate aquifer model, allowing about 10% of CO_2 to return to the atmosphere. This may not be the most appropriate aquifer model, but it is currently the only module for the underground drinking water sources in the NRAP-IAM-CS. The NRAP team has developed unconfined carbonate and confined alluvial aquifers as endmember modules to assess the impact of leakage on underground drinking water sources and is currently adding the confined alluvial aquifer to NRAP-IAM-CS.

5.0 Summary and Conclusions

The NRAP-IAM-CS was used to estimate the AoR and the impact of leakage from legacy wells located within the AoR for two illustrative carbon storage sites for the Central Appalachian Basin

CarbonSAFE Integrated Prefeasibility Project. For Illustrative Site A, the risk-based analysis yielded an AoR (57.6 km^2) that was slightly larger in size to the AoR directly calculated from the GEM model and using the critical pressure approach (43.4 km^2). Note that both approaches resulted in the AoR being based on the plume footprint rather than the critical pressure. Similarly, for Illustrative Site B, the risk-based analysis also yielded an AoR (68 km^2) that was slightly larger in size to the AoR defined using the critical pressure approach. Leakage from legacy wells located within the Area of Review for Site A and Site B should not adversely impact groundwater quality over the 30-year injection period, because the leakage flux and total mass are quite small. Fluxes are lower than the minimum allowable flux used to calibrate the aquifer impact models currently in the NRAP-IAM-CS tool kit.

6.0 Recommendations

The NRAP-IAM-CS toolset was released in 2017. The strength of the toolset is the ability to perform probabilistic assessments that account for the uncertainty of the storage complex. This work represents some of the first applications of the tools to potential CO_2 storage sites. The following recommendations to the toolset could advance its use for the determination of probabilistic assessments of risk-based AoR and leakage from legacy wells on quality to USDWs.

- The AoR calculations would be more robust if the toolset could sample pressures and CO_2 saturations from many 2D planes within the reservoir. This is particularly important for stacked storage reservoirs where stratigraphic heterogeneity will control pressure and CO_2 gas saturations. A ROM specific to the site reservoir would further improve a probabilistic assessment of the AoR.
- USDW ROMs need to be calibrated against the high leakage fluxes generated from open wellbores. All USDW ROMs were calculated for cemented wellbores, where leakage is controlled by the permeability of damage zones within the completed wells.
- The NRAP-IAM-CS currently has one option for a USDW ROM, the unconfined carbonate aquifer, where CO_2 leaks to the aquifer and to the atmosphere. NRAP is updating the toolset with a confined alluvium aquifer in which all CO_2 leaked stays within the aquifer system. The alluvium aquifer may be a better match for both sites.

Acknowledgements

This work was performed under the auspices of the U.S. Department of Energy by Lawrence Livermore National Laboratory under Contract DE-AC52-07NA27344, by Los Alamos National Laboratory under Contract DE-AC52-06NA25396, and Pacific Northwest National Laboratory under contract DE-AC06-76RLO1830. The authors acknowledge Traci Rodosta (NETL Carbon Storage Program) and Mark Ackiewicz (DOE Office of Fossil Energy) for programmatic guidance, direction, and support. Section 4.0 has been reviewed and released as a Lawrence Livermore technical report, LLNL-TR-753166. LANL contribution to this report has been reviewed and released under publication release number LA-UR-18-23719.

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Central Appalachian Basin CarbonSAFE Integrated Pre-Feasibility Project

Attachment 2 - Legal Feasibility

Overview

Background

This Memorandum has been prepared at the request of Battelle Memorial Institute ("Battelle") in connection with the Central Appalachian Basin CarbonSAFE Integrated Pre-Feasibility Project. After several meetings and telephone discussions, Battelle determined Vorys should focus on two specific areas of legal concern that may affect the feasibility of commercial carbon sequestration in Ohio: property rights and liability. This Memorandum addresses these two areas. The statutes and regulations cited are summarized (and linked in the electronic version) in Appendix A, as are two relevant Supreme Court of Ohio cases. Ultimately, the memo answers the following questions: Under Ohio law, what are the legal challenges a project developer would encounter when implementing a large-scale carbon sequestration program? How can these challenges be addressed?

V

Vorys, Sater, Seymour and Pease LLP
Legal Counsel

M E M O R A N D U M

TO: Battelle Memorial Institute

FROM: Vorys, Sater, Seymour and Pease LLP

DATE: August 24, 2017

RE: Legal Feasibility of Commercial Carbon Sequestration in Ohio

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This Memorandum has been prepared at the request of Battelle Memorial Institute ("Battelle") in connection with the Central Appalachian Basin CarbonSAFE Integrated Pre-Feasibility Project. After several meetings and telephone discussions, Battelle determined Vorys should focus on two specific areas of legal concern that may affect the feasibility of commercial carbon sequestration in Ohio: property rights and liability. This Memorandum addresses these two areas. The statutes and regulations cited are summarized (and linked in the electronic version) in Appendix A, as are two relevant Supreme Court of Ohio cases.

Question Presented

Under Ohio law, what are the legal challenges a project developer would encounter when implementing a large-scale carbon sequestration program? How can these challenges be addressed?

Brief Answer

There are at least two primary legal challenges for implementing a carbon sequestration program in Ohio: 1) property rights for CO2 storage and 2) long-term liability. The most fitting solution to these challenges is the passage of legislation which provides clear and unambiguous guidance for the development of a carbon sequestration program.

Section 1: Property Rights for CO2 Storage

Carbon capture and storage (CCS) involves injecting carbon dioxide (CO2) deep into underground rock formations. The CO2 is injected into spaces between the rocks that are called pore spaces. Utilizing pore spaces for sequestration purposes is a relatively new technological field. Consequently, there is an absence of substantial Ohio law determining the rights and privileges regarding pore spaces. This section will discuss the current landscape of property rights for CO2 storage in Ohio. It will also outline the methods for acquiring pore space, unitizing pore space, obtaining permits for injection wells, and transporting CO2.

I. Is the pore space owned by the surface owner or the mineral rights owner?

a. *Currently, there are no Ohio laws that govern who owns the pore space.*

- The majority of states in the U.S. will likely find that the pore space is owned by the surface owner.[1]
- **Wyoming**, **Montana**, and **North Dakota** are leading the CCS movement and all have laws that state that the surface owner owns the pore space.
  - Wyoming: "*The ownership of pore space in all strata below the surface lands and waters of this state is declared to be vested in the several owners of the surface above the strata.*"[2]
  - Montana: *"If the ownership of pore space cannot be determined from deeds or severance documents, it is presumed that the surface owner owns the storage reservoir."*[3]
  - North Dakota: *"Title to pore space in all strata underlying the surface of lands and water is vested in the owner of the overlying surface estate."*[4]
- In Ohio there is no basis to speculate as to which party a court would likely find to have superior rights to pore space ownership because no court has spoken on the issue in a definitive way.[5]

b. *What can the project developer do?*

- **The project developer's primary focus should be to push and guide the Ohio General Assembly to enact potential laws that directly state that surface owners own the pore space.**
  - Legislation will provide certainty as to who owns the pore space.
  - Makes the selling/leasing/transferring of pore space easier.
- It is not recommended that the project developer begin an extensive CCS project before legislation is passed.
  - The current uncertainty of ownership means that it is possible that the project developer would have to lease/buy the surface and mineral rights.
  - There is a potential for litigation if a court determines that the project developer is using pore space that it does not legally own.

II. What are the options for acquiring pore space for CO2 storage projects?

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[1] Ian J. Duncan, Scott Anderson, and Jean Philippe Nicot, Pore Space Ownership issues for CO2 sequestration in the U.S.
[2] WYO. STAT. §34-1-152.
[3] MONT. CODE ANN. §82-11-180(3).
[4] N.D. CENT. CODE §47-31-03.
[5] 1-14 Oh. Real Prop. Law and Practice §14.01.

a. Purchase surface rights.

- If it is determined that the pore space belongs to the surface owner, the project developer could purchase the necessary surface rights.
- **Wyoming**, **North Dakota**, and **Montana** statutes determine that the transfer of surface ownership is also the transfer of pore space.
    - Wyoming: *Conveyance (transfer) of surface ownership is a conveyance of the pore space unless it is previously severed or is explicitly excluded in the conveyance.*[6]
    - North Dakota: *A conveyance of title to the surface of real property conveys the pore space in all strata underlying the surface of the real property.*[7]
    - Montana: *If the ownership of pore space cannot be determined from deeds or severance documents, it is presumed that the surface owner owns the storage reservoir.* [8]
- **Advantages** of purchasing surface rights:
    - Grants uninterrupted access to the pore space for an indefinite amount of time.
    - As surface owner and pore space owner, the project developer would be able to build the necessary structures for sequestration without having to worry about encroaching on surface rights of others.
- **Problems** with purchasing surface rights.
    - Given the expansive pore space needed to undertake CCS projects, **acquiring the space by purchasing the surface rights may not be feasible.**
    - Purchasing the surface rights for vast areas of land just to access the pore space below may be costly, inefficient, and impractical.

b. Purchase pore space rights.[9]

- The project developer can **purchase the rights to just the pore space,** similar to purchasing mineral rights.
    - This gives the project developer an easement/right to utilize the seller's property so that the developer has access to the pore space.
- Grant of subsurface rights will often allow for machinery or even buildings, which aid in the utilization of the pore space, to be constructed on the surface.
- The surface owner cannot impede on the rights of the pore space owner and vice versa.

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[6] WYO. STAT. §34-1-152(b).
[7] N.D. CENT. CODE, §47-31-04.
[8] MONT. CODE ANN. §82-11-180(3).
[9] 1-14 Oh. Real Prop. Law and Practice §14.01.

- o All construction/activities/improvements **must not obstruct the rights of the other.**

c. *Leasing pore space rights.*[10]

- The leasing of pore space rights should follow the same procedure and guidelines as other mineral leases.
- The surface owner will agree to allow the lessee to use pore space in exchange for immediate payment or a prospective payment, commonly a periodic payment of royalties.
  - **Caution:** The nature of carbon sequestration may make this difficult as the economic benefits of storing carbon dioxide underground are not the same as producing other minerals for commercial purposes.
  - Must have funds to pay lessor and CCS does not currently produce such funds.
- Terms of leases
  - Mineral leases usually consist of 1) a definite term and 2) a term of indefinite duration which may be extended if specified conditions are met.
  - Specific length in years, with an extension if the resource is still being produced.
- **It would be difficult and nearly impossible to apply leases to CCS.**
  - CCS requires indefinite access to pore space rights as the carbon is permanently injected, so a lease for any term of years is impractical and unsustainable.

d. *Acquiring pore space rights by eminent domain.*

- Eminent domain is the power of the state to take, or authorize the taking of private property for a public use without the owner's consent.[11]
- Federal and Ohio laws forbid the state from delegating the power of eminent domain to a private party.
- Furthermore, Ohio is very strict on what constitutes a public use.
- The project developer should advise the Ohio General Assembly to designate CO2 as a benefit (commodity) as opposed to a waste.
  - This designation would make it easier for the state of Ohio to impose eminent domain to further the interests of the CCS projects.

e. *What should the project developer do?*

[10] *Id.* at §14.05.
[11] Oh. Real Prop. Law and Practice §26.01.

- **For the long term vitality of a CCS project, the project developer should purchase the rights to the pore space.**
    - Guaranteed indefinite access to the pore space.
    - Surface owner cannot obstruct the project developer's utilization of pore space.
    - Do not have to spend the money to purchase all of the surface space.
    - As the outright owner of the pore space, the developer would not need to pay royalties or other periodic payments for the use of the pore space.
- <u>Challenges with purchasing the pore space:</u>
    - Lacking control over the surface space could limit or prohibit the construction of equipment necessary for CCS.
    - Although a grant of pore space would generally allow for the construction of equipment, a vast system of pipelines and wells could potentially be deemed as over intrusive on the rights of the surface owner.
    - Must ensure that the utilization of pore space does not encroach on the rights of others (e.g., mineral owners).
    - Cannot interfere with the production of oil, gas, and other mineral interests that may be nearby.
- **The project developer should push for legislation that confirms surface owners own the pore space and that pore space rights can be purchased and conveyed similar to other mineral rights.**
    - If Ohio law states that surface owners own the pore space, and the developer purchases the pore space from the surface owner, then the developer will know that it has legally purchased the pore space and has all rights and privileges that come with it.
    - Again, certainty of the law regarding property rights is critical to determining the best way to acquire pore space.

III. Mechanisms for Unitization

a. Currently Ohio has unitization laws that apply to oil wells, but nothing that applies to carbon sequestration.

- The Division of Oil and Gas Resources Management of the Ohio Department of Natural Resources oversees unitization.[12]
- Process for Unitization:[13]

[12] OHIO REV. CODE ANN. §1509.27.
[13] *Id.*

- Apply to the chief of the Division who will hold a hearing if owners of **65% of the land** overlying the pool apply.
  - All owners of land in the pool must be given notice and an opportunity to be heard.
  - An order for mandatory pooling shall be granted when it is reasonably necessary to substantially increase the recovery of oil and gas.
- The order granting the pooling must contain reasonable terms and conditions and shall prescribe a plan for unit operations including but not limited to:
  - A description of the area
  - Provision for providing how expense of unit operations will be determined
  - Provision for supervision and conduct of unit operations.
  - Time when unit operations will commence
  - Other appropriate provisions for carrying on the unit operations.
  - Entire prescription of the plan can be found in the **Ohio Revised Code §1509.28.**

b. *Wyoming has enacted legislation that directly speaks to unitization of geologic sequestration sites.*

- The process for the unitization of geologic sequestration sites in Wyoming parallels Ohio's unitization for oil and gas.[14]
  - Wyoming's process requires approval of 80% of owners of land.
  - Requires a hearing and a plan for unitization similar to Ohio's.
- Controlled by Wyoming Oil and Gas Conservation Commission.
- Purpose is to protect the corresponding rights of all pore space owners in a unit area, comply with environmental requirements, and to facilitate the use and production of Wyoming energy resources.

c. *What can the project developer do?*

- **Ideally, the project developer should work to get legislation passed that directly speaks to the unitization of carbon sequestration sites.**
  - The current framework for unitization in Ohio would most likely not work when applied to carbon sequestration.
    - Orders for mandatory pooling are only passed when it enhances the economic production of oil and gas.

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[14] WYO. ST. § 35-11-314-318.

        - CCS lacks the same tangible economic benefit as oil and gas and, therefore, unitization would most likely not be enacted on those grounds.
    - Advocacy for the environmental benefits of carbon sequestration will be important to pass this type of legislation.
        - The developer must show that the environmental benefit of CCS outweighs the cost of unitization.
    - Should be modeled off of Wyoming legislation.

IV. What is the process for acquiring permits for wells?

a. There is currently no legislation in place that directly speaks to the process and requirements for obtaining permits for ***Class VI/CO2 storage operation wells*** *in Ohio.*

- Ohio has an EPA state approved Underground Injection Control (UIC) program only for Class I, II, III, IV, and V wells.[15]
    - This means that the state of Ohio, through Department of Natural Resources, governs these underground injection wells by statutes and regulations.
    - All underground injection activities, including construction and operation of an injection well, are prohibited unless authorized by permit or rule.
- Applications to operate **Class I and Class V** wells are required under Ohio Administrative Code rule 3745-34.
- Any person who proposes to construct, convert to, or operate a **Class II well** shall submit an application for a permit to the division of Mineral Resources and Management of the Ohio Department of Natural Resources.[16]

b. Class VI regulations are discussed in section 2 of this memorandum.

V. Transportation of CO2.

a. Current law in Ohio regarding CO2 pipelines.

- CO2 pipeline developers have no access to federal siting or federal eminent domain authority for construction of pipelines; instead, they have to deal with a patchwork of state laws and regulations.[17]
- No federal entity has directly claimed jurisdiction over carbon dioxide pipelines.[18]

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[15] C.F.R. §§ 147.1800, 147.1801, 147.1802, 147.1803, and 147.1805.
[16] OAC Ann. §1501.9
[17] Richard R. Nordhaus and Emily Pitlick, *Carbon Dioxide Pipeline Regulation*, Energy Law Journal.
[18] *Id.*

- Ohio Power Siting Board certificates intrastate pipelines greater than 500 ft.[19]
- Ohio Department of Natural Resources (ODNR regulates production lines).[20]
- Gathering lines and liquid lines fall under local jurisdiction.[21]

b. *What can the project developer do?*

- **It is in the project developer's best interest to get legislation passed that brings the control of CO2 pipelines under one state agency.**
    - o Uniform legislation regarding the CCS program is important to its vitality.
    - o One state agency responsible for all of the regulation for CO2 pipelines regardless of size or location will greatly benefit a large scale CCS plan.

<u>Section 2: CCS Long-Term Liability</u>

CO2 will remain in the rock formations for hundreds, if not thousands, of years. This poses a unique liability issue: who would be liable if an incident occurred from the storage site hundreds of years in the future, especially if the storage site had been abandoned for many years? The financial burden may be unbearable if the owner/operator of the original carbon dioxide injection well is found to be liable for this future incident. This unlimited owner/operator liability could make CCS in Ohio unfeasible. Unfortunately, Ohio law has yet to address this issue explicitly.

This section will first analyze the current law in Ohio regarding injection wells and the long-term liability associated with them. Then it will analyze the federal regulations of CCS. Third, it will evaluate how other states have addressed this long-term liability issue. Finally, this section will give a history of CCS legislation in Ohio. Throughout this section, recommendations will be made on what a potential project developer can do to address this long-term liability issue.

I. Current Law in Ohio Regarding Long-Term Liability for Injection Wells

a. *Currently, there are no definite laws in Ohio that govern long-term liability for injection wells. The owner/operator at the time of the incident will most likely be liable.*

- Ohio has an EPA state approved Underground Injection Control (UIC) program for Class I, II, III, IV, and V wells.[22]

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[19] Ohio Siting Power Board. http://www.opsb.ohio.gov/opsb/index.cfm/information/natrual-gas-pipeline-faq/
[20] *Id.*
[21] *Id.*
[22] 40 C.F.R. §§ 147.1800, 147.1801, 147.1802, 147.1803, and 147.1805.

- This means that the state of Ohio, through the Ohio Department of Natural Resources, governs these underground injection wells by statutes and regulations.

- Ohio has extensive regulations for Class I wells[23] (there are ten Class I wells operating in Ohio currently).
    - Class I wells inject hazardous and non-hazardous wastes into deep, isolated rock formations (very similar to CCS).

- These Class I well regulations deal with various liability issues. However, the liability issues addressed in these regulations are associated only with Class I wells that inject hazardous wastes and CO2 is not considered a hazardous waste in Ohio:[24]
    - The permit owner of the Class I well has the financial responsibility to plug and abandon the well.[25]
    - Owners of Class I wells cannot plug or abandon wells in a manner that allows the movement or fluid containing any contaminant into an underground source of drinking water.[26]
    - The owner or operator must submit a plan of "corrective action" that will prevent movement of fluid into underground sources of drinking water.[27]
    - The owner shall submit a closure report 60 days after closure.[28]
    - The regulations are silent as to who is liable for long-term liability of the storage facility. However, the regulations do require that the owner or operator of a Class I well for hazardous materials assure financial responsibility for closure and post-closure care. This includes maintaining liability coverage.[29]
- Ohio Revised Code Chapter 1571 deals with the storage of gas underground. It is silent regarding who is liable for the stored gas long-term. However, it does state that the reservoir owner needs to use methods to prevent the escape of gas from the reservoir. Thus, if an incident happens where gas escapes, the owner of the reservoir at the time of the incident would most likely be liable.
- Ohio Revised Code §§ 1509.22-1509.226 deal with brine disposal. These sections state that no person shall place or caused to be placed surface water brine, crude oil, natural gas, or other fluids associated with well stimulation (fracking) in ground water that would cause damage or injury to public health or the environment. These statutes

[23] OAC Ann. 3745-34.
[24] OAC Ann. 3745-51-04(H).
[25] OAC Ann. 3745-34-60.
[26] OAC Ann. 3745-34-07.
[27] OAC Ann. 3745-34-30.
[28] OAC Ann. 3745-34-60.
[29] OAC Ann. 3745-34-62.

are silent as to who is liable for the injected brine long-term. However, it can be inferred that the entity that placed the brine water in the ground will likely be liable.

- Ohio's Orphan Well Program
  - Ohio has a plugging program for abandoned oil and natural gas wells.[30] It is governed under § 1509.071 of the Ohio Revised Code. If an owner or operator cannot be found to plug an abandoned well that is leaking, the state of Ohio will pay for the well to be plugged. Ohio will also pay for any clean-up costs associated with the leaking.
  - The state uses funds from oil and gas taxes to pay for the plugging and clean-up.
  - This program has only been used for oil and natural gas wells.

b. *What can the project developer do?*

- As shown by the statutes and regulations governing injection wells in Ohio, there is no definitive answer as to who is liable for these injection sites long-term. An inference that the owner/operator at the time the event occurs would be liable can be made. Another inference can be made that since the owner/operator is obligated to plug and abandon the well, the owner/operator who plugged and abandoned the well would be liable for an incident that occurred in the future. Nevertheless, this does not specifically address the unique long-term liability issue involved with CCS (that the owner/operator of the carbon dioxide injection well may not be around when an incident occurs at the abandoned storage site in the distant future).
- The Orphan Well Program may be a suitable option for the state of Ohio if a CCS injection site causes damage in the distant future, but the Orphan Well Program has only been used for oil and natural gas wells. There is no indication that the state of Ohio would use this program for a carbon dioxide injection well.
- **Under current law, if a project developer opens and operates a carbon dioxide injection well, then plugs and abandons it, the developer would likely be liable for any future damages caused by the well as long as the developer is still operating as a company.**

II. Class VI Well Federal Regulations

a. *Class VI wells are used for geologic sequestration of CO2. Companies must apply for a permit from the federal government in order to operate a Class VI well.*

- There is no state approved UIC program for Class VI wells in Ohio.

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[30] ODNR DIVISION OF OIL & GAS RESOURCES, http://oilandgas.ohiodnr.gov/orphanwellprogram (last visited July 21, 2017)

- Therefore, the EPA implements its own regulations in states that do not have a state approved UIC program.[31]
- The State of Ohio can petition the federal government for primacy over Class VI wells and enact its own regulations.

- There are many requirements in these regulations that address:
  - Siting
  - Construction
  - Operation
  - Testing
  - Monitoring
  - Closure
- The owner or operator of the Class VI injection well must prepare, maintain, and comply with a plugging plan that is acceptable to the EPA.[32]
- The owner or operator of the Class VI injection well must prepare, maintain, and comply with a plan for post-injection site care and closure.[33]
  - After the closure of the injection well, the owner or operator must continue to conduct monitoring of the injection site for at least 50 years.[34] The post-injection monitoring period may be less than 50 years if the owner or operator can show that the injected CO2 is not a threat to any underground sources of drinking water.[35]
  - These regulations are silent as to who is liable for the long-term in the event of an incident past the 50 year monitoring period, but the regulations do state that an emergency plan must be in place in case an incident does occur.[36]

b. *What can the project developer do?*

- **Ideally, the project developer can apply for and obtain a Class VI well permit from the EPA.** Since Ohio does not have primacy over Class VI wells, the federal government regulates Class VI wells in Ohio. This gives the project developer an opportunity to obtain a permit from the federal government.
- **Pros of Obtaining a Class VI Well Permit from the EPA:**
  - Explicit and precise regulations
  - Would be one of the first permits ever granted
  - The Ohio General Assembly would be put on notice that regulations for CCS at the state level are needed

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31 *Leblanc v. EPA*, 310 F. App'x 770, 771 (6th Cir. 2009).
32 40 C.F.R. 146.92(b).
33 40 C.F.R. 146.93(a).
34 40 C.F.R. 146.93(b).
35 *Id.*
36 40 C.F.R. 146.94.

  - The permit states that the owner/operator is liable for monitoring of the site for at most 50 years after closure
- **Cons of Obtaining a Class VI Well Permit from the EPA:**
  - The federal regulations are still silent as to who is liable long-term
    - Would probably still be owner/operator of the site at the time the incident occurs
  - There is no option under the federal regulations to transfer liability over to a government entity or third party
  - There is no history of how liability has been handled under it

III. CCS Regulations in Other States

a. *Currently, Ohio has no statutes or regulations dealing with CCS. Many states, on the other hand, have passed legislation that encompasses CCS. Although no state has been given primacy over Class VI wells yet.*

- Almost all of the states that have passed legislation address the unique long-term liability issues that are associated with CCS. Some states that have passed CCS legislation include:
  - North Dakota
    - Chapter 38-22 of the North Dakota Century Code deals with CCS.
    - North Dakota is also in the process of gaining primacy over Class VI injection wells from the federal government. This process started in 2013 and is pending final approval in 2017.[37]
    - The storage operator has title to the carbon dioxide injected and stored in the reservoir. The operator holds that title until the State issues a certificate of project completion. While the title is held by the storage operator, the operator is liable for any damage the carbon dioxide may cause.[38]
    - A certificate of project completion may only be issued by the state ten years after the carbon dioxide injections end. The storage facility must meet other requirements as well to gain a certificate of project completion, such as showing the carbon dioxide storage reservoir has become stable.[39]
    - Once a certificate of project completion has been issued, the title to the storage facility and the stored carbon dioxide transfers to the state

[37] FEDERAL REGISTER, https://www.federalregister.gov/documents/2017/05/19/2017-10001/state-of-north-dakota-underground-injection-control-program-class-vi-primacy-approval (last visited July 21, 2017).
[38] N.D. CENT. CODE § 38-22-16.
[39] N.D. CENT. CODE § 38-22-17.

without compensation. The state bears the responsibility of monitoring and managing the storage site thereafter.[40]

- Texas
  - Chapter 119 of the Tex. Nat. Res. Code deals with CCS on-shore.
  - The state of Texas immediately takes control of the carbon dioxide injected into the ground and relieves any liability from the owner or operator of the clean coal project.[41]
  - Chapter 382, Subchapter K of the Tex. Health & Safety Code deals with CCS off-shore.
  - The state of Texas will take control of the carbon dioxide stored when the state determines that the storage site has met all applicable state and federal requirements for closure. This transfer relieves any liability from the owner/operator of the site.[42]
- Wyoming
  - Wyoming has passed several statutes that address the issues involved with CCS.
  - Wyo. Stat. § 34-1-153 states that the injector of the carbon dioxide is the owner of it. Thus, the injector is liable for any effects associated with the injection of carbon dioxide.
- Montana
  - The legislation passed in Montana only takes effect if the state gains primacy from the federal government to regulate CCS.
  - The operator of the carbon dioxide storage site is liable for the operation and management of the injection well, the storage reservoir, and the injected carbon dioxide.[43]
  - A certification of completion may be issued by the state, but not until after twenty-five years of the injection well ceasing operations. The operator must also meet certain other requirements to gain a certification of completion. Once the certification of completion is issued, the state and the operator will monitor the injection site for another twenty-five years. After twenty-five years of additional monitoring, the operator of the injection well may transfer title and liability over to the state of Montana.[44]
- Kentucky
  - Chapter 353 of the Kentucky Revised Statutes deals with CCS.

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[40] *Id.*
[41] TEX. NAT. RES. CODE § 119.002.
[42] TEX. HEALTH AND SAFETY CODE § 382.507.
[43] MONT. CODE ANN. 82-11-182.
[44] MONT. CODE ANN. 82-11-183.

- The storage operator shall close and plug the carbon dioxide injection wells as required by the state.[45]
- After the wells are plugged, the storage operator shall monitor the storage site for the time period specified on the issued permit (statute does not specify an exact time period).[46]
- After the monitoring period has passed, the storage operator may apply to the state to transfer ownership and liability of the stored carbon dioxide.[47]

- As shown by the five states above, most states with enacted legislation eventually take title to the injection well and stored carbon dioxide after certain requirements are met and a specified time period has passed. This would be the preferred model for new legislation in Ohio because the state, unlike companies, will most likely be able to survive as long as the stored carbon dioxide. Therefore, if an incident does occur in the future, there will be an entity around to deal with it. The state will also have the resources available to handle incidents in the future. Finally, this transfer of liability to the state will also relieve companies of the "unlimited future liability" associated with CCS in Ohio and entice them to open and operate CCS projects.

b. *What can the project developer do?*

- **Ideally, the project developer can use these other states' enacted legislation as guides for passing new legislation in Ohio.**
- The amount of legislation already available in other states is an advantage for the project developer's legislation efforts.

IV. Ohio Legislative History of CCS Regulations

a. *Ohio has been slow on the push for CCS legislation. Nonetheless, there have been some previous CCS bills introduced in the Ohio General Assembly.*

- The Ohio General Assembly has introduced a few bills in the past that in some way have dealt with CCS:
    - In 2007, OH H.B. 487 was introduced by representative McGregor. This bill focused on creating a Renewable Energy Authority in Ohio with a focus on expanding renewable energy across the state. One of the renewable energies targeted in the bill was geological storage of carbon dioxide. The bill stated

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[45] KY. REV. STAT. ANN. § 353.810 (1).
[46] KY. REV. STAT. ANN. § 353.810(2).
[47] KY. REV. STAT. ANN. § 353.810(4).

that long-term liability for carbon storage would eventually be absorbed by the state ten years after the closing of the facility.[48]

- However, this bill did not gain much traction in the House.

- In 2007, OH H.B. 357 was also introduced by representative McGregor. This bill focused on Ohio becoming more energy efficient. Geological storage of carbon dioxide was discussed in this bill. Long-term liability for carbon storage, as in OH H.B. 487, would eventually be taken on by the state ten years after the facility closed.[49]
    - However, this bill did not gain much traction in the House.
- In 2017, OH H.R. 115 was introduced to the Ohio House of Representatives. This resolution is sponsored by eight democrats. Its purpose is to urge the United States Congress to enact legislation to extend and expand the current federal tax credit for carbon capture, utilization, and storage and to urge Congress to support other policies relating to energy generation and protecting the environment.[50]

- In 2017, U.S. Senators Rob Portman (OH) and Michael Bennet (CO) introduced a bill called *The Carbon Capture Improvement Act*. This bill tries to make CCS more economically feasible by allowing businesses to use private activity bonds issued by local or state governments to finance carbon capture projects.[51]
- These past legislative actions show that there is some support for CCS inside and outside the Ohio General Assembly.

b. What can the project developer do?

- **Ideally, the project developer can look to educate the public about CCS, which would hopefully lead to the potential of new legislation being passed by the Ohio General Assembly.** If the public is educated on the benefits of CCS, there might be a public push for legislation to be passed in Ohio. If legislation is passed, Ohio would then petition the EPA for primacy over Class VI wells. Being awarded primacy from the federal government would give Ohio exclusive control over Class VI wells.
    - The new legislation would address the long-term liability issue attached to CCS.

[48] OHIO GENERAL ASSEMBLY ARCHIVES, http://archives.legislature.state.oh.us/bills.cfm?ID=127_HB_487 (last visited July 21, 2017).
[49] OHIO GENERAL ASSEMBLY ARCHIVES, http://archives.legislature.state.oh.us/bills.cfm?ID=127_HB_357 (last visited July 21, 2017).
[50] OHIO GENERAL ASSEMBLY ARCHIVES, https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA132-HR-115 (last visited July 21, 2017).
[51] Devin Henry, *Senators Push Bill to Fund Carbon Capture Projects*, THE HILL (April 5, 2107), http://thehill.com/policy/energy-environment/327487-senators-push-bill-to-fund-carbon-capture-projects.

   - The legislation would be modeled after other states' statutes and the failed Ohio bills in the past.
   - The new legislation would include a plan for closure and post-closure care.
     - Favorable provisions would be included for project developers of CCS projects in the state. Most importantly, a provision that would transfer the liability of the storage site to the state would be included.
     - For example: ten years after closure, if the storage site appears to be stable, the state of Ohio would issue a certificate of project completion. The project developer would then transfer liability of the storage site over to the state of Ohio.
- **Pros for Potential CCS Statutes Being Passed by the Ohio General Assembly:**
   - Would solve the long-term liability issue
     - Statute would specify a point when the operator would be able to transfer liability to the state of Ohio
   - Definite and precise regulation of CCS at the state level
     - Help garner public support for the project and CCS as a whole
- **Cons for Potential CCS Statutes Being Passed by the Ohio General Assembly:**
   - Legislative process is unpredictable
   - Possibility that the legislation might fail
     - Two bills have failed in the past
   - Possibility that the legislation might be enacted with significant changes
     - Could be passed without a "transfer of liability to Ohio" provision
   - Might take a long-time
     - Legislative process is not quick
     - Took North Dakota around four years to gain primacy over Class VI wells
   - Managing the public and interest groups' competing interests

Appendix A: Statutes and Regulations Used in CCS Legal Feasibility Memo

Below is a list of links to the statutes and regulations cited in the CCS Legal Feasibility Memorandum. The *BP Chemical* and *Columbia Gas* cases are also attached at the end of this appendix as they involve interesting case law applicable to CCS.

Section 1: Property Rights for CO2 Storage

- Ohio
  - O.R.C § 1509.27:
    - http://codes.ohio.gov/orc/1509.27
  - O.RC. § 1509.28:
    - http://codes.ohio.gov/orc/1509.28
  - OAC 1501.9.02
    - http://codes.ohio.gov/oac/1501%3A9-1

- North Dakota
  - North Dakota § 47-31-03:
    - http://www.legis.nd.gov/cencode/t47c31.html

- Montana
  - Montana § 82-11-180:
    - http://leg.mt.gov/bills/mca/title_0820/chapter_0110/part_0010/section_0800/0820-0110-0010-0800.html

- Wyoming
  - Wyoming § 34-1-152:
    - http://law.justia.com/codes/wyoming/2011/title34/chapter1/section34-1-152/
  - Wyoming § 35-11-314:
    - http://law.justia.com/codes/wyoming/2011/title35/chapter11/section35-11-314/
  - Wyoming § 35-11-315:
    - http://law.justia.com/codes/wyoming/2011/title35/chapter11/section35-11-315/
  - Wyoming § 35-11-316:
    - http://law.justia.com/codes/wyoming/2011/title35/chapter11/section35-11-316/
  - Wyoming § 35-11-317:
    - http://law.justia.com/codes/wyoming/2011/title35/chapter11/section35-11-317/

- Wyoming § 35-11-318:
  - http://law.justia.com/codes/wyoming/2011/title35/chapter11/section35-11-318/

Section 2: CCS Long-Term Liability

- Ohio
  - O.R.C. § 1571:
    - http://codes.ohio.gov/orc/1571
  - O.R.C. § 1509.22-1509.226:
    - http://codes.ohio.gov/orc/1509
  - O.R.C. § 1509.071:
    - http://codes.ohio.gov/orc/1509.071v1
  - OAC Ann. 3745-34:
    - http://codes.ohio.gov/oac/3745-34
  - OAC Ann. 3745-51-04:
    - http://codes.ohio.gov/oac/3745-51-04
  - OAC Ann. 3745-60:
    - http://codes.ohio.gov/oac/3745-34-60
  - OAC Ann. 3745-34-07:
    - http://codes.ohio.gov/oac/3745-34-07
  - OAC Ann. 3745-34-30:
    - http://codes.ohio.gov/oac/3745-34-30v1
  - OAC Ann. 3745-34-62:
    - http://codes.ohio.gov/oac/3745-34-30v1

- Federal
  - 40 C.F.R. § 146.92:
    - https://www.law.cornell.edu/cfr/text/40/146.92
  - 40 C.F.R. § 146.93:
    - https://www.law.cornell.edu/cfr/text/40/146.93
  - 40 C.F.R. § 146.94:
    - https://www.law.cornell.edu/cfr/text/40/146.94

- North Dakota
  - North Dakota § 38-22-16 and § 38-22-17:
    - http://www.legis.nd.gov/cencode/t38c22.html

- Texas
  - Tex. Nat. Res. Code § 119.002:
    - http://www.statutes.legis.state.tx.us/Docs/NR/htm/NR.119.htm#119.002

- Texas Health and Safety Code § 382.507:
    - http://www.statutes.legis.state.tx.us/Docs/HS/htm/HS.382.htm#382.507

- Wyoming
  - Wyoming § 34-1-153:
    - http://law.justia.com/codes/wyoming/2011/title34/chapter1/section34-1-153/

- Montana
  - Montana § 82-11-182:
    - http://leg.mt.gov/bills/mca/title_0820/chapter_0110/part_0010/section_0820/0820-0110-0010-0820.html
  - Montana § 82-11-183:
    - http://leg.mt.gov/bills/mca/title_0820/chapter_0110/part_0010/section_0830/0820-0110-0010-0830.html

- Kentucky
  - Kentucky § 353.810:
    - http://lrc.ky.gov/STATUTES/chapter.aspx?id=38944

Last updated August 02, 2017 02:38:33 pm GMT

Columbia Gas Transmission Corp. v. An Exclusive Natural Gas Storage Easement

Supreme Court of Ohio

June 3, 1993, Submitted ; October 27, 1993, Decided

No. 93-129

Reporter

67 Ohio St. 3d 463 *; 620 N.E.2d 48 **; 1993 Ohio LEXIS 2123 ***; 1993-Ohio-105; 127 Oil & Gas Rep. 346

Columbia Gas Transmission Corporation v. An Exclusive Natural Gas Storage Easement in the Clinton Subterranean Geological Formation et al.

Prior History: [*1]** On Order from the United States District Court, Northern District of Ohio, Eastern Division, Certifying a Question of State Law, No. C88-0936A.

Core Terms

fair market value, storage, easement, just compensation, tract, natural gas, condemned, oil and gas, landowner, native, alternative method, comparable sale, capitalization, lease, paying quantities, rental income, filing date, probability, underground, comparable, formation, involves, equated, rental

Case Summary

Procedural Posture

The United States District Court for the Northern District of Ohio, Eastern District, pursuant to Ohio Sup. Ct. Prac. R. XVI, certified the following question as to state law: According to the law of the State of Ohio, what was the measure of just compensation for the appropriation of an underground gas storage easement?

Overview

In determining just compensation for a gas storage easement, the courts should consider fair market value. The fair market value was the fair and reasonable amount that could be obtained in the open market at a voluntary sale. The court noted that there were alternative methods of determining fair market value, including whether there existed native natural gas to the extent that its recovery would be economically justified. Other methods included comparable sales, the existence of sufficient natural gas allowing for the commercial recovery in sale of the natural gas, depreciation in the condemned tract as a whole, mineral leases, and viewpoint of value. Under that method just compensation was measure from the point of view of the landowner. The yardstick was what the landowner lost, not what the gas company gained. The courts were not to consider the value of the storage easement to the gas company, nor could the court consider any increase or increment in value by virtue of the activities of the gas company in reference to the gas storage field for which the easement was acquired.

Outcome

The court answered the question by declaring that fair market value and alternative methods should be used to determine just compensation.

LexisNexis® Headnotes

Energy & Utilities Law > Pipelines & Transportation > Easements & Rights of Way

Real Property Law > ... > Elements > Just Compensation > Property Valuation

Civil Procedure > Special Proceedings > Eminent Domain Proceedings > General Overview

Energy & Utilities Law > Pipelines & Transportation > Eminent Domain Proceedings

HN1[] **Pipelines & Transportation, Easements &**

Rights of Way
In determining just compensation for an easement fair market value should be considered. The fair market value is the fair and reasonable amount that could be attained in the open market at a voluntary sale.

Energy & Utilities Law > Pipelines & Transportation > Easements & Rights of Way

Energy & Utilities Law > Oil, Gas & Mineral Interests > General Overview

Energy & Utilities Law > Pipelines & Transportation > Eminent Domain Proceedings

Energy & Utilities Law > Pipelines & Transportation > Natural Gas Gathering Systems

Real Property Law > Encumbrances > Limited Use Rights > General Overview

HN2[] **Pipelines & Transportation, Easements & Rights of Way**
Just compensation for a gas storage easement is measured from the point of view of the landowner. The yardstick is what the landowner has lost, not what the gas company has gained.

Headnotes/Syllabus

Headnotes

Appropriation of underground gas storage easement -- Determining measure of just compensation.

Counsel: *H.L. Snyder* and *Amos Perrine; Noble & Sullivan* and *David D. Noble*, for petitioner Columbia Gas Transmission Corp.

Vorys, Sater, Seymour & Pease, Stephen M. Howard and *M. Howard Petricoff*, for respondents Matthew K., Luann, Ross, and Phyllis G. McCullough, and Universal Exploration, Inc.

Kenneth R. Long; Critchfield, Critchfield & Johnston, Daniel H. Plumly and *Robert C. Berry*, for *amicus curiae* East Ohio Gas Company.

Judges: Moyer, C.J., A.W. Sweeney, Douglas, Wright, Resnick, F.E. Sweeney and Pfeifer, JJ., concur.

Opinion

[*463] [49]** The United States District Court, Northern District of Ohio, Eastern Division, pursuant to S.Ct.Prac.R. XVI, has certified the following question to us:

"According to the law of the state of Ohio, what is the measure of just compensation for the appropriation of an underground gas storage easement?"

We hold that the proper manner to determine the value of an underground gas storage easement was delineated by United States District Court Judge Dowd, Jr., **[***2]** when he instructed the commission which he had appointed under Fed. R.Civ.P. 71A(h). Judge Dowd's analysis is as follows:

HN1[] "In determining just compensation for the easement, you shall consider fair market value. The fair market value is the fair and reasonable amount which could be attained in the open market at a voluntary sale. In this case, there are alternative methods of determining fair market value based upon your preliminary determinations, including whether there exists native natural gas in the Clinton formation under the condemned tract to the extent that its recovery would be economically justified.

[*464] "1. *Comparable Sales*. One method in determining fair market value would be to consider comparable sales of easements for the purpose of allowing the storage of natural gas in the Clinton formation. If no evidence is offered of such comparable sales, this method is not available to assist you in determining just compensation.

"2. *The Existence of Sufficient Natural Gas Allowing for the Commercial Recovery in Sale of the Natural Gas*. A second method of determining fair market value, and in turn just compensation, rests upon evidence offered by landowner **[***3]** that sufficient natural gas remains under the landowner tract so as to allow the commercial recovery and sale of that natural gas. If the landowner so proves, then in determining just compensation, you may assess the foreseeable net income flow from the property for its productive life reduced to a present value figure.

"In other words, in fixing just compensation, you would determine the probable revenues and costs for the production and sale of native natural gas from the condemned tract and reduce the net sales value by the interest the landowners will enjoy for an early, one time payment.

"3. *The Fair Market Value of the Storage Easement Based upon a Capitalization of Retail Income for the Right to Store the Gas*. If you do not find there exists commercially recoverable reserves of oil and gas, a third alternative method of finding fair market value, and in turn just compensation, involves determining the fair market value of the storage easement based upon a capitalization of the rental income for the right to store the gas. In so determining, you shall use the date of the filing of the condemnation as the starting point and the termination of the storage field as the **[***4]** ending date.

"Fair market value by a capitalization of the rental income is determined by multiplying the acreage rental by the comparable storage rights to arrive at the present worth of the future income stream. In applying this method, the fair market value of the storage easement is equated to a capital sum which, when invested as of the date of filing, would earn income equal to the comparable storage rentals for the future.

"4. *Depreciation in the Fair Market Value of the Condemned Tract as a* **[**50]** *Whole by Reason of the Taking of the Storage Easement*. This alternative method of determining fair market value, and, in turn, just compensation, involves determining the difference in the fair market value of the entire condemned tract before and after the taking. This determination is accomplished by establishing the fair market value of the entire condemned tract before the taking and deducti[ng] the fair market value of the entire tract immediately after the taking. If this method is chosen to determine just compensation, the fair **[*465]** market value of the storage easement is equated to the difference, if any, between these before-and-after values of **[***5]** the entire condemned tract.

"5. *Mineral leases*. The existence of a lease for the production of native oil and gas from the property is not evidence of the existence of such oil and gas. However, you must award nominal damages to the holder of such a lease even if the presence of native oil and gas in paying quantities is not proven to a reasonable probability.

"6. *Viewpoint of value*. HN2[] Just compensation is measured from the point of view of the landowner. The yardstick is what the landowner has lost, not what Columbia has gained. Therefore, you are not to consider the value of the storage easement to Columbia, nor may you consider any increase or increment in value by virtue of the activities of Columbia in reference to the gas storage field for which the easement is acquired. For example, if there is, within the storage easement, some amount of native oil and gas, but not in paying quantities, so that they had no effect on the market value of the subject tract on the date of taking, you would not take native oil and gas into account."

Moyer, C.J., A.W. Sweeney, Douglas, Wright, **[***6]** Resnick, F.E. Sweeney and Pfeifer, JJ., concur.

End of Document

Last updated August 02, 2017 02:37:07 pm GMT

CHANCE v. BP CHEMICALS, INC.

Supreme Court of Ohio

May 8, 1996, Submitted ; October 30, 1996, Decided

No. 95-970

Reporter
77 Ohio St. 3d 17 *; 670 N.E.2d 985 **; 1996 Ohio LEXIS 1664 ***

CHANCE ET AL., APPELLANTS, v. BP CHEMICALS, INC., APPELLEE, ET AL.

Subsequent History: [*1]** As Amended.

Prior History: APPEAL from the Court of Appeals of Cuyahoga County, Nos. 66622 and 66645.

This litigation commenced on July 17, 1991, when the named plaintiffs-appellants, Rose M. Chance, Eliza Avery, and Bessie Shadwick, filed a complaint in the Court of Common Pleas for Cuyahoga County on behalf of those whose interests in real property had allegedly been injured by the described operation of a chemical refining plant operated by defendant-appellee BP Chemicals, Inc. in Lima, Ohio. Appellants' claims focused on appellee's practice of disposing of hazardous waste byproducts from the manufacture of industrial chemicals through the use of "deepwell" injection technology. Appellants in essence claimed that the "injectate" placed under the surface of appellee's property by appellee had laterally migrated to be below the surface of appellants' properties and that the migration violated their rights as property owners.

Appellants sought recovery for trespass, nuisance, negligence, strict liability, and fraudulent concealment. The complaint prayed for one billion dollars in general and punitive **[***2]** damages and included a request for injunctive relief. Appellee answered the complaint on October 24, 1991, and denied that appellants were entitled to recovery.

On June 17, 1992, appellants moved for class certification and filed a memorandum in support, stating that the controversy was particularly appropriate for resolution as a class action and urging that all requirements for class certification were met. On July 30, 1992, appellants moved for a ruling on their class certification motion before the court entertained a motion for summary judgment to be filed by appellee, arguing that the case could be certified without an evidentiary hearing. Appellants did not make any suggestion in this motion as to how the class should be described if the court did grant class certification.

On July 31, 1992, appellee filed a motion for summary judgment with a supporting brief. Appellee stated in the brief that deepwell injection is used by companies and governmental entities throughout the country and the world to place waste liquids thousands of feet deep into the earth, under thick layers of nonporous rock. Appellee claimed that the injectate at the Lima location is ninety-five percent water, **[***3]** approximately four percent dissolved salt and approximately one percent organics, and that the injectate disperses into the native fluid (connate brine) that naturally exists in the geologic rock formations where the injecting is done.

Appellee stated that it had three active deepwells at its Lima site, with the oldest well having been used continuously since 1968. Appellee stated that it operated the three injection wells pursuant to permits and regulatory practices of both the Ohio and United States Environmental Protection Agencies and argued that the wells were safe and the technology behind them effective. Among the reasons listed by appellee for its position that summary judgment was appropriate were that appellee had not violated a duty owed to appellants, that no injectate had migrated under appellants' properties, that appellants had no damages, and that some of the claims advanced by appellants were unavailable as a matter of law.

Appellants' response to the summary judgment motion, filed on September 30, 1992, stated their positions that what appellee was injecting was actually dangerous toxic waste and that the waste had migrated away from the property owned by appellee **[***4]** for a distance of approximately four to five miles in all directions. Appellants stated that extreme pressures were used by appellee to inject the waste into the rocks beneath the area. Appellants claimed that appellee had damaged the substrata of appellants' properties, that the substrata had been made unusable for other purposes, such as oil or gas extraction, and that their property values had been lowered by the deepwell injection. Among the arguments made in support of their case was that appellee was being unjustly enriched by using appellants' properties to dispose of toxins that would cost more to dispose of in some other way, so that appellants deserved a part of appellee's profits in return for the use of their properties.

On December 2, 1992, after the trial court had heard oral arguments on the summary judgment motion, the court ruled in favor of appellee on appellants' claim for punitive damages and on appellants' claim for intentional or negligent infliction of emotional distress. The court denied summary judgment to appellee on appellants' other claims.

The trial court held a pretrial conference on March 23, 1993 and set the trial date for November 3, 1993. The trial **[***5]** court set due dates for the parties to file briefs on issues relating to certification of the class. In a series of filings by each side, the parties made arguments to the trial court concerning how the class action was to be conducted. Many of these arguments concerned the possibility of bifurcating the action, so that whether appellee was liable would be determined first, and if liability was found, then damages would be quantified at a later time. Appellants generally opposed bifurcating the action in this way, although they did indicate at one point their amenability to a form of bifurcation that would include delaying determination of damages until after the extent of migration had been resolved. Appellee argued in favor of bifurcation of liability and damages.

The issue of the extent of the lateral migration of the injectate was vigorously contested by the parties at all stages throughout the litigation, and both sides presented extensive arguments based on expert testimony to support their respective positions on the extent of the lateral migration. The extent of migration was a particularly crucial factor in appellants' case, in that their theory of recovery was predicated **[***6]** upon the presence of injectate below the surface of their properties and the violation of property rights due to the presence of that injectate. Appellee continued to assert that there was no liability regardless of the extent of migration and argued that bifurcation was appropriate because if it prevailed on the liability question there would be no need for further proceedings.

Appellants, on May 27, 1993, moved to amend their complaint to add a request for a judgment declaring that appellants owned everything below the surface of their properties, including the geologic formations into which the injectate was allegedly going, and further declaring that they had the right to exclude appellee from using their properties. The motion to amend was denied by the trial court.

On August 9, 1993, the trial court issued its class certification order. The court certified a class "for purposes of a trial on the issues of where the injectate is located and whether there is liability to any member of the class." The certification order made no mention of how or when the amount and distribution of damages would be determined if liability were found.

In addition to setting forth the issues for **[***7]** trial, the trial court's certification order also defined the class: "The class consists of persons owning real property, as of the date the complaint was filed, within the following limits around the three deepwells at BP Chemicals' facility in Lima Ohio: 4.88 miles west of well 2; 4.58 miles north of well 3; 3.25 miles east of well 1; and 3.05 miles south of wells 2 and 1." The trial court adopted this class definition from an opinion of one of appellants' experts regarding his conclusions on the distances the injectate had migrated.

On September 23, 1993, the trial court issued an order requiring appellants' counsel to mail notice of the class action to identifiable class members by October 6, 1993, and to publish notice by the same date in The Lima News. The order provided that class members would have until October 27, 1993, to opt out of the class by mailing a request for exclusion to appellants' counsel.

The parties disagree over whether appellants had requested that their expert's opinion of the extent of the migration be used to define the class. In any event, appellants' attorneys did not initially object to the class definition, but later encountered problems when they **[***8]** prepared to send notices to members of the class using this class definition. Because the defined area did not directly correspond to any mailing list that could be practically compiled, appellants came to realize that some people would surely receive notices who should not. Also, because no map was included as part of the class description, there would be confusion about who was in the allegedly affected area.

The trial court journalized an entry on October 5, 1993, which approved the parties' agreement that the mailing date of the class notice would be extended to October 8, 1993, and the appellants' counsel published the notice and accomplished the mailing before that date, with notices apparently sent to in excess of 20,000 people on October 7, 1993. Those property owners not wishing to be involved sent in requests to opt out of the class, which were filed with the court.

Plaintiff-appellant Mary Virginia Rauch, a member of the described class, received a class notice. Appellant Rauch did not return an exclusion request, but instead filed a document denominated a "motion to intervene" with the trial court. In this document, appellant Rauch claimed that she needed additional time **[***9]** to decide whether to intervene, opt out, or remain as a passive class member, arguing that the time period set by the trial court for sending in exclusion requests was too short. The trial court denied appellant Rauch's motion in an entry journalized on November 4, 1993.

A final pretrial conference was held on October 27, 1993. At that time, the trial court granted several of appellants' motions to exclude evidence regarding the importance of appellee's operations to the Lima economy, including the exclusion of evidence of the number of jobs provided to local people by appellee. The trial court granted several of appellee's motions to exclude evidence from the trial, including the exclusion of evidence regarding complaints about appellee's facilities that did not involve the deepwell injecting. The trial court also granted appellee's motion to exclude evidence of problems at deepwell sites other than appellee's facility at Lima. Other rulings entered by the trial court included excluding evidence regarding Ohio's property disclosure law, excluding evidence regarding appellants' CERCLA (Comprehensive Environmental Response, Compensation, and Liability Act, Sections 9601-9675, Title **[***10]** 45, U.S.Code) claims, excluding evidence regarding emotional distress, and excluding evidence regarding affordability of the Lima housing market.

Trial commenced on November 3, 1993, and a jury was seated. Testifying for appellants were property owners who were concerned about the possible presence of the injectate under their properties. Appellants' key expert was a hydrogeologist who had developed a model to determine the extent the injectate had laterally migrated away from appellee's property. On cross-examination, appellee's attorney challenged the expert's model as inaccurate. The witness in turn explained the reasoning behind decisions he had made in setting up his model, and also criticized the model on extent of migration developed by appellee's expert. In particular, appellants' witness did not accept the accuracy of data obtained by appellee through its use of a test well to monitor the site, and so did not incorporate that site-specific data into his model.

At the close of appellants' case in chief, the trial court granted appellee's motion for directed verdicts as to appellants' claims of ultrahazardous activity, fraud, and nuisance. The trial court thus limited the **[***11]** case to appellants' trespass claim, eliminating other claims, including negligence, from the suit.

Appellee's presentation of its case included testimony of a geological engineer on the permeability and porosity of the substrata into which the injecting was done. This geological engineer's testimony explained why, in his opinion, appellee's site in Lima was suited to deepwell injection. Several impermeable (or barely permeable) layers of rock contained the injectate in the relatively permeable and porous, mostly sandstone injection zone in the Eau Claire geologic formation (beginning at a depth of approximately 2,430 feet) and the Mt. Simon formation (beginning at a depth of approximately 2,813 feet). The geological engineer testified that in his opinion the injectate was safely contained in the injection zone. On cross-examination, appellants' attorney observed that the real issue was the extent of lateral migration of the injectate, so that the witness's testimony that the injectate had not migrated upward was irrelevant to appellants' trespass claim.

Another of appellee's expert witnesses was a hydrogeologist who had developed his own model of the extent of lateral migration. **[***12]** This witness was critical of the model developed by appellants' expert and of appellants' expert's view of the extent of lateral migration, opining that appellants' expert had erred by failing to take into account available site-specific data in developing his model.

Prior to the final arguments, appellants moved for a directed verdict, arguing that appellee had admitted through at least one of its witnesses that the injectate had migrated below the surface of the properties of at least some members of the class. Appellants sought a ruling that a trespass had therefore occurred and that damages could be presumed from the act of trespassing. The trial court orally denied the motion.

On November 18, 1993, the jury returned a general verdict in favor of appellee on the trespass claim and answered ten interrogatories. The jury found (1) that the injectate was more than 2,600 feet below the surface of the earth; (2) that the model of appellee's expert best described the extent of its migration; (3) that appellants did not prove by a preponderance of the evidence that appellee had unreasonably interfered with the named plaintiffs' use of their properties; (4) that the named plaintiffs **[***13]** did not prove by a preponderance of the evidence that the deepwells had caused any actual and substantial damage to their properties apart from any claim of stigma or diminution in property values; (5) that appellants did not prove by a preponderance of the evidence that appellee had committed a trespass on the named plaintiffs' properties; (6) that the named plaintiffs did not prove by a preponderance of the evidence that the fair market value of their properties had been decreased as a direct and proximate result of the operation of the deepwells; (7) that no trespass as to the property owners had occurred, assuming portions of the injectate had migrated into the native brine flowing through the Eau Claire and Mt. Simon formations located more than one-half mile below the surface of their properties; (8) that appellants did not prove by a preponderance of the evidence that properties into which the injectate had migrated had suffered actual and substantial damage directly and proximately caused by the deepwells, apart from any claim of stigma or diminution in property values; (9) that appellants did not prove by a preponderance of the evidence that owners of properties into which **[***14]** the injectate had migrated had suffered actual damages directly and proximately caused by the deepwells; and (10) that appellants did not prove by a preponderance of the evidence that appellee was liable to any member of the class.

Appellants appealed to the Court of Appeals for Cuyahoga County, and appellee cross-appealed. In addition, appellant Rauch appealed concerning the trial court's denial of her motion to intervene. The court of appeals consolidated the various appeals, and addressed them all in a single opinion.

The court of appeals affirmed as to appellants' appeal (thus upholding the jury verdict in favor of appellee) and affirmed the denial of appellant Rauch's motion to intervene.

The cause is now before this court upon the allowance of discretionary appeals -- the appeal of the class appellants and also the appeal of appellant Rauch.

Disposition: Judgment affirmed.

Core Terms

injectate, appellants', trial court, trespass, appellee's, migration, rights, properties, damages, subsurface, deepwell, circumstances, brine, ownership, invasion, native, absolute ownership, court of appeals, foreseeable, lateral, oil and gas, speculative, capture, parties, cases

Case Summary

Procedural Posture

Appellant property owners sought review of an order from the Court of Appeals of Cuyahoga County (Ohio), which granted appellee chemical company's motion for a directed verdict as to certain of the property owners' claims and entered judgment in the chemical company's favor on a trespass claim. The action alleged injury related to the chemical company's disposal of hazardous waste byproducts using "deepwell" injection technology.

Overview

The property owners claimed that their property rights were violated when injectate that the chemical company placed under its property laterally migrated to be below their property. As a preliminary matter, the court affirmed the grant of summary judgment in favor of the chemical company on claims for emotional distress and for punitive damages, affirmed the directed verdict in favor of the chemical company on certain of the property owners' claims, and agreed with the appellate court that the property owners bore the burden of proving all elements of their claim for trespass. As to the trespass claim, the property owners argued that they had absolute ownership of all the subsurface property. The court held that the property owners' subsurface rights were not absolute, but were contingent on interference with the reasonable and foreseeable use of their property. The court found that the property owners' evidence as to interference was too speculative; thus, they failed to establish trespass. The court did not address the remainder of the property owners' claims.

Outcome

The appellate court's judgment was affirmed.

LexisNexis® Headnotes

Environmental Law > Administrative Proceedings &

Litigation > General Overview

Real Property Law > Water Rights > Riparian Rights

HN1[] **Environmental Law, Administrative Proceedings & Litigation**
See Ohio Rev. Code Ann. § 6111.08.

Commercial Law (UCC) > Sales (Article 2) > Form, Formation & Readjustment > General Overview

Real Property Law > Torts > Trespass to Real Property

Torts > Premises & Property Liability > Trespass to Real Property > General Overview

Environmental Law > Administrative Proceedings & Litigation > Nuisances, Strict Liability, & Trespasses

HN2[] **Sales (Article 2), Form, Formation & Readjustment**
Trespass is an unlawful entry upon the property of another.

Real Property Law > Encumbrances > Adjoining Landowners > Airspace

Real Property Law > Estates > General Overview

HN3[] **Adjoining Landowners, Airspace**
A property owner owns so much of the space above the ground as that owner can occupy or make use of, in connection with the enjoyment of his land. This right is not fixed. It varies with the owner's varying needs and is coextensive with them. The owner of land owns as much of the space above him as he uses, but only so long as he uses it.

Real Property Law > Estates > General Overview

HN4[] **Real Property Law, Estates**
Just as a property owner must accept some limitations on the ownership rights extending above the surface of the property, there are also limitations on property owners' subsurface rights.

Headnotes/Syllabus

Headnotes

Real property -- Determining actionable trespass -- Property owners subsurface rights are not absolute -- Subsurface rights include the right to exclude invasions of subsurface property that actually interfere with the property owners' reasonable and foreseeable use of the subsurface.

Counsel: Murray & Murray Co., **[***15]** L.P.A., James T. Murray and Joseph A. Zannieri, for appellants.

Katherine Walsh, Williams & Williams Co., L.P.A., and Mark R. Williams; and Thomas G. Rauch, for appellant Rauch

Squire, Sanders & Dempsey, Frederick R. Nance, Damond R. Mace and Steven A. Friedman; and David L. Bell, for appellee.

Judges: ALICE ROBIE RESNICK, J., DOUGLAS, F.E. SWEENEY, COOK and STRATTON, JJ., concur. MOYER, C.J., concurs in judgment only. PFEIFER, J., concurs in part and dissents in part.

Opinion by: ALICE ROBIE RESNICK

Opinion

[*22] **[**990]** ALICE ROBIE RESNICK, J. This case presents unique questions surrounding the process of deepwell disposal of wastes. We stress at the outset that, because appellee's operation of the wells is authorized by the relevant regulating bodies, **[*23]** this case does not involve the general propriety of deepwell waste injection. This case also does not involve the specific question whether appellee should be using deepwell technology at its Lima facility.

The Ohio General Assembly has set up a scheme for the granting of permits for and the supervision of injection wells by state agencies. See R.C. 6111.043 and 6111.044, formerly R.C. 1509.051 and 1509.081, enacted in 1967 by Am.S.B. No. 226, 132 Ohio Laws, Part I, 689 **[***16]** and 692. Appellee's operation of the wells is authorized by permits issued by the Ohio Environmental Protection Agency pursuant to R.C. Chapter 6111 and Ohio Adm.Code Chapter 3745-34. The United States Environmental Protection Agency, which also exercises some regulatory authority over the wells, granted appellee's "no migration" petition on May 7, 1992, allowing continued operation of the wells. See 57 F.R. 23094, 23095.

However, even though appellee operates the wells pursuant to the permits, that fact in and of itself does not insulate appellee from liability. **HN1**[] R.C. 6111.08 provides: "Chapter 6111. of the Revised Code does not abridge rights of action or remedies in equity or under the common law, nor does such chapter, or any act done under such chapter, estop the state, or any municipal corporation or person, as riparian owners or otherwise, in the exercise of their rights in equity or under the common law to suppress nuisances or to abate pollution."

As a preliminary matter, we affirm the portions of the judgment of the court of appeals holding that the trial court correctly granted summary judgment to appellee on claims for emotional distress and for punitive damages.

We also **[***17]** affirm the court of appeals' holding that the trial court properly directed a verdict in favor of appellee on the issues of nuisance, fraud, and ultrahazardous activity. Appellants desired to introduce evidence of problems, such as earthquakes and contamination of drinking water, at other deepwell sites, but were prevented from doing so by rulings of the trial court. Appellants had no evidence of specific problems at appellee's site, other than speculative opinion testimony that problems may arise in the future. As mentioned above, appellee's operation of the wells is fully authorized by the regulating bodies, and in the absence of evidence that appellee's wells were a nuisance or that appellee was negligent in some way, appellants could not recover on their nuisance claim.

Moreover, we affirm the holding of the court of appeals regarding appellants' argument that appellee should have borne the burden of proving that no trespass occurred. Appellants base their argument on this issue on appellee's reliance throughout the litigation on voluminous data obtained from a "stratigraphic test well" drilled to monitor the three injection wells. Appellants argue that appellee's "unique access" **[***18]** to this data justified placing the burden of proof on **[**991]** appellee. We agree with the court of appeals that appellants, as plaintiffs, bore the burden of proving all elements of their claim for trespass.

[*24] Our agreement with the conclusions reached by the court of appeals on the foregoing issues leaves appellants' trespass claim as the principal issue to be resolved. **HN2**[] Trespass is an unlawful entry upon the property of another. See *Keesecker v. G.M. McKelvey Co.* (1943), 141 Ohio St. 162, 166, 25 Ohio Op. 266, 268, 47 N.E.2d 211, 214. In order to address the trespass issue, we first must examine the extent of the property interest owned by appellants involved here.

Both parties have cited cases on oil and gas law, and ask this court to draw analogies between this case and oil and gas cases. Appellee in particular cites cases on the "negative rule of capture" and asks us to apply that rule. In *RR. Comm. of Texas v. Manziel* (Tex. 1962), 361 S.W.2d 560, 568, the Supreme Court of Texas explained the negative rule of capture by quoting Williams & Meyers, Oil and Gas Law (1959), Section 204.5, at 60.2: "Just as under the rule of capture a land owner may capture such oil or gas as will migrate **[***19]** from adjoining premises to a well bottomed on his land, so also may he inject into a formation substances which may migrate through the structure to the land of others, even if it thus results in the displacement under such land of more valuable with less valuable substances."

We find that the situation before us is not analogous to those present in the oil and gas cases, around which a special body of law has arisen based on special circumstances not present here. Although the above quotation from *Manziel* does contain the word "inject," the injection in that case was directly related to oil and gas extraction, and was fundamentally dissimilar to the unique situation before us, which involves the injection of waste byproducts from the production of industrial chemicals. Since appellee's injection well operation has nothing to do with the extraction or storage of oil or gas, we find the negative rule of capture inapplicable to our consideration of this case. For the same reason, we also reject appellants' argument that this court's opinion in *Columbia Gas Transm. Corp. v. Exclusive Natural Gas Storage Easement* (1993), 67 Ohio St. 3d 463, 620 N.E.2d 48, which involved the determination **[***20]** of compensation due for the appropriation of an underground gas storage easement, is relevant to the resolution of this case.

Appellants argue in their Proposition of Law No. I that "the owner of land has absolute ownership of all the subsurface property." If this proposition is correct, then as one of the incidents of absolute ownership, appellants have the right to exclude others. See *Bank of Toledo v. Toledo* (1853), 1 Ohio St. 622, 662. Appellants claim that while this court has recognized some limitations on absolute ownership of air rights by surface property owners, no such limitation exists on ownership of subsurface property rights by surface owners.

Appellants' argument implicates the ancient Latin maxim *cujus est solum, ejus est usque ad coelum et ad inferos*, defined in Black's Law Dictionary (6 Ed. 1990) **[*25]** 378, as "to whomsoever the soil belongs, he owns also to the sky and to the depths. The owner of a piece of land owns everything above and below it to an indefinite extent." In *Winton v. Cornish* (1832), 5 Ohio 477, 478, this court appeared to adopt the position illustrated by that maxim, stating, "The word *land* includes not only the face of the earth, but **[***21]** everything under it or over it. He who owns a piece of land, therefore, is the owner of everything underneath in a direct line to the center of the earth and everything above to the heavens."

In *Willoughby Hills v. Corrigan* (1972), 29 Ohio St. 2d 39, 49, 58 Ohio Op. 2d 100, 105, 278 N.E.2d 658, 664, this court, citing the United States Supreme Court in *United States v. Causby* (1946), 328 U.S. 256, 66 S. Ct. 1062, 90 L. Ed. 1206, stated that "the doctrine of the common law, that the ownership of land extends to the periphery of the universe, has no place in the modern world." The court in *Willoughby Hills*, 29 Ohio St. 2d at 50, 58 Ohio Op. 2d at 106, 278 N.E.2d at 665, quoted from *Hinman v. Pacific Air Transp.* (C.A.9, 1936), 84 F.2d 755, 758: **HN3**[] "'We own so much of the space above the ground as we can occupy or make use of, in connection with the **[**992]** enjoyment of our land. This right is not fixed. It varies with our varying needs and is coextensive with them. The owner of land owns as much of the space above him as he uses, but only so long as he uses it.'"

Appellee claims that injectate is placed into the native brine in the Mt. Simon and Eau Claire formations, and that the native brine **[***22]** waters are "waters of the state" under R.C. 6111.01(H), and therefore are exclusively regulated by the state of Ohio. Appellee argues that the court of appeals correctly found that appellants have no possessory interest in these waters, and further argues that the alleged presence of injectate does not, as a matter of law, infringe any property right of appellants. To the extent that appellee appears to be arguing that the way the injectate disperses into the native brine serves to insulate appellee from all liability in all circumstances, we reject appellee's contention. The native brine exists naturally in the porous sandstone into which the injecting is done. The injectate displaces and mixes with the brine in the injection zone. Appellants have a property interest in the rock into which the injectate is placed, albeit a potentially limited one, depending on whether appellants' ownership rights are absolute. If appellee's act of placing the injectate into the rock interferes with appellants' reasonable and foreseeable use of their properties, appellee could be liable regardless of the way the injectate mixes with the native brine.

Our analysis above concerning the native brine **[***23]** illustrates that appellants do not enjoy absolute ownership of waters of the state below their properties, and therefore underscores that their subsurface ownership rights are limited. As the discussion in *Willoughby Hills* makes evident, ownership rights in today's world are not so clear-cut as they were before the advent of airplanes and injection wells.

[*26] Consequently, we do not accept appellants' assertion of absolute ownership of everything below the surface of their properties. **HN4**[] Just as a property owner must accept some limitations on the ownership rights extending above the surface of the property, we find that there are also limitations on property owners' subsurface rights. We therefore extend the reasoning of *Willoughby Hills*, that absolute ownership of air rights is a doctrine which "has no place in the modern world," to apply as well to ownership of subsurface rights. Furthermore, as we will discuss below regarding other considerations in this case, given the unique facts here we find that appellants' subsurface rights in their properties include the right to exclude invasions of the subsurface property that actually interfere with appellants' reasonable and foreseeable **[***24]** use of the subsurface.

Having determined that appellants' subsurface rights are not absolute, we must determine whether appellants proved an actionable trespass given the facts of this case. The trespass appellants attempted to establish was an "indirect" one, and was complicated by the nature of the invasion of property that appellants were attempting to prove. The alleged invasion of property was dependent on appellants' explanation of the extent of the lateral migration of the injectate and of how the injectate came to be under their properties.

As discussed previously, the actual location of the injectate was vigorously contested by the parties throughout the litigation, with each side's experts testifying as to the models developed to illustrate the extent of the migration. The parties' experts disagreed as to the permeability and porosity of the rocks into which the injecting is done. Permeability and porosity are two factors upon which the models were based that would affect the extent of the lateral migration of the injectate. The experts also disagreed over the thickness of the "injection interval" into which the injectate is placed. If the injectate were placed into a relatively **[***25]** thin layer, as appellants' expert placed it in his model, the injectate would laterally migrate farther than if it were placed in a thicker layer, as appellee's expert placed it in his model.

Another variable that figures in the equation involving lateral migration and the location of the injectate is the concentration of the injectate at any given point in the substrata as it intermixes with the native brine. As the injectate diffuses into the brine, its **[**993]** concentration decreases as the distance from the injection point increases. Therefore it is theoretically impossible to define an absolute perimeter on the extent of lateral migration, since any statement on the extent of migration must be in terms of a particular concentration level at that perimeter. In addition, there was testimony about the degradation of the injectate, and how that degradation would affect the injectate's migration over time.

All of these and more disputed variables went into the construction of the hypothetical models that attempted to illustrate the lateral extent of the migration. **[*27]** Given all these variables, there were great difficulties in appellants' establishing, as a factual matter, that a property invasion **[***26]** had occurred, so that appellants' claim must be regarded as somewhat speculative.

Appellants in essence argue that through its rulings, the trial court mistakenly imposed a requirement that they prove "actual" damages as an element of their trespass claim. Appellants argue that damages can be presumed in every case of trespass, and given that the bifurcation order left damages to be quantified at a future time, the trial court erred in requiring proof of any damages at all, much less of "actual" ones. We do not accept appellants' argument in this regard in the specific circumstances of this case, but find that some type of physical damages or interference with use must be shown in an indirect invasion situation such as this. Even assuming that the injectate had laterally migrated to be in an offending concentration under some of the appellants' properties, we find that some type of physical damages or interference with use must have been demonstrated for appellants to recover for a trespass.

Additionally, appellants in essence argue that even if the trial court was correct in requiring them to prove "actual" damages as an element of their trespass claim, the trial court erred by **[***27]** unduly restricting what type of damages they were required to demonstrate. For example, appellants argue that the trial court should have allowed appellants to present evidence that environmental stigma associated with the deepwells had a negative effect on appellants' property values due to the public perception that there may have been injectate under appellants' properties and that the injectate may be dangerous. We find that the trial court did not abuse its discretion in the circumstances of this case in foreclosing appellants from presenting evidence of speculative stigma damages. Therefore, the trial court was correct in requiring appellants to prove some physical damages or interference with use proximately caused by the deepwells as part of their trespass claim in the circumstances of this case, thus placing on appellants the burden of establishing that the injectate interfered with the reasonable and foreseeable use of their properties.

Appellants have cited no cases in which the non-negligent operation of a deepwell has resulted in liability. The court of appeals remarked in a footnote to its opinion that after extensive research of other jurisdictions, it was unable to **[***28]** find "a single cause of action based upon conceptual as opposed to actual and substantial damage associated with permitted, non-negligent deepwell disposal." Our research also has produced no such precedent.

We find that appellants, given all the factors present in this case, did not, as a matter of law, establish an unlawful entry on their properties by appellee. Our ultimate conclusion that appellants did not prove an actionable trespass is dictated by considering the sum total of the circumstances of this case, as we **[*28]** have done in our foregoing discussion. Appellee operates the wells pursuant to required permits; appellants' subsurface property rights are not absolute and in these circumstances are contingent upon interference with the reasonable and foreseeable use of the properties; the trespass alleged is an indirect one and, due to the type of invasion alleged, physical damage or actual interference with the reasonable and foreseeable use of the properties must be demonstrated; appellant's trespass claim is a novel one, of a type previously unrecognized by any court. When all of the circumstances of this case are considered, appellants' evidence of trespass was simply too speculative. **[***29]** The trial court was correct in refusing to direct a **[**994]** verdict in appellants' favor that a trespass had occurred. In fact, we believe that the trial court could have granted a directed verdict to appellee on that claim at the close of appellants' presentation of evidence. [1] However, we cannot fault the trial court in these circumstances for allowing the claim to survive beyond that stage. Due to the unique nature of appellants' claim, the trial court understandably erred on the side of caution in allowing the case to go forward.

[*30]** Appellants make several arguments concerning procedural and substantive rulings made by the trial court that allegedly prejudiced their right to a fair trial. In particular, appellants take issue with the failure of the trial court to make the class action findings required by Civ.R. 23, as discussed by this court in *Warner v. Waste Mgt., Inc.* (1988), 36 Ohio St. 3d 91, 521 N.E.2d 1091. *Warner* stands for the proposition that specific findings should be made in virtually every class action. The error, if any, is now moot. As to the trial court's refusal to grant a continuance, we find no abuse of discretion under the specific facts of this case. Furthermore, we believe that many of the rulings of the trial court that appellants object to were made as they were due to the speculative nature and novelty of appellants' claims. The procedural progress of this case was tied to the uncertainty of the substantive claims being made, and the procedural and substantive difficulties magnified each other, and caused many of the proceedings in this case to lack focus. For example, the dispute over the location of the injectate had a direct and inseparable effect on the problems encountered **[***31]** by the trial court in determining whether to bifurcate the action and also caused difficulties in defining the class.

[*29] We are convinced that, at bottom, the question of the actual location of the injectate, at best a complicated inquiry not easily susceptible of a definitive answer, was further complicated by the fact that the parties were attempting to illustrate the extent of lateral migration based primarily on experts' hypothetical models that were each attacked in minute detail as flawed by the other side. When the nature of the alleged property invasion is considered in light of appellants' apparent lack of specific and readily demonstrable concrete damage, this was a highly unusual case. The parties in this litigation disagreed on virtually every facet of this case, both factually and legally, from the outset, which further complicated the role of the several judges who presided over the action and of the jury.

We will not individually address all of the issues posed by appellants' remaining propositions of law. Rather, we simply state that we find no abuse of discretion in the rulings of the trial court on these issues.

In addition, we agree with the holding of the court **[***32]** of appeals as to appellant Rauch's appeal and affirm it.

For all the foregoing reasons, the judgment of the court of appeals is affirmed.

Judgment affirmed.

DOUGLAS, F.E. SWEENEY, COOK and STRATTON, JJ., concur.

MOYER, C.J., concurs in judgment only.

PFEIFER, J., concurs in part and dissents in part.

Concur by: PFEIFER (In Part)

Dissent by: PFEIFER (In Part)

Dissent

PFEIFER, J., concurring in part and dissenting in part. I dissent from the majority's holding that the measure of compensation enunciated by this court in Columbia Gas Transm. Corp. v. Exclusive Natural Gas Storage Easement (1993), 67 Ohio St. 3d 463, 620 N.E.2d 48, is inapplicable to this case. The jury should have been instructed to apply the *Columbia* **[**995]** *Gas* test to determine whether any part of plaintiffs' properties affected by the injection had any rental value. I concur with the remainder of the majority opinion.

End of Document

[1] Against one member of the class, a directed verdict might not have been proper. An officer of a local business, Superior Forge and Steel Corporation, testified that his company abandoned plans to drill for natural gas on its property after learning of the deepwell waste disposal. After conducting a thorough review of this witness's testimony, we question whether, as a factual matter, the company would have actually followed through on plans to drill for gas on its property. However, if Superior Forge actually was prevented from enjoying the reasonable and foreseeable use of its property by appellee's deepwell operations, it may have had a cognizable trespass claim against appellee. In any event, this claim was resolved in appellee's favor by the verdict.

Central Appalachian Basin CarbonSAFE Integrated Pre-Feasibility Project

Attachment 3 - Economic Analysis

Overview

1. Scenarios Analyzed
2. Cost Analysis Methodology and Assumptions
3. Capital and Operating Costs
4. Summary
5. Anticipated Financial Needs and Strategies

Background

This attachment describes the economic analysis methodology, assumptions and results for the integrated CO2 source-transport-storage opportunities identified in the Central Appalachian Basin of eastern Ohio as part of CAB-CS program. Also discussed in this appendix are estimated financing needs and strategies necessary to develop, own and operate a successful project in this region. The economic analysis for CAB-CS focused on developing source-to-sink business case scenarios which were modeled using a comprehensive discounted cash flow financial model adapted from the FutureGen 2.0 integrated commercial carbon capture and storage project. The results of this analysis help to demonstrate how an integrated capture and storage project can be economically viable and likely to be viewed positively by the public and other stakeholders.

Acronym List

Btu	British thermal unit
EBIT	earnings before interest and taxes
kW	kilowatt
kWh	kilowatt hour
MMBtu	million Btu
MW	megawatt
MWh	megawatt hour
NGCC	natural gas combined cycle
NOL	net operating loss
SPC	sub-critical pulverized coal
SCPC	super-critical pulverized coal

1. Scenarios Analyzed

A source-to-sink business case scenario for the CAB-CS program consisted of a CO_2 source, pipeline, and storage site(s). The scenarios identified for the pre-feasibility phase (Phase I) of the project are listed in Table 1 below. Multiple CO_2 sources, rather than a single source, were considered in the analysis in two distinct categories; electric generation facilities and industrial facilities. The sources considered included: 1) retrofit of a super critical coal-fired power plant with carbon capture; 2) retrofit of a conventional natural gas combined cycle facility with carbon capture; 3) a new natural gas combined cycle facility; 4) a new natural gas-fired technology being developed and built by NET Power, LLC, based on the Allam Cycle; 5) a hydrocarbon cracker facility being developed in Belmont County, Ohio and; 6) a proposed independent steel manufacturing being developed by New Steel, Inc. in Scioto County, Ohio.

The prefeasibility study assumed that the project would entail a 50-million metric tonne (MMt) storage goal over 30 years (1.67-million tonnes annually) with a start date of 2025. Site screening was performed to identify and rank selected areas within the CAB-CS storage complex. As required by the FOA a primary and secondary saline storage site was identified and modeled for the pre-feasibility phase. The two selected storage site areas identified were: Area B in Coshocton County, Ohio, and Area A near the intersection of Tuscarawas, Harrison, and Guernsey Counties, Ohio. Area B had a more appealing combination of injection zones and CO_2 sources, so it was designated the primary site (Figure 1).

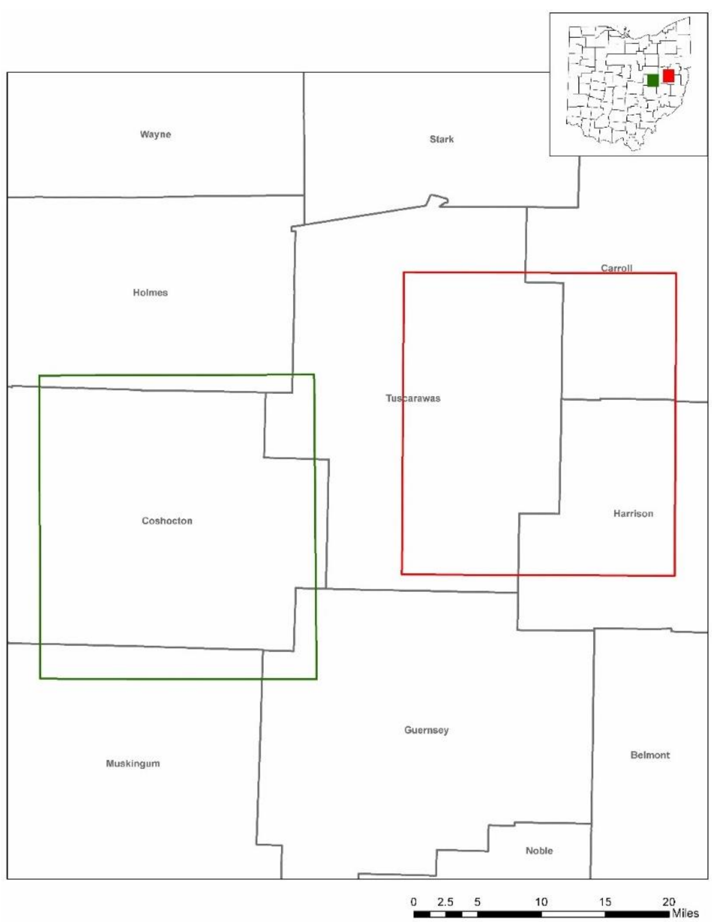

Figure 1. Study Areas A (red outline) and B (green outline).

The sub-basinal analysis showed that both sites have suitable geologic setting, storage zone properties, and caprock for the CAB-CS facility. The deep Cambrian-Ordovician aged rock layers have multiple flow zones with high transmissivity that have been confirmed by brine disposal well tests and long-term operations in the region. The results of dynamic modeling predict a two-well injection system would be adequate and that the critical pressure and CO_2 saturation plume would extend to an area less than 18 mi^2 at both sites. CO_2-EOR, in a 50/50 combination with saline storage and 100% EOR storage were also evaluated as alternate storage mechanisms.

Table 1. CO_2 source and storage options evaluated in the economic analysis

Category	Source Type	Storage Site Location
Electric Generation	Super Critical Pulverized Coal Plant (SCPC) Retrofit	Storage Site B
	Natural Gas Combined Cycle Plant (NGCC) Retrofit	Storage Site A
	New NGCC	Storage Site B
	Net Power NGCC	Storage Site B
Industrial Facility	Hydrocarbon Cracker Plant	Storage Site A
	Independent Steel Facility	Storage Site B

2. Cost Analysis Methodology and Assumptions

The economic analysis for the CAB-CS prefeasibility study relied on publicly available cost and performance information from DOE/NETL, Battelle in-house expertise, information from FutureGen 2.0, and expert judgement from members of the project team. In addition, information regarding proposed CO_2 pipeline routes and distances was developed using the Los Alamos National Laboratory's (LANL's) SimCCS program (Middleton and Bielicki, 2009) and elevation changes were found by comparing the source elevation to the elevation of the sink area using Google Earth. The cost estimating sources and method used for each component (source, pipeline and storage reservoir) of a scenario is described below.

2.1 Saline Storage Costs

Preliminary capital, operating, and Class VI permit financial responsibility costs were estimated using the Fossil Energy (FE) National Energy Technology Laboratory FE/NETL CO_2 OnShore Saline Storage Cost Model (DOE/NETL-2017/1669). The cost estimate developed for the 50-MMt storage facility, and used in the analysis, was the same for Site A and B because of the similar geologic conditions. The cost estimates derived from NETL model reflect the input of site specific geologic conditions from data collected by Battelle from their experience with the AEP Mountaineer pilot sequestration project and other well data collected from brine and oil and gas industry. The model default values were used for other costs items with the idea to adjust them as costs became firmer in future phases of the project. Capital and operating costs estimated by this model were in constant 2008 dollars. Each scenario that incorporated saline storage assumed the project lifecycle (i.e., phases and durations) shown in Table 2.

Figure 2 summarize the capital, operating and post-injection site care (PISC) and site closure PISC/SC cost components estimated from NETL storage model for the 50 MMT storage option for either Site A or B. The operations and PISC/SC costs presented are the total over the 30-year forecasted operating period and proposed 50-year post-injection period, respectively. These same costs were also used for the 25 MMT storage option associated with 50/50 storage and EOR combination because the number of wells required to sequester and monitor the CO_2 plume were identical.

Table 2. Storage project phase lifecycle.

Project Phase	Duration (yrs.)	Start Year	End Year	Calendar Years
Site Screening	1	1	1	2018 - 2018
Site Selection & Site Characterization	3	2	4	2019 - 2021
Permitting & Construction	3	5	7	2022 – 2024
Operations	30	8	37	2025 – 2054
PISC and Site Closure	50	38	87	2055 - 2104

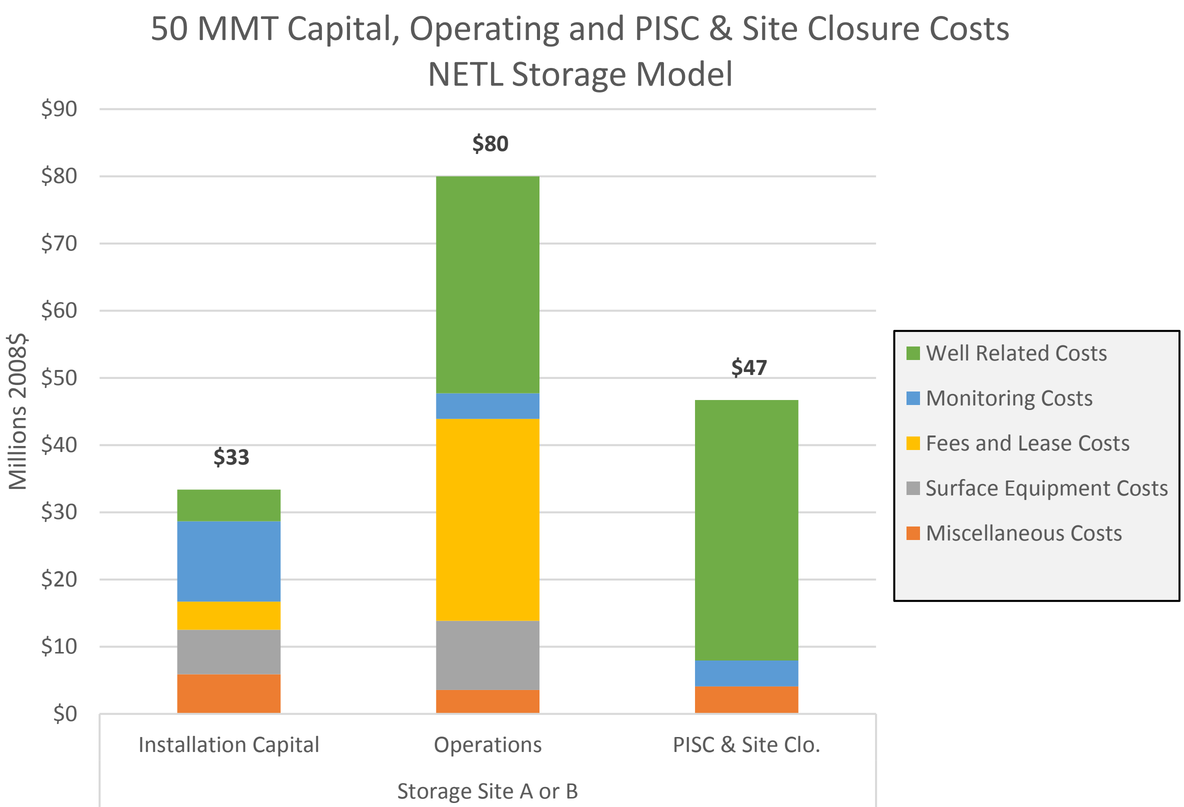

Figure 2. Area A or B MMT capital, operating, and PISC/SC costs in constant 2008$.

2.2 Pipeline Costs

Preliminary CO_2 pipeline capital and operating costs were developed using the NETL FE/NETL CO_2 Transport Cost Model (DOE/NETL-2014/1667). Inputs to this model were developed from the LANL SimCCS simulation of each source-to-sink pipeline route and Google Earth. These inputs included both expected pipeline distance for the route and anticipated elevation changes. This model calculated costs in constant 2011 dollars.

Table 2 provides the estimated pipeline distance to the designated storage site and elevations changes using the LANL SimCCS model for each project source and CO_2 sequestration scenario. These distances and elevation changes along with the pipeline input pressure (2,200 psig) and the pipeline outlet pressure (1,850 psig) were input into the NETL Transport Model to estimate the capital and operating costs summarized in Figures 3 to 4 below.

Table 3. CO_2 Pipeline distances and elevation change between sources and storage options

Category	Source Type	Storage Site Location	Pipeline Distance to Storage Site	Elevation Change
Electric Generation	Super Critical Pulverized Coal Plant (SCPC) Retrofit	Storage Site B	4 miles	252 ft.
	Natural Gas Combined Cycle Plant (NGCC) Retrofit	Storage Site A	21 miles	414 ft.
	New NGCC	Storage Site B	4 miles	252 ft.
	Net Power NGCC	Storage Site B	4 miles	252 ft.
Industrial Facility	Hydrocarbon Cracker Plant	Storage Site A	47 miles	215 ft.
	Independent Steel Facility	Storage Site B	123 miles	460 ft.

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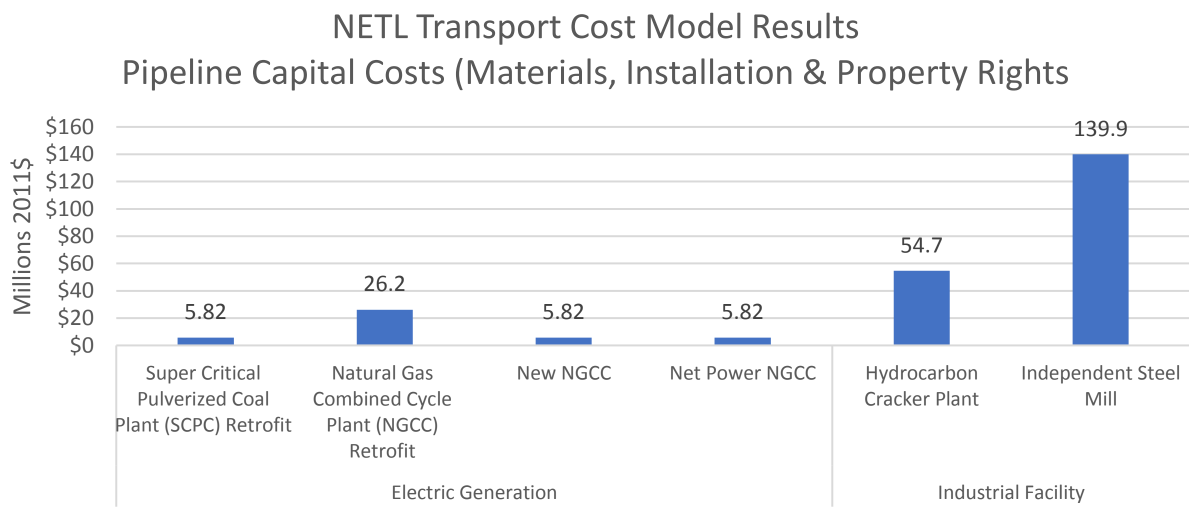


Figure 3. CO2 pipeline capital costs in constant 2011$

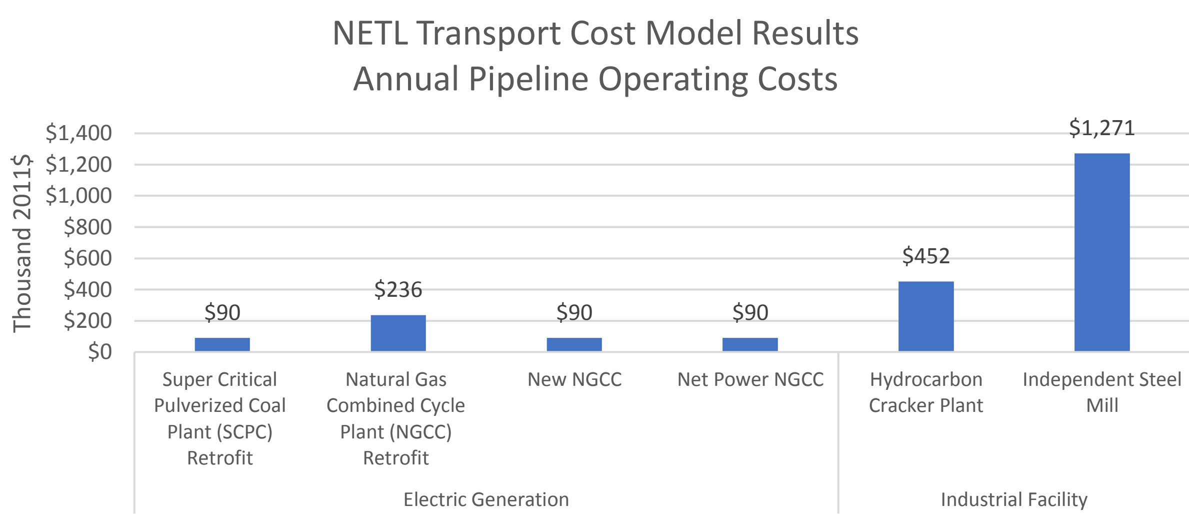


Figure 4. CO_2 pipeline annual operating costs in constant 2011$

2.3 Capture Costs

Preliminary CO_2 capture capital and operating costs were derived from several DOE/NETL studies and presentation materials. For electric power generation CO_2 sources, capital and operating costs were developed using Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3 (DOE/NETL-2015/1723) and Post-Combustion Capture Retrofit: Eliminating the Derate (DOE/NETL-2017). Table 3 summarizes the capital and operating cost components and projected performance of natural gas combined cycle (NGCC), sub-critical pulverized coal (SPC), and super-critical pulverized coal (SCPC) facilities with and without CO_2 capture from the DOE/NETL reports. However, since the CO_2 emissions from the SPC and SCPC facility designs were significantly greater than the 1.67 MMT per year required for the storage project, the costs and performance parameters were scaled down to capture approximately 45% and 46% of the emissions, respectively. The scaled SPC and SCPC costs and performance parameters are shown in Table 4. All costs listed are in constant 2011 dollars.

The cost and performance parameters in Tables 3 and 4 were used to estimate the incremental capital and operating cost of capture for the scenarios described in Table 1. The scaled SCPC costs and performance parameters were used to estimate the incremental cost for CO_2 capture associated with the independent steel mill. This assumption was based on discussions with the project sponsors regarding the power generation source to be developed to support the operations of the proposed steel mill. However, it must be noted that actual capture technology costs are likely to be significantly lower because of cost reductions realized from investments made by DOE's CO_2 capture R&D program and current and next generation technologies proceed from pilot to commercial deployment.

No incremental capital or operating costs for CO_2 capture were assumed for the NET Power Allam cycle technology. Based on a review of the NET Power information, the proposed facility would produce pipeline quality CO_2 as a standard byproduct with no additional infrastructure required for clean-up or compression.

Table 4. Performance and cost parameters for new NGCC, Sub-PC and Super-critical PC with and without CO_2 Capture.

Category	NGCC	NGCC w/ Capture	Sub-Critical PC	Sub-Critical PC w/ Capture	Super-Critical PC	Super-Critical PC w/ Capture
Gross Output - MW	641	601	580	642	580	612
Net Output (including capture) - MW	630	559	550	550	550	550
Net Plant Heat Rate - Btu/kWh	6,629	7,466	8,740	10,953	8,379	10,508
Capacity Factor - %	85%	85%	85%	85%	85%	85%
Total Plant Cost - $x000s	430,931	827,904	1,078,113	1,906,174	1,114,361	1,939,143
Total Plant Cost - $/kW, net	684	1,481	1,960	3,466	2,026	3,526
Fixed O&M – $/kW	25.21	48.96	69.25	112.70	71.46	114.67
Variable O&M - $/MWh	1.66	3.96	9.23	15.09	9.05	14.73
Fuel Consumption - $/MWh	40.70	45.87	25.67	32.18	24.61	30.87
CO_2 Emitted – lb. CO_2/MMBtu	118.50	118.50	204.00	204.00	204.00	204.00
Capture Rate - %	N/A	90%	N/A	90%	N/A	90%
CO_2 Captured – tonne/MWh	N/A	106.65	N/A	187.20	N/A	187.20

Table 5. Performance and cost parameters for new Sub-critical PC and Super-critical PC facilities scaled for 1.67 MMT for CO_2 capture.

Category	Sub-Critical PC w/ Capture	Super-Critical PC w/ Capture
Gross Output - MW	612	612
Net Output (including capture) - MW	550	550
Net Plant Heat Rate - Btu/kWh	9,839	9,477
Capacity Factor - %	85%	85%
Total Plant Cost - $x000s	1,588,400	1,635,150
Total Plant Cost - $/kW, net	2,888	2,973
Fixed O&M – $/kW	90.81	93.77
Variable O&M - $/MWh	12.14	11.98
Fuel Consumption - $/MWh	28.90	27.85
CO_2 Emitted – lb. CO_2/MMBtu	204.00	204.00
Capture Rate - %	44.70%	46.41%
CO_2 Captured – tonne/MWh	91.19	94.67

The capital and operation cost of capture for the hydrocarbon cracker facility were derived from costs reported in the Cost of Capturing CO_2 from Industrial Sources (DOE/NETL-2013/1602) for an ethylene oxide facility. These costs on unit basis are summarized in table 6 below.

Table 6. Performance and cost parameters used for hydrocarbon cracker plant with CO_2 capture

Category	Value
Capacity Factor - %	85%
Total Plant Cost - $/tonne of CO_2 captured	52.565
Fixed O&M – $/tonne of CO_2 captured	2.43
Variable O&M - $/tonne of CO_2 captured	5.47
Purchased Power - $/tonne of CO_2 captured	5.49

2.4 Aggregating Costs

Various ownership structures for the CO_2 capture, pipeline, and storage facilities were evaluated based on possible financing arrangements, regulatory schemes (e.g., rate regulated vs. independent power producer) and risk management considerations and are summarized in Figures 5a through 5d.   Some of these ownership models have been used by CCS projects currently operating, in construction, or previously proposed. For example, the Illinois Industrial Carbon Capture and Storage project in Decatur, Illinois is a fully integrated capture and deep saline storage facility jointly owned by Archer Daniel Midlands with other regional partners. FutureGen, Kemper County and Petro Nova are examples of projects that divided the ownership between the capture, transport and storage or EOR facilities.

The ownership model may also depend on the whether the capture facility is part of regulated utility. For example, in the case of Kemper County, the capture facility and pipeline were both to be included in the rate base of Mississippi Power; whereas, the FutureGen project aimed to recover the costs of CCS through long-term power purchase agreements with rate regulated distribution utilities in Illinois.

To successfully finance an integrated CO_2 capture and storage project from rate regulated natural gas or coal-fired electric generating stations, the State of Ohio will likely need to pass legislation to enable cost recovery by either allowing long-term power purchase agreements to be signed that cover such costs and/or allow the Public Utility Commission of Ohio (PUCO)to include such costs in electricity consumer rates. These types of cost recovery mechanisms are critical to the success of any CO_2 capture and storage project in the absence of a value for carbon in the wholesale electricity markets or federally mandated carbon reduction, even with the potential for EOR revenues included in this project.

At this pre-feasibility stage of the CAB-CS project, the single owner model (Figure 5a) was considered the best opportunity for a project scenario with deep saline storage to be successfully developed and financed. This fully integrated approach eliminates the financial, performance, and contractual offtake risks of having multiple entities involved in a complex project. Project lenders also have a single accountable project sponsor to ensure the facilities are constructed and operated properly. Revenues required to support the incremental costs associated with the CCS were assumed to be available either through the wholesale power market or recovered through a long-term power purchase agreement with one of the rate regulated utilities in Ohio.

Alternative scenarios, such as ownership of pipelines and/or saline and/or EOR storage sites by separate entities, were also considered potentially attractive options. However, this approach would require off-take agreements with the owner of the capture process to manage CO_2 liability issues.

Arrangements for CCS system cost recovery, whether from rate payers, the wholesale power markets or third-party sales of CO_2, along with allocation of federal and state tax and other incentives must be decided prior to final investment decisions regarding the ownership structure.

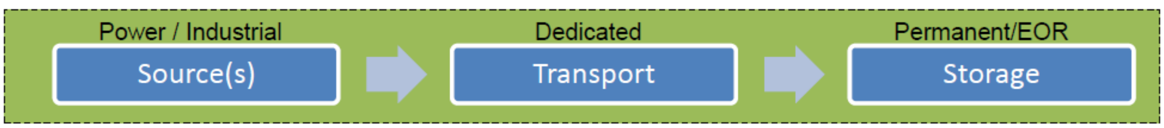


Figure 5a. Integrated CCS project ownership structure in which all project elements are owned by a single entity (Illinois Industrial Carbon Capture and Storage project)

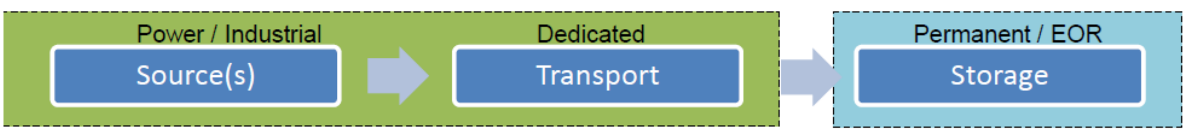


Figure 5b. Single owner of the capture and transport facilities transferring CO_2 to a separately owned storage project or EOR field (Kemper County model)

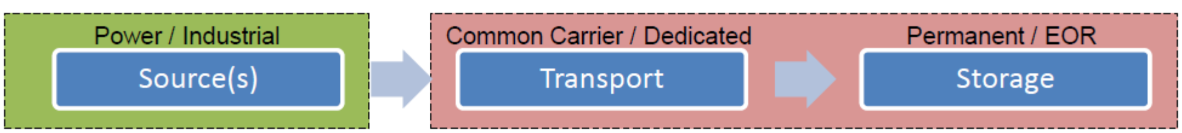


Figure 5c. Separately owned capture facility transferring CO_2 to a single owner of transport and storage project elements (FutureGen and Petro Nova model)

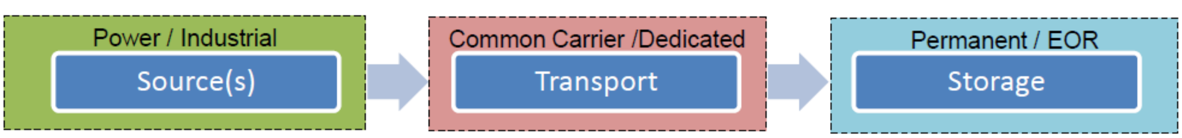


Figure 5d. Fully disaggregated CCS project structure in which all project elements are owned by separate entities

2.4 Assumptions

Key macro-economic and financial assumptions used in the cost analysis are summarized in Table 7 below. Escalation factors for capture, pipeline, and storage capital costs were derived from the Chemical Engineering Plant Cost Index. Escalation assumptions for revenues operating costs were developed using data published by the Philadelphia Federal Reserve**.** All scenarios included the benefits, to the maximum extent possible, from the recently enacted changes to the Federal tax code and to the Section 45Q carbon sequestration tax credits.

Table 7. Macro-economic and financial assumptions

Category	Value
ANALYSIS TIME PERIODS	
Project Start Date:	January 1, 2018
Project Commercial Operation Date	January 1, 2025
Capital Expenditures (including development and permitting)	Storage facility: A-yrs. Pipeline: 3-yrs (<25 miles); 4 years (>25 miles) Capture facility: 4-yrs
Operations	30 years
Post Injection Site Care & Site Closure	25 years
TAXES & TAX CREDITS	
Federal Income Tax[a]	21% statutory rate
State Income Tax	0.26% Gross receipts tax (Ohio does not have a corporate income tax)
State Sales Tax	100% exemption
Local Property Taxes	1% of Pre-finance capital expenditures
Tax Depreciation[b]	Storage Facility: 5-yr MACRS (wells); 15-yr MACRS (equipment and other costs) Pipelines: 15-yr MACRS Capture Facility: 20-yr MACRS
Federal Tax Credits: Section 45Q	Permanent sequestration: 50$/tonne Enhanced oil recovery: 35$/tonne Credit duration: 12-yrs
% of Capital Cost Depreciated	100%
ESCALATION FACTORS	
Capital Expenditures	3.42% Sources: *Chemical Engineering* Plant Cost Index. Nominal average annual escalation rate between 1950 and 2016
Revenues & Operating Expenditures	2.32% Source: Philadelphia Federal Reserve *Livingston Survey* long-term inflation forecast
COMMODITY PRICES	
Sale of CO_2 for EOR	25$/tonne (2018$)

Notes: [a] The calculation of Federal income tax liability included the limitation on interest deduction of 30% of EBIT starting in 2022, however this limitation does not apply to regulated utilities. Also included in the Federal income tax calculations was the limitation on NOL utilization of 80%; [b] 40% bonus depreciation was included based on the assumed project commercial operation date of January 1, 2025.

Financing assumptions were based on possible business ownership structures, (i.e., whether the project was subject to rate regulation), and differentiated between low and high costs of capital. These assumptions are listed in Table 8 below. The resulting pre-tax and after-tax costs of capital for each business structure are provided in Tables 9 through 11.

Table 8. Financing and Owners Cost Assumptions

Category	Regulated Utility		Independent Power Producer		Industrial Facility	
	Low Cost of Capital	High Cost of Capital	Low Cost of Capital	High Cost of Capital	Low Cost of Capital	High Cost of Capital
FINANCING						
Assumed credit rating	A	BBB	BBB	BBB-	BBB	BBB-
Construction financing all-in interest rate	3.14%	3.84%	3.84%	4.69%	3.84%	4.69%
12-mo. LIBOR Rate	1.77%	1.77%	1.77%	1.77%	1.77%	1.77%
Credit spread – long term average	1.37%	2.07%	2.07%	2.92%	2.07%	2.92%
Commitment fee	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Up-front fees	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Legal & other consultant costs (% of debt)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
Term financing – all-in interest rate	4.27%	4.97%	4.97%	5.82%	4.97%	5.82%
Treasury Rate (30-yr)	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
Credit spread – long term average	1.37%	2.07%	2.07%	2.92%	2.07%	2.92%
Tenor (yrs.)	30	30	30	30	30	30
P&I repayment schedule	Mortgage Style	Mortgage Style	Mortgage Style	Mortgage Style	Mortgage Style	Mortgage Style
Debt service reserve (months of P&I)	0	0	0	0	0	0
Working capital (months of OPEX)	2	2	2	2	2	2
LOC Fee on debt reserve + working capital	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
After-tax cost of equity	10%	11%	10%	15%	15%	20%
OWNERS COSTS						
Insurance (% of Pre-financing CAPEX)						
Builders risk (construction period)	1%	1%	1%	1%	1%	1%
Operating period	1%	1%	1%	1%	1%	1%
Commissioning & start-up (months of O&M)						
Capture facility	12	12	12	12	12	12
Pipeline and storage reservoir	6	6	6	6	6	6
Capital spares (% of Pre-financing CAPEX)	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Owners management reserve (% of Pre-financing CAPEX + financing costs)	15%	15%	15%	15%	15%	15%

Table 9. Pre-tax and after-tax costs of capital – Regulated Utility

Category	% of Total	Cost of Funds	Pre-Tax Weighted Cost of Funds	After-Tax Weighted Cost of Funds
LOW COST OF CAPITAL				
Equity	45	10%	4.50%	4.50%
Debt	55	4.27%	2.35%	2.35%
Total	100		6.85%	6.85%
HIGH COST OF CAPITAL				
Equity	50	11%	5.50%	5.50%
Debt	50	4.97%	2.49%	2.49%
Total	100		7.99%	7.99%

Table 10. Pre-tax and after-tax costs of capital – Independent Power Producer

Category	% of Total	Cost of Funds	Pre-Tax Weighted Cost of Funds	After-Tax Weighted Cost of Funds
LOW COST OF CAPITAL				
Equity	30	10%	3.00%	3.00%
Debt	70	4.97%	3.48%	3.48%
Total	100		6.48%	6.48%
HIGH COST OF CAPITAL				
Equity	40	15%	6.00%	6.00%
Debt	60	5.82%	3.49%	3.49%
Total	100		9.49%	9.49%

Table 11. Pre-tax and after-tax costs of capital – Industrial Facility

Category	% of Total	Cost of Funds	Pre-Tax Weighted Cost of Funds	After-Tax Weighted Cost of Funds
LOW COST OF CAPITAL				
Equity	30	15%	4.50%	4.50%
Debt	70	4.97%	3.48%	3.48%
Total	100		7.98%	7.98%
HIGH COST OF CAPITAL				
Equity	40	20%	8.00%	8.00%
Debt	60	5.82%	3.49%	3.49%
Total	100		11.49%	11.49%

The discounted cash flow analysis for the source-sink scenarios listed in Table 1 assumed that the electric generation CO_2 sources were included in the rate base of a regulated utility, while the hydrocarbon cracker facility was modeled as an industrial facility, and the independent steel mill power CO_2 source was modeled as an independent power producer.

2.5 Cost Build-Up Methodology

The capital cost estimates for the CO_2 storage and pipeline facilities that were developed using NETL models described above were adjusted to include appropriate owner's costs including; start-up and commissioning, working capital, builders risk insurance, upfront financing costs and related fees. These constant dollar cost estimates were then escalated at the capital cost escalation rate listed in Table 7 from 2008 and 2011 dollars respectively to arrive at a total "overnight" estimate for both the storage and pipeline facilities at the project start date of January 1, 2018.

The starting point for developing the overall total capital costs for the CO_2 capture facilities was the Total Plant Cost (TPC) for the various capture technologies listed in Tables 4 through 6. As described above for the storage and pipeline estimates, the TPC was adjusted to include appropriate owner's costs and in addition to process and project contingencies included in the TPC, an owner's management reserve of 15% was added to the total. These constant dollar cost estimates were also escalated from 2011 dollars to arrive at a total "overnight" estimate for the capture facility at the project start date of January 1, 2018. Interest during construction and escalation were included for each of the storage, pipeline and capture facilities during the construction period to arrive at an as-spent mixed-year dollars final estimate prior to the commencement of operations on January 1, 2025.

This cost build-up methodology assumes that an engineering, procurement and construction management (EPCM) strategy will be utilized by the project owners. Use of an EPCM approach is typically more cost effective (compared to a fully wrapped turnkey approach which is referred to as an EPC agreement) because it eliminates the premium paid to contractors for assuming overall performance, schedule and cost risk. An EPCM contract would transfer the overall project completion, integration and performance risk to the owner, and typically requires stronger financial backing from the owner for lenders to support such an arrangement.   No matter the contracting scenario, it is incumbent upon the project owner to ensure that thorough scope definition and engineering is completed prior to the commencement of construction. A phased engineering approach that includes a Front-End Engineering & Design (FEED) phase followed by detailed final engineering is considered advisable to minimize scope changes and cost increases. This approach can produce a level of design and cost certainty that helps to reduce the risk associated with obtaining the necessary financing.

3. Capital and Operating Costs

3.1 Capital Costs

The all-in storage project capital costs in constant 2018 dollars and mixed, as-spent dollars, assuming low a cost of capital and a high cost of capital is shown in Figure 6. The all-in pipeline project capital costs in constant 2018 dollar and mixed, as-spent dollars, for each project scenario listed in Table 1 assuming either a low cost of capital or high cost of capital are shown in Figures 7 through 12. The all-in incremental capture project capital costs in constant 2018 dollar and mixed, as-spent dollars for each project scenario listed in Table 1 assuming either a low cost of capital or high cost of capital are shown in Figures 13 through 17.

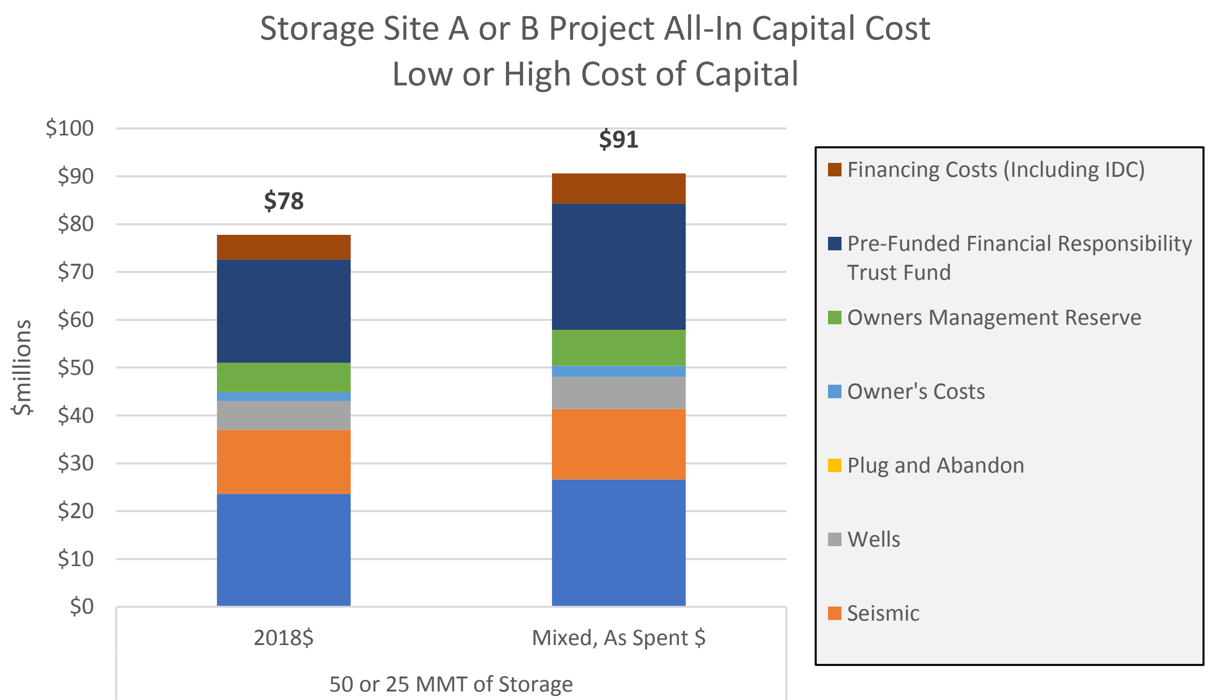


Figure 6. Storage Site A or B total project capital in 2018$ and mixed, as spent dollars assuming a low or high cost of capital

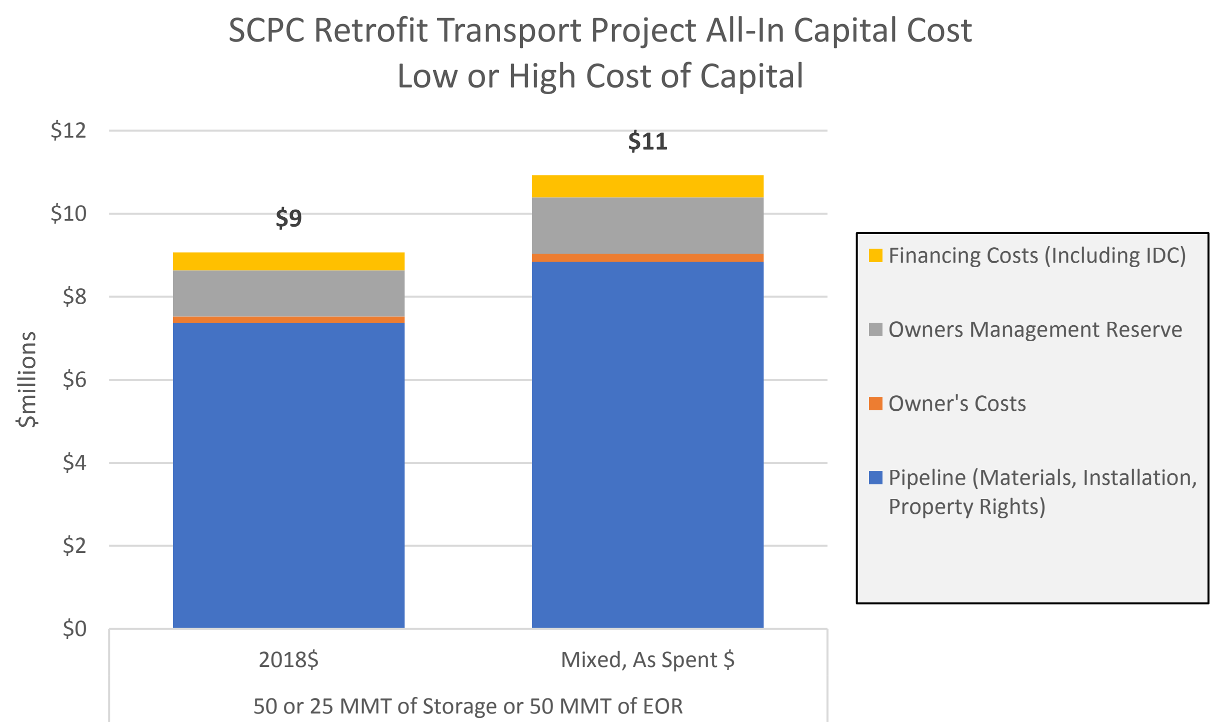


Figure 7. SCPC retrofit scenario transport all-in capital costs in 2018$ and mixed, as spent dollars with a low or high cost of capital

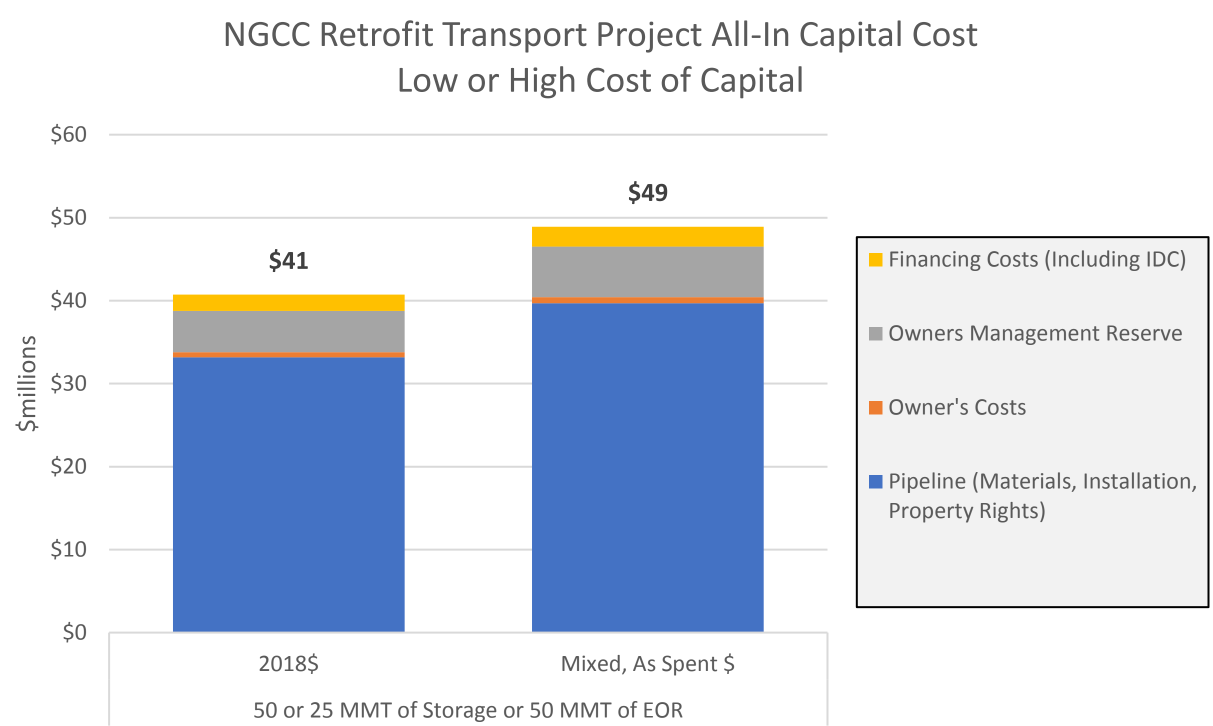


Figure 8. NGCC retrofit scenario transport all-in capital costs in 2018$ and mixed, as spent dollars with a low or high cost of capital

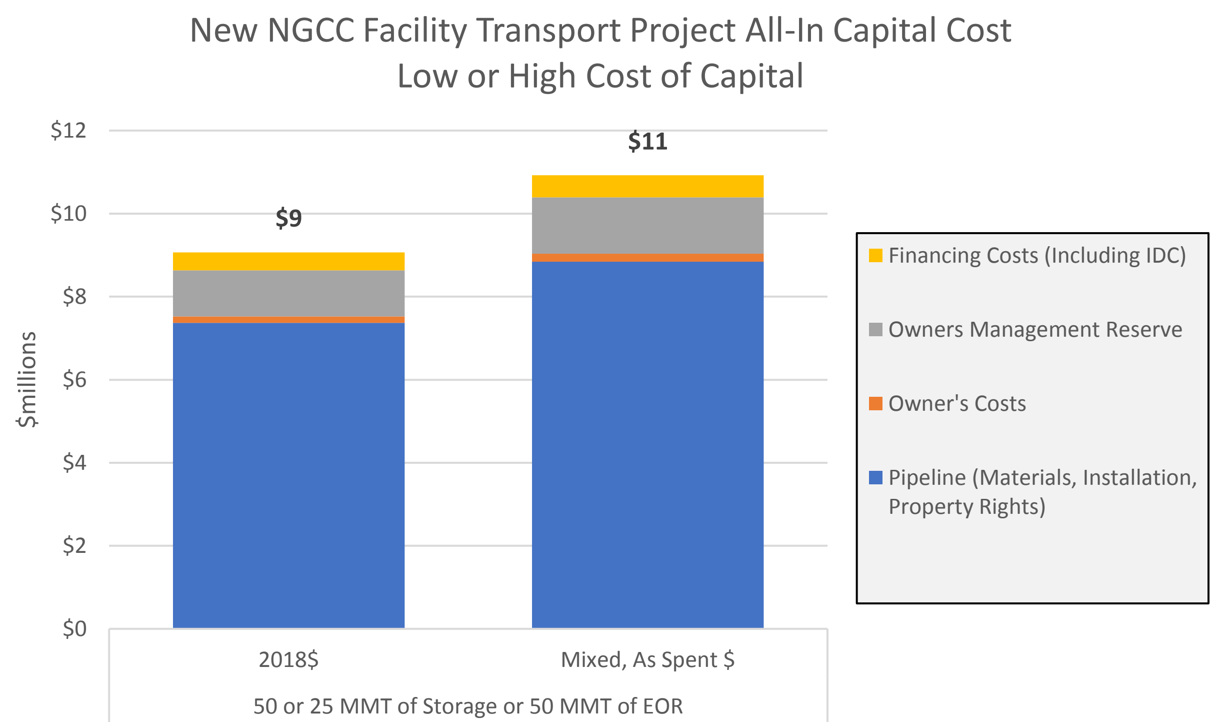


Figure 9. New NGCC facility scenario transport all-in capital costs in 2018$ and mixed, as spent dollars with a low or high cost of capital

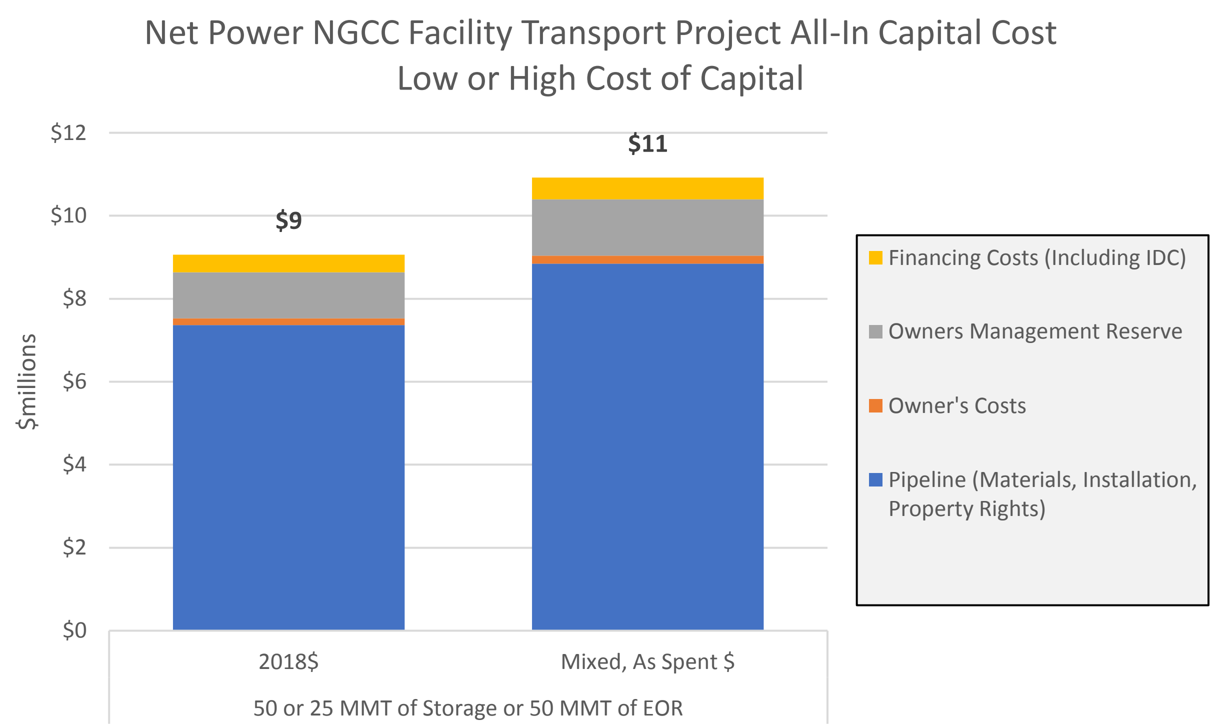


Figure 10. Net Power NGCC facility scenario transport all-in capital costs in 2018$ and mixed, as spent dollars with a low or high cost of capital

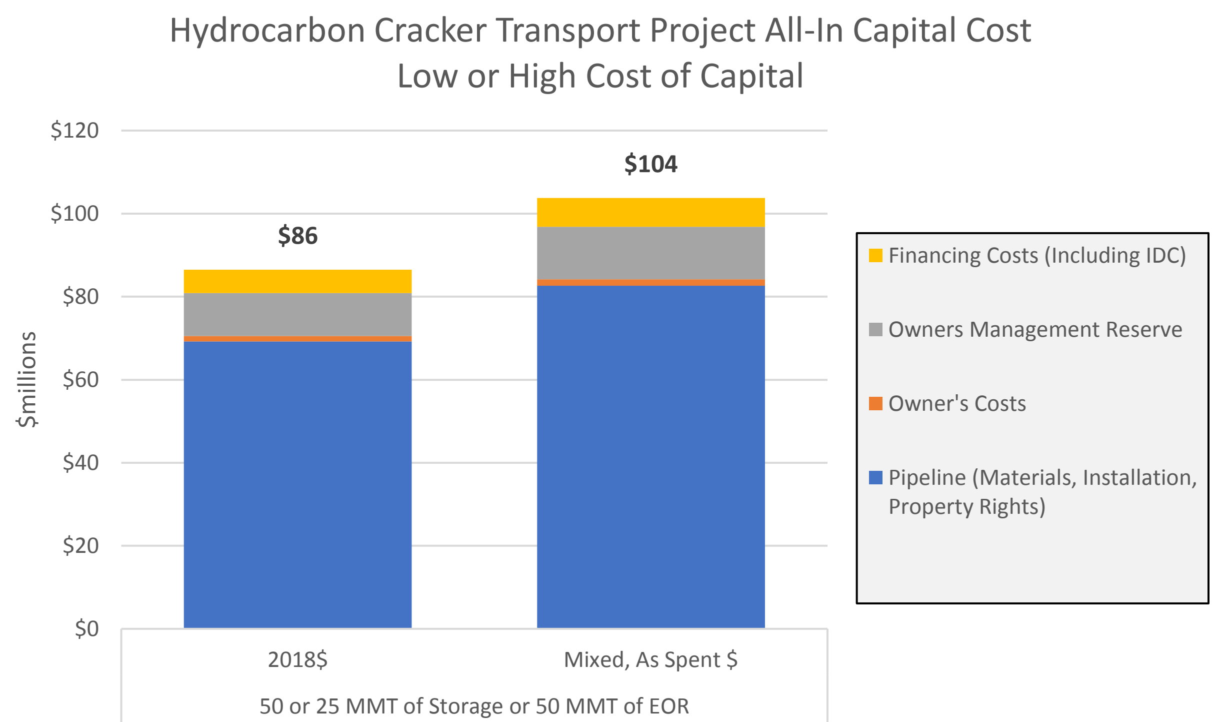


Figure 11. Hydrocarbon cracker facility scenario transport all-in capital costs in 2018$ and mixed, as spent dollars with a low or high cost of capital

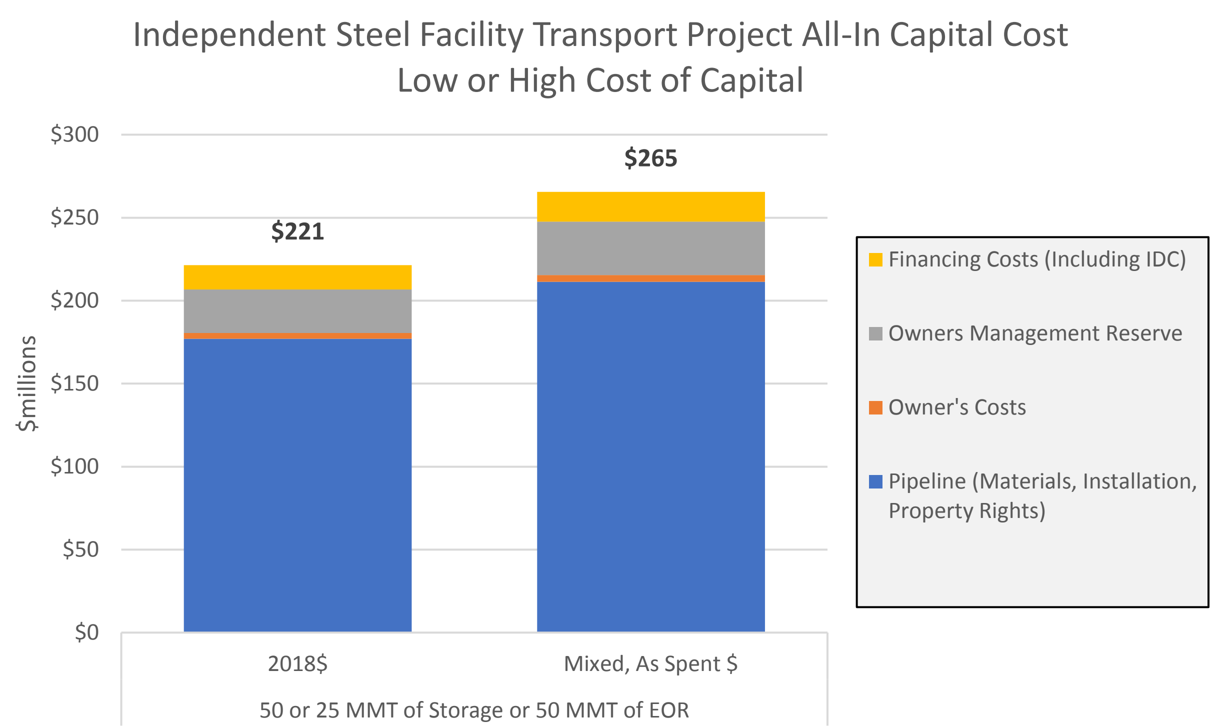


Figure 12. Independent steel mill scenario transport all-in capital costs in 2018$ and mixed, as spent dollars with a low or high cost of capital

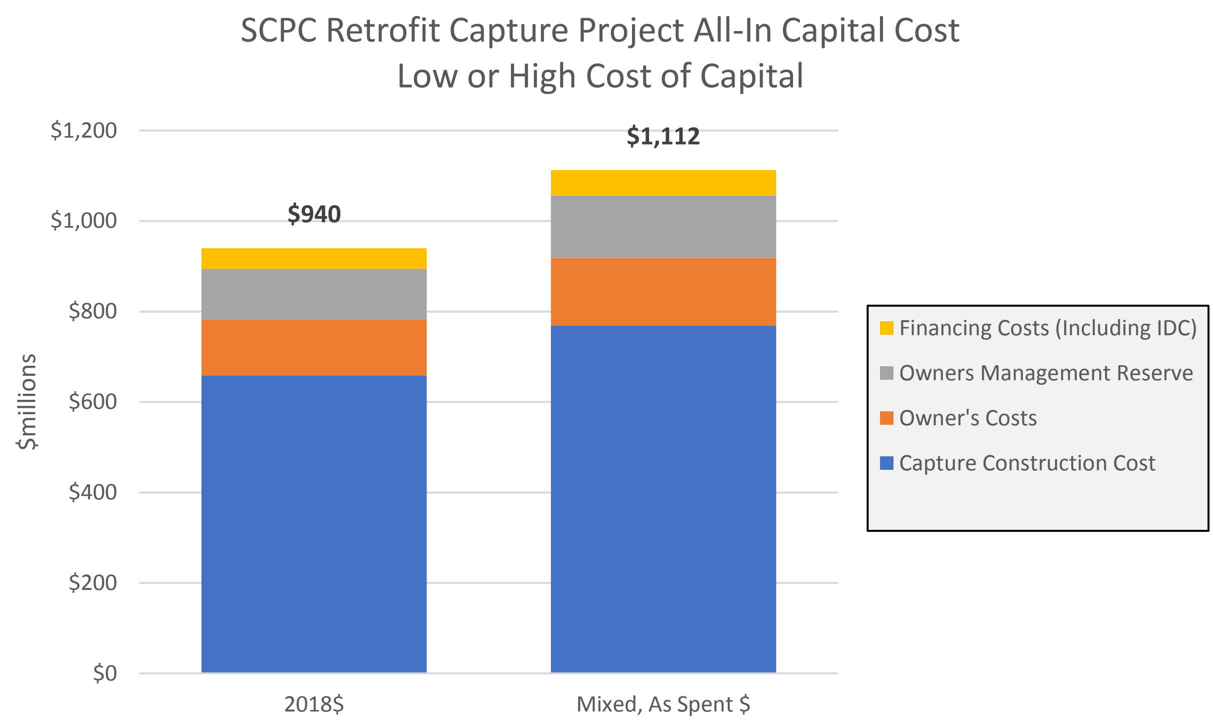


Figure 13. SCPC retrofit scenario incremental capture all-in capital costs in 2018$ and mixed, as spent dollars with a low or high cost of capital

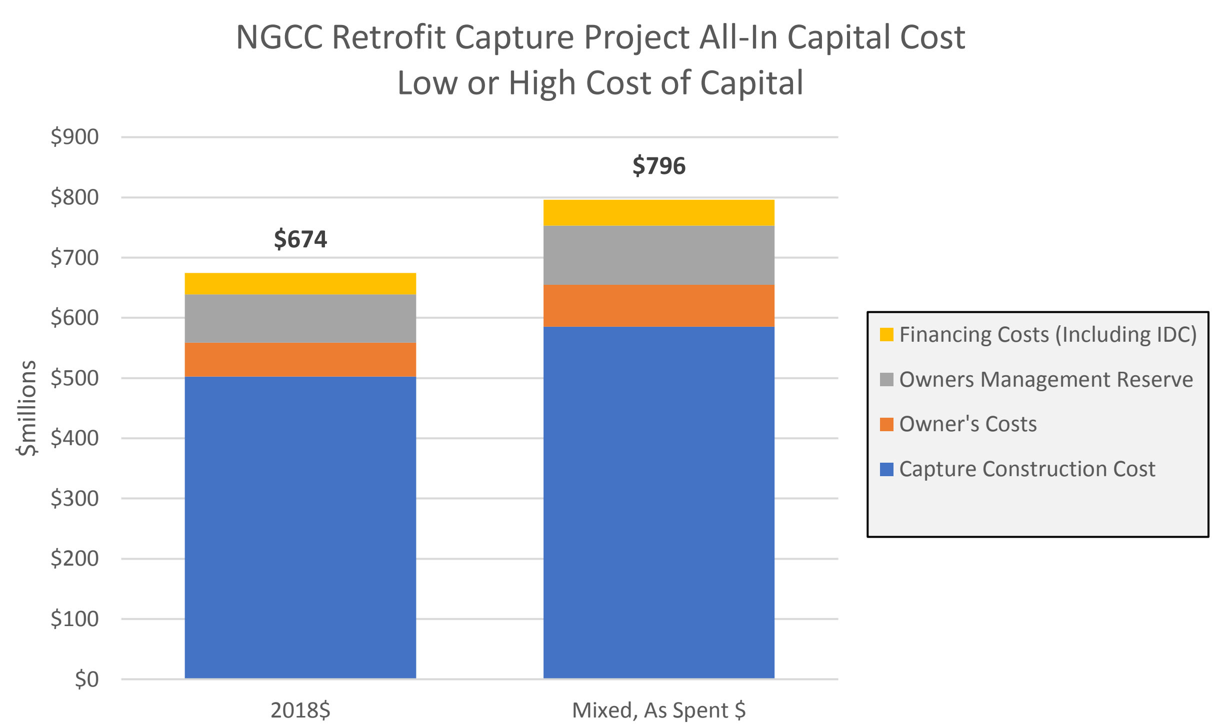


Figure 14. NGCC retrofit scenario incremental capture all-in capital costs in 2018$ and mixed, as spent dollars with a low or high cost of capital

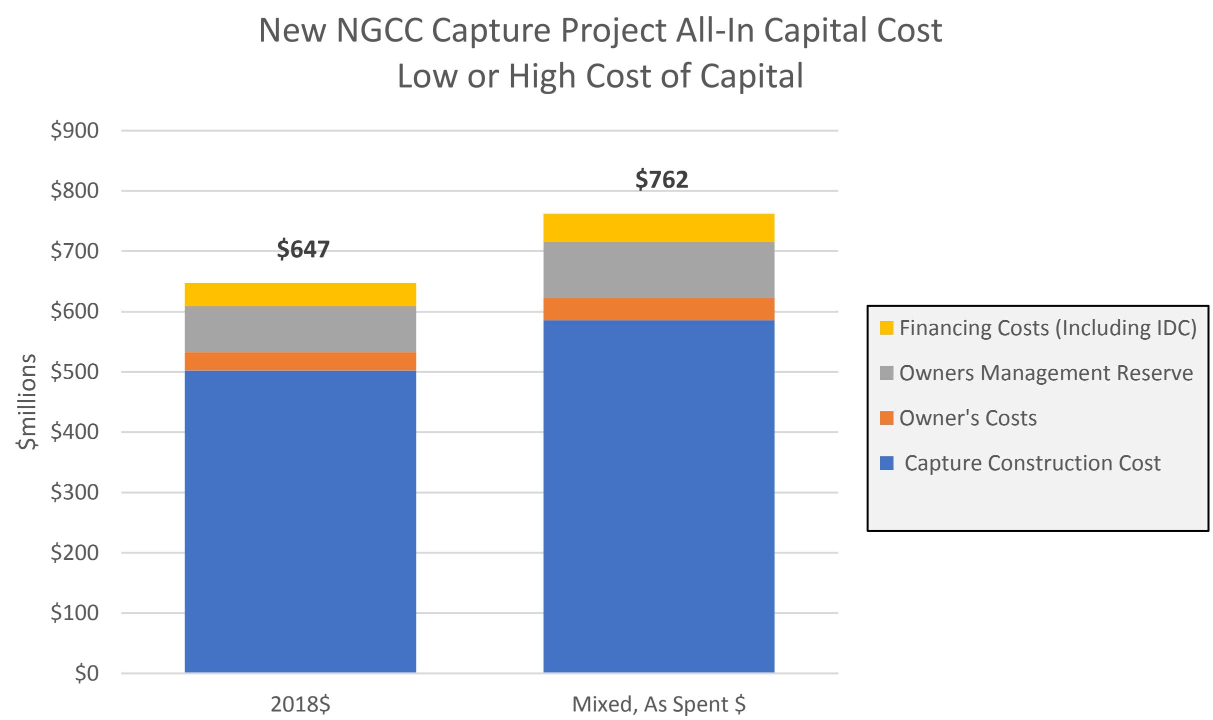


Figure 15. New NGCC scenario incremental capture all-in capital costs in 2018$ and mixed, as spent dollars with a low or high cost of capital

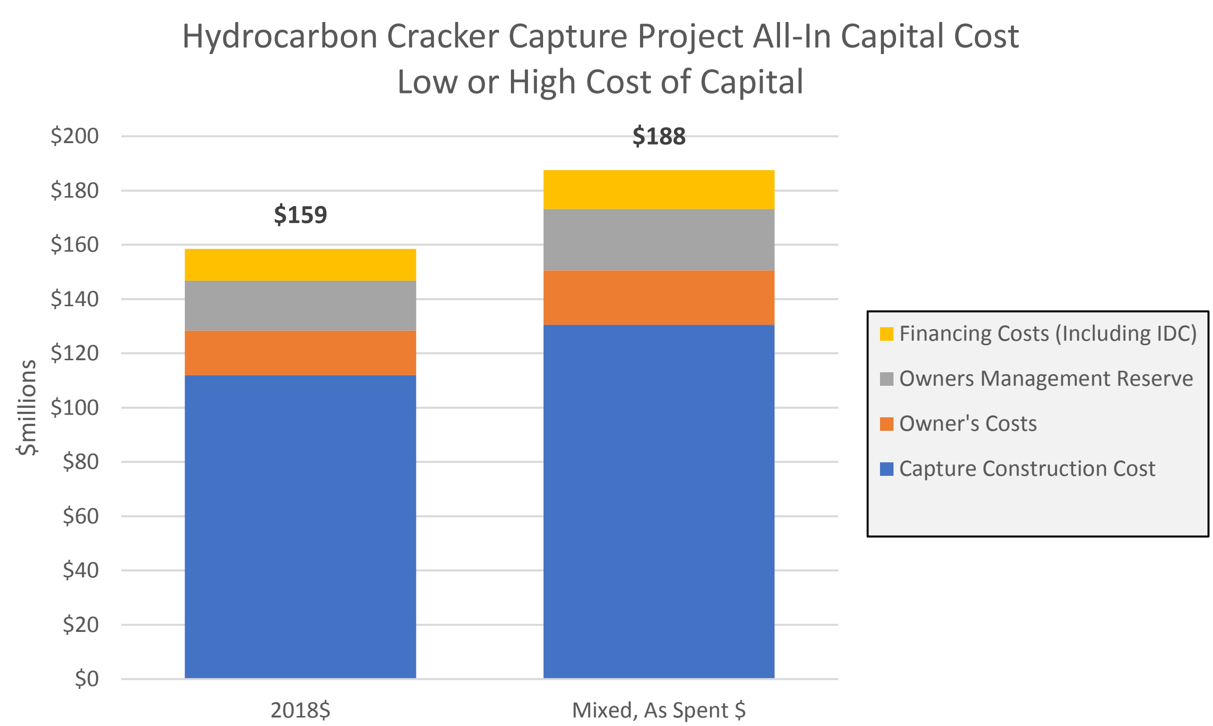


Figure 16. Hydrocarbon cracker scenario incremental capture all-in capital costs in 2018$ and mixed, as spent dollars with a low or high cost of capital

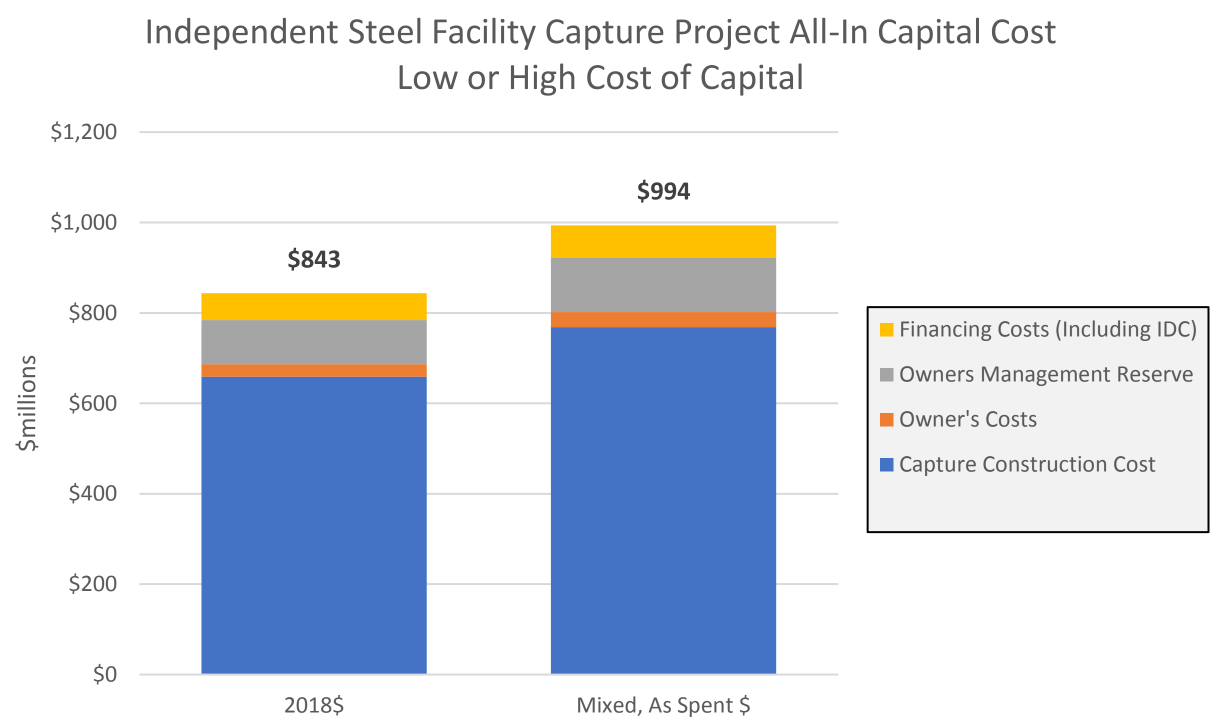


Figure 17. Independent steel mill scenario incremental capture all-in capital costs in 2018$ and mixed, as spent dollars with a low or high cost of capital

3.2 Operating Costs

Operating period costs for the CO_2 storage facility and pipeline were also escalated from 2008 and 2011 dollars respectively to the appropriate year of operation based on operating cost escalation rate in Table 7. Post-injection site care and site closure costs (PISC/SC) were estimated using the NETL storage model and information from Battelle based on the UIC Class VI permitting experience for FutureGen 2.0. These PISC/SC costs were included as part of the estimate of the Financial Responsibility (FR) requirements in EPA's Class VI regulations [40 CFR §146.85]. Fixed and variable operating costs, including fuel and power related costs included in the DOE studies for the capture technologies, were also escalated from 2011 dollars to the appropriate year during the expected 30-year operating period.

3.3 Levelized Costs for Each Scenario

The results of the cost and economic analyses for the scenarios described in Table 1 are summarized below in Figures 18 through 41 (there are four figures for each of the sources: costs levelized in 2018 (start of project) dollars; costs levelized in 2025 (first year of injection) dollars; low cost of capital finance cost; low cost of capital finance cost). Each plot shows the cost components and anticipated source of the revenues for a scenario on a 30-year levelized basis; expressed in either 2018$/tonne (the project-start date) or in 2025$/tonne (the first year of injection) on a low or high cost of capital basis. Furthermore, each cost bar is divided into capture (yellow), transport (blue), and storage (green) components, where applicable. A companion bar of equal value shows the levelized revenue requirement necessary to cover the integrated cost of capture, transport, and storage. In all cases, the primary revenue source is assumed to be either from the market or a ratepayer-based (light blue) source. In cases where

EOR sales were considered, the EOR revenue (gray) is differentiated from the market- or ratepayer-based revenues and reduces the overall amount of revenue to be collected from either the market or ratepayers.

On some plots it appears that capture costs vary within the same CO_2 source and CO_2 capture quantity, when it seems that cost should be the same. This is not an error. The reason the levelized cost of capture varies for the same source depends on the amount of and benefit attributed to the federal tax credits.

- In the case of 50 MMT of storage without EOR, the value of the tax credits is $50/tonne
- In the case of 25 MMT of storage and 25 MMT of EOR, the value of the tax credits is a weighted average of $50/tonne and $35/tonne.
- In the case of 50 MMT of EOR, the value of the tax credits is $35/tonne.

However, in all the cases the upfront capital cost, the ongoing operating costs, and the expected return on equity over the 30-year operating period are the same. What changes is how much benefit the Section 45Q tax credits provide to lower the overall cost of capture.

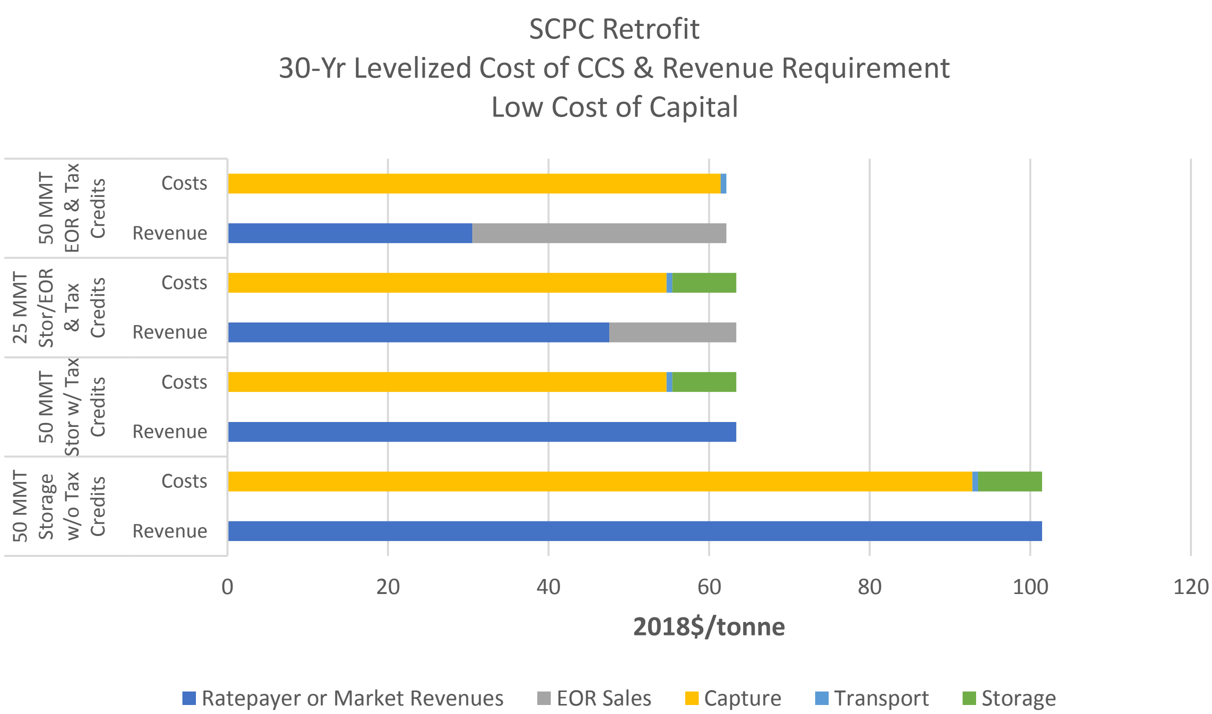


Figure 18. SCPC retrofit scenario levelized cost of CCS and revenue requirements low cost of capital; 2018$/tonne (start of project)

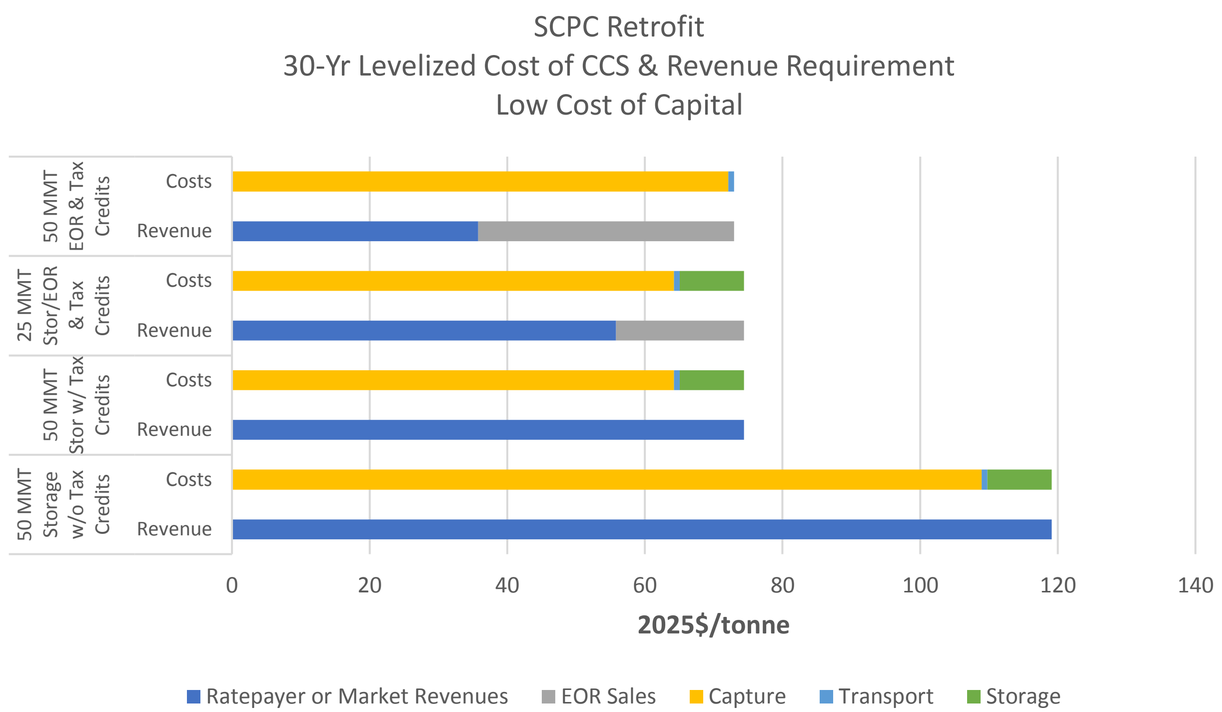


Figure 19. SCPC retrofit scenario levelized cost of CCS and revenue requirements low cost of capital; 2025$/tonne (first year of injection)

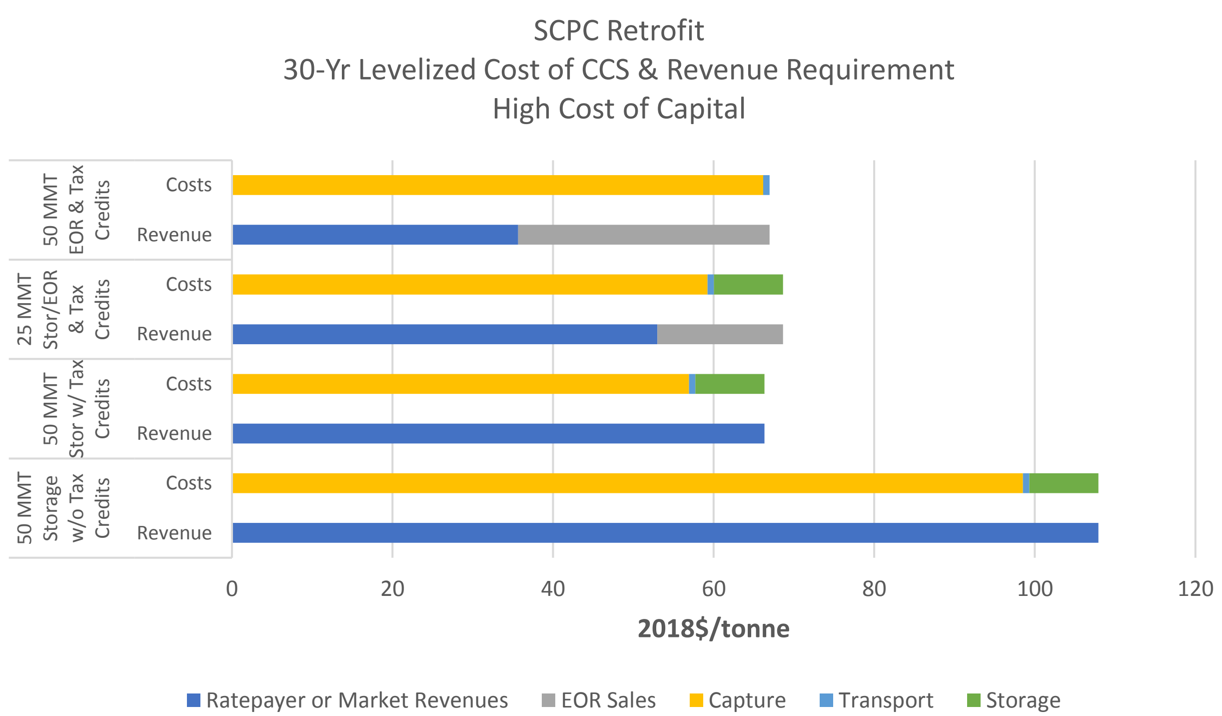


Figure 20. SCPC retrofit scenario levelized cost of CCS and revenue requirements high cost of capital; 2018$/tonne (start of project)

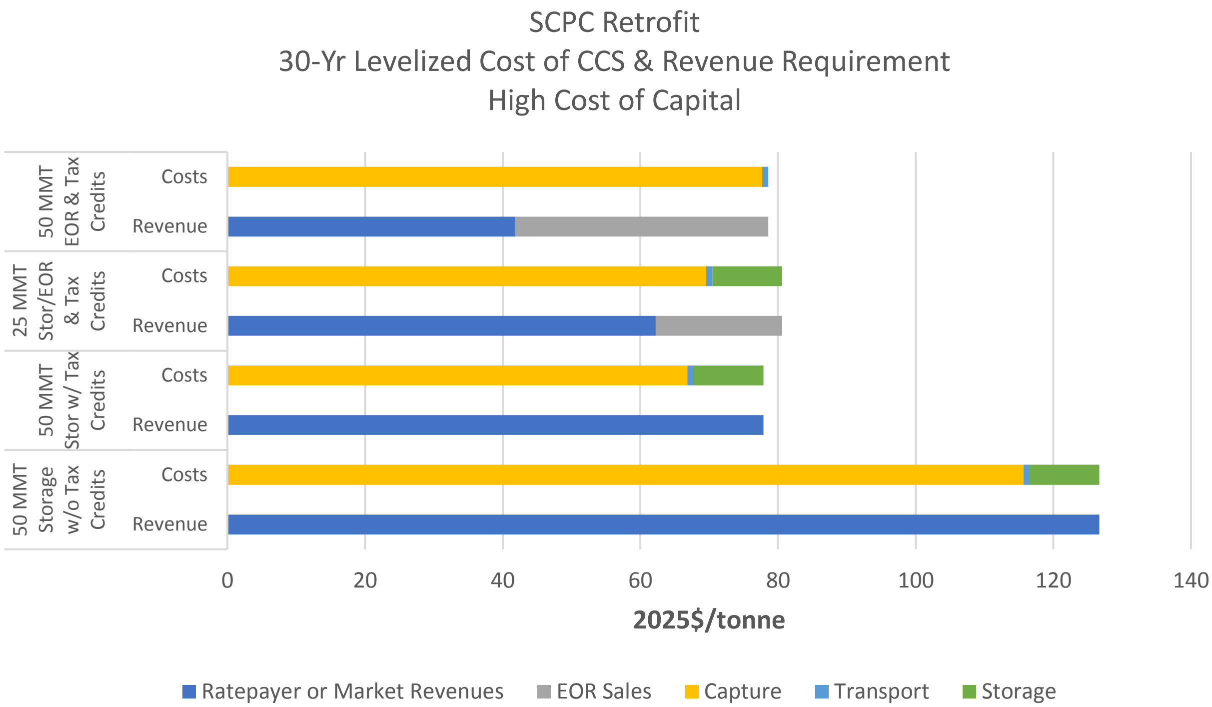


Figure 21. SCPC retrofit scenario levelized cost of CCS and revenue requirements high cost of capital; 2025$/tonne (first year of injection)

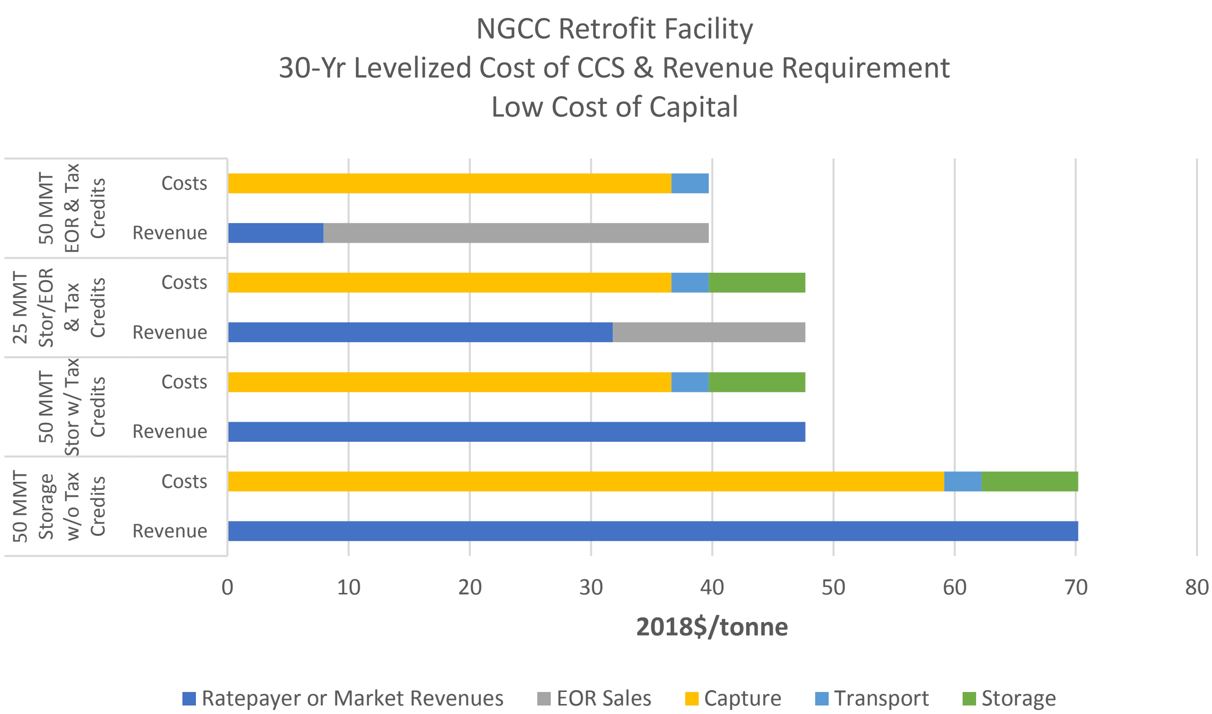


Figure 22. NGCC retrofit scenario levelized cost of CCS and revenue requirements low cost of capital; 2018$/tonne (start of project)

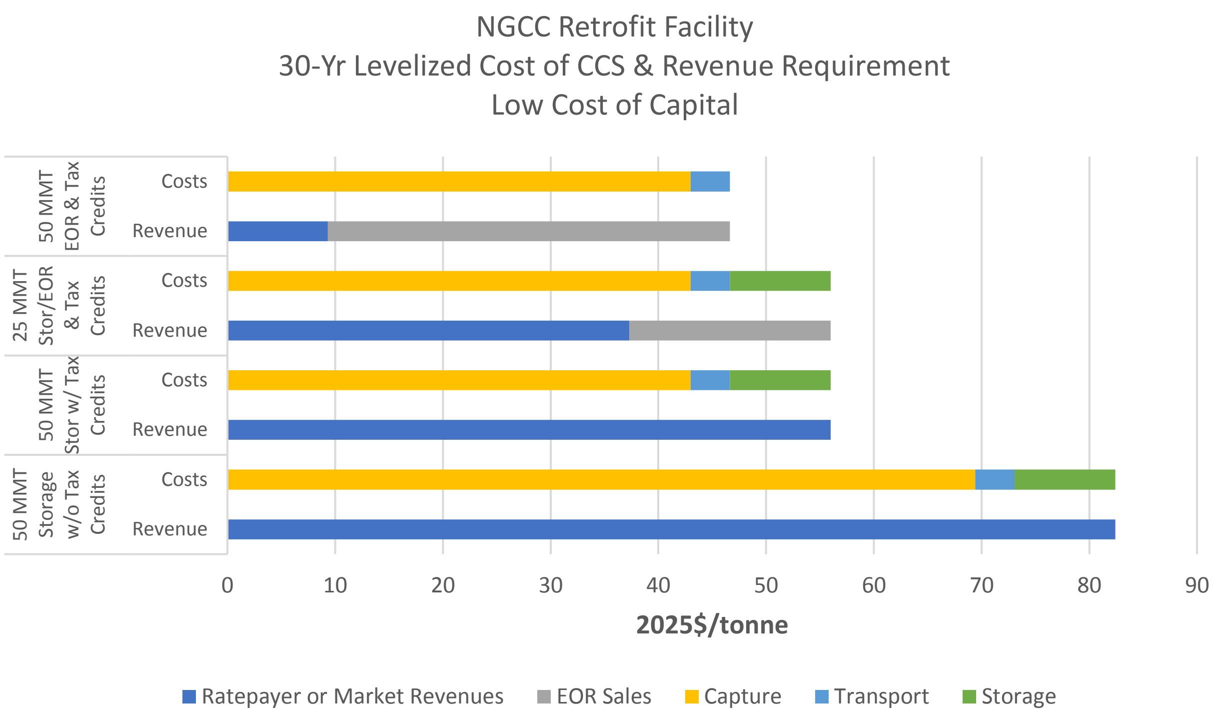


Figure 23. NGCC retrofit scenario levelized cost of CCS and revenue requirements low cost of capital; 2025$/tonne (first year of injection)

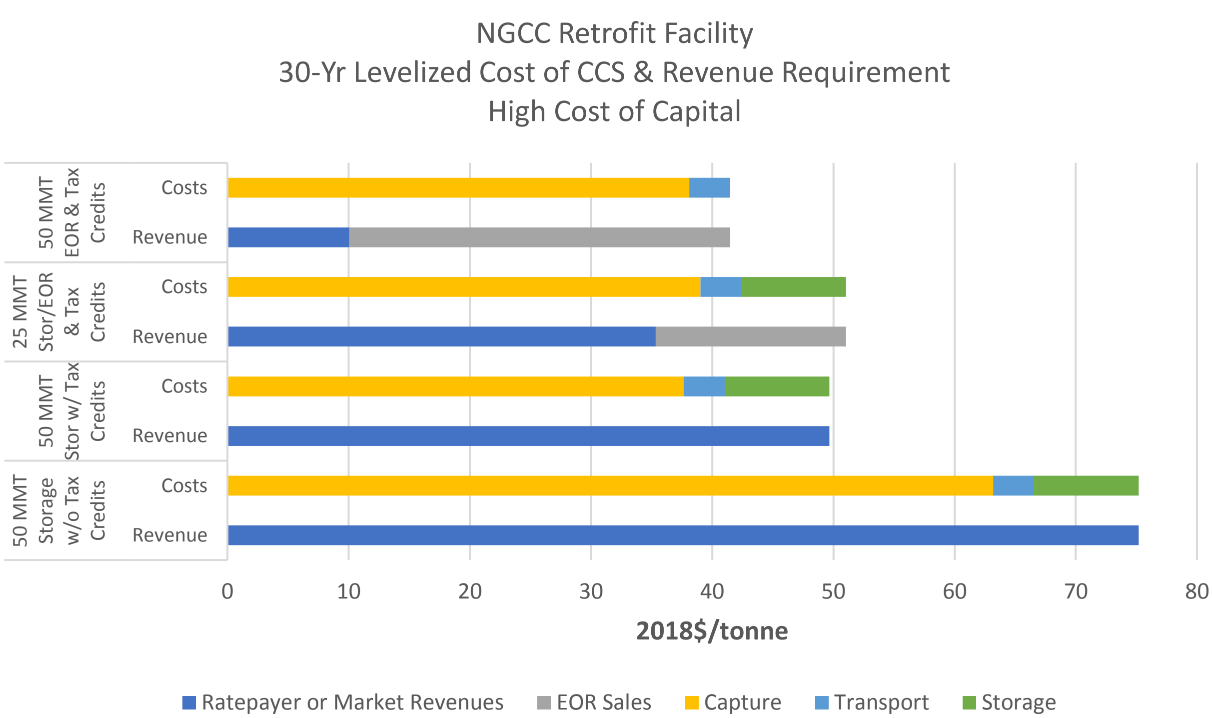


Figure 24. NGCC retrofit scenario levelized cost of CCS and revenue requirements high cost of capital; 2018$/tonne (start of project)

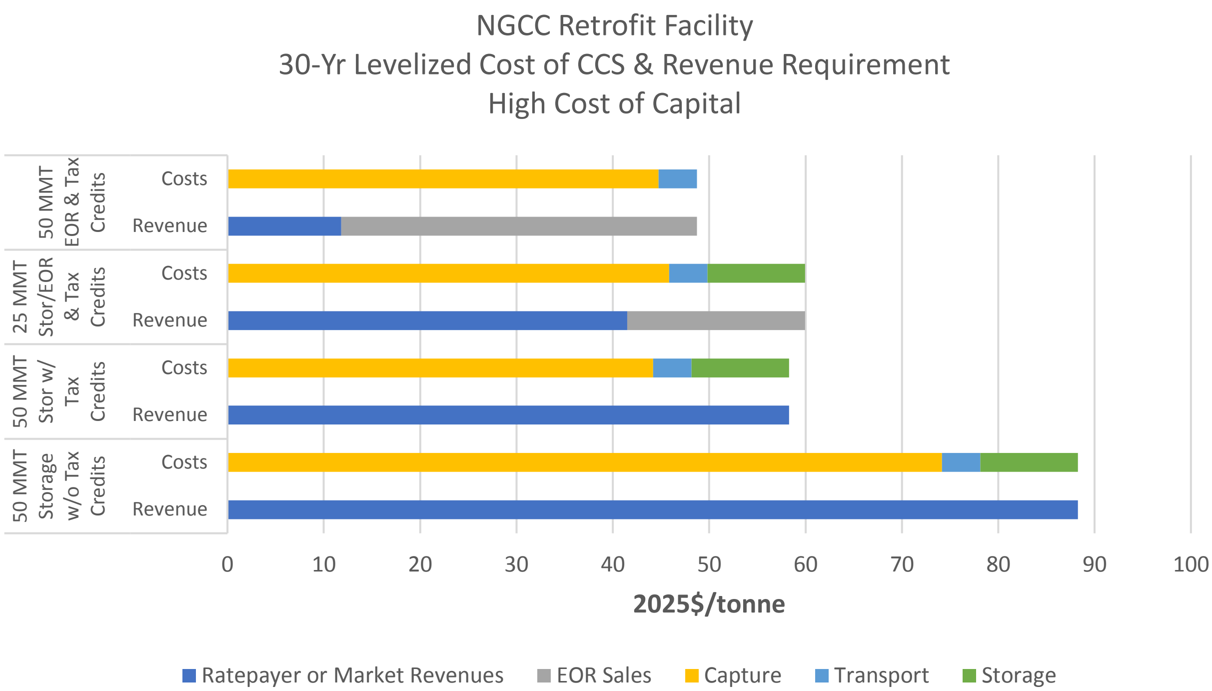


Figure 25. NGCC retrofit scenario levelized cost of CCS and revenue requirements high cost of capital; 2025$/tonne (first year of injection)

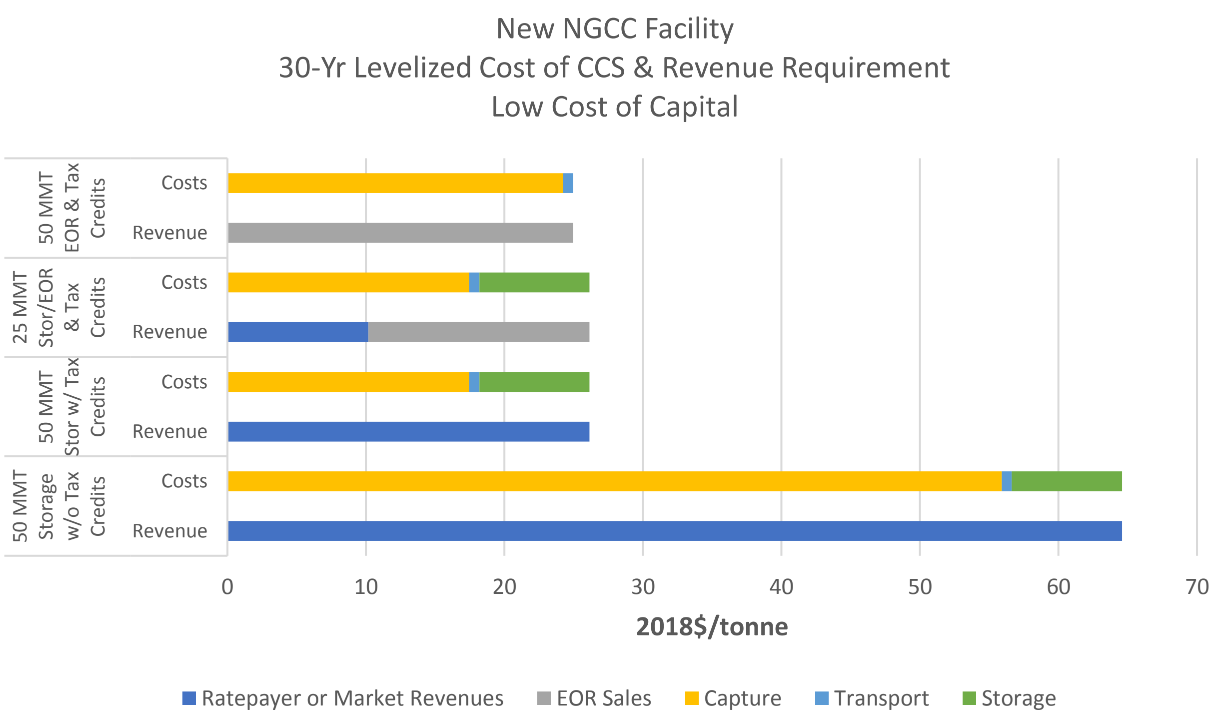


Figure 26. New NGCC facility scenario levelized cost of CCS and revenue requirements low cost of capital; 2018$/tonne (start of project)

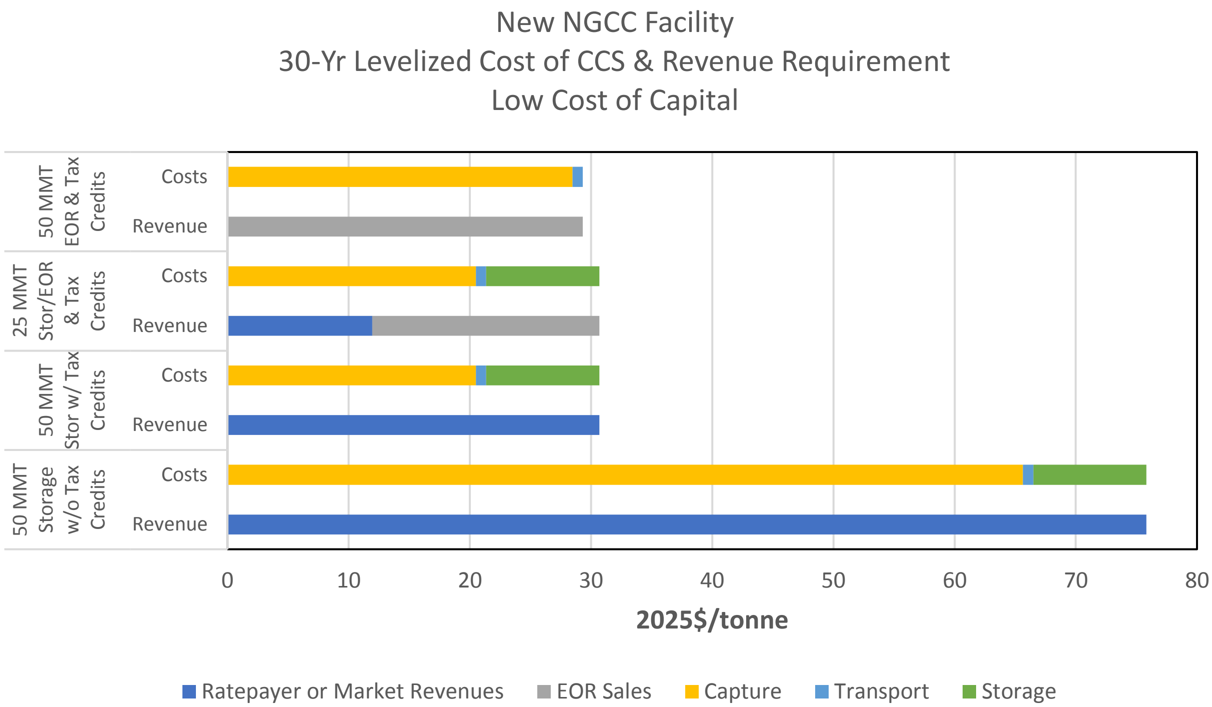


Figure 27. New NGCC facility scenario levelized cost of CCS and revenue requirements low cost of capital; 2025$/tonne (first year of injection)

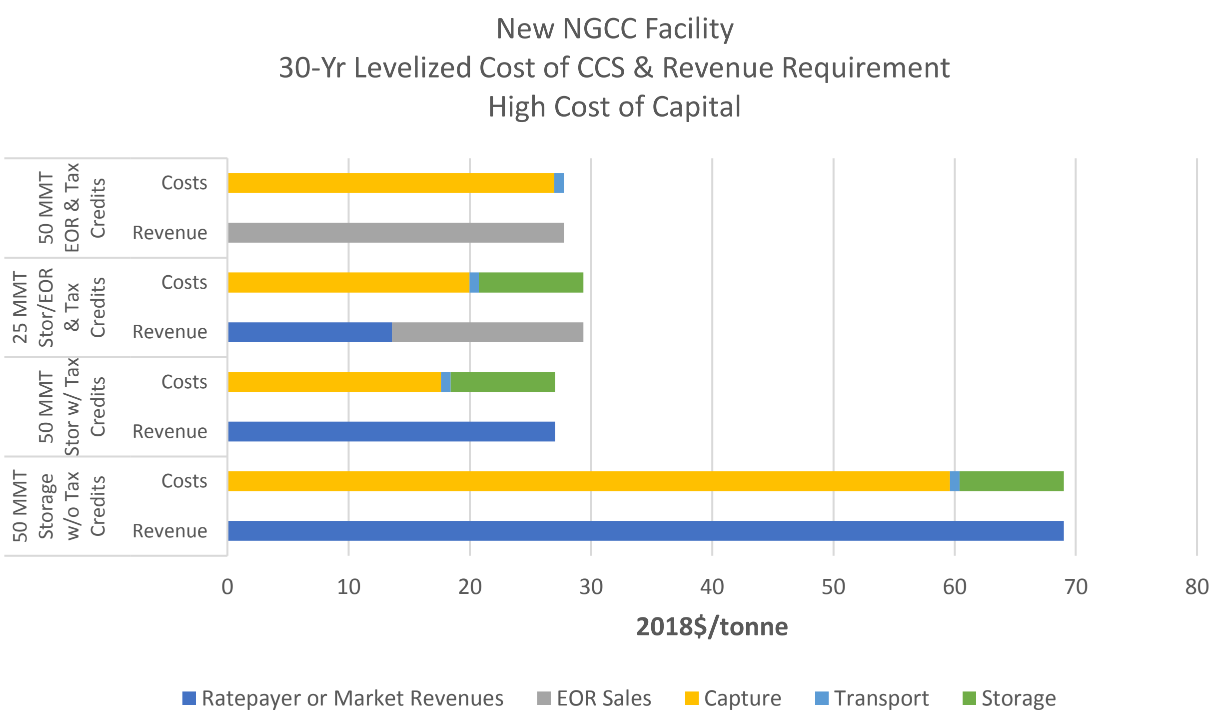


Figure 28. New NGCC facility scenario levelized cost of CCS and revenue requirements high cost of capital; 2018$/tonne (start of project)

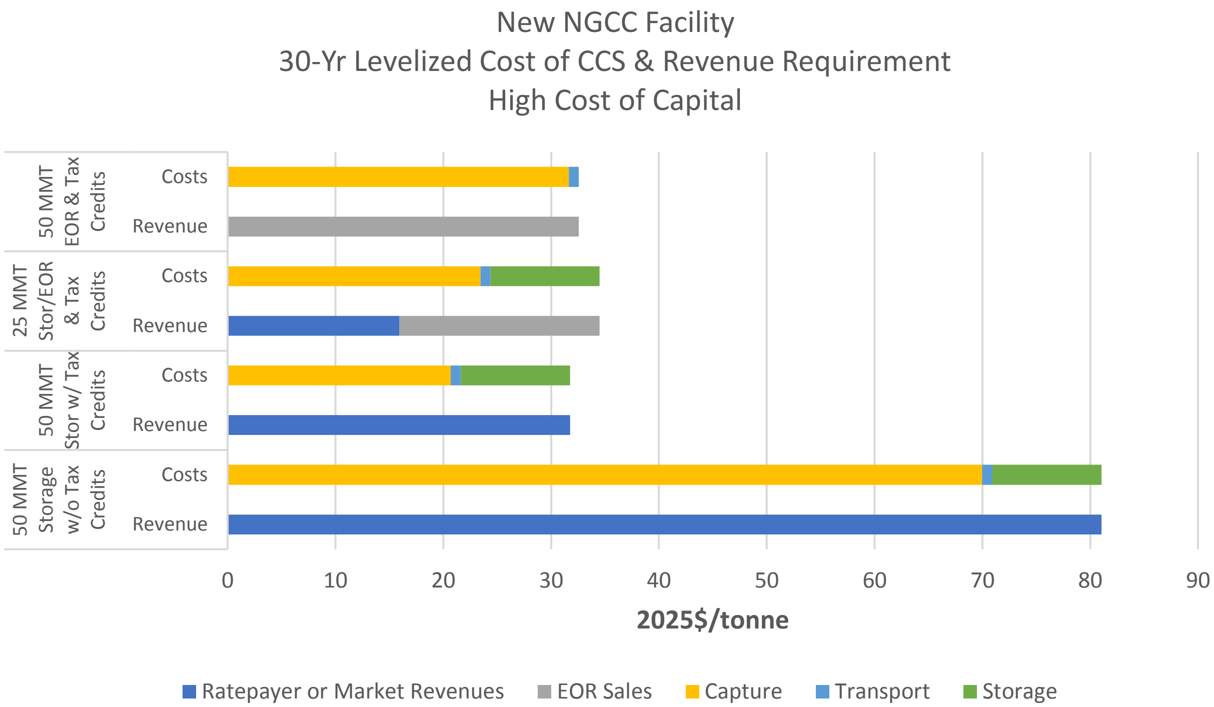


Figure 29. New NGCC facility scenario levelized cost of CCS and revenue requirements high cost of capital; 2025$/tonne (first year of injection)

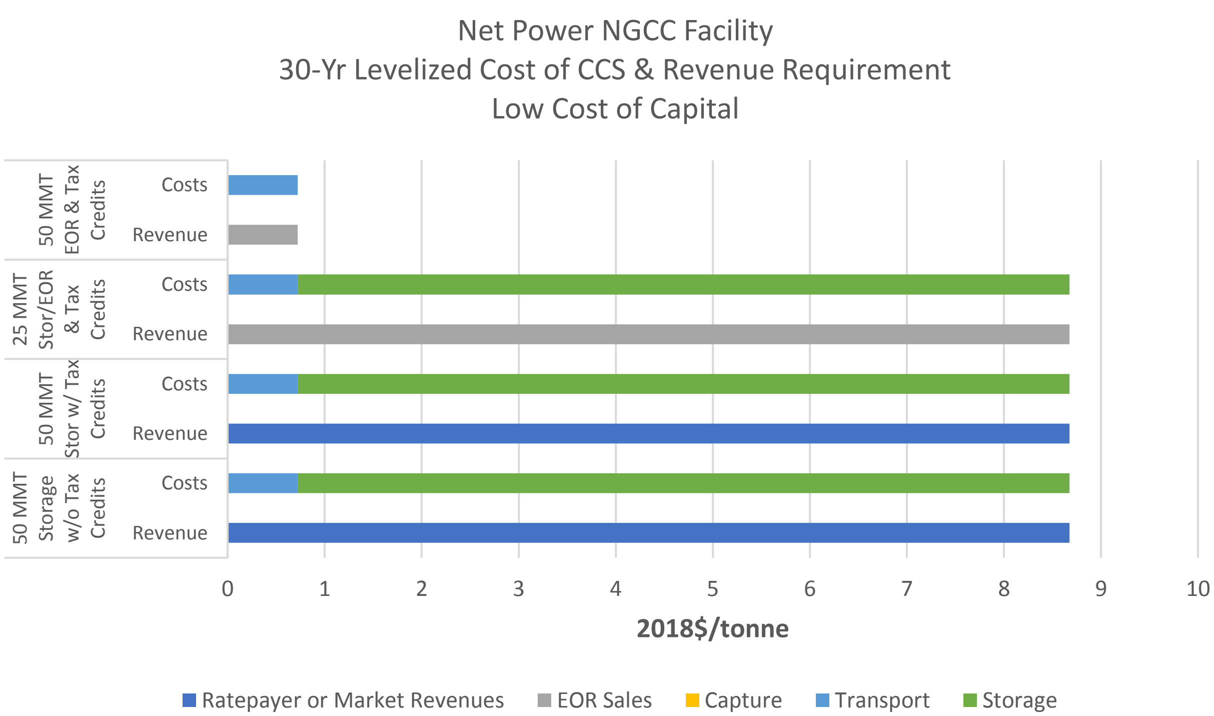


Figure 30. Net Power NGCC facility scenario levelized cost of CCS and revenue requirements low cost of capital; 2018$/tonne (start of project)

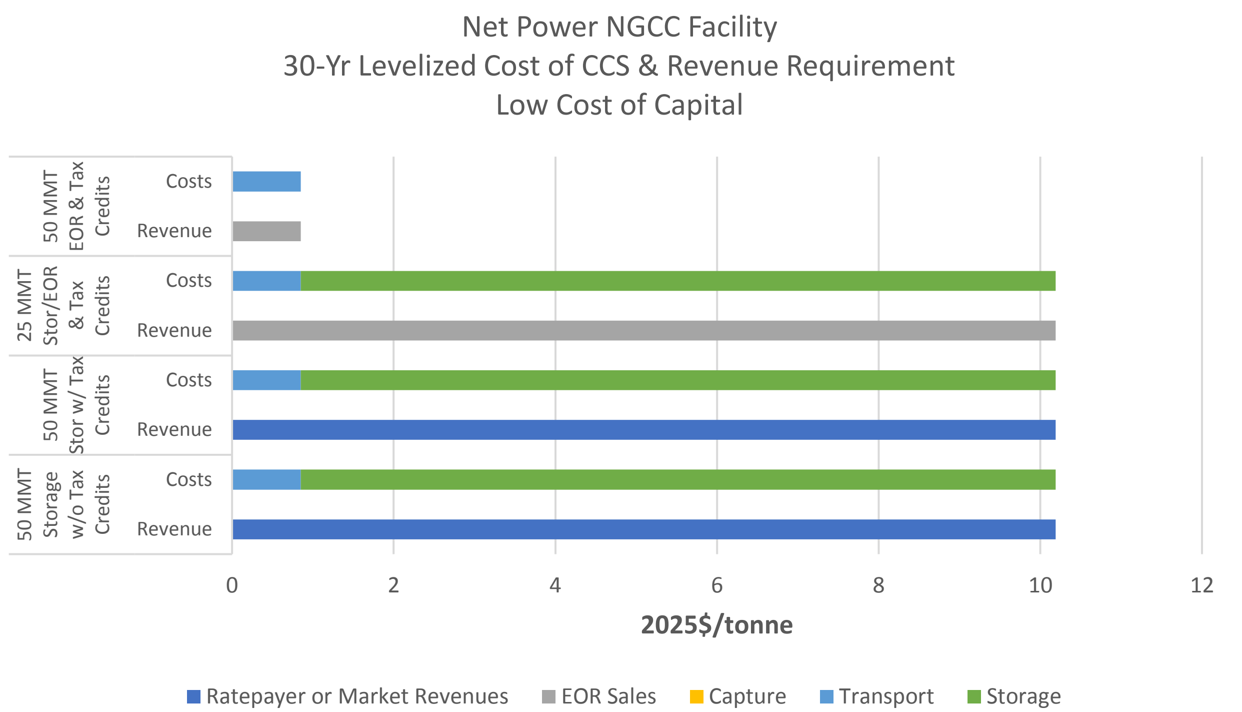


Figure 31. Net Power NGCC facility scenario levelized cost of CCS and revenue requirements low cost of capital; 2025$/tonne (first year of injection)

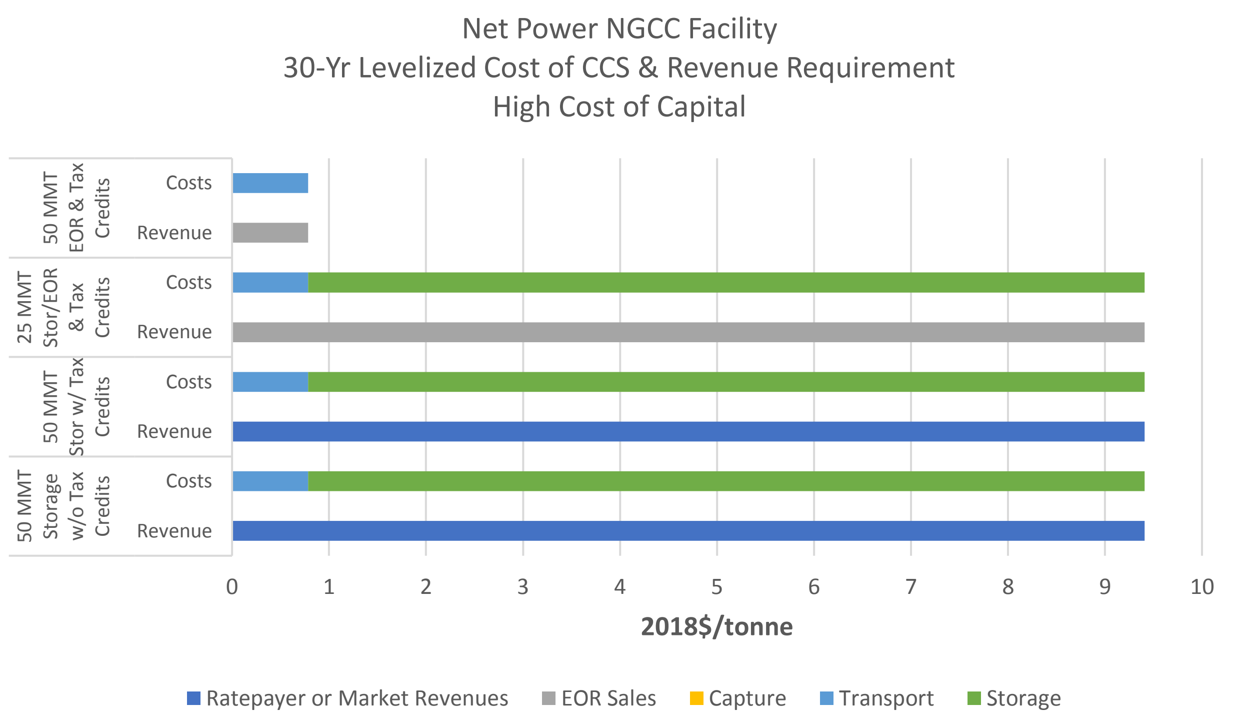


Figure 32. Net Power NGCC facility scenario levelized cost of CCS and revenue requirements high cost of capital; 2018$/tonne (start of project)

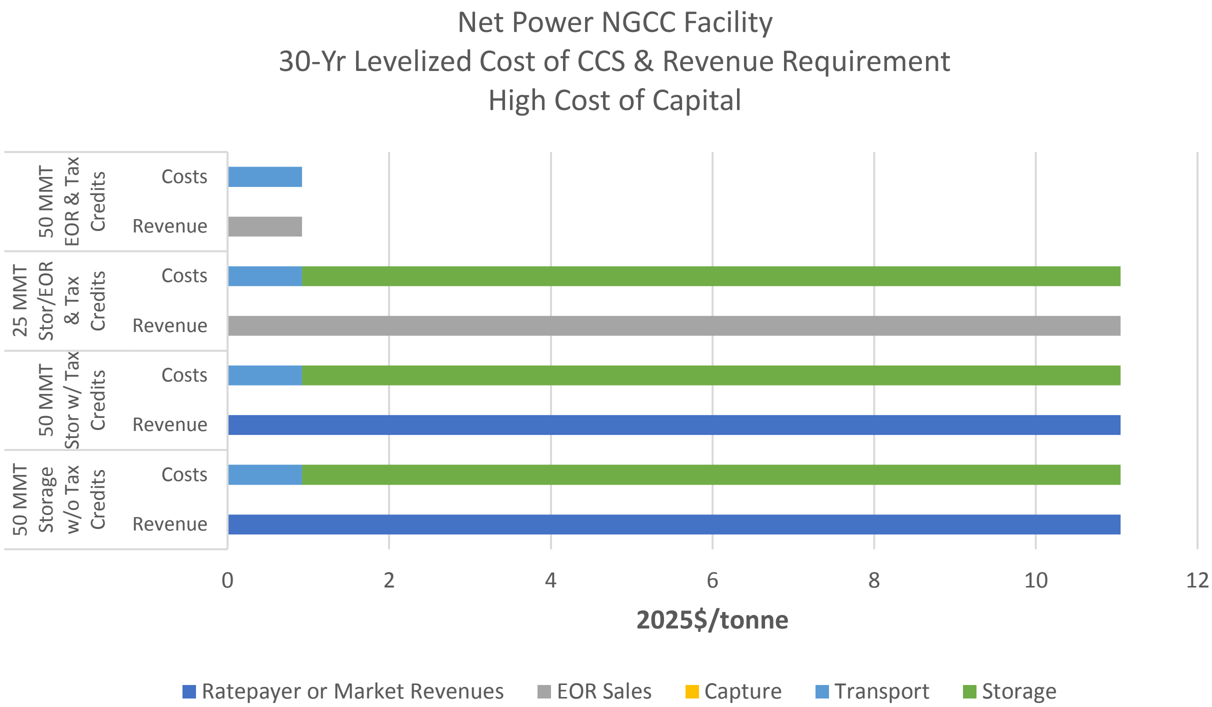


Figure 33. Net Power NGCC facility scenario levelized cost of CCS and revenue requirements high cost of capital; 2025$/tonne (first year of injection)

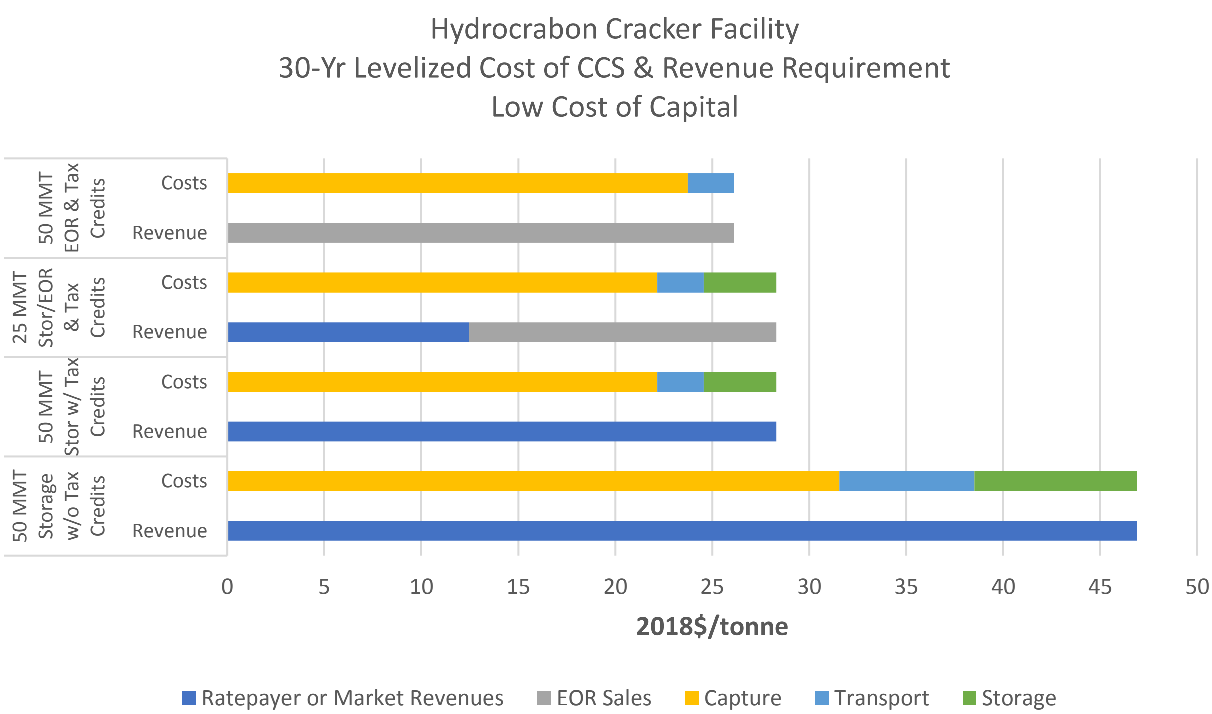


Figure 34. Hydrocarbon cracker facility scenario levelized cost of CCS and revenue requirements low cost of capital; 2018$/tonne (start of project)

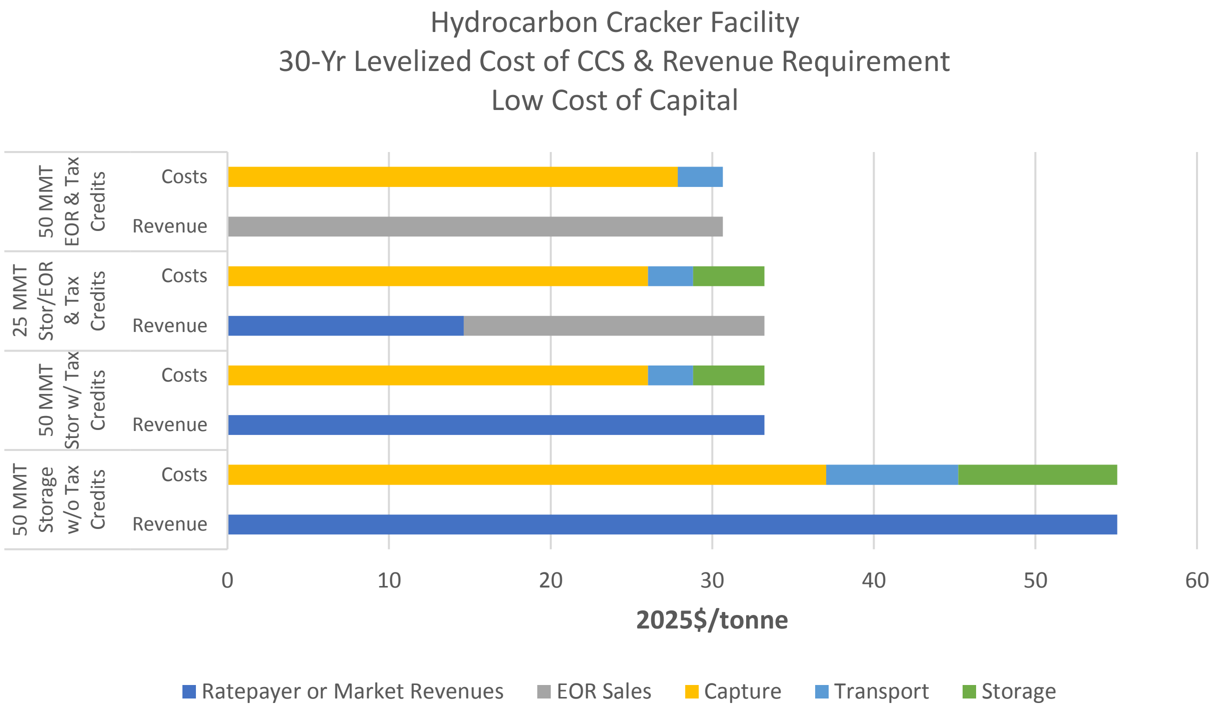


Figure 35. Hydrocarbon cracker facility scenario levelized cost of CCS and revenue requirements low cost of capital; 2025$/tonne (first year of injection)

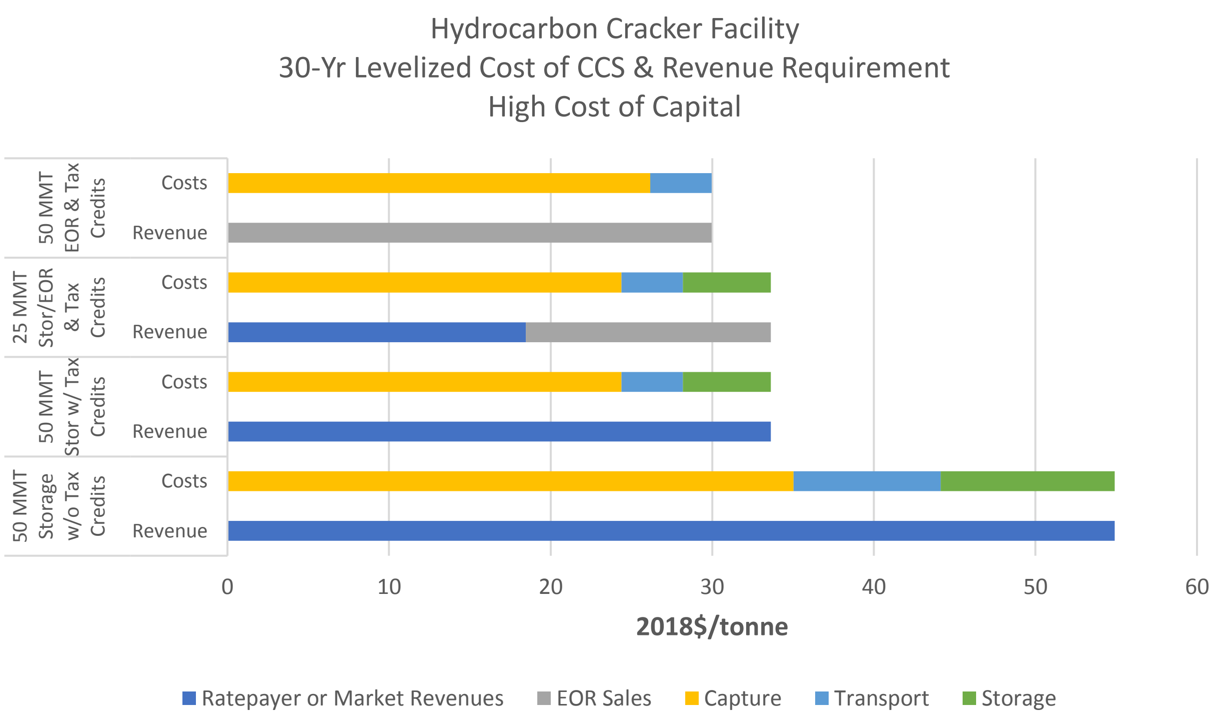


Figure 36. Hydrocarbon cracker facility scenario levelized cost of CCS and revenue requirements high cost of capital; 2018$/tonne (start of project)

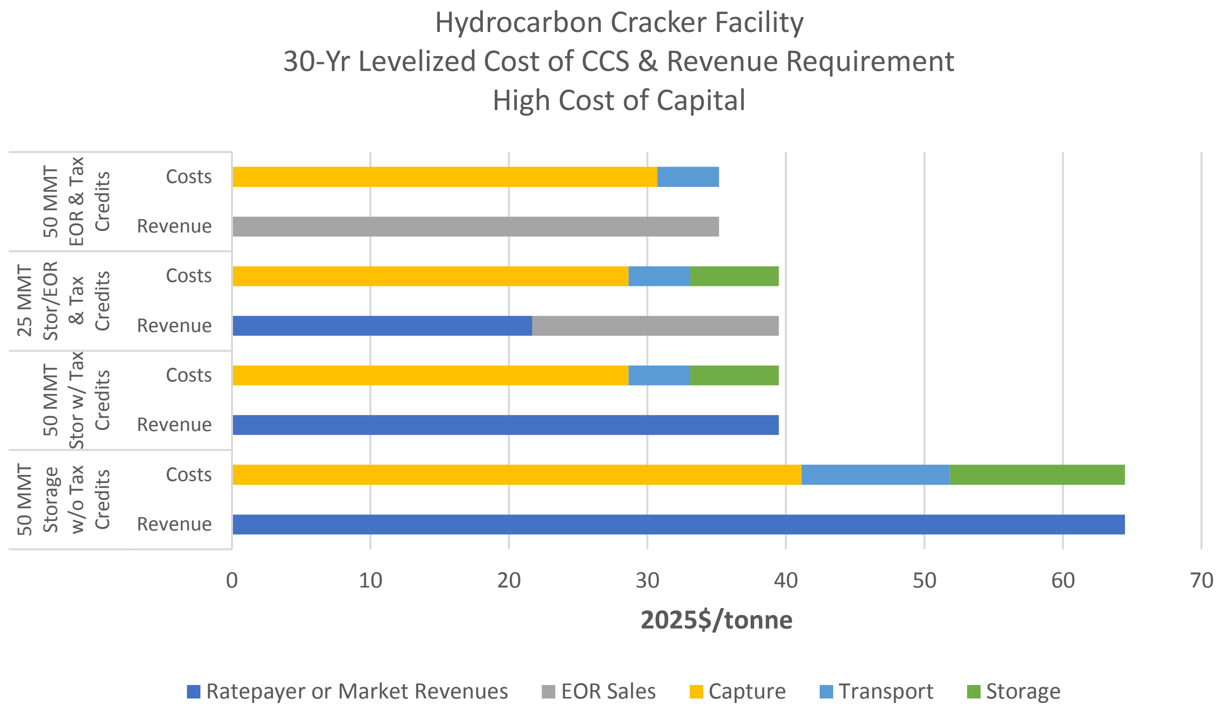


Figure 37. Hydrocarbon cracker facility scenario levelized cost of CCS and revenue requirements high cost of capital; 2025$/tonne (first year of injection)

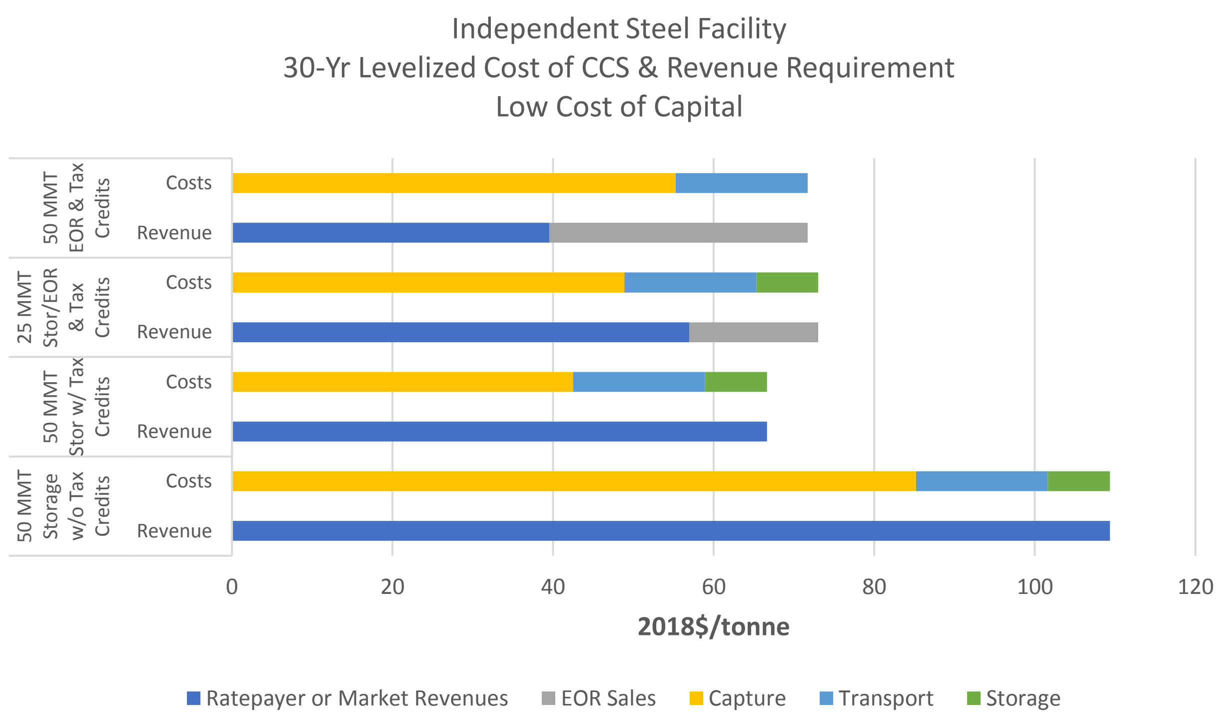


Figure 38. Independent steel facility scenario levelized cost of CCS and revenue requirements low cost of capital; 2018$/tonne (start of project)

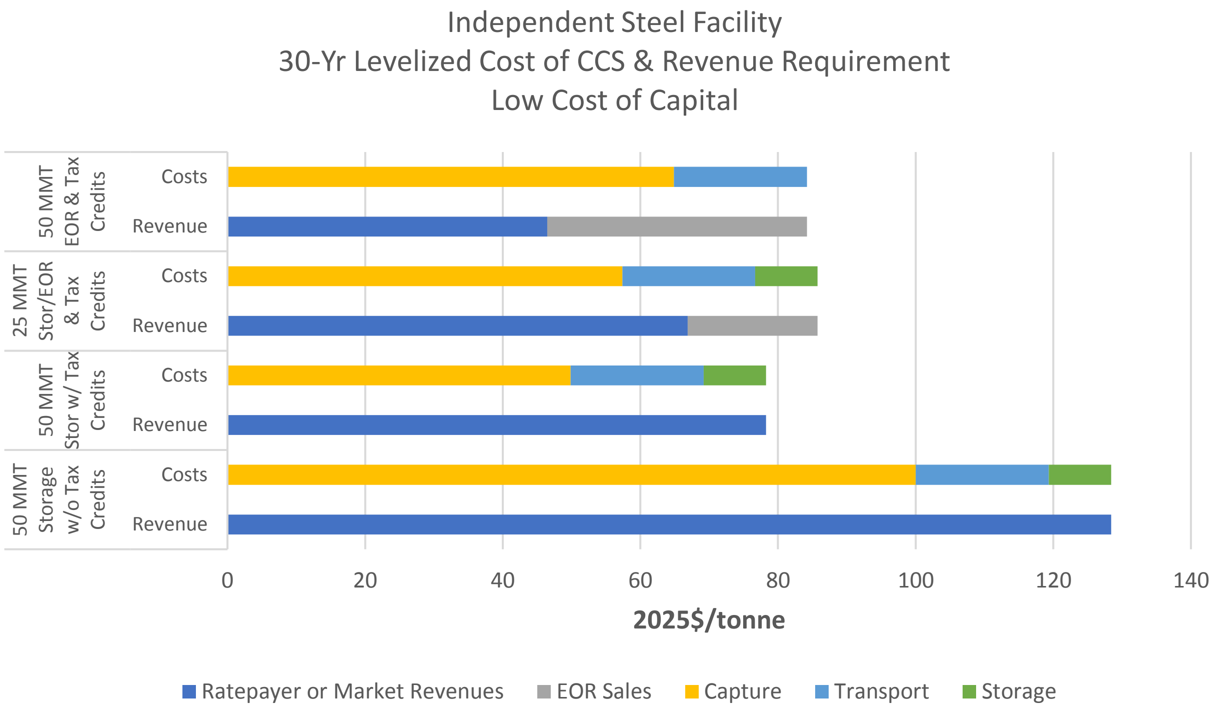


Figure 39. Independent steel facility scenario levelized cost of CCS and revenue requirements low cost of capital; 2025$/tonne (first year of injection)

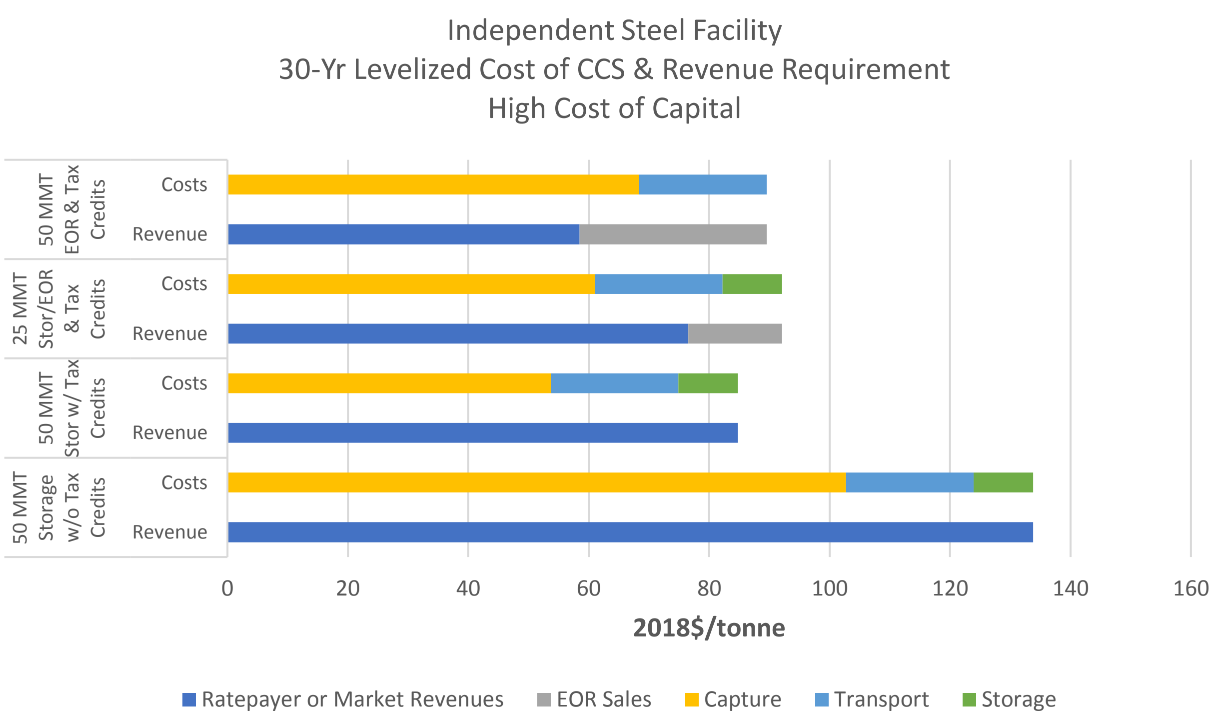


Figure 40. Independent steel facility scenario levelized cost of CCS and revenue requirements high cost of capital; 2018$/tonne (start of project)

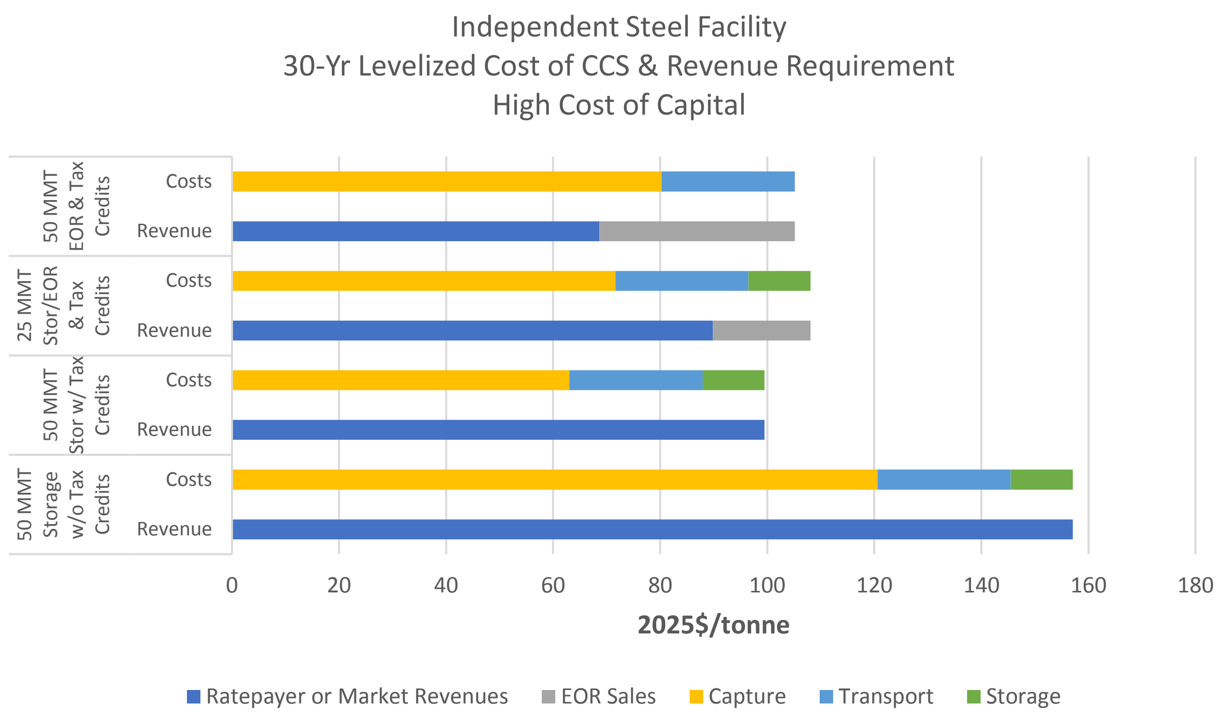


Figure 41. Independent steel facility scenario levelized cost of CCS and revenue requirements high cost of capital; 2025$/tonne (first year of injection)

4. Summary

This preliminary analysis indicates that the most economically viable scenarios emerging were the new NGCC with 100% EOR (see Figures 26 through 29) storage, the NET Power NGCC technology with either 50% or 100% EOR storage (see Figures 30 through 33), and the hydrocarbon cracker facility with 100% EOR storage (see Figures 34 through 37). As these charts illustrate, the sale of CO_2 for EOR alone covers the costs associated with CCS for each of these scenarios. It was assumed that the EOR operator would be responsible for all costs associated with the operation of EOR reservoir and that operation and maintenance costs are reflected in the price paid for the CO_2. In the case of the Net Power scenarios only transportation (pipeline) costs from the CO_2 source to the EOR field are necessary because the incremental cost of capture is assumed to be zero for the Allam Cycle; the facility produces a pipeline-quality CO_2 as a byproduct.

In the new NGGC facility scenario where only 50% of the CO_2 was to be sold for EOR operations and the other 50% is stored in the saline reservoir, there would be a modest net revenue requirement of only approximately \$10 per tonne in the low cost of capital case and \$15 per tonne in the high cost of capital case. (The net revenue requirement being defined as the amount of revenues obtained either from ratepayers or the market.) This net revenue requirement could be further reduced if oil prices increase, or if costs savings can be found from the operations and monitoring of the pipeline or storage reservoir.

It should also be stated that the capital and operating costs for the hydrocarbon cracker facility may not truly reflect the cost of capture because they were mapped from an ethylene oxide facility analysis. At the time this economic analysis was developed, no information regarding the costs associated with carbon capture from a hydrocarbon cracker facility were available in the public domain.

As the figures above illustrate, the other scenarios (SCPC retrofit, NGCC retrofit, and independent steel facility) are less attractive for two principal reasons.

- First, the incremental cost of capture is still the most significant CCS cost driver and cannot be overcome even with the addition of the enhanced Section 45Q tax credits and 100% EOR storage. As shown in Figure 42 below, even a reduction of greater than 20% in the cost of capture for the SCPC retrofit scenario with 100% CO_2-EOR storage does not achieve a breakeven net revenue requirement. Even with additional EOR revenues up to $40/ton, as shown in Figure 43 below, retrofitting an existing coal-fired generation facility requires additional revenues from either the market or ratepayers to breakeven against uncontrolled plants.
- Second, the greater the distance from either the saline reservoir or EOR field the source is located, the cost of transport becomes a more significant negative factor for the scenario economics. This is very evident for independent steel facility which is located over 100 miles from the proposed saline and EOR storage fields.

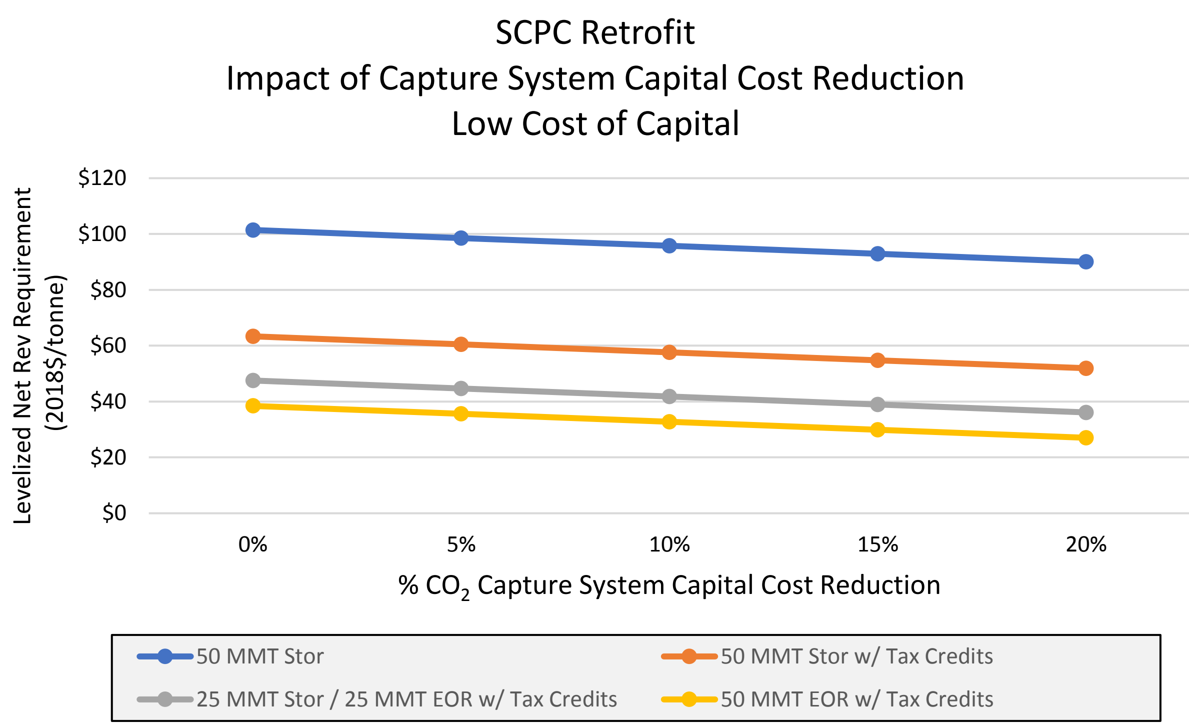


Figure 42. Impact of capture capital cost reduction on levelized net revenue requirement for the SCPC retrofit scenario

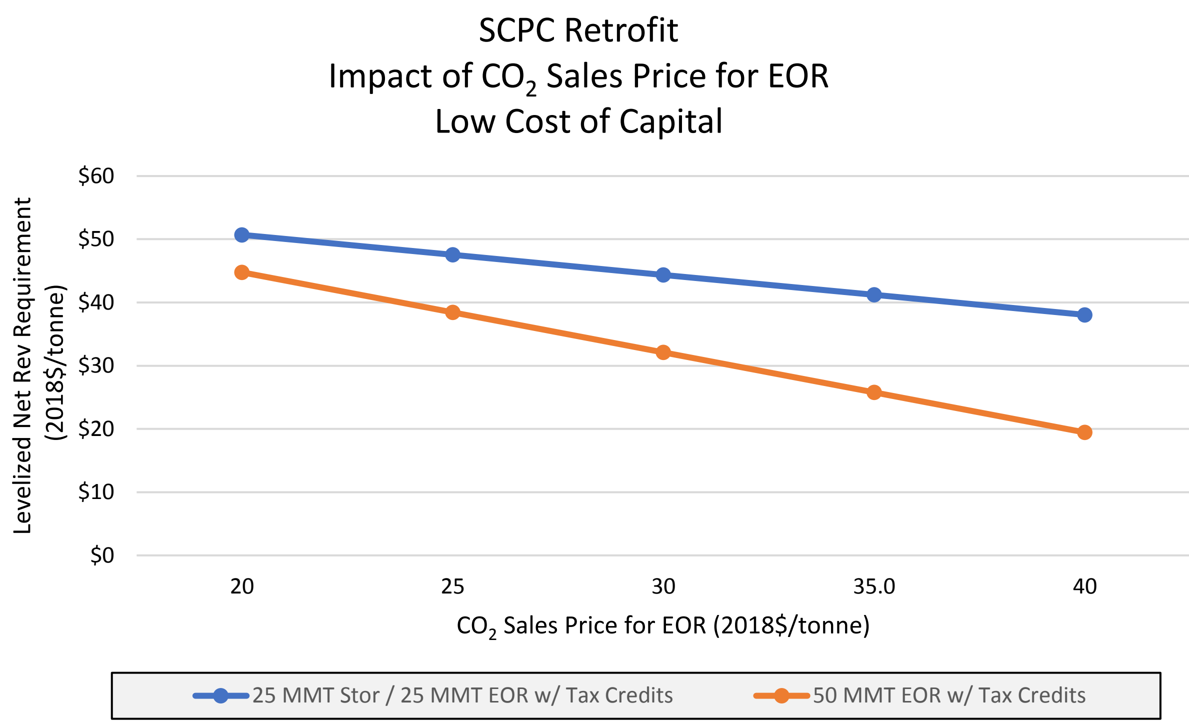


Figure 38. Impact of CO_2 sales price for EOR on levelized net revenue requirement for a SCPC retrofit scenario

Overall, this analysis indicates that the availability of the recently enacted tax credits will go a long-way towards closing the cost and revenue gaps, especially when combined with value added options such as CO2-EOR and low cost long-term financing. For the saline storage scenarios, it is anticipated that capture technology improvements, detailed pipeline design optimization, storage and monitoring system optimizations, state and local incentives, and eventually a carbon reduction policy could help close the revenue shortfall over the next few years.

The important takeaway from this analysis is that the value of combined EOR revenues and the EOR tax credits are much more important than the higher valued saline only tax credits, especially when it comes to new build opportunities.

5. Anticipated Financing Needs and Strategies

The ability to secure lower cost equity and debt financing for deployment of CCS will depend on future policy and incentives because the current environment does not support significant market-based investment. Research by the Clean Air Task Force suggests that without a carbon reduction mandate, the passage of proposed reforms allowing CCS projects to take advantage of the lower cost of capital through Master Limited Partnerships (MLP) and Project Activity Bonds (PAB) is still needed. These reforms, coupled with the changes to the Section 45Q program, make it more likely that investors and lenders will be attracted to CCS opportunities.

The recent passage of enhancements to the Section 45Q tax credits is a positive development to help support the financing of CCS projects. As has been demonstrated in the wind and solar energy sector, the use of Federal tax incentives has created a thriving market for development and investment in such projects using innovative tax equity structures. A similar market for CCS projects could very well develop first for EOR-supported opportunities and then for saline storage projects as reductions in the cost for capture technologies accelerates. In future phases, Battelle and its project partners will work to develop a comprehensive financing plan to support the implementation of any of the six scenarios listed above. This plan would include identifying potential equity sponsors who could maximize the use of the Federal tax credits, commercial bank lenders, and capital market debt financing alternatives. As the acceptance of CCS projects increases, more potential equity and debt financing options may be available.

With significant uncertainty surrounding the ultimate outcome of U.S. EPA’s Clean Power Plan, state-level incentives to promote carbon-free power generation and industrial facilities are also necessary. To successfully finance an integrated CO_2 capture and storage project from a natural gas or coal-fired generating station, the State of Ohio may need to pass legislation to enable cost recovery by either allowing long-term power purchase agreements to be signed that cover such costs and/or allow the PUCO to include such costs in electricity consumer rates. These types of cost recovery mechanisms are critical to the success of any CO_2 capture and storage project in the absence of a value for carbon in the wholesale electricity markets or Federally mandated carbon reduction, even with the potential for EOR revenues.

In addition to legislation that allows for cost recovery, other incentives, such as exemption to state sales tax during construction, property tax abatement, and an exemption to the corporate gross receipts tax, should be considered by policymakers to enable the growth of CCS projects. Additional incentives could include rebates on easements for pipelines and surface access for storage complex and enabling access to state owned pore space.

Central Appalachian Basin CarbonSAFE Integrated Pre-Feasibility Project

Attachment 4 - Outreach Plan

Overview

Background

This plan applies to Phase I and forms the foundation for Phase II outreach as indicated throughout the document. There is also an outline for Phase II outreach activities in Section K.

A. Summary of Next Steps (All Pending Phase II Decision)

- Document control
  - Organize Box (data sharing platform) access and develop protocol for document sharing
- Situational Analysis
  - Assess project needs/gaps
- Goals and Objectives
  - Guide the Phase II outreach plan
- Key Stakeholders and Target Audiences
  - Complete stakeholder map and evaluate for outreach planning
- Important Messages and Information
  - Evaluate feedback and further refine messaging
- Outreach Methods
  - Plan and implement specific outreach activities including materials development, one-on-one discussion, media, etc.

B. Document Control Strategy

- CAB-CS documents to include original date, revision date, and version number (if applicable)
- A Box folder has been established for the CAB-CS project on Battelle share site. This folder will house final and working draft materials from the project. It will also contain the master copy of primary documents and plans.
- Copies of all documents shared with the public shall be kept in the box folder and available to the team.

Status and Next Steps

Status:

- Box folder has been created,
- Project team has been given access,
- Documents are being organized and stored as developed and completed.

Next Steps:

- In Phase II, the folder will be further organized for working documents, outreach materials, and other important folders.
- Currently all team members have access to the box folder; during Phase II a protocol will be established for accessing, modifying, and sharing these documents.

C. Situational Analysis

- Project Description: The Central Appalachian Basin CarbonSAFE project (CAB-CS) is one of more than a dozen research projects funded through the Department of Energy to address key research gaps in the path toward the deployment of carbon capture and storage (CCS) technologies, including the development of commercial-scale (50+ million metric tons CO_2) geologic storage sites for CO_2 from industrial sources.

- CAB-CS is in the first phase (ending June 2018) of a multi-phase effort. The first phase calls for the development of a pre-feasibility study to assess the potential for developing a commercial scale project including a source of CO_2, options for moving it to a storage location(s), and long-term geologic storage. This phase entails screening a number of potential sources and storage locations as well as the technical, legal, social, and other challenges associated with project completion.
- During the first phase (in February 2017), CAB-CS will prepare a proposal for a second phase that entails a storage complex feasibility study. If successful, this will lead to site characterization and permitting, and finally, on to infrastructure construction.
- During this first phase, CAB-CS is considering sources throughout and adjacent to a 12-county area in the Central Appalachian region and it is reviewing potential geologic storage locations within that same 12-county area. Those counties include: Athens, Coshocton, Guernsey, Hocking, Holmes, Meigs, Morgan, Muskingum, Noble, Perry, Tuscarawas, Washington.
- Results from a preliminary social characterization (See Appendix A) of the communities show that on paper, the counties are largely similar in the primary economic factors examined, with a few exceptions. Based on the data, the counties appear to be equal social environments with respect to establishing a CCS project. One exception is perhaps Coshocton, which has large CO_2 Point sources that provide significant employment to the community. This economic driver could be contrasted perhaps with Athens, which seems to be more service and tourism driven.
- The additional insights from the social characterization (See Appendix A) need to be further verified but they suggest the following:
    - Due to the presence of numerous energy businesses, here appears to be good familiarity with the energy industry, although the bulk of the most recent shale developments have occurred on the edges of the 12-county area rather than throughout it.
    - As a result, it is likely that many stakeholders will be somewhat familiar with the technical aspects of geologic storage (i.e., subsurface drilling and injection). This may be helpful in terms of sharing technical information about the project and its safety; however, discussions may quickly move to royalties, mineral rights, and possibly even competition for pore space with brine disposal operations.
    - There is some ambivalence about climate change that should be explored further. It is not clear whether concerns about the economy and desires to increase local energy jobs will counter or overwhelm concerns about climate change, although some environmental groups are active in the 12-county area.
    - There is also a tourism industry in the area and some public concern about the potential visual and environmental impacts of a project may be encountered.
    - There seems to be a strong sense of independence among the counties. They don't necessarily act as a block.
- Preliminary legal and regulatory review suggests that potential issues around permitting, property rights, and long-term liability could provide hurdles to project deployment.
- Other insights will be developed through interviews, media analysis and continued discussion with CAB-CS team members. A preliminary set of interviews is described in Appendix B.
- Reassess the Tuscawaras Well Lessons learned – past experience with stakeholders while drilling a test well for the purpose of exploring storage opportunities (event occurred in 2007).

Status and Next Steps

Status:

- Primary research completed
- Focus to shift to Selected Areas
- Continue to monitor media, team member input

Next Steps:

- In Phase II, assess project needs/gaps, especially related to the primary selected area:
    - Conduct research to support development of key messages and information
        - Project benefits describe potential community and specific benefits attributable to the project
        - Further identify potential community concerns
    - Assess project Definition / P90 Plume implications for stakeholders
    - Develop plan to engage Project Owners/outreach team

D. Goal and Objectives

The goal of the public outreach program is to support the successful implementation of the proposed CCS project through good/effective working relationships with the involved communities.

The objectives of the public outreach program will evolve over time to support the steps necessary to complete each phase of the project. In particular, they are designed to help the team to identify and address existing and future project hurdles.

The Phase I outreach objectives include:

- Develop insights to characterize the identified communities.
- Identify initial stakeholders.
- Identify the preliminary public perceptions of CCS.
- Identify and articulate potential project benefits for the identified communities.
- Review potential legal, regulatory, and other non-technical hurdles for the project and implement initial outreach actions to address them.
- Implement near term outreach actions
- Develop an outline for the Phase II Outreach Plan.
- Develop key messages and information for initial one-on-one interviews
    - Win win story
    - Identify Handouts and Support Materials
    - Develop a strategy for interacting with government officials on project

The Phase II objectives include:

- Further characterize the short list of identified communities with regard to natural resources, economic drivers, historic environmental and industrial development, and other characteristics (considering the P90 plume size requirement in Phase II).
- Plan the initial outreach to support key events such as
    - Site screening, selection, and characterization
    - Permitting

- Develop a Phase III+ outreach plan

Status & Next Steps

Status:

- All Phase I objectives met or completed
- Phase II Outreach planning initiated

Next Steps

- Assess Phase I goals and objectives and revise as needed for Phase II
- Develop the Stakeholder Matrix into a stakeholder map that identifies specific contacts, key perceptions and conerns and other relevant information for outreach planning.

E. Key Stakeholders and Target Audiences

Below is a list of preliminary stakeholders to include in outreach planning:

- Community Level:
- Government officials
- Key civic group leaders
- Local environmental groups
- Other local influencers
- Business groups

Regional:

- Trade Association:
  - Ohio Oil and Gas Association
- Regional Government:
  - US EPA Region 5
- Regional Economic Development:
  - Ohio Mid-Eastern Governments Association (http://omegadistrict.us/)
  - Buckeye Hills Regional Council (http://buckeyehills.org/)
  - Appalachian Partnership for Economic Growth (http://apeg.com/).

State:

- Governor
- ODNR
- OEPA
- Ohio Public Utilities Commission
- Senate/Congress
- Economic Development

National

NGOs

Labor unions

Status & Next Steps

Status:

- List of initial primary influential in Ohio identified and contacted. Group included officials, regulators, and local economic development (See Appendix B).
- List of key stakeholders for Phase II developed, would serve as start of stakeholder map (See Appendix C).

Next Steps:

- Further develop the stakeholder map and populating map with data based on research and stakeholder outreach

F. Important Messages and Information

Preliminary work on messaging suggests following:

- Counties within the Appalachian region are economically disadvantaged compared to other parts of Ohio. Efforts are underway to jumpstart the economy and build on the energy industry. It may make sense to use some focus groups or one-on-one person interviews to get a better feel for how the project would fit with these aspirations.
- Some of the obvious connections include the economic benefit of the actual project including jobs and the multiplier effects from them. There can be a case made for the long-term economic benefit of developing solutions to address CO_2 from energy in this region but that may not be a real perceived benefit.
- There is also the possibility of tech transfer / internships with local workers or students, some links to community colleges and other ways in which the knowledge benefit may accrue to the community. Vocational training.
- And finally, there may be tax revenue benefits for the host-community and/or royalty or other payments to mineral rights owners.

Status & Next Steps

Status:

- A preliminary set of messages were compiled into a set of talking points
- Situational analysis was used to begin to assess the larger set of message and materials that would support the outreach program
- Several locally based communications firms weer identified and interviewed for selection pending Phase II to assist with communications

Next Steps:

- Going forward, the process to develop messages would draw on experiences gained through the MRCSP process and include steps such as developing and testing draft or strawman messages first internally and then externally with different stakeholders through focus groups, interviews and other discussions. We would also use other intenal techniques such as gap analysis and message and stakeholder mapping to ensure comprehensive outreach efforts.

- In Phase II a locally based communications firm was to be engaged to assist with message development and delivery

G. Outreach Methods / Actions

Following tables indicate the planned outreach methods and actions to achieve the objectives outlined in Section C. The second table reflects the preliminary outreach planning to support the Phase II events of site selection and permitting. Additional actions will be included in an updated version of the document.

Table 1. Methods and Actions to Achieve Outreach Plan Objectives

Objective	Method / Actions	Assignment	Date
Develop insights to characterize the involved communities.	-Online research -Team interviews -News / media searches	SMW	Ongoing
Identify initial stakeholders.	-Online research -Team interviews -News / media searches -Develop database	SMW / LC	Ongoing
Identify the preliminary public perceptions of CCS.	-Online research -Team interviews -News / media searches	SMW / LC	Ongoing
Identify and articulate potential project benefits for the involved communities.	-Team discussion – to be followed with stakeholder input in later Phase	Team	Initiated
Review potential legal, regulatory, and other non-technical hurdles for the project and implement initial outreach actions to address them.	-Online research -Team interviews	Vorys	Completed
Implement near term outreach actions	-Identify and implement Phase I action items	Team	Completed
Develop an outline for Phase II Outreach Plan.	-Review data, -confer with team - Develop budget	SMW/LC	Completed
Further characterize the short list of involved communities with regard to natural resources, economic drivers, historic environmental and industrial development, and other characteristics.	- Online research -Team interviews -News / media searches -Expand to stakeholder interaction if allowed	SMW/LC/Vorys	October 2017 - June 2018
Plan the outreach for the characterization and other events	Develop planning matrices		Phase II

Status & Next Steps

Status:

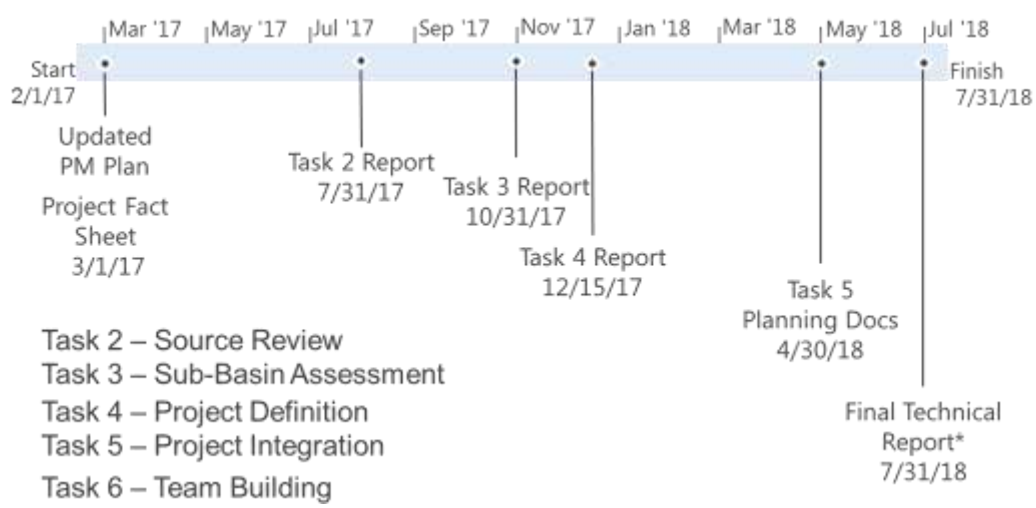
- Actions in Table 1 completed or initiated and underway

Next Steps

- Develop methods and actions for Phase II. Key questions to address:

- Develop benefits – what kind, and how much, and to what details
- What do we know now, that can help us to do benefits. We can look at FutureGEN, Phase II projects, assess local benefits, at a gross level (regional/state), how much detail
- Poll advisors on how information is needed and how detailed. Work with technical team to pull together a concise “what this looks like”
- Develop ballpark Project value in Phase II / Economic benefits to the community
- Develop a list of who we want letters from – industry folks, Ohio Coal, Enviro type, congressionals – what is in the letter, and what it takes to get them,
- Land rights – who we need support from, what support looks like (is it a letter?), how do we get that.

H. Timeline for the Phase I Project



I. Team Roles and Responsibilities

All outreach will be coordinated with the PI, Lydia Cumming. Specific outreach activities will be planned and executed by the outreach team. All media inquiries should be directed to T.R. Massey, 614-424-5544 (office), 614-202-7553 (cell), or masseytr@battelle.org. The outreach team, roles and responsibilities are listed in the table below.

Name	Organization	Project Role(s)
Lydia Cumming	**Battelle**	**PI**
Neeraj Gupta **Rod Osborne**	**Battelle**	**Business Strategy / Team Building Support**
T.R. Massey	**Battelle**	**Media relations and designated point person**
Sarah Wade	**WADE LLC**	**Outreach Support** **Outreach Plan Development Lead**
Lou Gentile	**Vorys Advisors**	**Outreach Support**
Web Vorys	**Vorys**	**Legal strategy**

J. Evaluation

During Phase I, evaluation will be based on whether the goals and objectives for Phase I have been met. In Phase II specific criteria for evaluating the goal of gaining public support need to be developed to include quantitative assessment of outreach actions and qualitative assessment of the effect of those actions on public perceptions of the project.

K. Outline of Phase II Outreach Plan

The Phase II Outreach Plan is expected to contain the same format as the Phase I plan, a slightly expanded outline is included below:

- Summary of Actions Underway
- Document Control
- Accessing, modifying, sharing documents
- Situational Analysis
- Refined assessment of Selected Area
- Review of background sociopolitical / economic conditions in Ohio
- Goals and Objectives
- Identify key milestones
- Key Stakeholders and Target Audiences
- Stakeholder map
- Stakeholder assessment
- Stakeholder engagement
- Important Messages and Information
- Project benefits identification process
- Project specifications
- Outreach Methods for Key Milestones
- Site characterization acitivites
- Federal and State Permitting
- Legal clarification efforts
- Neighbor relations
- Community enagagement
- Business plan for the project
- Phase III proposal
- Timeline
- Team Roles and Responsibilities
- Evaluation

APPENDIX A

CAB-CS – Preliminary Regional Social Characterization

Draft Date: May 1, 2017

Rev. June 26, 2018

Introduction

The Department of Energy's "Best Practices for Public Outreach and Education for Carbon Storage Projects"[i] outlines a framework for engaging communities on the topic of CCS and in support of project implementation. During the early stages of a project, the process for selecting a project location entails consideration of the local geology and other physical characteristics. The best practices manual suggests gathering information about the communities and stakeholders to help build a foundation of understanding about potential concerns, community interests, and outreach needs. Specifically, the manual describes social characterization as:

> *"an approach for gathering and evaluating information to obtain an accurate portrait of stakeholder groups, their perceptions, and their concerns about CO_2 storage. This can be applied to identifying the factors that will likely influence public understanding of CO_2 storage within a specific community. The information gathered will enable the project team to develop better insights into the breadth of diversity among community members, local concerns and potential benefits, and assist in determining which modes of outreach and communication will be most effective."*[ii]

A first step in social characterization is collecting statistics and information that helps to develop an appreciation for the communities in the study area and serves as a foundation for community engagement. A recent example of this approach is published on the Global CCS Institute website and provides a template that is used here.[iii]

The study area for this report currently includes 12 counties in Eastern Central Ohio and Southeast Ohio (alphabetically):

- Athens,
- Coshocton,
- Guernsey,
- Hocking
- Holmes,
- Meigs,
- Morgan,
- Muskingum,
- Noble,
- Perry,
- Tuscarawas, and
- Washington

This report identifies some of the contextual characteristics of the area that may contribute to public perceptions of CCS/CCUS projects. It is based primarily on online research.

This report was developed using publicly available information, statistics were collected for each county and for the region overall. What follows is a two-part initial assessment. Part 1 provides a general overview of topics including:

- *Political Factors* – local and national political trends
- *Economic Factors* – local and regional economic dynamics
- *Social Factors* – social distinctiveness, including demographics
- *Technological Factors* – regional technological development and competiveness
- *Environmental Factors* -- local and regional ecosystems that may be impacted
- *Legal Factors* – applicable regulations / legal issues that may impact project

Part 2 of the report includes a brief description of each of the 12 counties.

Based on the data, the counties appear to be equal environments with respect to establishing a CCS project. The counties are largely similar in all the basic factors examined, with a few exceptions. Coschocton has large CO_2 point sources that provide significant employment to the community. This economic driver could be contrasted with Athens, which is more tourism driven.

This report is an important companion study for the storage resources assessment. As further analysis helps to identify excellent candidate locations, next steps will be taken in the social characterization to identify and begin to engage specific stakeholders and stakeholder groups. This interaction will further help to refine our understanding of the communities and strengthen our outreach efforts.

Part 1. General Trends

A. Political Factors

2018 will be a big election year with 1 senate, the governor, and all house seats open for election.

The area can be generally characterized as Republican and conservative. However, the counties have a reputation for independence from each other and embody some interesting ranges of political distinctions. For example:

- Anecdotally, Athens is known as one of the most Democratic counties in Ohio and Washington is known as one of the most Republican counties.
- All of the counties but Athens went for President Trump but the margin varied from essentially evenly split to firmly Trump. (Interestingly in the primaries across the study area, Clinton narrowly beat Sanders and Kasich beat Trump by more than 10%.)
- In the US Senate, Ohio is represented by Sen Sherrod Brown (D) and Sen Rob Portman (R). In the 2016 election, Portman won all counties in the study area except Athens.
- In the US Congress, the study area spans all or parts of 4 congressional districts and all are currently represented by Republicans. There is a history of significant voter swings in the past decade.
- There is a spread of Republicans and Democrats in locally elected positions.

B. Economic Factors

The counties in the study area are economically disadvantaged compared to greater OH. The Appalachian Regional Commission (ARC) develops an index based on a 3-year average of county unemployment rates, per capita income, and poverty levels. The index is used to rate each county in comparison to the national levels. One of the study area counties (Meigs) ranked in the worst 10% of the country (Distressed). Three others (Athens, Perry and Morgan) ranked in worst 10-25% of the country (At Risk). And the remaining seven counties in the study area ranked better than the worst 25% but worse than the best 25% (In transition).[iv] This most recent rating shows a small improvement. In 2012, four counties were ranked Distressed, two At Risk, and only five in Transition.

The Utica Shale underlies most of eastern Ohio and there are more than 2,000 wells as of mid-June 2017 with more being drilled each month. In the counties in the study area, jobs in energy are listed as one of the main source of employment. The list of common employers also includes a mix of jobs in healthcare, manufacturing, and education. Jobs and the economy of eastern Ohio have suffered from the migration and automation of manufacturing as well as increased pressure on coal from low gas prices. There has been a focus on workforce development in the area to take advantage of the shale boom and create a more sustainable local benefit.

Although not a major economic force, tourism is increasing in Ohio. Three of the study area counties were in the second highest quintile for tourism sales for the state in 2016 (Muskingum, Tuscarawas, Washington) while four counties were in the lowest quintile (Meigs, Morgan, Noble, Perry).[v] While growth in tourism at the state level has been steady over last 3 years, the rate of growth in Appalachian region of Ohio is roughly 1% less than the rate of growth for the state. In 2015, tourism contributed $1.43B in sales in the study area and employed 16,325 people directly and indirectly.[vi]

C. Social Factors

Population Density- The counties in the study area are largely nonurban areas with low population densities (e.g., less than 165 people per square mile) and few urban centers that are lower than most of Ohio (e.g., 282 people/mi^2). In most of the counties, population is concentrated in a few “places” with populations as high as 25,000 but typically around 5,000-8,000 people. These ”places” include only 9 cities from the study area listed in the 2000 Census:

- Zanesville – 25K pop – Muskingum co
- Athens – 21K pop – Athens co
- New Philadelphia – 17K pop – Tuscarawas co
- Marietta – 15K pop – Washington co
- Dover – 12K pop – Tuscarawas co
- Coshocton – 11K pop – Coshocton co
- Logan City – 7K pop – Hocking Co
- Belpre – 6K pop – Washington co
- Nelsonville – 5K pop – Athens co

In the other major “places,” population is typically 1,000 – 2,000. Roughly 20-25% of the population lives in communities with smaller than 1,000 in population.

On average, population size in the study area has been stable or shown slight growth during the period 2000-2010. Washington and Guernsey showed slight population decline over the period (-0.1—5%) while the other counties showed 0-9.9% growth over that period.[vii]

Poverty- The rate of poverty in the study area is higher than the national average. An ARC study for the period 2010-2014 shows that Athens was the only county in the study area whose poverty levels were significantly lower than the national average. The same study showed that 3 counties were at or a little lower (ranging 13.7-14.4%) than the national poverty average of 15.6% (Noble, Tuscarawas, Holmes), and the rest were at or slightly worse than the national average.[viii]

Education - During the period 2010-2014 the study area is reasonably close to national high school completion rates – except for Holmes County. Holmes County does much worse than average in college completion rates; generally falling to 20-50% of the national average except for Athens and Washington, which both showed better completion rates.[ix] There are a number of educational assets in the study area include Ohio University in Athens and Zane State in Muskingum as well as other community colleges and vocational technical training.

Media Coverage - In keeping with the independence between counties, the area is serviced by numerous local media outlets including TV, Radio, daily papers, and weekly papers. In reviewing county and other local agency websites, it appears that there is extensive use of facebook and other social media sites as well.

Regional Economic Development Groups - Although the counties in the study area are noted for their independence, several regional groups have emerged as playing a role in addressing social challenges and improving the economy. These include: Ohio Mid-Eastern Governments Association (http://omegadistrict.us/), Buckeye Hills Regional Council (http://buckeyehills.org/), and Appalachian Partnership for Economic Growth (http://apeg.com/).

D. Technological Factors

Coal and energy industries in Central Appalachia have been hard hit by low cost natural gas and to an extent the cost of environmental regulation. In 2013 the CoalBlue project (http://coalblue.org/) was formed to support "coal as part of a sensible 'all of the above' energy strategy." The group advocates support for coal as a sustainable fuel in part by accelerating development of advanced technology. This then was echoed in a West Virginia hearing run by Sen Manchin in Aug 2016[x] who suggested that building infrastructure to process and utilize coal will help in the long run – the "if you build it they will come" concept. Generally there is political support for energy infrastructure in the region. Two recent projects may be good partners for CAB-CS:

> (1) Longview Power in Morgantown WV: proposed in 2002, began construction around 2005, filed Chapter 11 in 2013, up and running by 2016 as cleanest, most efficient plant in the PJM area. Baseload, 700MW net, built with room for capture as an option.[xi] Because the plant is separated from the study area by a major river, CO_2 transport may not be economically feasible.
> (2) Ohio Valley University – Alternative Clean Energy (OVU-ACE) project – will be a commercial scale coal to liquids processing plant with construction beginning in 2017 and operation by 2019.[xii]

In addition, experience with subsurface resource development (described under Environmental Factors) may provide familiarity with the technologies and processes for carbon storage projects.

E. Environmental Factors

The main driver of environmental concern in the region is likely to be the management of energy production impacts from development of the Utica Shale. There are more than 2,000 Utica wells in Eastern Ohio. The majority of these wells are drilled in the counties that border Pennsylvania, however there are a few hundred wells in Noble and Guernsey counties, and additional 30 or so in Washington and Tuscarawaras, and a handful of wells in Holmes, Coshocton, Muskingam, and Morgan. (see ODNR map at: http://oilandgas.ohiodnr.gov/Portals/oilgas/pdf/activity_maps/HorizontalWells_MonthlyUticaPagesize_04012017.pdf)

There are multiple Class II brine disposal wells in each county of the study area (see ODNR map at: http://oilandgas.ohiodnr.gov/portals/oilgas/pdf/Class_II_Map/Class%20II%20Brine%20Injection%20Wells%20of%20Ohio%2004032017.pdf)

To date there is not much written about induced seismicity in Ohio, however there was an incident linked to brine disposal in Youngstown, OH, in 2012. The incident became part of the EPA case study on addressing this issue for brine disposal (see report: https://www.epa.gov/sites/production/files/2015-08/documents/induced-seismicity-201502.pdf). In March 2017, a small quake was detected in Monroe County (abutting Noble and Washington) – see: https://www.usnews.com/news/best-states/west-virginia/articles/2017-04-02/earthquake-detected-in-southeast-ohio.

In addition, other environmental factors to consider:

- Forest land:
    - The area is home to what is known as Appalachian mixed-mesophytic forests, a biologically diverse[xiii] resource found here and in China.
    - There are 8 state parks in the area.[xiv] In addition, there are a number of protected areas including 3 state forests, 1 national forest, and several nature preserves.[xv]
- Environmental groups:
    - The area is home to several local environmental groups with attention focused on activism (mountain top removal (MTR)/coal/fracking, environmental justice, pollution impacts) and conservation. The area is also subject to attention from regional and national groups for same reasons. Key groups:

The Ohio Environmental Council[xvi] (Note: this group is a member of the MRCSP although not active)

The Alliance for Appalachia [xvii]

Appalachian Voices [xviii]

Sierra Club Environmental Justice[xix]

- Climate change
    - Ohio recorded highest temperatures, lowest rainfall in 2017 (see https://www.ncei.noaa.gov/news/national-climate-201702)
    - Yale "Six America's" study (see: https://www.nytimes.com/interactive/2017/03/21/climate/how-americans-think-about-climate-change-in-six-maps.html?_r=0) suggests climate not a "hot" topic in study area. Roughly 60% of population thinks emissions should be restricted and that while climate change is happening it won't hurt the region.

F. Legal Factors

- Class VI wells – US EPA Region V (this office is the only regional office with Class VI experience)
- Class II wells (And Class III) – Ohio Dept of Natural Resources (DNR) Division of Oil & Gas: http://oilandgas.ohiodnr.gov/regulatory-sections/underground-injection-control have primacy. There are class II wells in each county. There have been seismicity problems in northeast Ohio and recent coverage of activity in Monroe. US EPA published guidelines in Class II Brine protections
- Other State Agencies
    - Ohio EPA UIC Class I, IV, V
    - Ohio Public Utilities Commission (PUC) – active
- Property Rights / Mineral Rights – because of the Utica development, there is information for land owners on the ODNR website about selling rights to developers.

Part 2. County Reports

Athens

A. Political Factors

- City of Athens – website: http://www.ci.athens.oh.us/
- County information / links: http://cms.revize.com/revize/athenscounty/
- 80% of the population based in the top ten largest places. Distribution of place size:[xx]
  - >25K pop – 1place
  - 5-6.5K pop – 2place
  - ~2.5K pop – 4places
  - 1.6-1.9K pop – 3places

B. Economic Factors

- Based on ARC Index – Athens ranked as an “At Risk” community for FY2017. This is a small improvement in status from “Distressed: which had been in place 2009-2016. (ARC)
- Tourism 2015: sales - $154.3M; employees - 2,190 people (AppalachianOhio.org)
- In 2014, of 1,031 private sector establishments: 136 were in goods producing industries; 896 in service industry. In addition, there were 722 farms in the county. (OED)

C. Social Factors

- Population:
  - Athens experienced steady growth from 1950 (pop 45,839) through 2010 (pop 64,757). The 2000-2010 growth rate of 4.1% exceeds the same rate for the rest of Appalachian Ohio and the State of Ohio but is less than half the rate of growth in the US (9.7%). OED projects growth in Athens to peak in 2015 and then taper slightly. (ARC, OED)
  - Population density in 2010: 128.6 person/square mile. This is the third most-dense county in the study area but is considerably less dense than the average of 282.3 person/sq mile for the state of Ohio. (ARC)
- Financial:
  - The per capita income in 2014 was $30,977. This was lower than the average of $35,233 for Appalachian OH, $42,236 for OH, and $46,049 for the US.
  - The 2014 unemployment rate of 6.8% showed modest improvement in comparison to the 3 year average of 8.1% for the period 2012-2014. However, this rate is worse than the rate in the rest of Appalachian Ohio (6.7%), the state of Ohio (5.7%), and the US (6.2%)
  - The 2010-2014 poverty rate of 31.6% was the highest in the study area and was notably higher than the 17.8% in Appalachian OH, 15.9% in OH, and 15.6% in the US.
- Education:
  - Athens has a rate of high school completion (degrees) that is essentially the same for Appalachian OH, OH, and the US (roughly 85-88%).
  - It has a higher than average bachelor degree completion rate (28.8% in Athens, 16.4% in Appalachian OH, 25.6% in OH and 29.3% in US).

D. Technological Factors

- Academic – 2 colleges located in county
  - Ohio University – Main Campus is in Athens City
  - Hocking College (Nelsonville) – culinary arts, industrial ceramics, adventure tourism, etc
- Notable companies in manufacturing include:
  - Sunpower inc, - free-piston stirling engines and cryocoolers
  - Diagnostic Hybrids Inc – a pharma / Biotech company that is part of Quidel Company
- Other Major & Notable Employers (OED)
  - Alexander Local Schools (gov)
  - Athens City Schools (gov)
  - Athens County Government (gov)
  - ED MAP Inc (serv)
  - Federal Hocking Local Schools (gov)
  - Nelsonville-York City Schools (gov)
  - OhioHealth O'Bleness Hospital (serv)
  - Rocky Boot Company (trade)
  - University Medical Associates (Serv)
  - Wal-Mart Stores Inc (trade)

E. Environmental Factors

a. State Parks / Forests, Nature Preserves, scenic waterways, and wildlife areas: 13

b. Protected resources

- Burr Oak State Park (also in Morgan County)
- Strouds Run State Park
- Gifford State Forest
- Athens Conservancy preserve
- Wayne National Forest (largely here although split over several counties)

c. Located in the Hocking River Watershed

F. Legal Factors - TBD

G. Stakeholders - TBD

H. Media

- TV: 2 stations
- Radio: 11 stations
- Daily Paper: 1 (Circ 8,000)
- Weekly paper: 1 (Circ 15,576)
- Other papers:
  - The Post - http://www.thepostathens.com/
  - The Athens News - http://www.athensnews.com/
  - The Athens Messenger -http://www.athensmessenger.com/

I. Business websites

- Athens Chamber of Commerce - http://athenschamber.com/
- Athens County Economic Development - http://athenscountyohedc.com/

Coshocton

A. Political Factors

- County government website: *http://www.coshoctoncounty.net/*
- Coshocton City government site: http://www.cityofcoshocton.com/
- 72% of the population based in the top ten largest places. Distribution of place size:
    - >11K pop – 1 place
    - 2-3K pop – 1 place
    - 1.1-1.9K pop – 8 places

B. Economic Factors

- Based on ARC Index – Coshocton ranked as a "Transitional" community for FY2017. Since FY 2012, the status was at this level except for FY 2013 when the status worsened to "At Risk." (ARC)
- Tourism 2015: sales - $52.3M; employees - 759 people (App'l OH)
- In 2014, of the 624 private sector establishments: 129 were in goods producing industries; 495 in service industry. In addition, there were 1,122 farms in the county. (OED)

C. Social Factors

- Population:
    - Coshocton experienced modest growth from 1950 (pop 31,141) through 2010 (pop 36,901). The 2000-2010 the growth rate of 0.7% exceeds the same rate for the rest of Appalachian Ohio but is less than the rate in the State of Ohio (1.6%) and in the US (9.7%). OED projects growth in Athens to peak in 2011 and then taper slightly. (ARC, OED)
    - Population density in 2010: 65 person/square mile. This is the ninth most-dense county in the study area and is considerably less dense than the average of 282.3 person/sq mile for the state of Ohio. (ARC)
- Financial:
    - The per capita income in 2014 was $34,421. This was lower than the average of $35,233 for Appalachian OH, $42,236 for OH, and $46,049 for the US.
    - The 2014 unemployment rate of 7.3% showed improvement in comparison to the 3 year average of 9% for the period 2012-2014. However, this rate is worse than the rate in the rest of Appalachian Ohio (6.7%), the state of Ohio (5.7%), and the US (6.2%)
    - The 2010-2014 poverty rate was 18.1%, the sixth lowest rate in the study area. It was higher than the 17.8% in Appalachian OH, 15.9% in OH, and 15.6% in the US.
- Education:
    - Coshocton has a rate of high school completion (degrees) that is essentially the same for Appalachian OH, OH, and the US (roughly 85-88%).
    - In terms of college, Coshocton is about the same as the rest of Appalachian OH, with 12.1% of the population completing BA's. It is lower than the rate of 25.6% for the state of OH and 29.3% for the US.

D. Technological Factors

- Notable companies in manufacturing include:
  - AK Steel Holding Corp
  - American Electric Power Co
  - Kraft Heinz Company
  - McWane Corp/Clow Water Systems
  - WestRock/RockTenn

- Other Major & Notable Employers (OED)
  - Coshocton City Schools
  - Coshocton County Government
  - Coshocton County Memorial Hospital
  - Riverview Local Schools

E. Environmental Factors

a. State Parks / Forests, Nature Preserves, scenic waterways, and wildlife areas: 5 (20.4K acres)

b. No listed protected resources

F. Legal Factors - TBD

G. Stakeholders - TBD

H. Media

- TV: 0 stations
- Radio: 2 stations
- Daily Paper: 1 (Circ 3,070)
- Weekly paper: 0
- Other papers:
  - The Coshocton Tribune - http://www.coshoctontribune.com/

I. Business websites

- Coshocton Chamber of Commerce - http://www.coshoctonchamber.com/
- Coshocton Port Authority (Economic Development) - http://www.coshoctonportauthority.com/

Guernsey

A. Political Factors

- County government website: http://www.guernseycounty.org/
- Cambridge city government site: http://www.cambridgeoh.org/
- 70% of the population based in the top ten largest places. Distribution of place size:
    - 10.4K pop – 1 place
    - 2-4K pop – 4 places
    - 1.1-1.9K pop – 5 places

B. Economic Factors

- Based on ARC Index – Guernsey ranked as a “Transitional” community for FY2017. The status was “At Risk: for FY 2012-FY 2015 at which time is improved to “Transitional” where it has since remained. (ARC)
- Tourism 2015: sales - $162.5M; employees – 1.763 people (App’l OH)
- In 2014, of the 829 private sector establishments: 161 were in goods producing industries; 669 in service industry. In addition, there were 1,128 farms in the county. (OED)

C. Social Factors

- Population:
    - Guernsey’s population has wavered at around 40,000 since 1950. The 2010 population was 40,087. The 2000-2010 growth rate of -1.7% is less than for the rest of Appalachian Ohio, the State of Ohio (1.6%), and in the US (9.7%). OED projects growth in Guernsey to have peaked in 2010 and then taper slightly. (ARC, OED)
    - Population density in 2010: 78.2 person/square mile. This is the seventh most-dense county in the study area and is considerably less dense than the average of 282.3 person/sq mile for the state of Ohio. (ARC)
- Financial:
    - The per capita income in 2014 was $34,453. This was lower than the average of $35,233 for Appalachian OH, $42,236 for OH, and $46,049 for the US.
    - The 2014 unemployment rate of 6.7% showed improvement in comparison to the 3 year average of 8.1% for the period 2012-2014. However, this rate is equal to or worse than the rate in the rest of Appalachian Ohio (6.7%), the state of Ohio (5.7%), and the US (6.2%)
    - The 2010-2014 poverty rate was 18.7%, the seventh lowest rate in the study area. It was higher than the 17.8% in Appalachian OH, 15.9% in OH, and 15.6% in the US.
- Education:
    - Guernsey has a rate of high school completion (degrees) that is essentially the same for Appalachian OH, OH, and the US (roughly 85-88%).
    - In terms of college, Guernsey is about the same as the rest of Appalachian OH, with 12.3% of the population completing BA’s. It is lower than the rate of 25.6% for the state of OH and 29.3% for the US.

D. Technological Factors

- Notable companies in manufacturing include:
  - Colgate-Palmolive Co
  - Daimler AG/Detroit Diesel
  - Encore Plastics
  - Federal-Mogul Corp
  - JMC Steel Group/Picoma
  - Southeastern Ohio Reg. Medical Ctr
  - Wal-Mart Stores Inc

- Other Major & Notable Employers (OED)
  - Cambridge City Schools
  - Guernsey County Government
  - State of Ohio

E. Environmental Factors

a. State Parks / Forests, Nature Preserves, scenic waterways, and wildlife areas: 6 (21.8K acres)

- Salt Fork State Park

F. Legal Factors - TBD

G. Stakeholders - TBD

H. Media

- TV: 0 stations
- Radio: 6 stations
- Daily Paper: 1 (Circ 9,586)
- Weekly paper: 0
- Other papers:
  - Jeffersonian News: http://daily-jeff.com/

I. Business websites

- Guernsey Chamber of Commerce - http://www.guernseychamber.com/
- Guernsey economic development - http://cgccic.org/

Hocking

A. Political Factors

- County government website: https://www.co.hocking.oh.us/
- County Seat: Logan - https://www.loganohio.net/index.htm
- Roughly 90% of the population based in the top ten largest places. Distribution of place size:
  - > 5K pop – 2 places
  - 2-3K pop – 2 places
  - 1.1-1.9K pop – 6 places

B. Economic Factors

- Based on ARC Index – Hocking ranked as a "Transitional" community for FY2017. The status has been "Transitional since before FY 2012. (ARC)
- Tourism 2015: sales - $134.3; employees – 1,109 people (AppalachianOH)
- In 2014, of the 454 private sector establishments: 105 were in goods producing industries; 349 in service industry. In addition, there were 367 farms in the county. (OED)

C. Social Factors

- Population:
  - Hocking's population has hovered between 25,000-30,000 since 1990. The 2010 population was 29,380. The 2000-2010 growth rate of 4% is greater than for the rest of Appalachian Ohio and the State of Ohio, but less than the national average. OED projects growth in Hocking to peak in 2020 and then taper slightly. (ARC, OED)
  - Population density in 2010: 69.7 person/square mile. This is the eighth most-dense county in the study area and is considerably less dense than the average of 282.3 person/sq mile for the state of Ohio. (ARC)
- Financial:
  - The per capita income in 2014 was $32,502. This was lower than the average of $35,233 for Appalachian OH, $42,236 for OH, and $46,049 for the US.
  - The 2014 unemployment rate of 6.3% showed improvement in comparison to the 3 year average of 7.5% for the period 2012-2014 and was slightly better than the rate in the rest of Appalachian Ohio (6.7%). However, this rate is worse than the rate in the state of Ohio (5.7%), and the US (6.2%).
  - The 2010-2014 poverty rate was 16.8%, the fifth lowest rate in the study area. It was higher than the 15.9% in OH, and 15.6% in the US.
- Education:
  - Hocking has a rate of high school completion (degrees) that is essentially the same for Appalachian OH, OH, and the US (roughly 85-88%).
  - In terms of college, Hocking is about the same as the rest of Appalachian OH, with 13.7% of the population completing BA's. It is lower than the rate of 25.6% for the state of OH and 29.3% for the US.

D. Technological Factors

- Notable companies in manufacturing include:

  - Amanda Bent Bolt Co
  - General Electric Co
  - Gabriel Logan
  - Smead Manufacturing Co
- Other Major & Notable Employers (OED)
  - Hocking Valley Community Hospital
  - Logan Health Care Center
  - Kilbarger Construction
  - Kroger Co
  - Logan-Hocking Local Schools
  - State of Ohio
  - Wal-Mart Stores Inc

E. Environmental Factors

a. State Parks / Forests, Nature Preserves, scenic waterways, and wildlife areas: 18 (26.1K acres)

F. Legal Factors - TBD

G. Stakeholders - TBD

H. Media

  - TV: 0 stations
  - Radio: 2 stations
  - Daily Paper: 1 (Circ 3,350)- Logan Daily News: http://www.logandaily.com/
  - Weekly paper: 0

I. Business websites

- Hocking Hills Chamber of Commerce - https://www.facebook.com/hockingchamber/
- Hocking County Community Improvement Corporation - http://www.hockingcountycic.com/

Holmes

A. Political Factors

- County government website: http://www.co.holmes.oh.us/
- County seat: Millersburg Village: http://www.millersburgohio.com/index.html
- 80% of the population is based in the top ten largest places. Distribution of place size:
    - 2- 4.4K pop – 10 places

B. Economic Factors

- Based on ARC Index – Holmes is ranked as a “Transitional” community for FY2017. This has been the stable status since FY2012. (ARC)
- Tourism 2015: sales - $164.M; employees – 1,703 people (App’l OH)
- In 2014, of the 1,172 private sector establishments: 586 were in goods producing industries; 586 in service industry. In addition, there were 1,969 farms in the county. (OED)

C. Social Factors

- Population:
    - Holmes’ population has grown steadily from 18,760 in 1950 to 42,366 in 2010. The 2000-2010 growth rate of 8.8% is significantly greater than for the rest of Appalachian Ohio (0.1%) and the State of Ohio (1.6%). It is on par with the growth rate across the US (9.7%). OED projects growth in Holmes to continue a modest level of growth through 2030. (ARC, OED)
    - Population density in 2010: 100.3 person/square mile. This is the fourth most-dense county in the study area and is considerably less dense than the average of 282.3 person/sq mile for the state of Ohio. (ARC)
- Financial:
    - The per capita income in 2014 was $32,778. This was lower than the average of $35,233 for Appalachian OH, $42,236 for OH, and $46,049 for the US.
    - The 2014 unemployment rate of 3.9% showed improvement in comparison to the 3 year average of 4.8% for the period 2012-2014. This rate is better than the rate in the rest of Appalachian Ohio (6.7%), the state of Ohio (5.7%), and the US (6.2%)
    - The 2010-2014 poverty rate was 14.4%, the third lowest rate in the study area. It was better than the 17.8% in Appalachian OH, 15.9% in OH, and 15.6% in the US.
- Education:
    - Holmes’ rate of high school completion is 55.8%; this is significantly lower than the same for Appalachian OH, OH, and the US (roughly 85-88%).
    - With 7.8% of the population completing BA’s, Holmes is also lower than the rate of 16.4% for Appalachian OH, 25.6% for the state of OH, and 29.3% for the US.

D. Technological Factors

- Notable companies in manufacturing include:
    - Case Foods Inc
    - Centor Inc
    - International Automotive Overhead Door/Wayne-Dalton

    - Pomerene Hospital
    - Sperry & Rice Mfg Co LLC
    - Weaver Leather Goods Inc
- Other Major & Notable Employers (OED)
    - East Holmes Local Schools
    - West Holmes Local Schools

E. Environmental Factors

a. State Parks / Forests, Nature Preserves, scenic waterways, and wildlife areas: 4 (1.5K acres)

- Mohican State Forest

F. Legal Factors - TBD

G. Stakeholders - TBD

H. Media

    - TV: 0 stations
    - Radio: 1 stations
    - Daily Paper: 1 (Circ 9,586)
    - Weekly paper: 0

I. Business websites

- Holmes County Chamber of Commerce - http://www.holmescountychamber.com/
- Holmes economic development - http://www.holmescountydevelopment.org/

Meigs

A. Political Factors

- County government website: *none found*
- County seat: Pomeroy City / Village
- 76% of the population is based in the top ten largest places. Distribution of place size:
  - 2- 3K pop – 2 places
  - 1-1.9K pop – 8 places

B. Economic Factors

- Based on ARC Index – Meigs is ranked as a "Distressed" community for FY2017 and has been since FY 2012. (ARC)
- Tourism 2015: sales - $12.8M; employees - 342 people (App'l OH)
- In 2014, of the 269 private sector establishments: 59 were in goods producing industries; 211 in service industry. In addition, there were 588 farms in the county. (OED)

C. Social Factors

- Population:
  - Meigs' population has hovered around 23,000 since 1950. The population in 2010 was 23,770 and reflected a 2000-2010 growth rate of 3% is significantly greater than for the rest of Appalachian Ohio (0.1%) and the State of Ohio (1.6%). It is less than the growth rate across the US (9.7%). OED projects growth in Meigs to remain stable through 2030. (ARC, OED)
  - Population density in 2010: 55.3 person/square mile. This is the third lowest population density in the study area and is considerably less dense than the average of 282.3 person/sq mile for the state of Ohio. (ARC)
- Financial:
  - The per capita income in 2014 was $28,963. This was lower than the average of $35,233 for Appalachian OH, $42,236 for OH, and $46,049 for the US.
  - The 2014 unemployment rate of 9% showed improvement in comparison to the 3 year average of 10.8% for the period 2012-2014. However, this rate is worse than the rate in the rest of Appalachian Ohio (6.7%), the state of Ohio (5.7%), and the US (6.2%)
  - The 2010-2014 poverty rate was 23%, the second highest rate in the study area. It was worse than the 17.8% in Appalachian OH, 15.9% in OH, and 15.6% in the US.
- Education:
  - Meigs' rate of high school completion is 82.4%; on par with Appalachian OH, OH, and the US (roughly 85-88%).
  - With 11.9% of the population completing BA's, Meigs is lower than the rate of 16.4% for Appalachian OH, 25.6% for the state of OH, and 29.3% for the US.

D. Technological Factors

- Notable companies in manufacturing include:
  - Extendicare/Rocksprings Rehab Ctr
  - Gatling Ohio LLC
  - Overbrook Rehab Center

- Other Major & Notable Employers (OED)
    - Eastern Local Schools
    - Meigs County
    - Govt Meigs Local Schools
    - Southern Local Schools

E. Environmental Factors

a. State Parks / Forests, Nature Preserves, scenic waterways, and wildlife areas: 10 (4.1K acres)

- Forked Run State Park
- Shade River State Forest

F. Legal Factors - TBD

G. Stakeholders - TBD

H. Media

- TV: 0 stations
- Radio: 2 stations
- Daily Paper: 1 (Circ 3,818)
- Weekly paper: 0
- Other:
    - The Pomeroy Daily Sentinel - http://mydailysentinel.com/

I. Business websites

- Meigs County Chamber of Commerce - https://www.meigscountychamber.com/
- Meigs economic development - http://www.meigscountyohio.com/

Morgan

A. Political Factors

- County government website: http://www.morgancounty-oh.gov/
- County seat: McConnelsville – website: http://www.vomcc.com/
- 74% of the population is based in the top ten largest places. Distribution of place size:
    - 1 – 1.8K pop – 5 places
    - <1 K pop – 5 places

B. Economic Factors

- Based on ARC Index – Morgan is ranked as an "At Risk" community for FY2017. This is an improvement over the rating of "Distressed" from FY2012 – FY2016. (ARC)
- Tourism 2015: sales - $17.4M; employees - 186 people (App'l OH)
- In 2014, of the 161 private sector establishments: 30 were in goods producing industries; 131 in service industry. In addition, there were 510 farms in the county. (OED)

C. Social Factors

- Population:
    - Morgan's population was 12,836 in1950. It remained stable for a couple of decades until it jumped to over 14,000 in the 1980's and gradually climbed to 15,054 in 2010. The 2000-2010 growth rate of 1.1% is greater than for the rest of Appalachian Ohio (0.1%) but not as large as that in the State of Ohio (1.6%) or for the US. OED projects Morgan's population to decline gradually through 2030. (ARC, OED)
    - Population density in 2010: 36.2 person/square mile. This is the lowest population density in the study area and is considerably less dense than the average of 282.3 person/sq mile for the state of Ohio. (ARC)
- Financial:
    - The per capita income in 2014 was $29,880. This was lower than the average of $35,233 for Appalachian OH, $42,236 for OH, and $46,049 for the US.
    - The 2014 unemployment rate of 7.8% showed improvement in comparison to the 3 year average of 9.3% for the period 2012-2014. However, this rate is worse than the rate in the rest of Appalachian Ohio (6.7%), the state of Ohio (5.7%), and the US (6.2%)
    - The 2010-2014 poverty rate was 19.5%, the third highest rate in the study area. It was worse than the 17.8% in Appalachian OH, 15.9% in OH, and 15.6% in the US.
- Education:
    - Morgan's rate of high school completion is 86.5%; on par with Appalachian OH, OH, and the US (roughly 85-88%).
    - With 10.7% of the population completing BA's, Morgan is lower than the rate of 16.4% for Appalachian OH, 25.6% for the state of OH, and 29.3% for the US.

D. Technological Factors

- Notable companies in manufacturing include:
    - Hann Manufacturing
    - Highland Oaks

  - Kroger Co
  - MAHLE International
  - Miba Bearings US LLC
  - Warren's Morgan Co IGA
- Other Major & Notable Employers (OED)
  - Morgan County Govt
  - Morgan Local Schools

E. Environmental Factors

a. State Parks / Forests, Nature Preserves, scenic waterways, and wildlife areas: 3 (7.0 K acres) (OED)

- Muskingam River State Park
- Burr Oak (also in Athens County)

F. Legal Factors - TBD

G. Stakeholders - TBD

H. Media

  - TV: 0 stations
  - Radio: 0 stations
  - Daily Paper: 0
  - Weekly paper: 1 (circ 3,700)

I. Business websites

- Morgan County Chamber of Commerce - http://www.visitmorgancountyohio.com/our-front-porch/morgan-county-chamber-of-commerce/
- Morgan County economic development - http://www.morgancounty-oh.gov/development.htm

Muskingum

A. Political Factors

- County website: http://www.muskingumcounty.org/
- County seat: Zanesville – website: http://www.coz.org/
- 74% of the population is based in the top ten largest places. Distribution of place size:
  - >25K pop – 1 place
  - 8.1K pop – 1 place
  - 4.3-5.1K pop – 4 places
  - 2.4-3.6K pop – 4 places

B. Economic Factors

- Based on ARC Index – Muskingam is ranked as a “Transitional” community for FY2017. This rating has been consistent since FY2012. (ARC)
- Tourism 2015[xxi]: sales - $212.5M; employees – 3,139 people
- In 2014, of the 1,685 private sector establishments: 285 were in goods producing industries; 1,400 in service industry. In addition, there were 1,259 farms in the county. (OED)

C. Social Factors

- Population:
  - Muskingam’s population was 74,535 in1950 and grew gradually to 86,074 in 2010. The 2000-2010 growth rate of 1.8% is greater than for the rest of Appalachian Ohio (0.1%) and the State of Ohio (1.6%); however it is not as large as for the US (9.7%). OED projects Muskingam’s population will be stable or slightly smaller by 2030. (ARC, OED)
  - Population density in 2010: 129.5 person/square mile. This is the second highest population density in the study area but is still less dense than the average of 282.3 person/sq mile for the state of Ohio. (ARC)
- Financial:
  - The per capita income in 2014 was $35,319. This was slightly higher than the average of $35,233 for Appalachian OH but lower than the averages of $42,236 for OH and $46,049 for the US.
  - The 2014 unemployment rate of 7% showed improvement in comparison to the 3 year average of 8.5% for the period 2012-2014. However, this rate is worse than the rate in the rest of Appalachian Ohio (6.7%), the state of Ohio (5.7%), and the US (6.2%)
  - The 2010-2014 poverty rate was 19.2%, the fourth highest rate in the study area. It was worse than the 17.8% in Appalachian OH, 15.9% in OH, and 15.6% in the US.
- Education:
  - Muskingam’s rate of high school completion is 86.6%; on par with Appalachian OH, OH, and the US (roughly 85-88%).
  - With 14.6% of the population completing BA’s, Muskingam is lower than the rate of 16.4% for Appalachian OH, 25.6% for the state of OH, and 29.3% for the US.

D. Technological Factors

- Notable companies in manufacturing include:
  - 5 B's Inc
  - AK Steel Holding Co
  - Avon Products Inc.
  - AutoZone Inc
  - Dollar General Corp
  - Genesis HealthCare System
  - Kellogg's
  - Longaberger Co
  - Muskingum University
  - Owens-Illinois/Owens-Brockway
  - Wendy's Intl/East Balt Bakeries
- Other Major & Notable Employers (OED)
  - Muskingum County Government
  - Zanesville City Schools

E. Environmental Factors

a. State Parks / Forests, Nature Preserves, scenic waterways, and wildlife areas: 13 (34.2 K acres) (OED)

- Dillon State Park
- Black Rock State Forest

F. Legal Factors - TBD

G. Stakeholders - TBD

H. Media

  - TV: 1 stations
  - Radio: 5 stations
  - Daily Paper: 1 (circ 8,771)
  - Weekly paper: 0
  - Other:
    - Zanesville Times Recorder - http://www.zanesvilletimesrecorder.com/

I. Business websites

- Zanesville / Muskingam Chamber of Commerce - https://www.zmchamber.com/
- Zanesville Port Authority - http://zmcport.com/site/
- Muskingam Appalachian Partnership for Economic Growth - http://apeg.com/county/muskingum/

Noble

A. Political Factors

- County website: *none found*
- County seat: Caldwell
- 82% of the population is based in the top ten largest places. Distribution of place size:
    - 4K pop – 1 place
    - 1.5-1.9K pop – 2 places
    - <950 - 7 places

B. Economic Factors

- Based on ARC Index – Noble is ranked as a “Transitional” community for FY2017. Since FY 2012, the ranking has been improving from “Distressed” (FY2012-FY2014) to “At Risk” (FY2015-FY2016). (ARC)
- Tourism 2015[xxii]: sales - $5.9M; employees - 219 people
- In 2014, of the 233 private sector establishments: 63 were in goods producing industries; 171 in service industry. In addition, there were 595 farms in the county. (OED)

C. Social Factors

- Population:
    - Noble’s population was 11,750 in1950 and remained stable into the 1990’s. It grew to over 14,000 by 2000 and reached 14,645 by 2010. The 2000-2010 growth rate of 4.2% is greater than for the rest of Appalachian Ohio (0.1%) and the State of Ohio (1.6%); however it is not as large as for the US (9.7%). OED projects Noble’s population to grow to more than 15,500 by 2030. (ARC, OED)
    - Population density in 2010: 36.8 person/square mile. This is the second lowest population density in the study area and is signnificantly still less dense than the average of 282.3 person/sq mile for the state of Ohio. (ARC)
- Financial:
    - The per capita income in 2014 was $26,913. This was lower than the average of $35,233 for Appalachian OH, $42,236 for OH, and $46,049 for the US.
    - The 2014 unemployment rate of 7.6% showed improvement in comparison to the 3 year average of 9.4% for the period 2012-2014. However, this rate is worse than the rate in the rest of Appalachian Ohio (6.7%), the state of Ohio (5.7%), and the US (6.2%)
    - The 2010-2014 poverty rate was 13.7%, the lowest rate in the study area. It was better than the 17.8% in Appalachian OH, 15.9% in OH, and 15.6% in the US.
- Education:
    - Noble’s rate of high school completion is 80.8%; on par with Appalachian OH, OH, and the US (roughly 85-88%).
    - With 9.5% of the population completing BA’s, Noble is lower than the rate of 16.4% for Appalachian OH, 25.6% for the state of OH, and 29.3% for the US.

D. Technological Factors

- Notable companies in manufacturing include:
    - B&N Coal
    - International Converter Inc

  - Summit Acres
  - Warren Drilling Co
- Other Major & Notable Employers (OED)
  - Caldwell Exempted Village Schools
  - Noble County Government
  - Noble Local Schools
  - State of Ohio

E. Environmental Factors

a. State Parks / Forests, Nature Preserves, scenic waterways, and wildlife areas: 2 (4.1 K acres) (OED)

- Wolf Run State Park

F. Legal Factors - TBD

G. Stakeholders - TBD

H. Media

  - TV: 0 stations
  - Radio: 0 stations
  - Daily Paper: 0
  - Weekly paper: 1 (Circ 4,500)
  - Other: Non-daily – the Journal and Noble County Leader - http://journal-leader.com/

I. Business websites

- Noble Chamber of Commerce - http://www.noblecountychamber.com/
- Noble Appalachian Partnership for Economic Growth - http://apeg.com/county/noble/

Perry

A. Political Factors

- County website: http://www.perrycountyohio.net/
- County seat: Village of New Lexington - http://www.newlexington.org/
- 69% of the population is based in the top ten largest places. Distribution of place size:
    - 4.7K pop – 1 place
    - 2-3.6K pop – 6 places
    - 1.5-1.6K pop - 3 places

B. Economic Factors

- Based on ARC Index – Perry is ranked as a "At Risk" community for FY2017 and has been since FY2012. (ARC)
- Tourism 2015[xxiii]: sales - $11.5M; employees - 366 people
- In 2014, of the 438 private sector establishments: 82 were in goods producing industries; 357 in service industry. No farm count. (OED)

C. Social Factors

- Population:
    - Perry's population was 28,999 in1950. It declined slightly for two decades and then began to climb until it reached 36,058 in 2010. The 2000-2010 growth rate of 5.8% is greater than for the rest of Appalachian Ohio (0.1%) and the State of Ohio (1.6%); however it is not as large as for the US (9.7%). OED projects Perry's population to grow to more than 39,000 by 2030. (ARC, OED)
    - Population density in 2010: 88.4 person/square mile. This is the sixth lowest density in the study area and is a lower population density than in Appalachian OH and the state of OH (282.3 person/sq mile). (ARC)
- Financial:
    - The per capita income in 2014 was $31,086. This was lower than the average of $35,233 for Appalachian OH, $42,236 for OH, and $46,049 for the US.
    - The 2014 unemployment rate of 7.2% showed improvement in comparison to the 3 year average of 8.8% for the period 2012-2014. However, this rate is worse than the rate in the rest of Appalachian Ohio (6.7%), the state of Ohio (5.7%), and the US (6.2%)
    - The 2010-2014 poverty rate was 18.8%, the fifth highest in the study area. It was worse than the 17.8% in Appalachian OH, 15.9% in OH, and 15.6% in the US.
- Education:
    - Perry's rate of high school completion is 83.9%; on par with Appalachian OH, OH, and the US (roughly 85-88%).
    - With 11% of the population completing BA's, Perry is lower than the rate of 16.4% for Appalachian OH, 25.6% for the state of OH, and 29.3% for the US.

D. Technological Factors

- Notable companies in manufacturing include:
    - Westmoreland Coal
    - CerCo LLC
    - Cooper-Standard Automotive

- Eclipse Aluminum Trailer, LLC
- Ludowici Roof Tile
- PCC Airfoils LLC
- Shelly Materials Inc

- Other Major & Notable Employers (OED)
  - Crooksville Exempted Village Schools
  - New Lexington City Schools
  - Northern Local Schools
  - Perry County Government
  - Southern Local Schools

E. Environmental Factors

a. none identified

F. Legal Factors - TBD

G. Stakeholders - TBD

H. Media

- TV: 0 stations
- Radio: 0 stations
- Daily Paper: 0
- Weekly paper: 0

I. Business websites

- Perry Chamber of Commerce - http://perrycountyohiochamber.com/
- Perry Economic Development - http://perrycountyohio.net/agencies-and-offices/perry-county-community-improvement-corporation
- Perry - APEG - http://apeg.com/county/perry/

Tuscarawas

A. Political Factors

- County website: http://www.co.tuscarawas.oh.us/
- County seat: New Philadelphia - http://www.newphilaoh.com/Home
- 65% of the population is based in the top ten largest places. Distribution of place size:
    - 12.7-17.7 K pop – 2 places
    - 4.3 – 5.4 K pop – 3 places
    - 2.9 -3.5 K pop - 5 places

B. Economic Factors

- Based on ARC Index – Tuscarawas is ranked as a "Transitional" community for FY2017 and has been since FY2012. (ARC)
- Tourism 2015[xxiv]: sales - $397.6M; employees – 3,592 people
- In 2014, of the 2,096 private sector establishments: 483 were in goods producing industries; 1,613 in service industry. In addition, there were 1,014 farms in the county. (OED)

C. Social Factors

- Population:
    - Tuscarawas' population was 70,320 in1950. It has grown steadily since then and reached 95,582 in 2010. The 2000-2010 growth rate of 1.8% is greater than for the rest of Appalachian Ohio (0.1%) and the State of Ohio (1.6%); however it is not as large as for the US (9.7%). OED projects Perry's population to grow to more than 39,000 by 2030. (ARC, OED)
    - Population density in 2010: 163.1 person/square mile. This is the highest population density in the study area and it exceeds the rate in Appalachian but not the state of OH (282.3 person/sq mile). (ARC)
- Financial:
    - The per capita income in 2014 was $36,115. This was higher than the average of $35,233 for Appalachian OH, but lower than the averages of $42,236 for OH and $46,049 for the US.
    - The 2014 unemployment rate of 5.4% showed improvement in comparison to the 3 year average of 6.7% for the period 2012-2014. This rate is better than the rate in the rest of Appalachian Ohio (6.7%), the state of Ohio (5.7%), and the US (6.2%)
    - The 2010-2014 poverty rate was 14.3%. It was the second lowest rate in the study area and was better than the 17.8% in Appalachian OH, 15.9% in OH, and 15.6% in the US.
- Education:
    - Perry's rate of high school completion is 86.6%; on par with Appalachian OH, OH, and the US (roughly 85-88%).
    - With 14.7% of the population completing BA's, Perry is lower than the rate of 16.4% for Appalachian OH, 25.6% for the state of OH, and 29.3% for the US.

D. Technological Factors

- Notable companies in manufacturing include:

- Alamo Group/Gradall Industries
- Allied Machine & Engineering
- Lauren Manufacturing
- Marlite, Inc.
- Union Hospital
- Wal-Mart Stores Inc
- Zimmer Orthopedic

- Other Major & Notable Employers (OED)
  - Dover City Schools
  - New Philadelphia City Schools

E. Environmental Factors

a. State Parks / Forests, Nature Preserves, scenic waterways, and wildlife areas: 1 (300 acres) (OED)

F. Legal Factors - TBD

G. Stakeholders - TBD

H. Media

- TV: 0 stations
- Radio: 2 stations
  - WDNP -
- Daily Paper: 1 (circ 15,069)
- Weekly paper: 2 (circ 12,950)
- Daily – The New Philadelphia Times Reporter - http://www.timesreporter.com/

I. Business websites

- Tuscarawas Chamber of Commerce - http://www.tuschamber.com/
- Economic Development and Finance Alliance- http://www.tuscedfa.com/
- Tuscarawas Convention - http://traveltusc.com/
- http://www.co.tuscarawas.oh.us/OCED/

Washington

A. Political Factors

- County website: http://www.washingtongov.org/
- County seat: Marietta - http://www.mariettaoh.net/
- 76% of the population is based in the top ten largest places. Distribution of place size:
    - 13.9 K pop – 1 places
    - 4.4 – 6.4 K pop – 3 places
    - 2.3 -3.9 K pop - 5 places
    - <2K pop – 1 place

B. Economic Factors

- Based on ARC Index – Washington is ranked as a "Transitional" community for FY2017 and has been since FY2012. (ARC)
- Tourism 2015[xxv]: sales - $236.6M; employees – 2,116 people
- In 2014, of the 1,444 private sector establishments: 328 were in goods producing industries; 1,116 in service industry. In addition, there were 1,122 farms in the county. (OED)

C. Social Factors

- Population:
    - Washington's population was 44,047 in1950. It grew steadily until about 2000 and then population declined slightly. In 2010, the population was 61,778. This decline is reflected in t he 2000-2010 growth rate of -2.3%, the worst in the study area and lower than in the rest of Appalachian Ohio (0.1%), the State of Ohio (1.6%), and the US (9.7%). OED projects Washington's population to continue to decline to roughly 56,000 by 2030. (ARC, OED)
    - Population density in 2010: 97.8 person/square mile, the fifth highest in the study area. This is lower than the density in Appalachian OH and the state of OH (282.3 person/sq mile). (ARC)
- Financial:
    - The per capita income in 2014 was $37,157. This was higher than the average of $35,233 for Appalachian OH, but lower than the averages of $42,236 for OH and $46,049 for the US.
    - The 2014 unemployment rate of 6.2% showed improvement in comparison to the 3 year average of 7.7% for the period 2012-2014. This rate is better than the rate in the rest of Appalachian Ohio (6.7%) and the US (6.2%), but not the state of Ohio (5.7%).
    - The 2010-2014 poverty rate was 16.6%. It was the fourth lowest rate in the study area and was better than the 17.8% in Appalachian OH. It was higher than the rates of 15.9% in OH and 15.6% in the US.
- Education:
    - Washington's rate of high school completion is 89.1%; on par with Appalachian OH, OH, and the US (roughly 85-88%).
    - With 16.6% of the population completing BA's, Washington is higher than the rate of 16.4% for Appalachian OH but lower than the rates of 25.6% for the state of OH and 29.3% for the US.

D. Technological Factors

- Notable companies in manufacturing include:
    - American Electric Power Co
    - Americas Styrenics
    - Eramet Marietta Inc
    - Globe Metallurgical
    - KRATON Polymers LLC
    - Marietta College
    - Marietta Memorial Health System
    - Pioneer Pipe
    - RJF International Corp
    - Solvay Advanced Polymers
    - Thermo Fisher Scientific Inc
    - Wal-Mart Stores Inc

- Other Major & Notable Employers (OED)
    - Marietta City Schools

E. Environmental Factors

a. State Parks / Forests, Nature Preserves, scenic waterways, and wildlife areas: 9 (842 acres) (OED)

- No Listed protected natural resources
- Note this recent op-ed on climate change - http://www.mariettatimes.com/opinion/local-columns/2017/04/groups-address-climate-change/

F. Legal Factors - TBD

G. Stakeholders - TBD

H. Media

- TV: 0 stations
- Radio: 6 stations
    - WMOA - http://www.wmoa1490.com/
- Daily Paper: 1 (circ 7,622)
- The Marietta Times - http://www.mariettatimes.com/
- Weekly paper: 0

I. Business websites

- Marietta Chamber of Commerce - http://www.mariettachamber.com/
- Southeastern Ohio Port Authority - http://seohioport.com/

Appendix B

Memorandum

To: Battelle Memorial Institute
From: Lou Gentile, Vorys Advisors
RE: Outreach to Stakeholders for CarbonSAFE Project
Date: February 23, 2018

Battelle sought to listen and understand local needs and realities to improve the social-economic and legislative aspects of carbon capture and storage (CCS) technology and lay the foundation for developing commercial-scale CCS projects. For the initial phase of the project, Battelle asked Vorys Advisors to reach out to those that could have collaborative or opportunistic attitudes towards CCS development. Battelle determined that it was important to engage high level staff at state agencies such as the Ohio Environmental Protection Agency (OEPA) and the Ohio Department of Natural Resources (ODNR) collectively to promote a coordinated approach to addressing regulatory issues. During the three month engagement period with Battelle, Vorys Advisors conducted stakeholder outreach to senior staff in the Governor's Office, Cabinet Directors, state agency regulators, congressional staff, regional economic development directors in Appalachia Ohio and leaders in organized labor.

Vorys Advisors was successful at securing a stakeholder meeting to educate senior state officials on the CarbonSAFE program and Battelle's effort to deliver federal funding for Ohio in Phase II of the program. This was a noteworthy meeting that included the following senior level administration officials: The Governor's Assistant policy director on Energy and environment, The Director of the Ohio Department of Natural Resources (ODNR), the Director of the Ohio Environmental Protection Agency (OEPA), and regulators from both agencies. Tom Niehaus, a Principal at Vorys Advisors was instrumental in securing this meeting and bringing these parties together. This meeting was a critical part of educating high level state leaders on Battelle's effort to investigate the feasibility of a commercial scale CCS project in Ohio.

Broad support and local involvement is an important factor in a successful project. During the engagement period Vorys Advisors engaged with federal, state and local leaders about the perceptions of CCS. We had dialogue with political leaders, state regulators, economic development professionals and workforce representatives.

We found support in Appalachia Ohio from regional economic development leaders who are committed to preserving jobs and extending the use of fossil fuels in a responsible manner. We contacted members of our congressional delegation and found them to be receptive and well educated on the benefits of CCS. Many of them were already supporting legislation aimed at encouraging CCS through tax incentives. At the state level, the Governor's Office and state regulators were very knowledgeable about CCS, they recognize Battelle as a leader on this issue and reaffirmed their commitment to remain engaged as active stakeholders in the development of CCS. We also found support from unions whose jobs depend upon the continued use of coal. The United Mine Workers of America are particularly interested in remaining active and engaged when it comes to policy issues impacting CCS. The Ohio Valley Construction and Employers Council expressed support and would like to remain involved in developing CCS technology.

Key Findings

- Regional Stakeholders were very educated and enthusiastic about the benefits of CCS. These perceptions were based on the economic impact that CCS would have on protecting jobs and extending the use of fossil fuels.
- Members of the Ohio Congressional delegation (through staff contact) were very informed and supportive of CCS. After initial contact with the Congressional delegation, it was decided that Battelle would handle direct contact with federal legislators moving forward.
- State leaders were briefed through an in person meeting on January 24, 2018. The meeting included the Governor's Office, ODNR and OEPA. All parties understand the importance of CCS and recognize that Battelle is a leader when it comes to the development of this technology. Because of their role as regulators they decided that it would be a conflict for state agencies charged with regulating this activity to support the application; however they are committed to being ongoing stakeholders and remain engaged in Battelle's effort to secure this federal funding. Battelle did secure a letter of support from the Ohio Coal Office, demonstrating support at the state level.
- Outreach and education was conducted with three major labor organizations, all stakeholders, who directly benefit from the successful deployment of CCS.

Stakeholders Contacted for Outreach and Education

- Office of Governor John Kasich
- Director Jim Zehringer, Ohio Department of Natural Resources
- Director Craig Butler, Ohio Environmental Protection Agency
- Office of US Senator Sherrod Brown
- Office of US Representative Tim Ryan
- Office of US Rep. Bob Gibbs
- Office of US Sen. Sherrod Brown
- Appalachian Partnership for Economic Growth (APEG)
- Ohio Mid-East Governments Association (OMEGA)
- Buckeye Hills Regional Council (BHRC)
- United Mine Workers of America (UMWA)
- Utility Workers Union of America(UWUA)
- Ohio Valley Construction Employers Council

Deliverables

- Stakeholder Meeting arranged with Governor's Office, ODNR, OEPA, Vorys Advisors and Battelle on January 24, 2018.
- Support letter secured from Appalachian Partnership for Economic Growth (APEG).
- Support letter secured from Ohio Mid-Eastern Governments Association (OMEGA).
- Support letter secured from Buckeye Hills Regional Council (BHRC).
- Advised Battelle on drafting of the letters for stakeholder approval.
- Reported stakeholder perceptions.
- Expanded stakeholder outreach to include regional economic development leaders and union representatives.

Conclusion

Vorys Advisors was pleased to provide outreach and stakeholder engagement services to Battelle from November 2017 to February of 2018. During this period we found the relevant stakeholders at the federal, state and local level to be interested, informed and eager to see progress made in developing Carbon Capture and Storage (CCS). While some raised questions about the challenges in Darke County, many in the Appalachian Region expressed optimism and were willing to be supportive because of the positive impact it would have on economic growth and job retention.

Vorys Advisors did deliver on several of the stated objectives that Battelle had requested. Battelle had requested an audience with the Governor's Office, ODNR, and OEPA. This meeting was a critical component of the education process and occurred on January 24, 2018.

Additionally, Vorys Advisors secured three letters of support from regional economic development agencies and had productive conversations about CCS with 17 individual leaders who are critical to the success of CCS.

Thank you for the opportunity. Vorys Advisors would welcome an opportunity to continue working with Battelle during Phase II.

Stakeholders Contacted in preliminary On-on-one Interviews

Members of Congress

- Senator Sherrod Brown
    - Jon McCracken, Legislative Aide
- US Rep. Tim Ryan
    - Ryan Keating, Deputy Chief of Staff
- Senator Rob Portman
- US Rep. Bob Gibbs

State Officials

Governor's Office

- **Mike Fraizer,** Assistant Policy Director - Environment, Energy, Agriculture
    - Sarah Huffman, Legislative Liaison

Ohio EPA

- Craig Butler**,** Ohio EPA Director
- Laura Factor**,** Ohio EPA, Assistant Director
- Lindsay Taliaferro III**,** Ohio EPA, Asst. Chief Division of Materials and Waste Management (DMWM) and head of UIC program
- Bob Hodenbosi, Ohio EPA , Chief, Division of Air Pollution Control

ODNR

- James Zehringer**,** ODNR Director
- Thomas J. Serenko, ODNR State Geologist

Economic Development Agencies

Ohio Mid-Eastern Governments Association (OMEGA)

Jeannette Weirzbicki, Executive Director

Buckeye Hills-Hocking Valley Regional Development Commission (BHRC)

Misty Casto, Executive Director

Appalachian Partnership for Growth (APEG)

Ed Looman, Project Manager

Workforce

United Mine Workers of America (UMWA)

Adam Banig, Legislative Representative

Utility Workers Union of America (UWUA)

Kelly Cooper, Senior National Representative, Region III

Ohio Valley Construction Employers Council and Project BEST

Ginny Favede, Executive Director

Sources of Information / Endnotes

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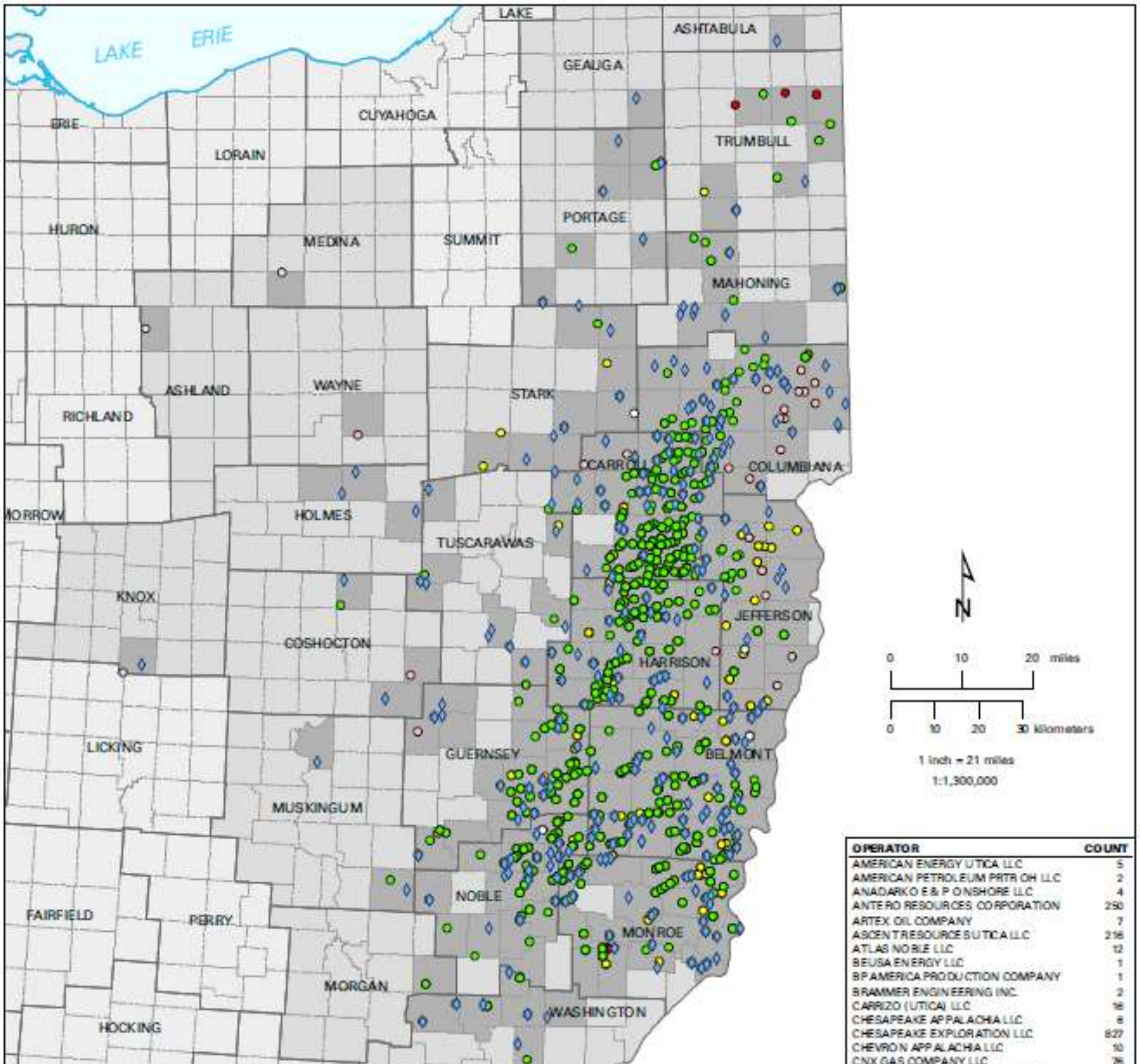
[i] See: https://www.netl.doe.gov/File%20Library/Research/Carbon%20Seq/Reference%20Shelf/BPM_PublicOutreach.pdf
[ii] See: https://www.netl.doe.gov/File%20Library/Research/Carbon%20Seq/Reference%20Shelf/BPM_PublicOutreach.pdf, page 20
[iii] See: https://hub.globalccsinstitute.com/sites/default/files/publications/119186/social-site-characterisation-stakeholder-engagement.pdf
[iv] See: https://www.arc.gov/research/MapsofAppalachia.asp?MAP_ID=116
[v] See: http://www.appalachianohio.com/resources/2016%20Appalachian%20Region-%20Ecomonic%20Impact%20Study.pdf
[vi] See: http://www.appalachianohio.com/resources/2016%20Appalachian%20Region-%20Ecomonic%20Impact%20Study.pdf
[vii] see: https://www.arc.gov/research/MapsofAppalachia.asp?MAP_ID=63
[viii] See: https://www.arc.gov/research/MapsofAppalachia.asp?MAP_ID=122
[ix] See https://www.arc.gov/research/MapsofAppalachia.asp?MAP_ID=122
[x] See: http://wvmetronews.com/2016/08/29/wvu-economist-tells-senators-capito-and-manchin-that-six-counties-are-now-in-great-depression-at-senate-field-hearing/
[xi] See: http://longviewpower.com/
[xii]See: http://www.wvcommerce.org/App_Media/assets/doc/energy/Energy_Summits/presentations_2016/5_DIMICK.pdf
[xiii] See: http://www.worldwildlife.org/ecoregions/na0402
[xiv] See: http://parks.ohiodnr.gov/findapark
[xv] See: https://en.wikipedia.org/wiki/List_of_protected_areas_of_Ohio
[xvi] see: http://www.theoec.org/
[xvii] See: http://thealliancefor appalachia.org/about-the-alliance-for-appalachia/member-groups/
[xviii] https://www.facebook.com/AppalachianVoices/
[xix] http://www.sierraclub.org/environmental-justice
[xx] Source: https://development.ohio.gov/ (https://development.ohio.gov/files/research/C1038.pdf)
[xxi] See this report for all tourism numbers by county: http://www.appalachianohio.com/resources/2016%20Appalachian%20Region-%20Ecomonic%20Impact%20Study.pdf
[xxii] See this report for all tourism numbers by county: http://www.appalachianohio.com/resources/2016%20Appalachian%20Region-%20Ecomonic%20Impact%20Study.pdf
[xxiii] See this report for all tourism numbers by county: http://www.appalachianohio.com/resources/2016%20Appalachian%20Region-%20Ecomonic%20Impact%20Study.pdf
[xxiv] See this report for all tourism numbers by county: http://www.appalachianohio.com/resources/2016%20Appalachian%20Region-%20Ecomonic%20Impact%20Study.pdf
[xxv] See this report for all tourism numbers by county: http://www.appalachianohio.com/resources/2016%20Appalachian%20Region-%20Ecomonic%20Impact%20Study.pdf

OHIO DEPARTMENT OF NATURAL RESOURCES

HORIZONTAL UTICA - PT PLEASANT WELL ACTIVITY IN OHIO



OPERATOR	COUNT
AMERICAN ENERGY UTICA LLC	5
AMERICAN PETROLEUM PRTR OH LLC	2
ANADARKO E & P ONSHORE LLC	4
ANTERO RESOURCES CORPORATION	250
ARTEX OIL COMPANY	7
ASCENT RESOURCES UTICA LLC	216
ATLAS NOBLE LLC	12
BEUSA ENERGY LLC	1
BP AMERICA PRODUCTION COMPANY	1
BRAMMER ENGINEERING INC.	2
CARRIZO (UTICA) LLC	16
CHESAPEAKE APPALACHIA LLC	6
CHESAPEAKE EXPLORATION LLC	827
CHEVRON APPALACHIA LLC	10
CNX GAS COMPANY LLC	76
DEVON ENERGY PRODUCTION CO.	13
ECLIPSE RESOURCES I LP	142
EM ENERGY OHIO LLC	13
ENERVEST OPERATING LLC	26
EQT PRODUCTION COMPANY	8
GEOPETRO LLC	2
GULFPORT BUCKEYE LLC	8
GULFPORT ENERGY CORPORATION	334
HALCON OPERATING COMPANY INC.	13
HESS OHIO DEVELOPMENTS LLC	89
HESS OHIO RESOURCES LLC	1
HG ENERGY LLC	7
HILCORP ENERGY COMPANY	49
MOUNTAINEER KEYSTONE LLC	8
NGO DEVELOPMENT CORP.	1
PDC ENERGY INC.	42
PROTEGE ENERGY III LLC	2
R E GAS DEVELOPMENT LLC	38
RICE DRILLING D LLC	103
SIERRA RESOURCES LLC	3
STATOIL USA ONSHORE PROP INC.	26
SWEPI LP	1
TRIAD HUNTER LLC	25
XTO ENERGY INC.	62
TOTAL	**2,451**

EXPLANATION

Horizontal well status as of 4/1/2017

- PERMITTED-(Permitted; Not Drilled; Canceled) (501)
- DRILLED-(Drilling; Well Drilled) (329)
- PRODUCING-(Producing; Plugged Back) (1,537)
- INACTIVE-(Drilled Inactive; Shut in) (44)
- Lost Hole or Final Restoration (14)
- Dry and Abandoned (3)
- Plugged and Abandoned (23)

Well permit information from the ODNR Division of Oil and Gas Resources Management

Recommended citation:
Ohio Department of Natural Resources, 2017, Horizontal Utica-Point Pleasant Well Activity in Ohio: Columbus, scale 1:1,300,000, revised 4/3/2017.