Midwestern Regional Carbon Sequestration Partnership (MRCSP) Phase III (Development Phase).

Final Technical Report

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Notice

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Acronyms and Abbreviations

AAPG	American Association of Petroleum Geologists
AAUW	American Association of University Women
ACR	Artificial Corner Reflectors
AGU	American Geophysical Union
AI	Acoustic Impedance
AiCHE	American Institute of Chemical Engineers
AMA	Active Monitoring Area
BHG	Borehole gravity
CCUS	Carbon Capture Utilization and Storage
CO_2	carbon dioxide
CO_2-EOR	Carbon-dioxide enhanced oil recovery
CRM	Capacitance-resistance model
CS-NMB	CarbonSAFE – Northern Michigan Basin
CSLF	Carbon Sequestration Leadership Forum
DAS	Distributed Acoustic Sensing
DOE	Department of Energy
DTS	Distributed Temperature Sensing
EDX	Energy Data Exchange
EGR	Enhanced Gas Recovery
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
FWI	Full Waveform Inversion
GHG LCA	Greenhouse Gas Emissions lifecycle analysis
GHGRP	Greenhouse Gas Reporting Program
GHGT	Greenhouse Gas Technology
Gt	gigatons
HTD	hydrothermal dolomite
IEA	International Energy Agency
IEAGHG	International Energy Agency Greenhouse Gas Program
ISO	International Standards Organization
InSAR	Interferometric Synthetic Aperture Radar
LCFS	Low Carbon Fuel Standard
MGSC	Midwest Geologic Sequestration Consortium
MMA	Maximum Monitoring Area
MMT	Million Metric Tons
MRCI	Midwest Regional Carbon Initiative
MRCSP	Midwest Regional Carbon Initiative
MRV	Monitoring, Reporting, and Verification
MT	Metric tons
NETL	National Energy Technology Laboratory
NNPRT	Northern Niagaran Pinnacle Reef Trend
OCDO	Ohio Coal Development Office
OOIP	Original oil in place

OWC	Oil Water Contact
PNC	Pulsed-Neutron-Capture Logging
PTTC	Petroleum Technology Transfer Council
PVT	Pressure volume temperature
RCSP	Regional Carbon Sequestration Partnership
RTP	Reverse Time Migration
SEM	Static Earth Model
SPE	Society of Petroleum Engineers
SREs	Storage Capacity Estimates
STB	Stock tank barrel
STEM	Science, Technology, Engineering, and Math
TDS	Total Dissolved Solids
UIC	Underground Injection Control
VSP	Vertical Seismic Profile
XCT	X-Ray Computed Tomography
XRD	X-Ray Diffraction

Executive Summary

MRCSP Introduction

The Midwest Regional Carbon Sequestration Partnership (MRCSP) was founded in 2003 as part of the U.S. Department of Energy's (DOE's) Regional Carbon Sequestration Partnership initiative to answer two important questions: how much carbon storage potential exists in deep geologic reservoirs within the states in the partnership, and how can we safely utilize this potential? MRCSP is one of seven such partnerships and spans from Indiana to New York (Figure ES-1). MRCSP examined these questions and assessed the technical potential, economic viability and public acceptability of carbon sequestration and utilization within the region. The success of the field tests conducted over the last decade suggests that carbon capture, utilization and storage (CCUS) provide a foundation for mitigating greenhouse gas emissions in the Midwest region. This Final Technical Report is a very high-level summary of the MRCSP program, primarily covering Phase III efforts. Additional details on all elements of the program are provided in a series of companion Topical Reports, which are available online and at the DOE's Energy Data Exchange (EDX) site.

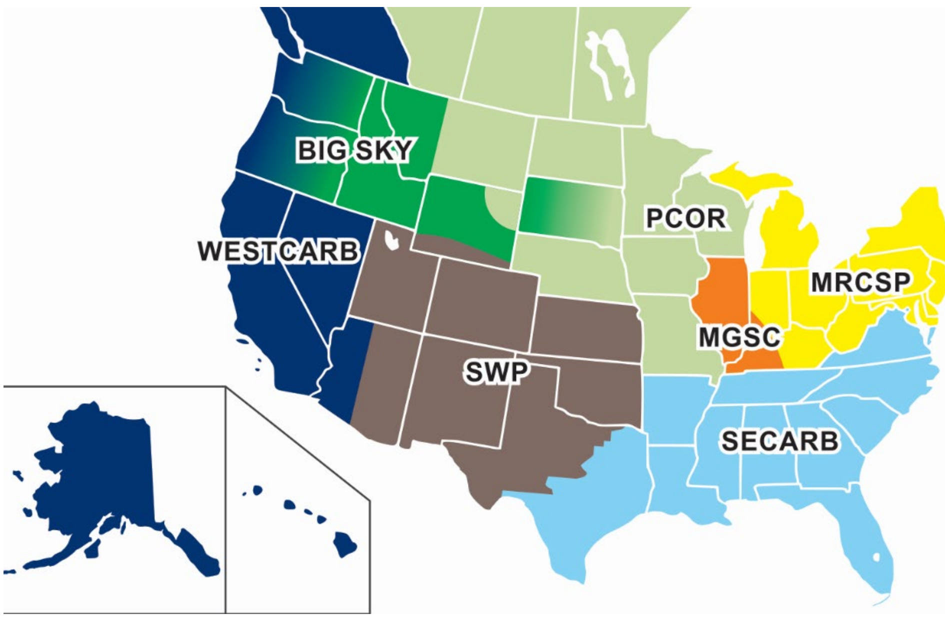


Figure ES-1. Map of the DOE regional partnerships showing MRCSP in yellow.

The region encompassed by MRCSP emits between 500 and 800 million metric tons of CO_2 from power and industrial point sources each year. The 45Q tax credit now provides incentives for companies to capture and sequester this CO_2 for long-term storage or utilization. The geologic reservoirs in the participating states have the potential to safely sequester more than 500 gigatons of CO_2—more than enough to accommodate all of the CO_2 produced by large point sources in the region for hundreds of years. In addition to storage in saline reservoirs, the MRCSP region also has depleted oil and gas fields, which can permanently store CO_2, with enhanced oil recovery (EOR), resulting in economic benefit and production of greener oil.

Since its founding, MRCSP has made significant strides toward making CCUS a viable option for states in the region. The public/private consortium, funded through the DOE Regional Carbon Sequestration Initiative, brings together nearly 40 industry partners and 10 states. Battelle, as the project lead, oversees research, development and operations and coordinates activities among the partners. The incremental, phased approach has built a valuable knowledge base for the industry and paved the way for commercial-scale adoption of CCUS technologies. Previous phases of the project include:

- Phase I (Characterization, 2003-2005) identified sources of CO_2 emissions in the region, assessed the storage potential of deep geologic reservoirs and identified locations for the first pilot-scale demonstration projects; and,
- Phase II (Validation, 2005-2010) took the work further through a series of three pilot-scale field validation tests to demonstrate the safety and effectiveness of geologic sequestration. Phase II also included testing for carbon storage in multiple terrestrial storage settings.

In 2008, MRCSP entered Phase III (Development). Work has continued through large-scale field testing and other activities to prepare for commercial-scale application of CCUS technologies and methods. Successful large-scale injection projects in the Michigan Basin have demonstrated that long-term geologic storage of CO_2 and utilization for EOR are now technically and economically feasible in the MRCSP region.

Over the course of the Phase III project, tremendous progress was made in establishing methods for site characterization, modeling, injection operations and monitoring. The final emphasis was on commercialization, technology transfer and outreach efforts.

MRCSP, along with other DOE Regional Partnership programs, has laid the groundwork that will enable the industry to put CCUS into practice. The success of the MRCSP demonstration project has already led to many additional CCUS projects within the region. In 2019, Battelle was selected for a new regional initiative project, named the Midwest Regional Carbon Initiative (MRCI), as part of the DOE Carbon Storage Program. This initiative combines the synergies of the MRCSP and Midwest Geological Sequestration Consortium (MGSC) in the Illinois Basin with an objective of accelerating CCUS deployment across a new 20-State region. This work will carry forward the lessons learned through the MRCSP demonstration projects and move the industry closer to widespread adoption of commercial-scale CCUS.

A Successful Large-Scale Demonstration of CCUS and EOR

MRCSP's Phase III Large-Scale Injection Project translated the lessons learned in Phases I and II into development and operation of a commercial-scale CCUS and EOR project in northern Michigan. The project injected more than one million metric tons of CO_2 into oil fields in the Northern Niagaran Pinnacle Reef Trend (NNPRT) for geologic sequestration and EOR. CO_2 for the project was sourced from gas processing plants used in production of natural gas from the nearby Antrim Shale fields.

This commercial-scale test provided additional real-world knowledge that has been used to further refine technologies and methods, reduce uncertainties, and demonstrate safety and effectiveness to increase public acceptance. The project demonstrated that commercial-scale carbon capture is now both technically possible and economically viable. Similar large-scale projects could capture up to 90% of carbon emitted from large point sources and, at the same time, produce additional oil that would otherwise not be recovered.

Between 2013 and 2019, the MRCSP project stored **1,732,500** metric tons of CO_2 and monitored the production of **1,167,000** barrels of oil. This is further represented by the values presented in Figure ES-2.

- Removal of **374,295** passenger cars for a year
- Amount stored by **2,262,565** acres of forest
- Switching **65,816,966** incandescent lights to LEDs

- **532** jobs yielding more than **$22.4 M** in income
- **$77.5 M** goods and services
- **$8.1 M** in other taxes and royalties

Figure ES-2. Equivalent CO_2 stored valued based on EPA's calculator tool[1] (left) and monitored production value based on a 2016 Michigan Oil and Gas study[2]. (right).

About the Northern Niagaran Pinnacle Reef Trend

MRCSP selected the site in the Northern Niagaran Pinnacle Reef Trend (NNPRT) based on the availability of large volumes of CO_2 from nearby gas processing plants, the suitability of deep geologic formations for injection and storage of CO_2, and the existence of oil fields already moving into the EOR phase of production.

The NNPRT consists of closely spaced, highly compartmentalized oil and gas reservoirs. Hydrocarbons are held in the pores of tall, mound like masses of dolostone and limestone known as pinnacle reefs. The reefs occur between 4,000 to 6,000 ft deep and are overlain above by thick deposits of evaporites, shales, and tight carbonates (Figure ES-3). The MRCSP injection project involved several of these reefs at different stages of oil and gas production, including:

- One late-stage reef (prior EOR activities completed)
- Seven reefs in active EOR-phase production
- Two reefs that had previously undergone primary production and began CO_2-EOR during the project.

Together, the three stages provided a unique opportunity to monitor CO_2 throughout the lifespan of an EOR reef. Additionally, the geologic variability between the reefs allowed MRCSP to develop new methodologies to characterize, model and monitor these complex systems.

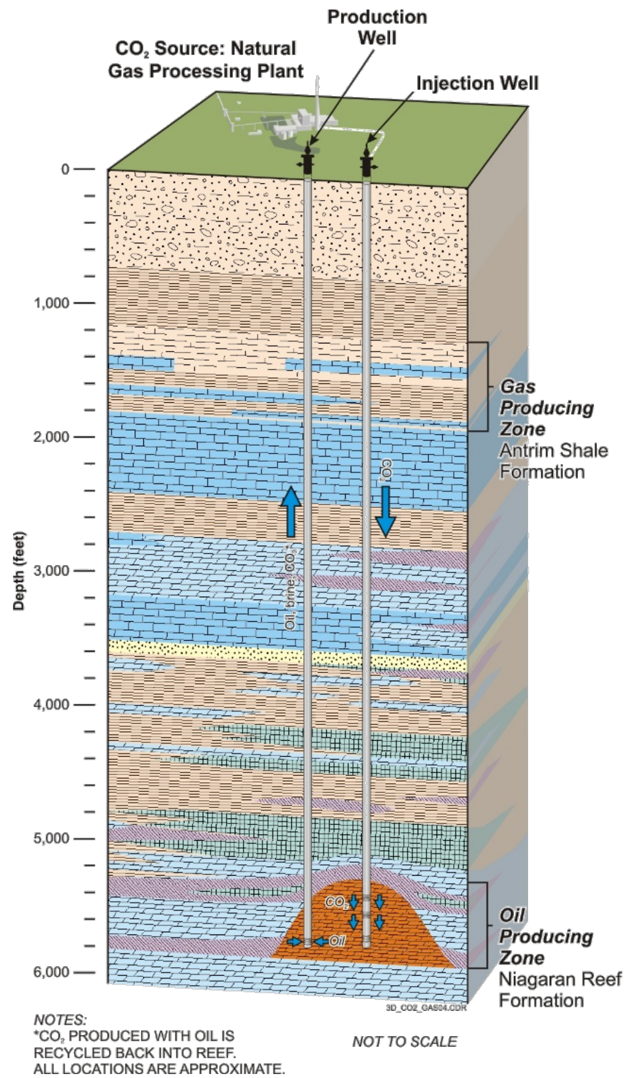


Figure ES-3. Simplified diagram of CO_2-EOR process in a pinnacle Niagaran reef.

[1] https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator
[2] http://www.michiganoilandgas.org/study_michigan_s_oil_and_gas _industry_drives_michigan_s_economy

Answering the Critical Questions

Phase III was designed to answer critical questions about the technical and economic feasibility of CCUS and EOR, the CO_2 storage capacity of pinnacle reef formations in Northern Michigan, and the safety and efficacy of injecting CO_2 for long-term storage and utilization in oil and gas recovery. These questions include:

- **Injectivity**: What is the rate at which CO_2 can be injected into the reefs? How many wells will be required to achieve EOR goals? (Injectivity is a significant cost driver for geologic storage.)
- **Capacity**: What is the total size of the target reservoir? How much CO_2 can it hold?
- **Containment**: What happens to CO_2 after it is injected? Are layers of rock above and below the storage zone sufficient to keep CO_2 out of the atmosphere for thousands of years or longer?
- **Safety**: What can be done to minimize activity-based risks related to drilling, well completion and injection operations? How can performance risks such as unintended migration of CO_2 be minimized?

MRCSP designed its project to address these questions through the integration of site characterization, reservoir modeling, injection operations, monitoring, and regional upscale and commercialization. Across all aspects of the program, MRCSP strived to produce stakeholder education and outreach materials to communicate the key findings and help define a path forward for successful deployment of CCUS (Figure ES-4).

Figure ES-4. Key aspects to the MRCSP program.

Accomplishments

Large-scale Injection Test

MRCSP aimed to answer the overarching question - can it be done? The extensive program has demonstrated that CCUS can safely and economically be conducted in EOR fields by exploring the following research questions:

1. Can CO_2 be safely injected as large volumes into carbonate reservoirs?
   - MRCSP research completed injection of more than 2 million metric tons of CO_2 into carbonate Niagaran Pinnacle Reefs at the large-scale field site in Michigan. In addition, several piggy-back injection tests in deep carbonate rock intervals in Ohio confirmed CO_2 injection potential in the MRCSP region.
2. Will the CO_2 be contained?
   - The containment of CO_2 in the deep subsurface reservoirs was demonstrated through site characterization and monitoring of the field testing. The reefs proved to be effective “containers” for CO_2 with no evidence of significant CO_2 leakage, out of zone pressure movement, or wellbore integrity issues.

3. What are the appropriate monitoring and modeling methodologies for these fields?
   - The MRCSP field tests demonstrated that basic pressure and temperature monitoring of the injection and storage zones can provide high value information when integrated with reservoir modeling. Other technologies were investigated for feasibility and suitability in the region. Some of these methods were not as conclusive due to the nature of the deep rock formations and site conditions.
4. What is the storage capacity and how can that be upscaled?
   - Overall, the field testing confirmed the CO_2 storage potential in the Niagaran Reef Trend in Northern Michigan. Analysis of 800+ reefs in this trend suggested these rock formations may store more than 250 million metric tons of CO_2.

MRCSP Regional Studies

While the primary focus of Phase III was to conduct the large-scale test in Michigan, the MRCSP program maintained an active collaboration with the Regional Geological Surveys and Universities (the MRCSP GeoTeam) that continued regional assessments in parallel with the large-scale test. The regional work spans the Michigan and Appalachian basins, Arches province, Coastal Plains, and offshore regions with focus on selected topics such as description of CO_2-EOR opportunities, onshore and offshore storage assessments along the Atlantic Coast, and storage resources in key rock formations across the MRCSP region. The GeoTeam produced multiple reports, regional geologic cross sections and maps, composite database of petroleum fields, and resource estimates database, while also acting as a technical resource for the stakeholders within the 10-state region. The regional geologic cross sections depict CO_2 storage intervals, caprocks, and geologic structures across key areas of the MRCSP region. The following highlights the key outcomes of the regional studies:

- The Appalachian Basin enhanced recovery opportunities task defined parameters for CO_2-EOR in MRCSP oil and gas fields, assessed CO_2 storage in MRCSP organic rich shales, and detailed potential CO_2-EOR fields in the Ohio-Pennsylvania-West Virginia tri-state area.
- The Michigan Basin task examined Silurian age Pinnacle Reefs in terms of their use for CO_2-EOR.
- The Mid-Atlantic Coastal Plain and adjacent offshore region task characterized carbon storage in the eastern portion of the MRCSP region based on log analysis, formation maps, and sequence stratigraphy.
- The Ordovician-Cambrian Units task applied several different resource calculation methods for key deep rock layers in the Michigan Basin, Cincinnati Arch, and Appalachian Basin.
- The Upper Silurian to Middle Devonian task examined storage in Ohio based on stratigraphy, formation maps, and structural features.
- The Triassic Rift Basins task assessed CO_2 storage potential in the Taylorsville Basin, Culpeper Basin, Gettysburg Basin, and Triassic mafic igneous rocks in the Maryland, New Jersey, and Delaware region.

Together, the regional characterization effort developed useful products to support project developers, policy makers and other stakeholders in the MRCSP region seeking to understand where potential storage exists relative to large stationary sources of CO_2 emissions.

Outreach

Technology transfer was a key aspect of MRCSP's work. The MRCSP team has conducted or participated in numerous workshops, technical conferences, stakeholder outreach open houses, and industry meetings for CCUS, and environmental applications. MRCSP has also published a large number of peer-reviewed or proceeding papers. Some examples of technology transfer include:

- **MRCSP Partners and GeoTeam Meetings** – Held annually at various venues (Columbus, Washington, Baltimore, Annapolis, and Traverse City) these attracted up to 100 participants where MRCSP's team presented latest research findings, held panel discussions, and status updates from invited speakers. The meetings were combined with the field trips, Regional Geology Team meetings and topical workshops.
- **Hosting Workshops and Visitors** - The most prominent event was the International Energy Agency Greenhouse Gas Program (IEAGHG) Monitoring Group Workshop in 2017 which attracted about 80 international visitors. Several other delegations visited the Michigan site to learn about CO_2-EOR and utilization.
- **Conferences and Workshop Presentations** – MRCSP work was presented at every biannual International Greenhouse Gas Control Technology (GHGT) meeting since 2004, at National CCUS Conferences, DOE Annual meetings, SPE, AAPG, and AIChE meetings, IEAGHG and IEA workshops, CSLF workshops, North American Energy Ministers Trilateral CCS Group meetings, US Japan Bilateral CCS meetings, Petroleum Technology Transfer Council, etc.
- **Peer-Reviewed and Conference Papers** – Papers covering various topics from project management to technical findings at both international and domestic venues were published as listed in the bibliography
- **STEM Outreach** – Outreach for children and young adults involved planning and running experiments with AAUW in Gaylord Michigan and BeWISE STEM camp in central Ohio.
- **MRCSP Website (www.MRCSP.org)** – The web site was used to share the latest information with the stakeholders, including updates on field work, sharing of published reports, updated CO_2 injection amounts, and What's New section.
- **DOE Best Practices Manuals** – MRCSP contributed to all of the DOE Best Practices Manuals for CO_2 storage.
- **Technical Exchange** – Technical exchange wtih other projects, such as Hontomin Project in Europe included twinning with a storage project in Spain in carbonate rocks, with online technical presentations.

Conclusions and Looking to the Future

MRCSP Phase III research included both an in-depth site-specific assessment of CO_2 storage in conjunction with CO_2-EOR and continued assessment of CO_2 storage opportunities across the 10-state region from mid-Atlantic to eastern midwestern US. The large-scale test demonstrated feasibility of commercial-scale CO_2 injection supported by comprehensive site characterization, use of numerical and analytical models, and standard and innovative monitoring. Despite the complex geology and resulting monitoring and modeling challenges, the basic requirements of injectivity, capacity, and containment were proven. The acceptance of the CO_2-EOR system under the USEPA Greenhouse Gas Reporting protocols, a prerequisite for commercial CCUS viability using the 45Q tax credit mechanisms, was demonstrated.

The characterization and performance data from 10 study reefs were extended to the entire reef complex to estimate CO_2 storage potential under storage only (inject CO_2 into depleted reefs), EOR only (EOR business as usual) and enhanced EOR storage (injecting CO_2 after EOR phase to fill the reservoirs). This indicates potential for more than 250 MMT of storage potential with more than 100 million barrels in additional oil production.

MRCSP's emphasis on technology transfer is enabling deployment within the US through projects under the DOE CarbonSAFE Program and commercial work under the 45Q regime. MRCSP has also shared knowledge with collaborators in Germany, Japan, Spain, Australia, and Taiwan. Battelle's team has used MRCSP lessons learned in CCUS projects funded by international development banks in places such as China, Mexico, South Africa, and Indonesia

As the current phase of MRCSP draws to a conclusion, the outlook for CCUS deployment has been better than ever with expanded tax credits, state regulations, and international mechanisms such as the Paris Agreement. The MRCSP mission will continue under the new Regional Initiatives, wherein MRCSP and Midwestern Geological Storage Consortium (MGSC) have combined to form the Midwestern Regional Carbon Initiative (MRCI) which covers 20 states in northeast and midwestern US.

The future deployment of CCUS in the region will also need to account for profound shifts in the energy supply portfolio across the region over the last ten years. These have been driven by a combination of environmental, regulatory, and techno-economic factors. The most significant change has been due to the shale gas revolution, leading to plentiful and low-cost supply of natural gas, which has lower CO_2 emissions compared to coal. The natural gas availability combined with environmental regulatory requirements have resulted in a major shift from coal to natural gas fired power generation. Additionally, the proportion of renewable energy in power generation has increased. Thus, future CCUS deployment will be essential for coal-fired sources, but focus on natural gas power generation and industrial sources is also needed.

1.0 Background

1.1 Introduction and Background

The Midwest Regional Carbon Sequestration Partnership was established in 2003 as part of the U.S. Department of Energy's (DOE's) Regional Carbon Sequestration Partnership (RCSP) initiative. The MRCSP region originally included seven contiguous states: Indiana, Kentucky, Maryland, Michigan, Ohio, Pennsylvania and West Virginia. Over time, the partnership grew to include New York, New Jersey and Delaware (Figure 1-1).

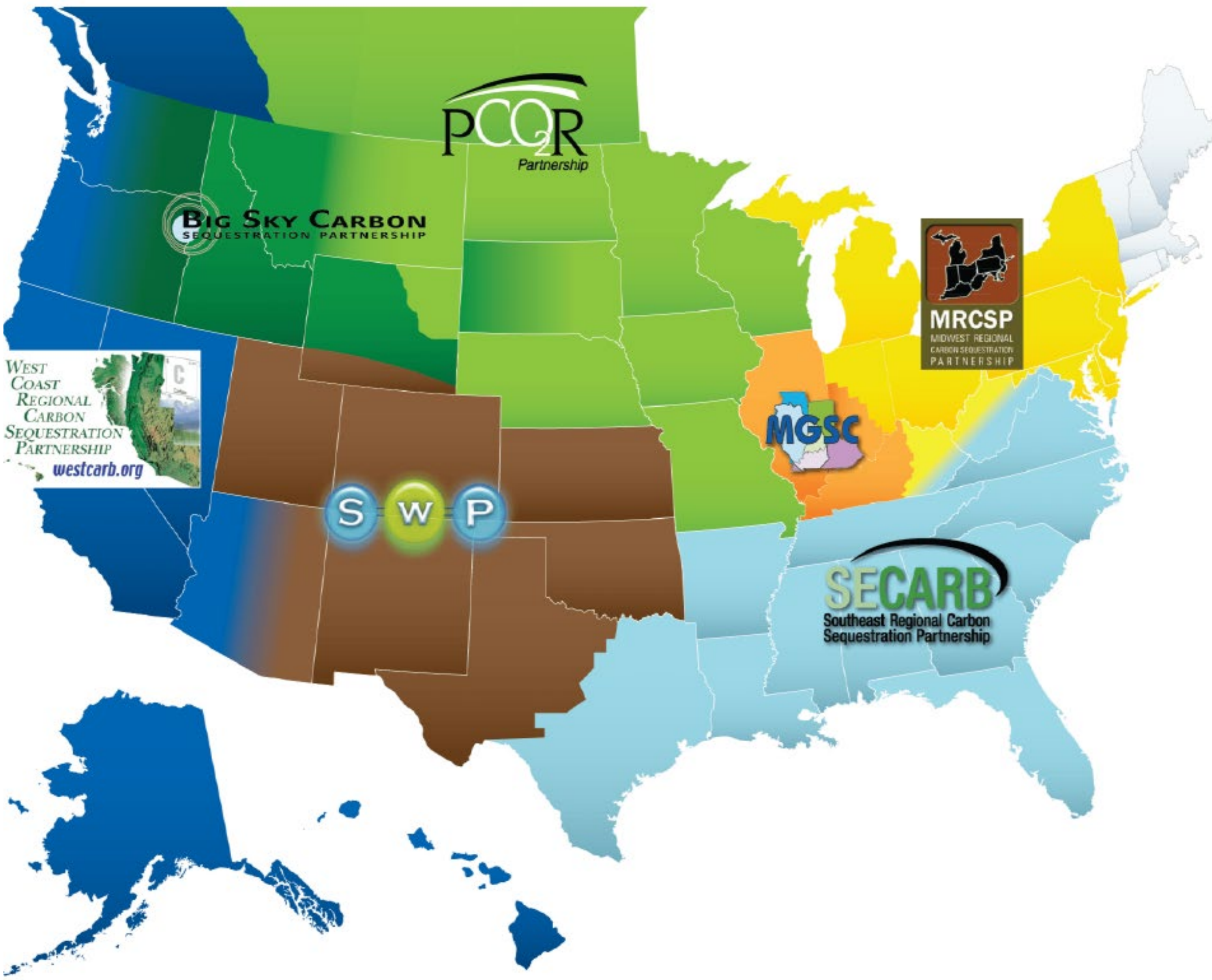


Figure 1-1. Map of regional partnerships with MRCSP in yellow. The MRCSP development phase is located in northern Michigan.

The partnership brings together 40 participating research and industry members under the leadership of Battelle. These members include leading universities, research firms, environmental organizations, state geologic surveys, state energy agencies, energy companies and other industrial and agricultural companies. They joined together with several long-term goals:

- Bring together internationally recognized research leaders to help develop practical carbon management solutions.

- Define the real-world potential of carbon sequestration and what it will take to realize this potential in the region.
- Help the region create a robust and cost-effective means for reducing greenhouse gas emissions.
- Enable the region to take a leadership position in developing local and global carbon management solutions.

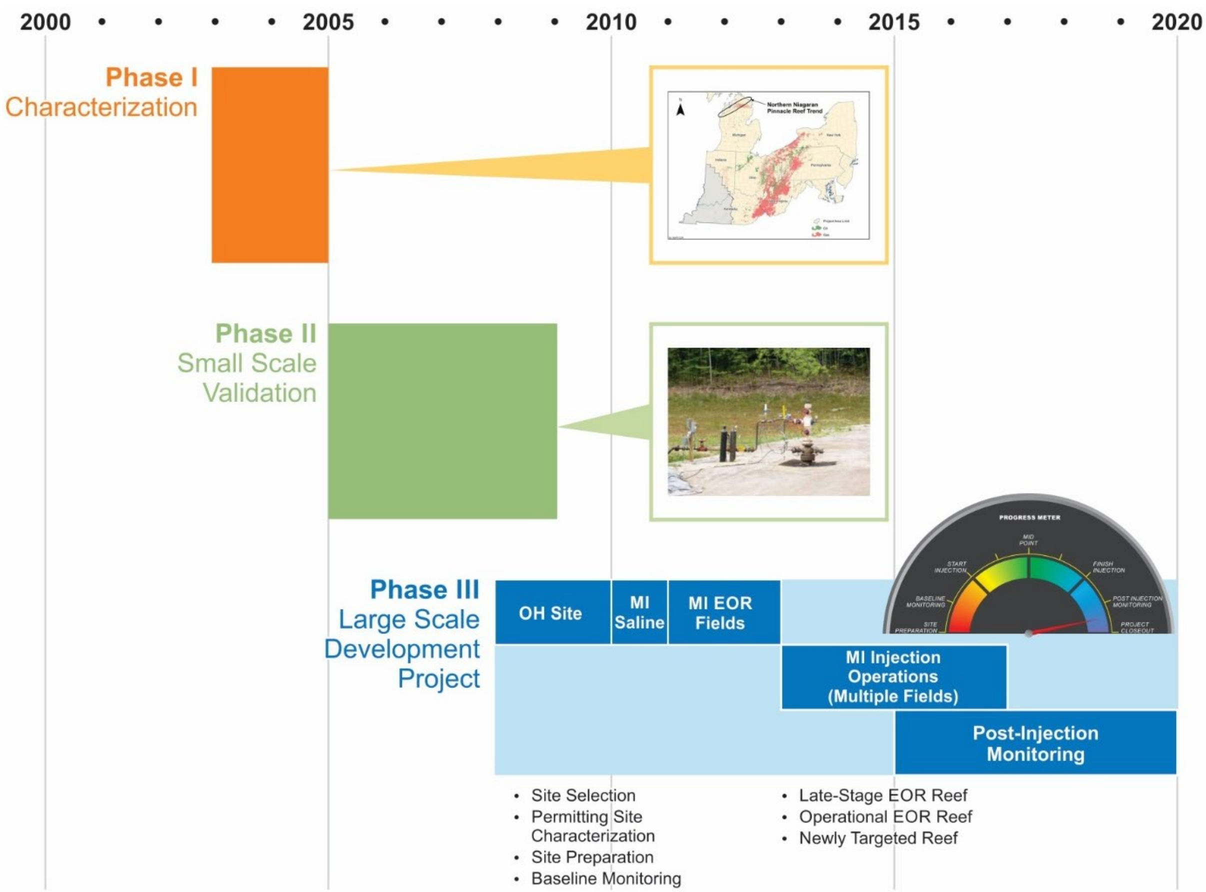


Figure 1-2. Timeline of MRCSP projects since 2003 showing the transition from characterization, to validation, to large scale development.

Since its founding, MRCSP has made significant strides toward making Carbon Capture Utilization and Storage (CCUS) a viable option for states in the region. The incremental, phased approach has built a valuable knowledge base for the industry and paved the way for commercial-scale adoption of CCUS technologies.

- Phase I (Characterization, 2003-2005) identified sources of CO_2 emissions in the region, assessed the storage potential of deep geologic reservoirs and identified locations for the first demonstration projects.
- Phase II (Validation, 2005-2010) took the work further through a series of three pilot-scale field validation tests to demonstrate the safety and effectiveness of geologic sequestration. Phase II also included multiple tests to evaluate potential for carbon sequestration in various terrestrial soil systems.

In 2008, MRCSP entered Phase III (Development Phase). Work has continued through large-scale field testing and other activities to prepare for commercial-scale application of CCUS technologies and methods. Successful large-scale injection projects in the Michigan Basin have demonstrated that long-term geologic storage of CO_2 and utilization for EOR are now technically and economically feasible in the MRCSP region. Over the course of the project, tremendous progress has been made in establishing methods for site characterization, modeling, injection operations and monitoring. The emphasis is now on commercialization, technology transfer and outreach efforts.

MRCSP, along with other regional partnership programs, has laid the groundwork that will enable the industry to put CCUS into practice. The success of the MRCSP demonstration projects has already led to many additional CCUS projects within the region. In 2019, Battelle was selected for a new regional initiative project, named the Midwest Regional Carbon Initiative (MRCI), as part of the DOE Carbon Storage Program. This initiative combines the synergies of the MRCSP and Midwest Geological Sequestration Consortium (MGSC) in Illinois Basin with an objective of accelerating CCUS deployment across a new 20-State region. This work will carry forward the lessons learned through the MRCSP demonstration projects and move the industry closer to widespread adoption of commercial-scale CCUS.

1.2 MRCSP CCUS Environment Over Time

A program like MRCSP, conducted over 17 years, had to be both technically resilient and flexible to adjust and adapt to changing economic, policy, and technology conditions over time. Management of complex, long-term research and development programs with a government-industry interface has numerous facets, any of which can impact the ultimate success. In this regard, it was very important to develop and follow collaborative processes to ensure successful completion of projects. Some of the changes MRCSP faced during the project include:

- **Growth in EOR fields over time** - MRCSP Phase III was conducted in an actively growing complex of small oil fields owned and operated by Core Energy. The addition of new oil fields offered a chance to customize the research based on the individual field geology, layout, and observations from the preceding fields. This customized approach required planning to preserve budget for newly identified technical efforts as well as technical flexibility to adjust the priorities.
- **Changes in site (having plan A, B, and C)** – Program success depends on being able to make major changes in response to unforeseen conditions. For the MRCSP Phase III, the initial proposed location was at an ethanol plant in rural western Ohio, directly above a suitable storage reservoir. However, due to public concerns, an early decision was made to move to another saline reservoir site in Michigan with CO_2 from gas processing. At this time, EPA's new UIC Class VI regulation was coming into effect that included some requirements (in particular the 50-year post injection monitoring requirement) that made this site infeasible for the Phase III project. Once again, the program was shifted to evaluate CO_2 storage in depleted oil fields including CO_2-EOR, permitted under Class II injection well protocols. This highlights the need for having multiple back-up options.
- **Changes in regulatory landscape:** During the MRCSP program, there were multiple changes in the regulatory environment. On a federal level, the overall policy on climate change shifted based on the political priorities, affecting stakeholder interest. The emphasis within the DOE moved between saline storage and EOR over time. Finally, the EPA regulations for CO_2 injection evolved from Class V experimental well status to more stringent Class VI wells with related post-injection monitoring requirement. The availability of the Core Energy EOR assets in the same area allowed the program to promptly shift focus to potential EOR opportunities thereby mitigating the impact of regulatory changes on the program.

- **Changes in market conditions (i.e. oil prices, field services):** The fieldwork intensive programs such as MRCSP can be strongly impacted by oil prices, which fluctuated between ~$30 and ~$110 per barrel during the project period of performance. While low prices can reduce oil field service costs they can also make it difficult for the host site to continue operations or invest in new facilities. High oil prices can significantly increase services cost and availability, at the same time offering new research opportunities in an expanding operational context. Because the overall project budget is fixed, the program must be able to absorb these fluctuations.
- **Changes in emissions**: Since 2005, CO_2 emissions have declined 10-15% with fewer large coal-fired power plants and more natural gas power plants (Figure 1-3). Additionally, the U.S. trends show increasing usage of electricity generation from natural gas and decreasing dependence on nuclear and coal generated energy (AEO2019, Figure 1-4).

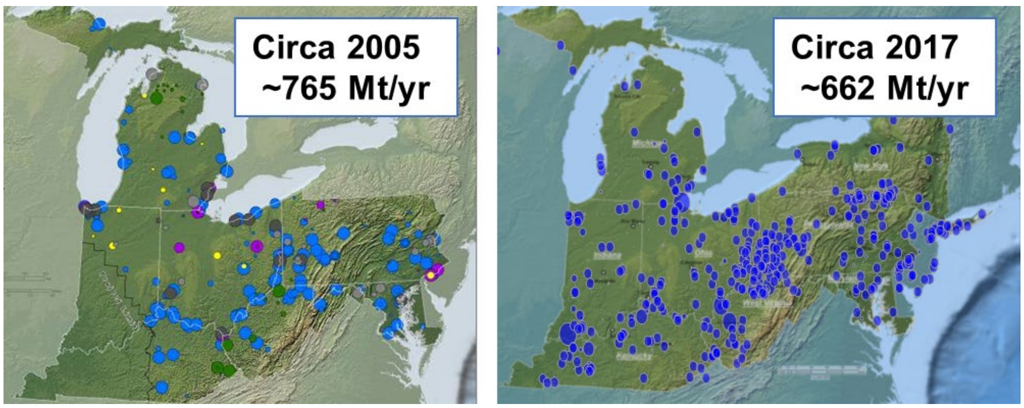


Figure 1-3. Changes in CO_2 emissions between 2005 and 2017 showing a 10-15% decrease in annual emission totals across the MRCSP region.

- **Changes in economic drivers:** Just like other emerging energy technologies, CCUS also requires a suitable economic and regulatory framework that allows project developers a viable cost recovery mechanism. This can be in the form of carbon reduction mandates, development of trading mechanisms with carbon credits, or direct financial incentives. While there were several efforts during the last 17 years, there is still no consistent national regulation on carbon reduction mandates. In the MRSCP region, several states are members of the Regional Greenhouse Gas Initiative (RGGI). However, the carbon price in the RGGI areas is still well below the cost of CCUS. The federal tax credits under Section 45Q, as modified in 2018, are seen as a major boost for enabling CCUS. These allow up to $50/ton in CO_2 storage credits and $35/ton for CO_2 use for EOR.

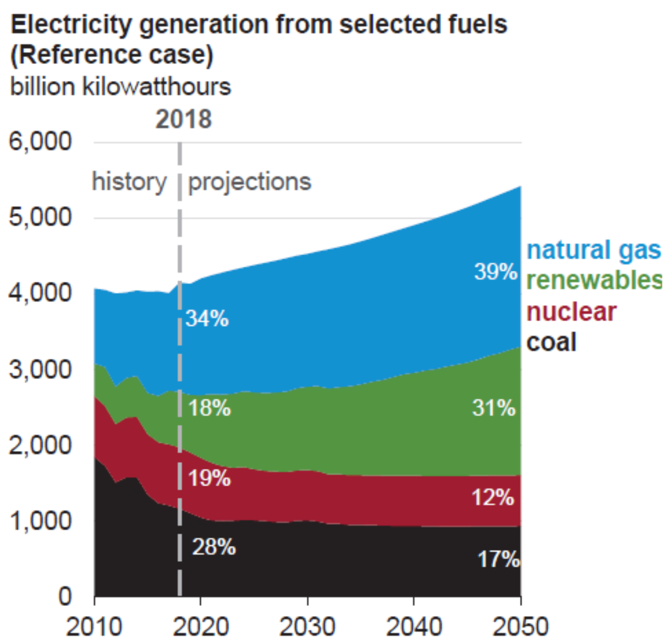


Figure 1-4. Trends in the U.S. electricity source showing an increase in natural gas and renewables with a decrease in nuclear and coal. (source: U.S. Energy Information Administration, AEO2019)

1.3 Summary and Accomplishments from Phase I

Phase I of the MRCSP initiative laid the groundwork for deployment of CCUS technologies for long-term storage and utilization of CO_2 in the region (Battelle, 2005). The critical goals included:

- Identification of CO_2 sources in the region.
- Assessment of the cost of capturing CO_2 from these sources.
- Assessment of the region's potential for storing CO_2 in deep geologic reservoirs and terrestrial ecosystems.
- Identification of critical issues for technology deployment, safety, economics, regulation and public acceptability.
- Engagement with stakeholders to inform them about carbon sequestration and obtain their feedback.
- Identification of potential Phase II field demonstration projects.

1.3.1 CO_2 Source Evaluation

Since 2005, CO_2 emissions from large point sources in the MRCSP region have ranged from 500-800 million tons of CO_2 per year. Large point sources of CO_2 emissions in the MRCSP region include power plants, refineries, cement plants, and iron and steel plants. While agricultural activities and automobiles also produce large volumes of greenhouse gases, it is these point sources (producing more than 100,000 metric tons of CO_2 annually at a single site) that provide the greatest opportunities for carbon capture. At the time of the Phase I assessment, fossil-fired power plants were responsible for 84% of emissions from large point sources, making them a logical focus for a regional CO_2 emissions reduction strategy. Updated numbers from the expanded MRCSP region estimate that power plants now contribute 71% of emissions (Figure 1-5).

1.3.1.1 A Region with Excellent Carbon Storage Potential

Phase I work showed that the MRCSP region has excellent potential for deep geologic sequestration of carbon, including numerous deep saline formations found throughout the region, organic shale formations, active and depleted oil and gas fields in the Michigan Basin and Northern Appalachian Basin, and unmineable coal seams in the Appalachian Basin. In addition, there are many opportunities to use captured CO_2 for enhanced oil recovery. The combined geologic storage potential of these resources exceeds 500 gigatons, enough to sequester all of the CO_2 emissions from large point sources in the region for hundreds of years.

The region also has good potential for terrestrial sequestration of carbon in land resource areas that act as "carbon sinks," where plants pulls carbon from the atmosphere and store it in the ecosystem. Land types with the greatest carbon sequestration potential include prime croplands, minelands, wetlands and marginal lands such as forest, pasture and severely eroded croplands.

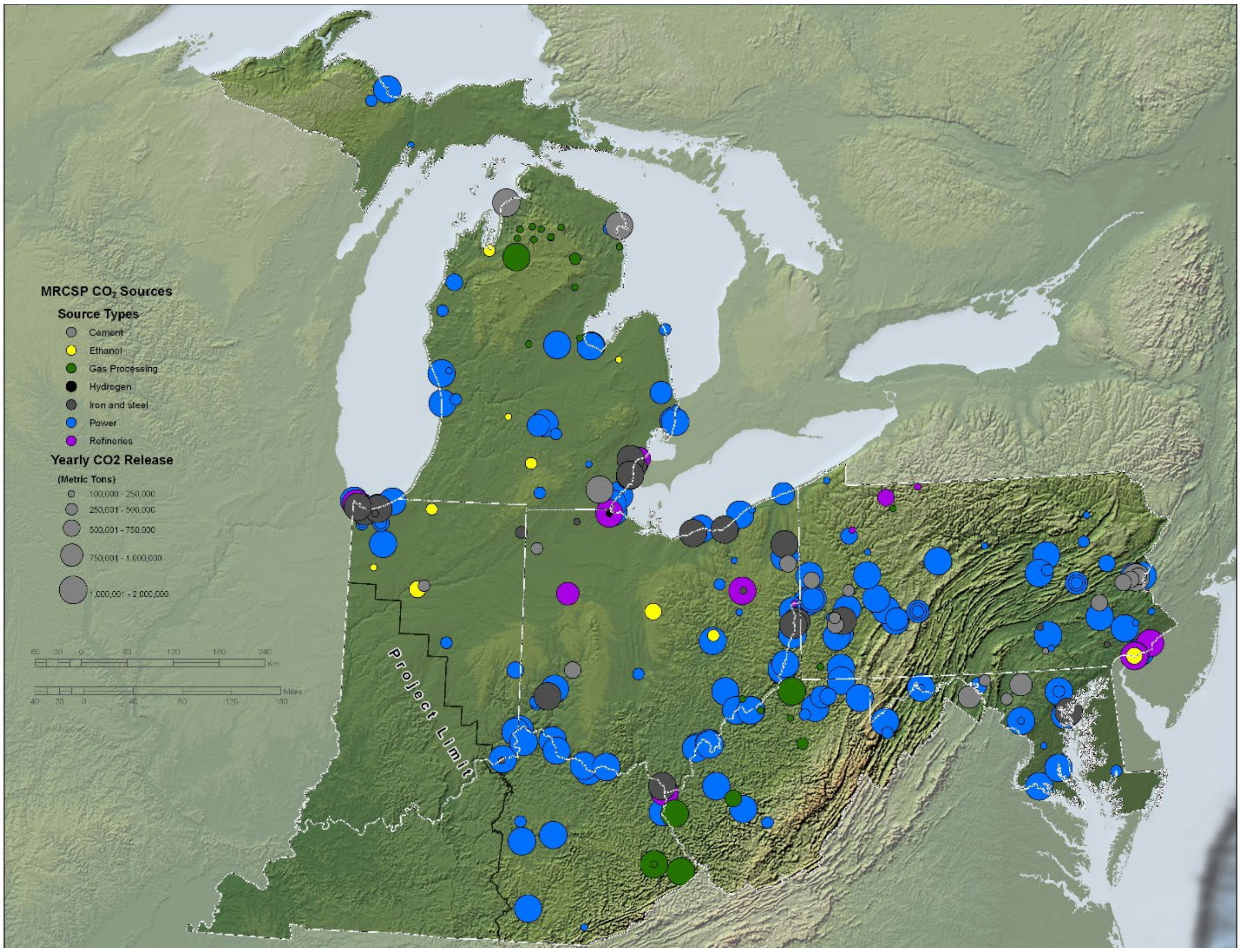


Figure 1-5. Large point sources in the MRCSP region during the Phase I project. At the time of the Phase I assessment, 80% of carbon emissions in the region came from just 31% of the large point sources (85 facilities).

The key findings from the storage potential assessment included:

- The geologic characterization efforts focused on four reservoir classes: deep saline formations, oil and gas fields, unmineable coalbeds, and organic shales
- The Mt. Simon, St. Peter, and Rose Run sandstones were identified as the region's largest assets for long-term CO_2 storage (Figure 1-6)
- Deep saline storage could potentially store 450-500 Gt of CO_2
- Oil and gas fields were estimated to have at least 2.5 Gt of CO_2 storage potential, not including the increased storage potential that could result from enhanced oil recovery using CO_2
- The unmineable coalbeds could potentially store 0.25 Gt of CO_2 with the possibility to increase storage potential through enhanced coal bad methane recovery
- Organic shales could potentially store as much as 45 Gt of CO_2 but the research was in the laboratory phase during this time

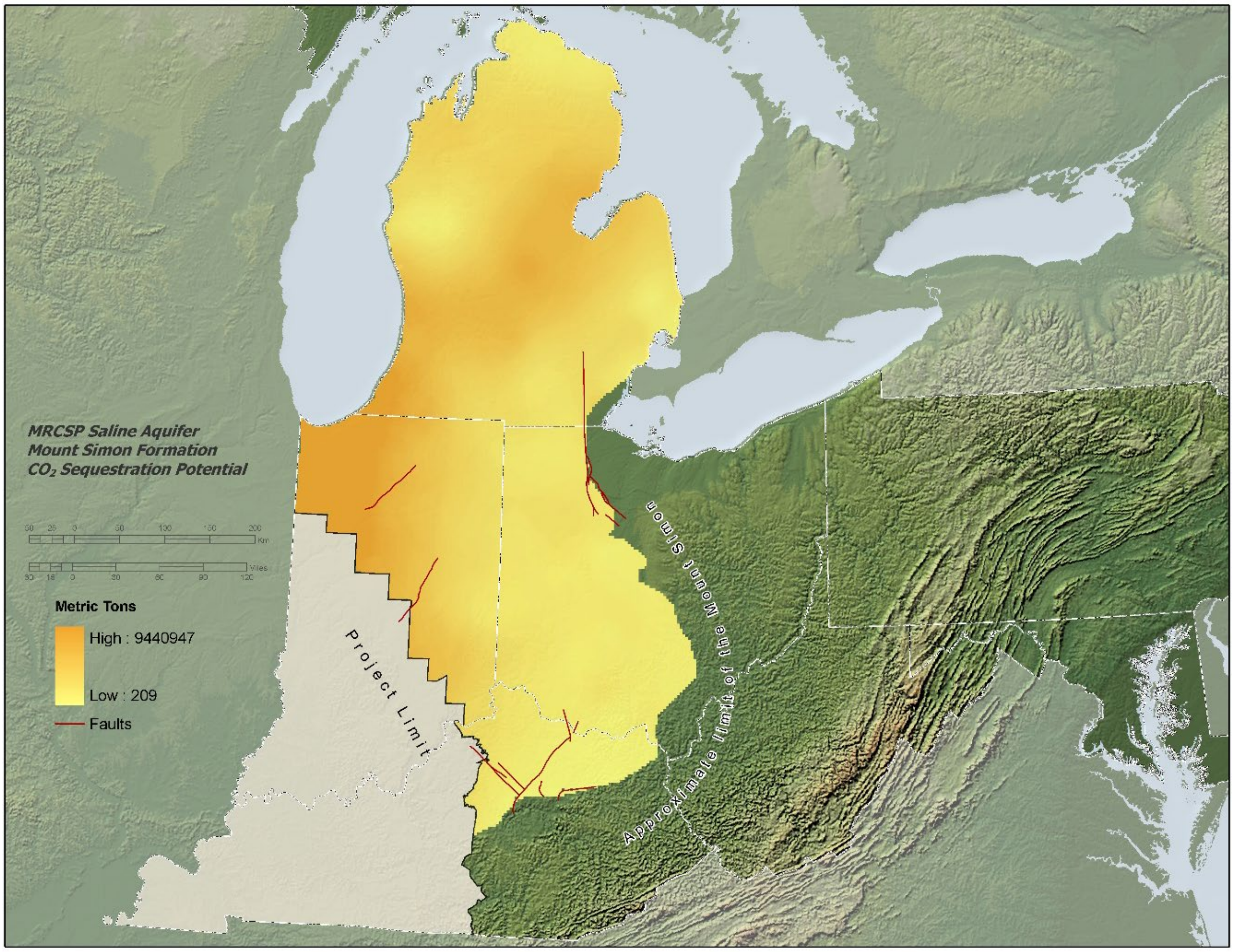


Figure 1-6. Map of the Mt. Simon sandstone storage potential across the MRCSP region with higher potential indicated by darker yellow and lower potential in lighter yellow. The greatest potential was identified in central Indiana and lower to central Michigan.

1.3.1.2 Promising Technologies for CCUS

Phase I evaluated a number of promising carbon capture technologies that were emerging during this time period. At the time, technologies were focused on post-combustion and pre-combustion CO_2 capture from power plants. The initial assessment established that CO_2 capture and compression from large point sources was technically possible, but further development was needed to make it economically attractive for widespread adoption. In the years since this assessment was completed, technological advances have continued to bring costs down and improve capture efficiency.

1.3.1.3 A Safe and Economical Option for Transporting CO_2

Dedicated CO_2 transmission pipelines were already in use in the MRCSP region in Northern Michigan during this time, and were in widespread use especially in the Permian Basin region of the country, with 3,000 miles of dedicated CO_2 pipeline in the U.S. The evaluation determined that dedicated CO_2 pipelines were a safe and economical option for transport of CO_2 to geologic storage sites in the region. These pipelines could be established within the existing regulatory framework, but work would be needed to acquire rights of way and permits. A "shared use" model utilizing existing right-of-way corridors was determined to be a promising path forward.

1.3.1.4 Answering Questions for Stakeholders and Regulators

At the time Phase I was completed, there were few laws or regulations in existence relevant to CCUS. However, the MRCSP region has a long history of oil & gas operations that provided experience and models for regulating subsurface injection. Key stakeholders—including policy makers, industry leaders, environmental groups and the general public—demonstrated limited awareness of the issues around carbon sequestration and the role it might play in CO_2 mitigation within the MRCSP region. Since this time, MRCSP has played a large role in educating stakeholders and providing a framework for regulators including:

- Local Communities
- Research Organizations
- Oil & Gas Operators
- Government Agencies/Regulators
- Non-Governmental Organizations (NGOs)
- International Community
- Economic Development Authorities
- Educational Institutions

1.4 Summary and Accomplishments of Phase II

Phase II built on the success of Phase I through a series of three validation-scale field tests of geologic sequestration (Figure 1-7). These projects were designed to enable further evaluation of carbon capture, storage and monitoring technologies and validate models of the storage potential of deep geologic reservoirs. Each test provided valuable information about regional geography and trends (e.g., permeability, porosity, geochemistry and mineralogy) (Battelle, 2011).

During these tests, CO_2 was injected into deep saline reservoirs, the class of reservoirs with the greatest storage potential in the MRCSP region. Each test site required navigation of complex technical, regulatory and public relations issues, including:

- Obtaining the cooperation and support of a host site.
- Obtaining all required federal and state permits.
- Outreach to stakeholders including press, elected officials, special interest groups and the general public.
- Drilling of the well and injection of CO_2 into the deep saline formations.
- Monitoring to confirm the success of the injection and delineate the movement of CO_2 in the formation.

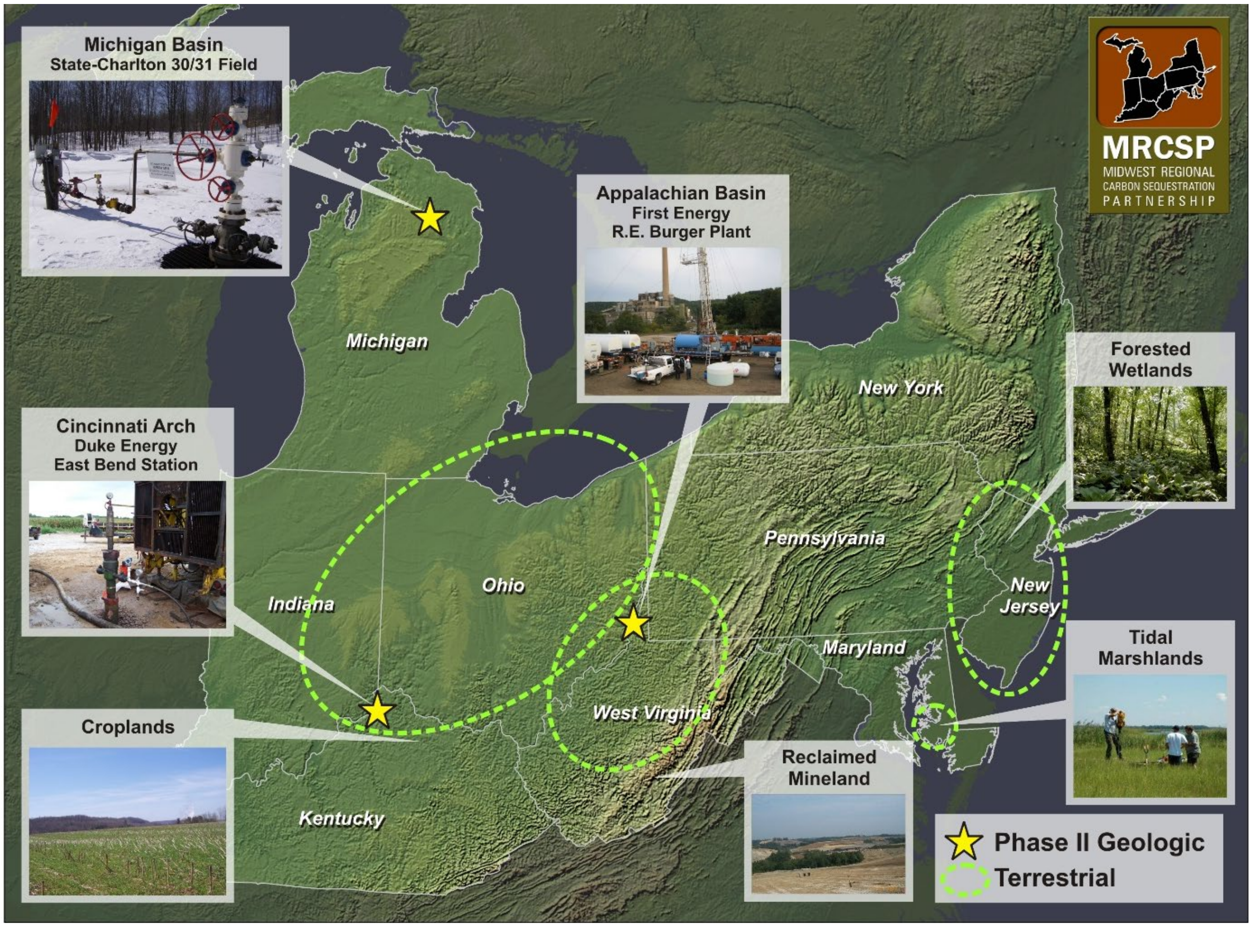


Figure 1-7. Map of Phase II geologic and terrestrial test sites. Stars represent geologic tests (wells) while the green dashed circles highlight areas where terrestrial studies were conducted.

Additional to the deep saline test injection field sites, Phase II included the characterization of four terrestrial field tests including croplands, reclaimed minelands, reclaimed marshlands, and forested wetlands. Table 1-1 summaries the terrestrial sequestration potential.

Table 1-1. Summary of terrestrial sequestration potential by land type and state as assessed under the MRCSP Phase II project and field validation tests.

Category	Area (Mha)	Sequestration Potential (million metric tons CO_2/year)							
		IN	KY	MD	MI	OH	PA	WV	Total
Cropland	10.7	4.4	1.1	0	3.7	4	0.4	0	**14**
Eroded Cropland	1.6	6.6	0	0	0.7	4	0	0	**11**
Marginal Land (Forest)	6.5	19.5	16.9	3.7	16.2	17.7	17.7	7.7	**99**
Mineland	0.6	0	0.7	0.4	0.7	0.7	1.1	1.8	**6**
Wetland	3.4	2.9	0	1.8	8.8	0.7	0	0	**14**
Total	**22.8**	**33.5**	**18.8**	**5.9**	**30.2**	**27.2**	**19.1**	**9.6**	**144**

1.4.1.1 Successful Large-Scale Injection in a Michigan Basin Saline Formation

Core Energy State-Charlton 30/31 Field
Otsego County, Michigan (Michigan Basin)

A large amount of relatively low-cost CO_2, along with pre-existing compression and pipeline infrastructure, made this an attractive site for the Michigan Basin field test (Battelle, 2011a). The test utilized naturally occurring CO_2 captured from the shallow Antrim gas play. CO_2 gas was separated at the surface at a separating/processing facility and compressed for injection. At the time, this was the largest injection of CO_2 into a deep saline formation in the U.S.

- Carbonate formation in Bass Island Dolomite
- 60,000 metric tons injected (10,000 in 2008 and 50,000 in 2009)
- Injection depth 3,500 feet
- Injection rates of 600 metric tons per day

1.4.1.2 Demonstrating Sequestration Potential in Mount Simon Sandstone

Duke Energy East Bend Generating Station
Rabbit Hash, Kentucky (Cincinnati Arch)

The goal of this test was to demonstrate CO_2 sequestration potential in the Mount Simon Sandstone, which is the largest potential geologic storage reservoir in the U.S (Battelle, 2010). It utilized liquid food-grade CO_2 from a commercial supplier. While the test volume was small, the test demonstrated good permeability and injectivity.

- Mount Simon sandstone formation
- 910 metric tons injected
- Injection depth 3,500 feet
- Injection rates of up to 5 barrels per minute achieved

1.4.1.3 Testing the Injectivity of a Tight Sandstone Formation

FirstEnergy R.E. Burger Power Plant
Shadyside, Ohio (Appalachian Basin)

FirstEnergy's R.E. Burger Power Plant is located in the Ohio River Valley, one of the nation's largest power generation corridors. The area also provides access to geologic formations with significant storage potential, including the Oriskany Sandstone, Salina Formation and Clinton Formation. Ultimately, less than 50 metric tons of CO_2 was injected at this site due to the low injectivity of these formations. However, valuable knowledge was gained that has led to a better understanding of the regional geology and recommended best practices for injection in similar formations. (Battelle, 2011b)

- Tight sandstone formation
- <50 metric tons injected
- Injection depth 8,300 feet
- Low injectivity observed

1.5 Overview of Phase III

A primary goal of the MRCSP Phase III (Development) effort is to execute a large-scale CO_2 injection test on a scale of 1 million metric tons. The most practical opportunity for conducting this large-volume injection test was to plan and execute it in collaboration with enhanced oil recovery (EOR) activities, an approach which also allows research on concurrent utilization of CO_2.

In the MRCSP region, CO_2 for such large-scale injection is available from Antrim-shale gas processing plants. Some of this CO_2 is already utilized for oil recovery from pinnacle carbonate reefs located in the northern part of the lower peninsula of Michigan. About 850+ such carbonate reefs have been found in the area, and carbonate formations also form potential CO_2 storage targets in much of the MRCSP region. The reef structures are in various stages of the production life-cycle, including undiscovered and pre-production reefs, reefs in primary production, reefs undergoing EOR, and post-EOR depleted reefs.

The large-scale field test leveraged existing EOR operations in the MRCSP region to examine and optimize methods and technologies used to obtain and interpret data on geologic, hydrologic, geomechanical, and geochemical properties. The overall objective of the large-volume geologic injection of CO_2 is to address issues relevant to future CCUS projects. Figure 1-8 illustrates the key goals and approaches for the program.

The CO_2 procurement, injection, and monitoring operations in the oil fields (i.e., Niagaran-age reefs) are categorized according to stages in the life cycle of EOR operations, designated as follows: Category 1 (nearly depleted reefs); Category 2 (active CO_2-EOR reefs); and Category 3 (newly targeted reefs). For the CO_2 injection test, wells and pipelines were instrumented to obtain geological and operational data. The data has been used to validate reservoir simulation models and help account for material balance of EOR system components to determine how much CO_2 is retained in the formations. Category 1 (nearly depleted) Niagaran reefs are late-stage EOR reefs that have undergone extensive primary and secondary oil recovery and are pressure depleted. Category 2 (active) Niagaran reefs are operational EOR reefs, in which primary oil recovery is completed and secondary oil recovery phase is currently under way using CO_2 injection. Category 3 (newly targeted) Niagaran reefs typically have undergone primary oil recovery, but no secondary oil recovery using CO_2 has been attempted. As new wells were drilled for EOR operations in these reefs, MRCSP had the opportunity to collect extensive data in the form of core samples, advanced wireline logs, and advanced reservoir well tests and thus obtain valuable additional information about the subsurface geology.

The host/partner, Core Energy, LLC, provided injection-ready CO_2 for the large-scale injection test in a composition consistent with Class II permits. Core Energy also provided the infrastructure (wells, compressors, pipelines, and controls) needed for CO_2 injection for the project.

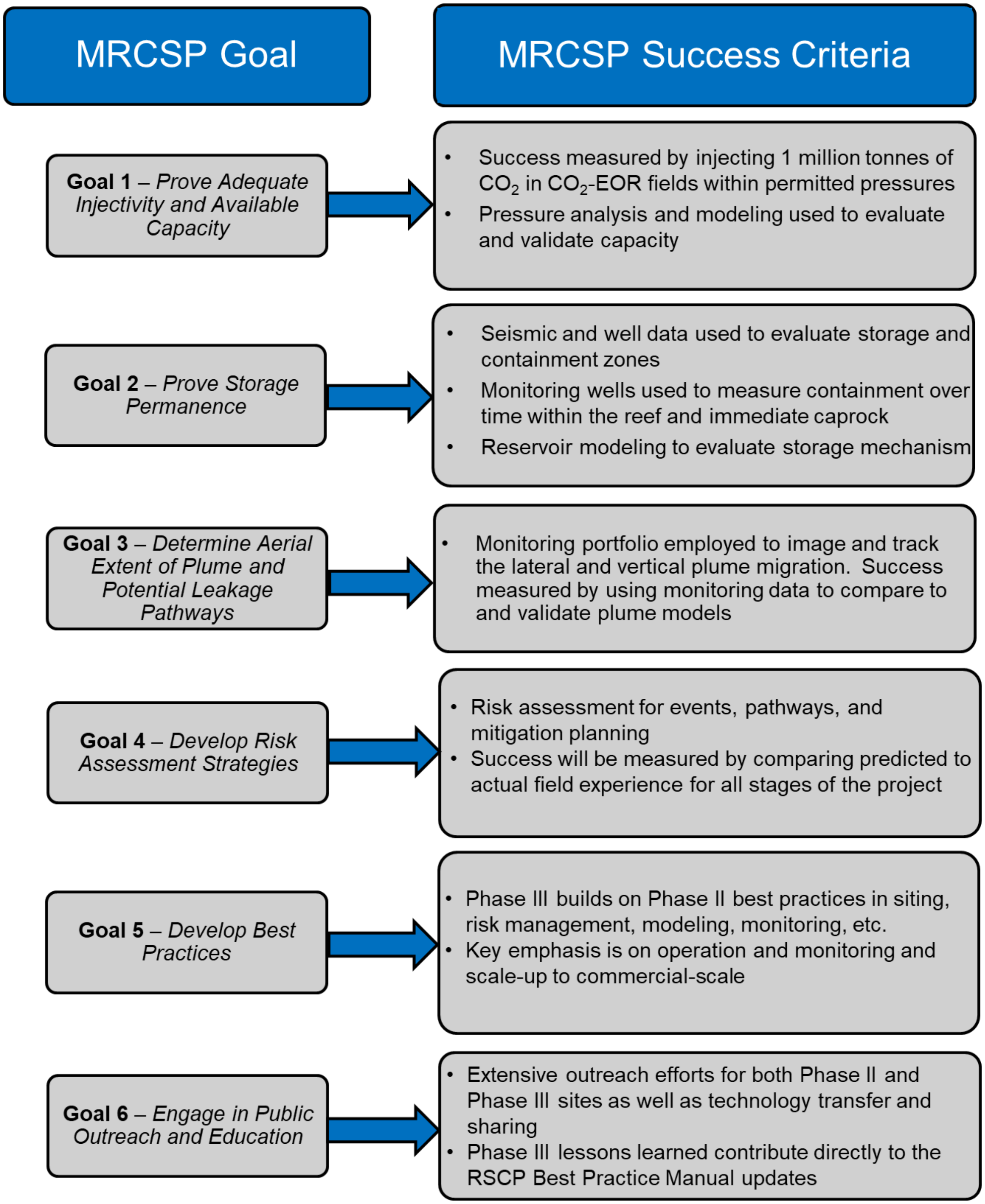


Figure 1-8. MRCSP goals and success criteria.

1.6 MRCSP Sponsors, Partners, and Stakeholders

The MRCSP program has built an active and extensive collaboration with regional Geological surveys, universities, industry, and other partners during the Phase III timeframe (Figure 1-9). Main partners and key stakeholders during Phase III are listed below. It is noted that the list below has evolved over time and names of some partner companies may have changed and several other companies who provided field services may not be mentioned below. Some entities may not be operational anymore.

Phase III Injection Test Host Site:

- Core Energy, LLC (Gaylord, Michigan, USA)

Geologic Surveys and Universities (regional geologic research team)

- Indiana Geological and Water Survey at Indiana University
- Kentucky Geological Survey at University of Kentucky
- Maryland Geological Survey
- Division of Geological Survey at Ohio Department of Natural Resources
- The Ohio State University
- Pennsylvania Geological Survey
- Rutgers University
- West Virginia Geological and Economic Survey
- Michigan Geological Repository for Research and Education at Western Michigan University
- Delaware Geological Survey at University of Delaware
- New York State Museum

Industrial and Other Partners

- AES Warrior Run
- AJW (Wade Consulting)
- Alliance Resource Partners
- American Coalition for Clean Coal Energy
- American Electric Power (AEP)
- AMP Ohio
- Arcelor Mittal
- Arch Coal
- Baard Energy
- Babcock and Wilcox
- BP
- Center for Energy and Economic Development
- Chicago Climate Exchange
- Cinergy (Duke Energy)
- Consol Energy
- Constellation Energy Group
- Consumers Energy
- Dominion
- DTE Energy
- Duke Energy
- Electric Power Research Institute
- ESG
- First Energy
- Indiana Office of Utility Consumer Counselor
- Maryland Energy Administration
- Michigan State University
- Monsanto
- National Regulatory Research Institute
- National Rural Electric Cooperative Association (NRECA)
- New Jersey Department of Environmental Protection
- New York State Energy Research and Development Authority
- New York State Museum
- NiSource
- Office of the Ohio Consumers Council
- Ohio Coal Development Office
- Ohio Corn Growers Association
- Ohio Environmental Council
- Ohio Forestry Association
- Ohio Soybean Council
- Ohio Turfgrass Foundation
- Pacific Northwest National Laboratory
- Paulsson, Inc.
- Penn State University
- Praxair
- RWE (Germany)
- Schlumberger
- Scotts Company
- Sinotech Engineering (Taiwan)
- Stanford University
- The Keystone Center
- University of Maryland
- Wade Consulting
- West Virginia University

Figure 1-9. Partner logos from Phase III of the MRCSP

1.7 Reporting Structure

A significant amount of work has been conducted throughout the lifespan of MRCSP. Only a brief summary is included in this report. However, all aspects of the program are described in significant details in a series of companion Topical Reports. These Topical Reports have been organized into categories to best represent the main goals and objectives (Figure 1-10). Volume I is composed of the integrated geologic characterization work which encompasses ten reefs used for detailed studies. Separate reports have been written to summarize the regional characterization efforts conducted by geological team partners and the regional characterization of the northern reef trend. Volume II focuses on the monitoring results with an integrated summary and several individual monitoring reports for each technology tested. Additionally, reports have been written to summarize the life cycle analysis and monitoring, reporting, and verification (MRV) plan produced using the data from the project. Volume III is the integrated modeling report which walks through the various modeling techniques applied to the reefs and the key findings. Table 1-2 provides a list of all reports, category, and associated task.

The MRCSP Phase III was organized into tasks based on the overall research program. Task 1 included the MRCSP regional assessments, mainly in collaboration of the Regional geological surveys and universities. Task 2 covered stakeholder outreach and technology transfer. Tasks 3, 4, and 5 aligned with the three reef categories evaluated in the large-scale test in Michigan.

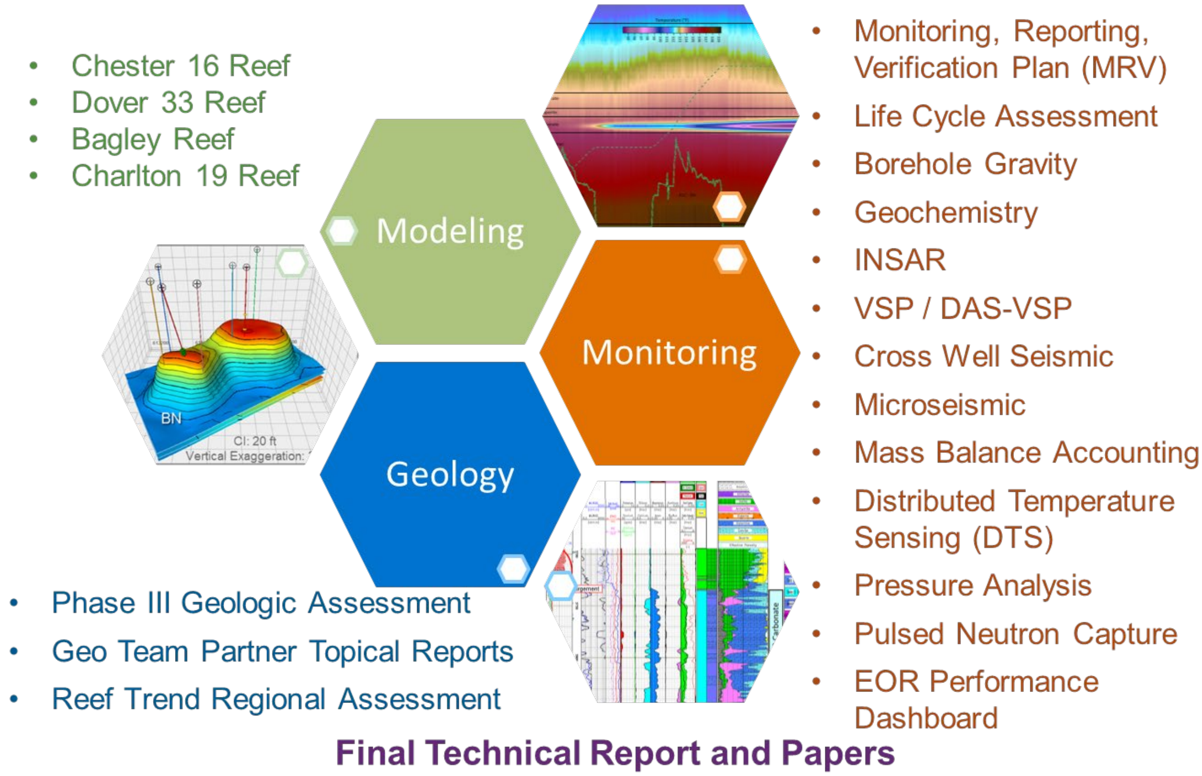


Figure 1-10. MRCSP reporting structure colored by topic for modeling, monitoring, and geology.

Table 1-2. Summary of MRCSP reports with associated category and task numbers.

Report Title	Category	Task(s)
Final Technical Report	All	All
Large-Scale Test Topical Reports		
Geologic Characterization for CO_2 Storage with Enhanced Oil Recovery in Northern Michigan	Geology	3,4,5
Integrated Modeling Report for CO_2 Storage with Enhanced Oil Recovery in Northern Michigan	Modeling	3,4,5
Integrated Monitoring Volume		
Integrated Monitoring Summary Report for CO_2 Storage with Enhanced Oil Recovery in Northern Michigan	Monitoring	3,4,5
Pulsed Neutron Capture for monitoring CO_2 Storage with Enhanced Oil Recovery in Northern Michigan	Monitoring	3,4,5
Time-Lapse Vertical Seismic Profiling (VSP) for CO_2 Storage in a Depleted Oil Field in Northern Michigan	Monitoring	3
InSAR Monitoring to Evaluate Surface Changes with CO_2 Storage in a Depleted Oil Field in Northern Michigan	Monitoring	3
Distributed Temperature Sensing (DTS) to Monitor CO_2 Migration in an Enhanced Oil Recovery Field in Northern Michigan	Monitoring	5
Mass Balance Accounting or CO_2 Storage with Enhanced Oil Recovery in Northern Michigan	Monitoring	3,4,5
Cross-Well Seismic Monitoring of CO_2 Injected for Enhanced Oil Recovery in Northern Michigan	Monitoring	5

Report Title	Category	Task(s)
Distributed Acoustic Sensing (DAS) Seismic Monitoring of CO_2 Injected for Enhanced Oil Recovery in Northern Michigan	Monitoring	5
Assessment of Borehole Gravity (Density) Monitoring for CO_2 Injection in a Depleted Oil Field in Northern Michigan	Monitoring	3
Microseismic Monitoring Study to Assess the Potential for Induced Seismicity in a Depleted Oil Field in Northern Michigan	Monitoring	3
Analysis of Transient Pressure and Rate Data in a Complex of Enhanced Oil Recovery Fields in Northern Michigan.	Monitoring	3,4,5
Geochemical Changes in Response to CO_2 Injection in a CO_2-EOR Complex in Northern Michigan	Monitoring	3,4,5
Monitoring, Reporting, and Verification Plan (MRV)- Meeting EPA Guidelines for GHGRP and Subpart RR	Commercialization	3,4,5
Life Cycle Analysis of Greenhouse Gas Emissions for the Niagaran Reef Complex CO_2-EOR Operations	Commercialization	3,4,5
MRCSP Regional Reports		
State Charlton & MRCSP 1 Characterization Well Report	Geology	
Regional Assessment for the CO_2 Storage Potential in Northern Niagaran Pinnacle Reef Trend	Geology	1
Regional Geology Capstone Report for the Midwestern Regional Carbon Sequestration Partnership	Geology	1
Regional Geologic Cross Sections for Potential Storage and Containment Zones in the MRCSP Region	Geology	1
Appalachian Basin: Enhanced Recovery Opportunities	Geology	1
Michigan Basin: Assessment of Enhanced Oil Recovery Using Carbon Dioxide in Silurian Pinnacle Reefs	Geology	1
Mid-Atlantic Coastal Plain and Adjacent Offshore Region: Characterization of Carbon Storage Targets	Geology	1
Ordovician-Cambrian Units: Hierarchical Evaluation of Geologic Carbon Storage Resource Estimates	Geology	1
Upper Silurian to Middle Devonian Strata of Ohio: Structural Characterization of Potential CO_2 Reservoirs and Adjacent Strata	Geology	1
Triassic Rift Basins: Preliminary Study of Long-Term CO_2 Storage Potential	Geology	1

Additionally, numerous reports were generated from the Phase I and Phase II work, which is available at www.MRCSP.org or through EDX. Key reports are listed in the Technical Reports section.

2.0 Michigan Basin Large Scale Injection Test

2.1 Introduction

The Michigan Basin large scale injection test took place in Otego County in northern Michigan, along the NNPRT. The NNPRT is composed of more than 800 individual pinnacle reefs which occur thousands of feet below the surface. More than 700 of these reefs have been used for oil and gas production with a subset of ten reefs used for CO_2-EOR within the MRCSP study. Overlying the reefs, is the Antrim Shale, which naturally produced CO_2. The CO_2 is separated at the nearby Chester 10 gas processing plant and transported vis Core Energy through pipelines to the reefs, thus creating the CO_2-EOR infrastructure (Figure 2-1).

Figure 2-1. Aerial photograph of the Chester 10 gas processing facility.

The Michigan Basin large scale injection test focused on the integration of three components to fully assess the safe storage of more than one million metric tons of CO_2 into ten Niagaran reefs (Figure 2-2). This included: 1) geologic characterization, 2) modeling, and 3) monitoring and accounting. Phase III was designed to answer critical questions about the technical and economic feasibility of CCUS and EOR, the CO_2 storage capacity of pinnacle reef formations in Northern Michigan, and the safety and efficacy of injecting CO_2 for long-term storage and utilization in oil & gas recovery. These questions include:

- ***Injectivity:*** What is the rate at which CO_2 can be injected into the reefs? How many wells will be required to achieve EOR goals? (Injectivity is a significant cost driver for geologic storage.)
- ***Capacity:*** What is the total size of the target reservoir? How much CO_2 can it hold?
- ***Containment:*** What happens to CO_2 after it is injected? Are layers of rock above and below the storage zone sufficient to keep CO_2 out of the atmosphere for thousands of years or longer?
- ***Safety:*** What can be done to minimize activity-based risks related to drilling, well completion and injection operations? How can performance risks such as unintended migration of CO_2 be minimized?

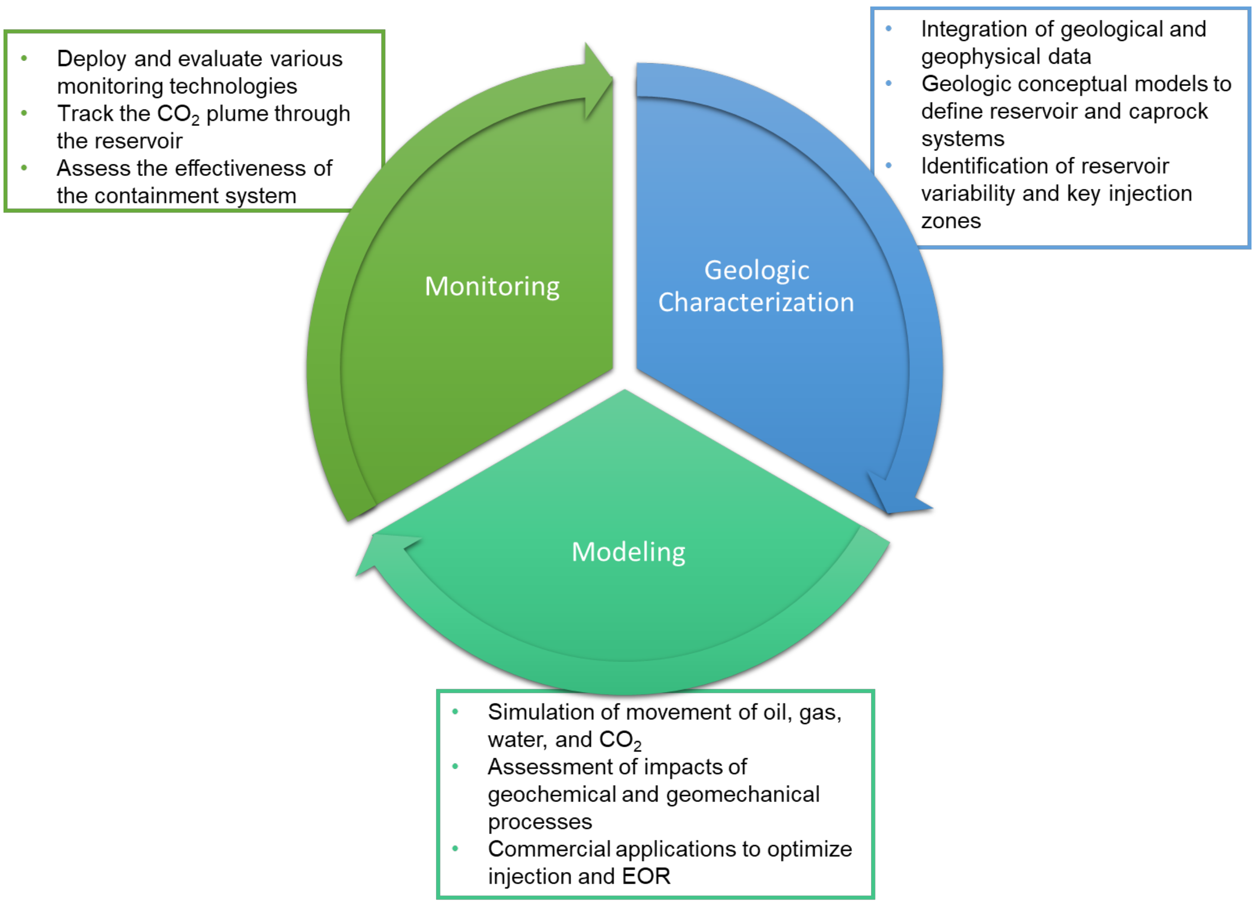


Figure 2-2. Major components of the large-scale injection test analyses performed on the Niagaran reefs which integrate monitoring, geologic characterization, and modeling.

MRCSP Phase III efforts were primarily focused on 10 reefs owned by Core Energy, LLC located in Otsego County, Michigan (Figure 2-3) which were at different stages of the CO_2-EOR lifecycle: late-stage reef (undergone primary and secondary production), active EOR reefs (currently undergoing CO_2-EOR), and new EOR reefs (recently started or will start CO_2-EOR). Additionally, each reef underwent different analyses based on data availability, access, and productivity (Table 2-1).

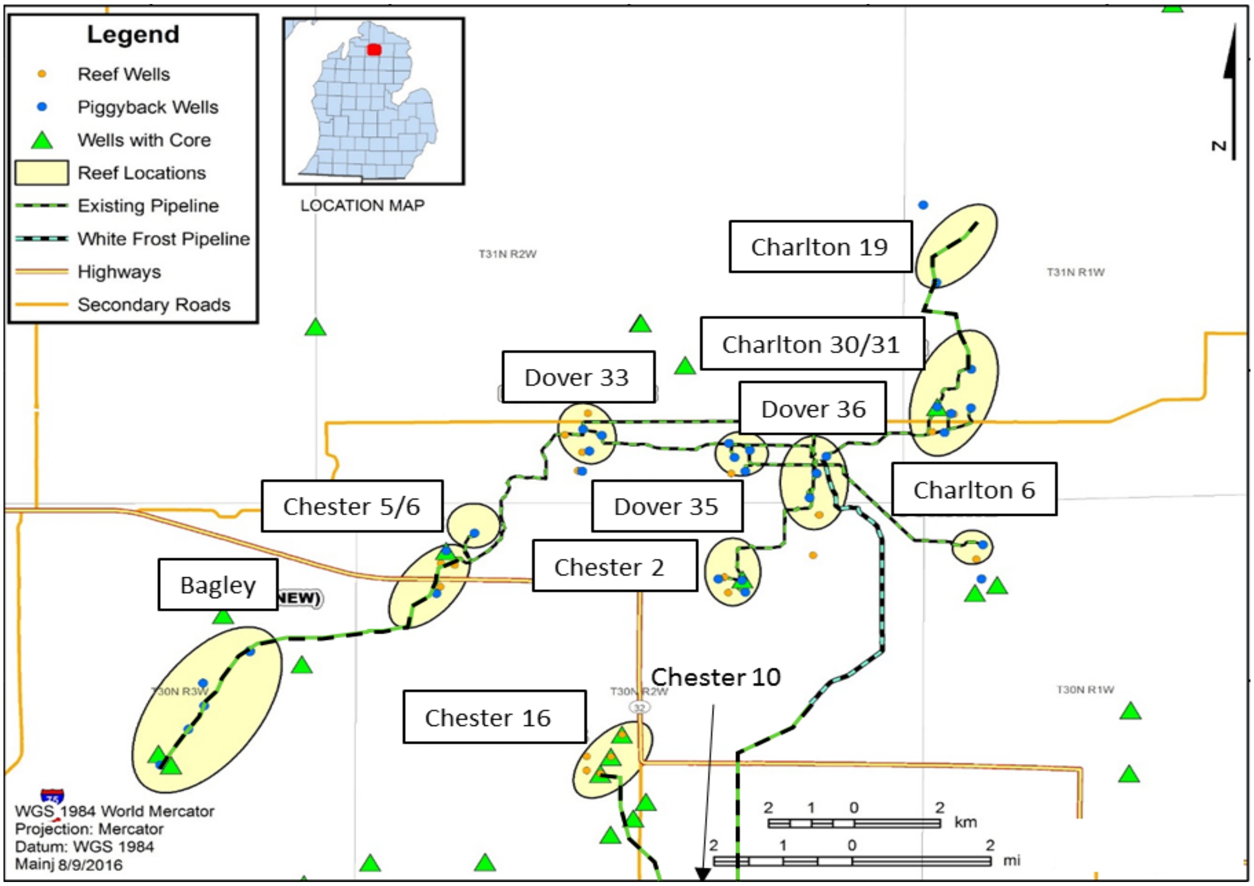


Figure 2-3. Map of reefs used for CO_2-EOR in Otsego County, Michigan and studied as part of MRCSP.

Table 2-1. Overview of analyses performed by reef.

Reef	Geologic Characterization	Modeling	Monitoring	Stage
Dover 33	X	X	X	Late
Charlton 19	X	X	X	New
Bagley	X	X	X	New
Chester 2	X		X	Active
Charlton 6	X		X	Active
Charlton 30/31	X		X	Active
Chester 5/6	X		X	Active
Dover 35	X		X	Active
Dover 36	X		X	Active
Chester 16	X	X	X	New

2.2 Geologic and Site Characterization

2.2.1 Geologic Setting

The Phase III large scale injection test takes place in Northern Michigan within the Northern Niagaran Pinnacle Reef Trend (NNPRT). This is composed of over 800 individual pinnacle reefs. Individual reef complexes developed on the slope and margins of the Michigan Basin. These reefs range from 2,000 feet to over 6,000 feet deep, with many occurring at depths of 3,500 to 5,000 feet. Individual reefs are closely spaced and compartmentalized from the enclosing rock; they average 50 to 400 acres in area and up to 700 feet in height, with steep flanks of 30° to 45°.

The reefs were originally developed in the 1970s-1980s, have undergone primary production; some have also undergone secondary recovery by water flood and tertiary recovery by CO_2 (Grammer et al., 2009; Harrison III, 2010; Barnes et al., 2013; Haagsma et al., 2017). Reef reservoir rocks develop in the Brown Niagaran lithostratigraphic interval of the Guelph formation (Figure 2-4) and may be completely dolomitized, essentially all limestone, or a heterogeneous mix. Reservoir quality is generally enhanced by dolomitization, and upper parts of reefs often, but not always, are more dolomitized than the lower parts. Hydrothermal dolomite is locally present and is related to structure, fractures, and migration of deep fluids (Grammer, 2007).

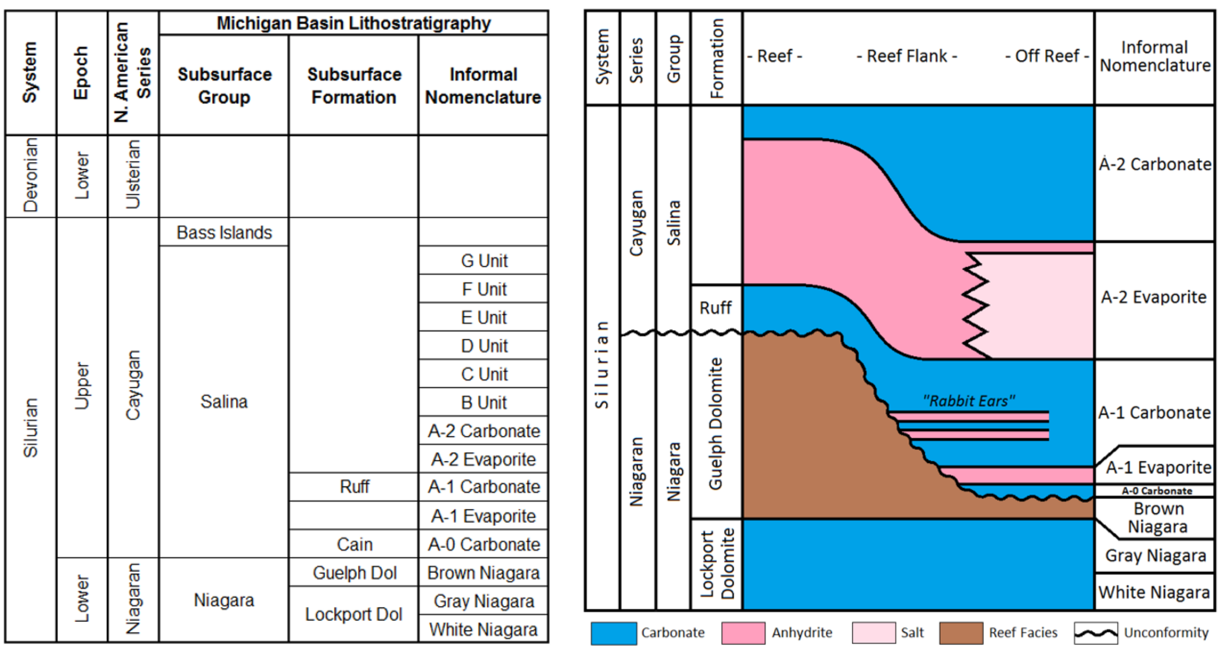


Figure 2-4. Stratigraphy of the Silurian-age Niagaran and Salina Groups in the Michigan Basin. On left is the formal and informal Silurian stratigraphic nomenclature (modified from Trout, 2012, and Rine, 2015). On right is a conceptual model and stratigraphy of the Brown Niagaran reef interval (after Gill 1973, 1979; and Huh 1973).

The fields, in general, were found to be asymmetrical with distinctly different internal lithofacies (or rocks of the same geologic formation with different reservoir properties). The reservoirs were sealed above and along the sides by overlying evaporites (salt and/or anhydrite), tight carbonates, and shales thus creating a well-defined and contained reservoir. Figure 2-5 illustrates a generic cross section through a field composed of two pods with reservoir facies in purple, green, teal, and orange, with remaining layers as confining units.

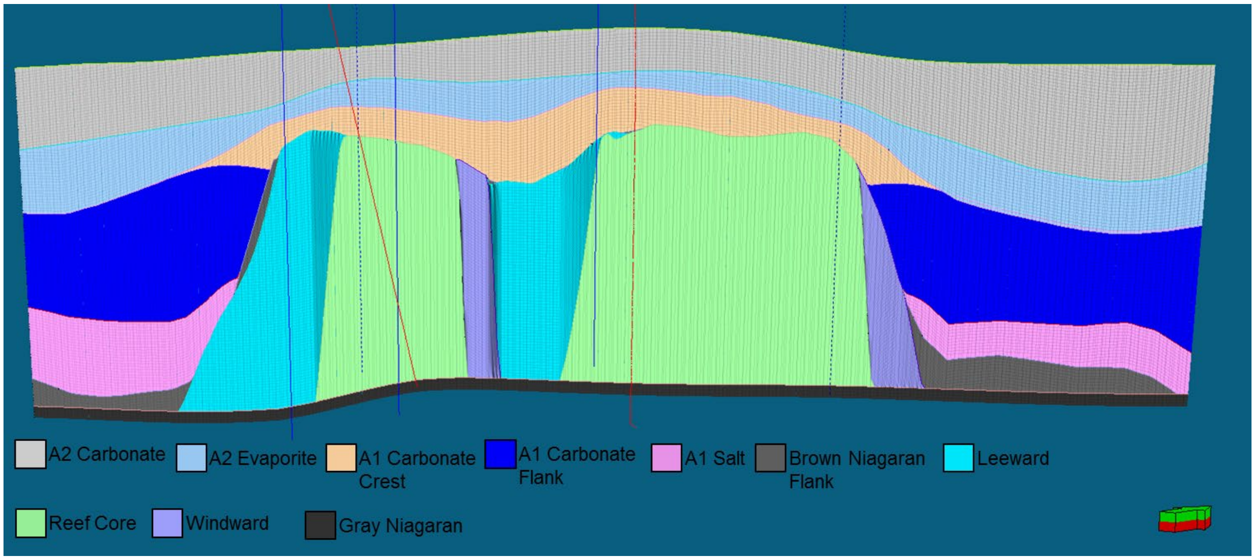


Figure 2-5. Generic cross section through the Chester 16 reef field showing geologic architecture of the field including reservoirs and confining units. The green zone represents the main reef core facies with highest reservoir potential and the overlying orange zone represents high porosity A-1 Carbonate.

2.2.2 Goals of Geologic and Site Characterization

The overall goal of the geologic and site characterization of Task 3,4, and 5 reefs was to develop geologic characterization methodologies for complex carbonate reservoirs to better understand geologic variability and data applications to inform modeling efforts. Characterization included detailed analysis of the geophysical, seismic, geomechanical and geochemical properties of the geologic formations. During this stage, MRCSP collected and analyzed data to answer critical questions about the proposed injection sites, including:

- ***What is the geology of the formation?*** The ideal formation has a deep layer with high porosity and permeability topped by a dense impermeable layer (caprock) that prevents injected CO_2 from escaping.
- **Does the formation have suitable strength and stability to support planned injection pressures and enable safe long-term storage?**
- ***How does the geology effect the storage capacity and injectivity of the reservoir?*** (Determined by the total size as well as the porosity of the rock, and permeability.)

2.2.2.1 Geologic Characterization of the Reefs

It was important to establish consistent and efficient workflows to characterize each reef so that the reservoirs and caprocks were well defined. This included the integration of multiple data types such as wireline logs, whole core observations and analyses, petrophysics, seismic, and production records. Additionally, statistics was used to develop and validate relationships. The goal of the geologic characterization at each site was to produce a conceptual model (Figure 2-6), or interpretation, of the reef complex which would be used for further modeling.

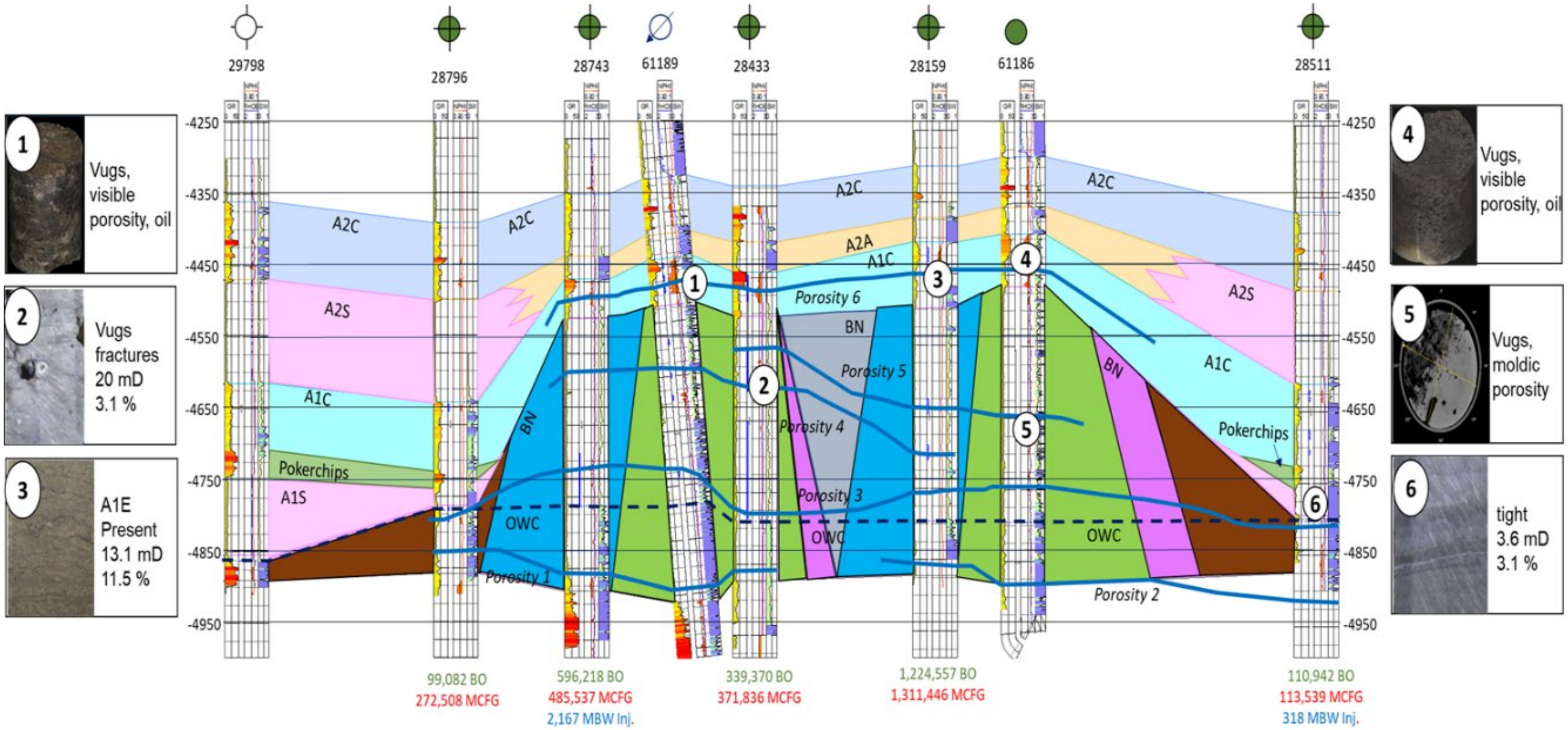


Figure 2-6. Example integration of multiple data types to develop the geologic conceptual model of the Chester 16 reef. The lithofacies are colored between well tracks. The images along the edges are from core or sidewall core samples which were correlated with the wireline logs. The blue lines cutting through the cross section represents potential porosity zones from 3D seismic.

The key findings included:

- Data was often of different vintages, vendors, and log types between reef fields (and even within a reef field) due to a long history of oil and gas production. Many wireline logs were digitized, corrected, and checked for quality to remove erroneous data and make logs more comparable. Additionally, industry standard relationships were used to compute missing logs such as bulk density and acoustic travel time.
- Gas effects are a common concern in oil and gas fields; however, most of the logs were collected under pressure conditions where gas was in solution. Little to no gas effects were observed for the reefs.
- The presence of salt, both massive and void-plugging, could greatly influence the bulk density and falsely display as porosity. Standard density and porosity plots could capture larger quantities of salt by vertical trending toward massive salt. Small quantities of salt were not captured. Advanced statistical predictions successfully identified intervals of salt in the Bagley reef field.
- Industry standard analyses, including wireline log plots, pay flags, and petrophysics on a well-by-well basis, were successful in generating initial assessments of wells and reefs.
- Seismic analyses were critical for defining the extents and geometries of each reef field. Additionally, advanced analyses, such as attribute analyses, were conducted to track high porosity zones throughout the 3D seismic volumes.
- Integration of all data types was crucial to developing geologic interpretations.

2.2.2.2 Formation Strength and Stability

Geomechanical characterization is critical for predicting how the formation will respond to CO_2 injection and quantifying potential geomechanical risks of long-term geologic sequestration. The geomechanical characteristics of the formation determine how CO_2 will move after injection and whether it is likely to escape the formation.

Measurements of geomechanical parameters were taken at six reservoir formations. Laboratory testing was conducted on core samples of the primary caprock and the different types of rock found in the reservoir itself. Measurements included mechanical properties, unconfined and confined compressive strength, and tensile strength. These tests provided information about how brittle or ductile rocks in the formation are and what magnitudes of stress can be safely maintained within the well and reservoir. Key findings included:

- The geomechanical analysis confirmed that reservoirs and caprock formations are strong enough to safely handle projected injection pressures typically encountered during CO_2-EOR operations.
- Due to the injection rate and pressure of the equipment used, fracture pressures (the pressure under which the rock will fracture) cannot be reached under typical operating conditions thus ensuring reservoir and caprock stability.

2.2.2.3 Geologic Variability and CCUS Impact

Researchers characterized ten CO_2-EOR fields. The analysis looked at field characteristics that impact the productivity of a field and its suitability for CO_2 injection and storage. These included:

- Porosity (the amount of space in the pores of the rock)

- Permeability (how well fluid can move through the rock)
- Lithology (the type of rock in the formation)
- Salt plugging (salt contained in the pores of the rock)
- The number of pods in a field
- The oil recovery percentage for the formation (a real-world indication of the ability of fluid to move through the formation)

The analyses were used to establish the reservoir quality and rank each field based on physical characteristics of the rock, degree of salt plugging, porosity, and oil recovery. Reservoirs which were more dolomite were found to have higher reservoir quality than those that were more limestone. Reservoirs which had more salt plugging tended to have poorer reservoir quality. Additionally, secondary porosity (vugs and fractures) could aide in the performance of the field. The key findings included:

- The reefs under study had a lithology trend which matched the regional interpretation of more dolomitization up-dip. The Dover 33, Bagley, and Charlton 19 reef fields were predominantly dolomitic. The Chester 16, Chester 2, and Charlton 6 were limestone.
- Salt plugging was observed to some degree at all reefs but varied from minor (Charlton 19) to extremely pervasive (Chester 2).
- Diagenetically enhanced porosity ranged from extreme (karst) to streaky in the reefs which influenced the reservoir pattern. In dolomitized reefs, porosity trended higher toward the top, while limestone reefs were streakier in nature.
- Production was predominantly recorded from the Brown Niagaran formation; five reef fields also recorded production from the overlying A-1 carbonate.
- Average reef porosity ranged from 1.4% to 11.7%, with average permeabilities up to 94 mD. Dolomitic reefs have higher porosities and NTG ratios in the Brown Niagaran, while limestone reefs are higher in the A-1 carbonate.
- The number of pods in a reef field varied from one to four (Figure 2-7).
- Diagenesis and degree of salt plugging were assigned ranks and plotted with porosity and oil recovery to illustrate reservoir quality. When plotted using porosity, Charlton 19 was ranked as the best reservoir, followed by Dover 33 and Bagley. When plotted with percent recovery, Dover 33 and Chester 16 were the highest. The porosity method assumes that log porosity is indicative of good reservoir. Percent recovery is a good indicator of reservoir quality; however, it is dependent on well design and estimated original oil in place (OOIP).

The results of the characterization efforts indicated the reefs could be divided into three main categories: 1) dominantly dolomitized reefs, 2) mixed carbonate reefs, and 3) dominantly limestone. Additionally, there were certain reefs that the overlying A-1 Carbonate was a significant reservoir contributor.

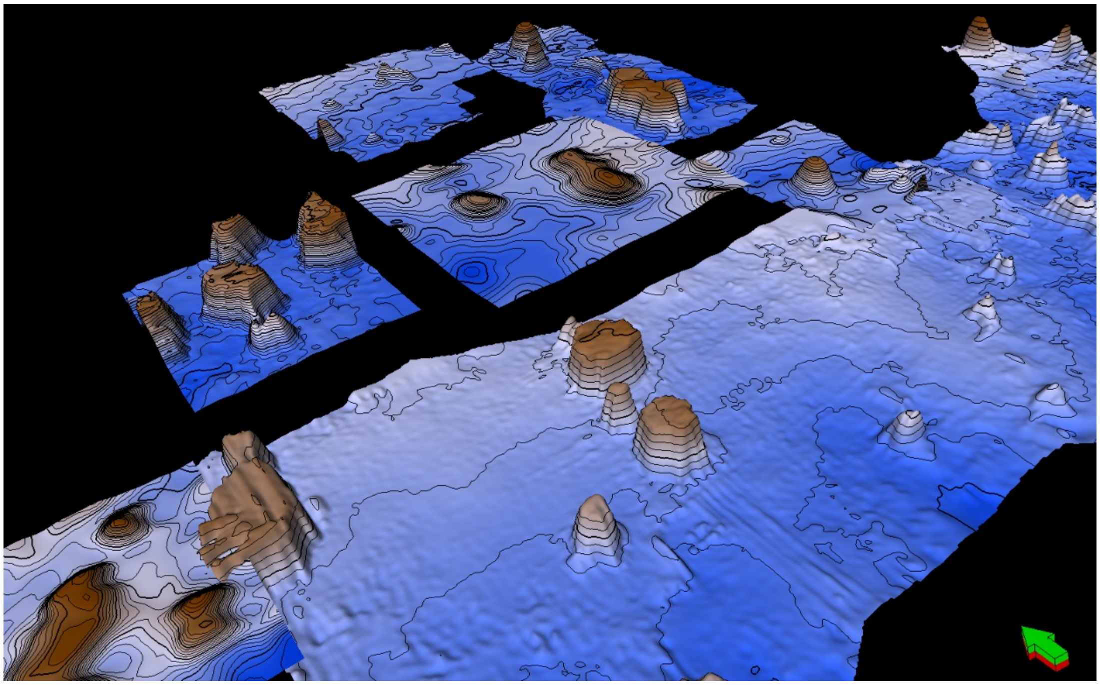


Figure 2-7. Top of the reef structure as interpreted from 3D seismic showing multiple reef fields with varying geometry, extent, and number of reef pods.

Overall, the geologic characterization efforts provided important insight into reservoir variability and the importance of reservoir controls. Additionally, the work has demonstrated the different analyses that can be used to interpret a field. The results informed the development of static earth models, dynamic models, and geomechanical models, which assessed the fields in more detail. The lessons learned guided the regional assessment of complex carbonate fields by identifying important attributes and properties which are applicable regionally and to different carbonate reservoirs outside of the study area. Figure 2-8 summarizes the characteristics of each category and Figure 2-9 summarizes characteristics by reef.

Dominantly Dolomite	Mixed Carbonate	Dominantly Limestone	A-1 Carbonate
• Dover 33, Charlton 19, and Bagley	• Dover 35, Dover 36, and Chester 5/6	• Chester 16, Chester 2, Charlton 30/31, and Charlton 6	• Chester 16, Bagley, Dover 35, Chester 5/6, and Chester 2
• 8-12% porosity, highest near the top	• 4-5% porosity, streaky where dolomitized	• 3-5% porosity, streaky to isolated	• 5-8% porosity, along cap of reef
• Minor to mild salt plugging	• mild salt plugging	• Mild to pervasive salt plugging	• all dolomitic
• Streaky to pervasive vugs & fractures	• streaky, thin intervals of vugs	• Isolated to streaky vugs	• minor salt plugging
• higher production	• moderate production	• lower production	• can contribute to production

Figure 2-8. Summary of major reef categories listing common characteristics observed during geologic analyses.

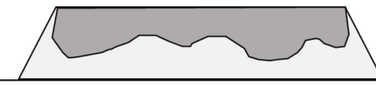
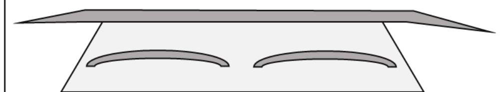
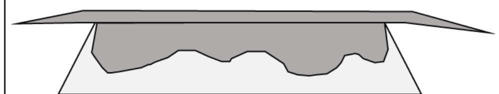
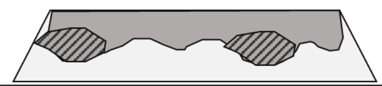
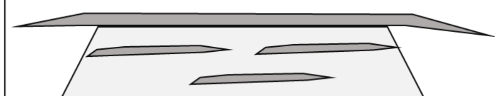
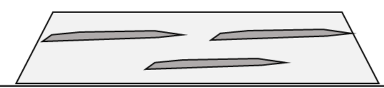
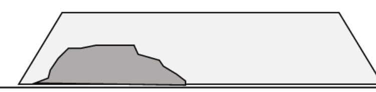
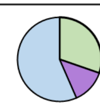
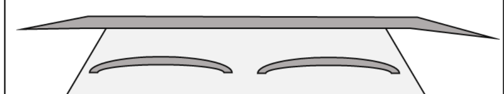
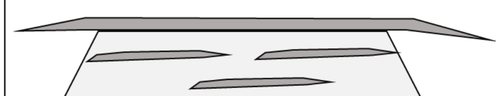
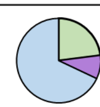
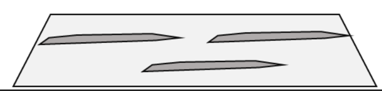
Reef	Petrophysical and Core Properties	Reservoir Attributes	Lithofacies	Production	Reservoir Pattern
Dover 33	Avg. Porosity- 8.2% Avg. Permeability-6.5 mD Lithology-Dolomite	Primary-Brown Niagaran Salt Plugging-Mild Diagenesis-Pervasive # of Reefs- 1		OOIP-3.5 MBBL Oil-1.8 MBBL Gas-1.8 MMCF	
Chester 16	Avg. Porosity- 3.6% (BN), 7.8% (A1C) Avg. Permeability- 23 mD(BN), 7.0 mD(A1C) Lithology- Dolomite (A1C), Limestone (BN)	Primary-BN and A1C Salt Plugging- Minor Diagenesis-Streaky # of Reefs- 2		OOIP-6.9 MBBL Oil-3.0 MBBL Gas-2.6 MMCF	
Bagley	Avg. Porosity- 7.9% (BN), 5.8% (A1C) Avg. Permeability- 94 mD(BN), 7.0 mD(A1C) Lithology-Dolomite	Primary-BN and A1C Salt Plugging-A1C Diagenesis- Pervasive # of Reefs- 4		OOIP-9.0 MMBL Oil- 2.9 MMBL Gas-6.7 MMCF	
Charlton 19	Avg. Porosity-11.7% Avg. Permeability-unknown Lithology-Dolomite	Primary- BN Salt Plugging-Minor Diagenesis- Extreme (Karst) # of Reefs-2		OOIP-2.6 MMBBL Oil-1.1 MMBBL Gas-2.3 MMCF	
Dover 35	Avg. Porosity- 4.7% (BN), 3.1% (A1C) Avg. Permeability-unknown Lithology-mixed carbonate	Primary- BN and A1C Salt Plugging-mild Diagenesis-Streaky # of Reefs-1		OOIP-2.5 MMBBL Oil-1.9 MMBBL Gas-.8 MMCF	
Dover 36	Avg. Porosity-1.4% Avg. Permeability-unknown Lithology- mixed carbonate	Primary-BN Salt Plugging-mild Diagenesis-Streaky # of Reefs-3		OOIP-3.7 MMBBL Oil-1.8 MMBBL Gas-1.2 MMCF	
Chester 2	Avg. Porosity- 4.0% Avg. Permeability-.2 mD Lithology- limestone, dolomitized pod	Primary-BN Salt Plugging-Pervasive Diagenesis- Isolated # of Reefs-1		OOIP- 3.2 MMBBL Oil- 1.1 MMBBL Gas-.7 MMCF	
Chester 5/6	Avg. Porosity- 4.2%(BN), 6.0% (A1C) Avg. Permeability-.8mD (BN), 16 mD (A1C) Lithology- mixed carbonate	Primary-BN and A1C Salt Plugging- mild Diagenesis- streaky # of Reefs-3		OOIP- 2.9 MMBBL Oil- 1.3 MMBBL Gas-1.3 MMCF	
Charlton 30/31	Avg. Porosity-4.6% (A1C), 4.2%(BN) Avg. Permeability-unknown Lithology- limestone	Primary- BN and A1C Salt Plugging- mild Diagenesis- streaky # of Reefs-3		OOIP-6.8 MMBBL Oil- 3.0 MMBBL Gas-3.9 MMCF	
Charlton 6	Avg. Porosity-5.3% Avg. Permeability-unknown Lithology- Limestone	Primary- BN Salt Plugging-Mild Diagenesis- Streaky # of Reefs-1		OOIP-1.7 MMBBL Oil- .7 MMBBL Gas-1.5 MMCF	

Figure 2-9. Reef properties, attributes, lithofacies, production, and reservoir pattern by reef. The lithofacies pie chart shows relative volume of each reef lithofacies where green is reef core, blue is leeward, and purple is windward.

2.3 Monitoring CCUS Performance and Evaluating Technologies

2.3.1 Overview of the Phase III Monitoring Program

Monitoring of the CO_2 storage systems helps ensure that the injected CO_2 is retained within the intended reservoir and containment zones, evaluates storage efficiency and CO_2 migration, and helps address regulatory requirements. Another key objective of the MRCSP Phase III project was to evaluate the effectiveness of various technologies for monitoring CO_2 that has been injected into deep geologic formations (i.e., the Niagaran reefs). The MRCSP Phase III project included a comprehensive monitoring program that included deploying 11 different monitoring technologies at one or more of the reefs that are operated by Core Energy for CO_2-EOR. Given the expansion of the Core Energy operations to several new reefs during the MRCSP program, the monitoring program was adapted to benefit from the addition of new reefs and lessons learned from the initial monitoring. Table 2-2 lists the monitoring technologies, their primary objective, and the reefs where the technology was deployed.

Table 2-2. MRCSP Monitoring Technologies by Objective and Reefs

	Monitoring Objective				Monitoring by Reef				
Monitoring Technology	**Mass-Balance Accounting**	**Leak Detection/ well integrity**	**CO_2 plume tracking/ interaction**	**Induced seismicity, land displacement**	**Dover 33**	**Charlton 19**	**Chester 16**	**Bagley**	**Other reefs**
CO_2 injection/ production	X				X	X	X	X	X
Reservoir Pressure		X	X		X	X	X	X	X
Temperature (DTS)		X	X				X		
PNC logging		X	X		X	X	X	X	
Borehole gravity			X		X				
Geochemistry			X		X	X	X	X	
Vertical seismic profile – geophone		X	X		X				
Vertical seismic profile – DAS		X	X				X		
Cross-well seismic			X				X		
Microseismicity				X	X				
InSAR (Satellite radar)				X	X				

2.3.2 Organization and Presentation of Monitoring Information

A separate report has been prepared for each of the 11 monitoring technologies that provides a detailed discussion of the data acquisition and interpretation methodology and results. These 11 monitoring reports together comprise the *Integrated Monitoring Volume for CO_2 Storage with Enhanced Oil Recovery in Northern Michigan*. In addition to the 11 monitoring reports, the *Monitoring Volume* includes an introductory report titled *Monitoring Summary Report* that provides an executive-summary style overview of each of the 11 monitoring technologies including key outcomes. Table 2-3 lists the reports included in the *Integrated Monitoring Volume*. The reader interested in developing a general understanding of the MRCSP Phase III monitoring program and results is directed to the *Monitoring Summary Report*. The reader interested in gaining a detailed understanding of one or more monitoring technologies is directed to the induvial monitoring reports.

Table 2-3. Reports Included in the Integrated Monitoring Volume for CO_2 Storage with Enhanced Oil Recovery in Northern Michigan

Volume	Report Title	Authors/Citation
II.A	Mass Balance Accounting or CO_2 Storage with Enhanced Oil Recovery in Northern Michigan	Mawalkar, S., Burchwell, A., Keister, L., Pasumarti, A., and Gupta, N. 2020. MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH
II.B	Time-Lapse Vertical Seismic Profiling (VSP) for CO_2 Storage in a Depleted Oil Field in Northern Michigan	Kelley, M., Haagsma, A., and Gupta, N. 2020. MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH
II.C	Distributed Acoustic Sensing (DAS) Seismic Monitoring of CO_2 Injected for Enhanced Oil Recovery in Northern Michigan	Kelley, M., Grindei, L., Humphries, M., Coleman, T., Modroo, A., and Gupta, N. 2020. MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH
II.D	Cross-Well Seismic Monitoring of CO2 Injected for Enhanced Oil Recovery in Northern Michigan	Kelley, M., Kolb, C., and Gupta, N. 2020. MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH
II.E	InSAR Monitoring to Evaluate Surface Changes with CO2 Storage in a Depleted Oil Field in Northern Michigan	Place, M., Banwell, MJ., Falorni, G., and Gupta, N. 2020. MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH
II.F	Pulsed Neutron Capture for monitoring CO_2 Storage with Enhanced Oil Recovery in Northern Michigan	Conner, A., Place, M., Chace, D., and Gupta, N 2020. MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH
II.G	Assessment of Borehole Gravity (Density) Monitoring for CO_2 Injection in a Depleted Oil Field in Northern Michigan	Place, M., Bonneville, A., Black, A., and Gupta, N. 2020. MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH
II.H	Distributed Temperature Sensing (DTS) to Monitor CO_2 Migration in an Enhanced Oil Recovery Field in Northern Michigan	Mawalkar, S., Burchwell, A., and Gupta, N. 2020. MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH
II.I	Geochemical Changes in Response to CO_2 Injection in a CO_2-EOR Complex in Northern Michigan	Place, M., Hawkins, J., Grove, B., Keister, L., Sheets, J., Welch, S., Cole, D., and Gupta, N. 2020. MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH
II.J	Microseismic Monitoring Study to Assess the Potential for Induced Seismicity in a Depleted Oil Field in Northern Michigan	Kelley, M., Place, M., and Gupta, N. 2020. MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH
II.K	Analysis of Transient Pressure and Rate Data in a Complex of Enhanced Oil Recovery Fields in Northern Michigan.	Mishra, S., Kelley, M., Raziperchikolaee, S., Ravi Ganesh, P., Valluri, M., Keister, L., Burchwell, A., Mawalkar, S., Place, M., and Gupta, N. 2020. MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH

2.3.3 Summary of Key Highlights from the Monitoring Technologies

The purpose of this section is to provide a succinct summary of key highlights about each of the 11 monitoring technologies, focusing on results achieved and implications for future application of the technology for monitoring CO_2 storage and EOR operations in the Silurian-age pinnacle reefs of northern Michigan. For each technology, a brief synopsis of work performed, and results obtained is provided. Each technology discussion concludes with a table summarizing pros/cons, key results of the study, and an overall recommendation for using the technology to monitor CO_2 storage in Silurian pinnacle reefs of Northern Michigan.

2.3.3.1 Mass Balance Accounting

- During the MRCSP Phase III period of record for the mass balance accounting task (February 13, 2013 through September 30, 2019 a period of 6 years, ~8 months), Battelle conducted monitoring to document injection of approximately 1.5 million MT of new CO_2 in the 10-reef EOR complex, exceeding the program goal of 1 million MT. Table 2-4 and Figure 2-10 summarize the net CO_2 injected during the period of record.
- In order to achieve an accurate mass balance accounting of the amount of CO_2 stored in the EOR reefs, it was necessary to procure/install flow meters to measure CO_2 injection rate, cumulate CO_2 injected, CO_2 production rate, cumulative CO_2 produced, CO_2 removed via produced oil, and vented CO_2. The flow metering network was designed to make/record measurements continuously at a 10 second frequency.
- An analysis of storage efficiency across the reefs shows that every unit (e.g., tonne) of CO_2 stored requires a 2 to 3.5 times greater amount of injected CO_2.

Table 2-4. Reef-level Accounting for all 10 Reefs over MRCSP Monitoring Period

Task	Reef	CO_2 Injected (MT)	CO_2 Produced (MT)	Net CO_2 Injected (MT)	Produced Oil (BBL)	Produced Water (BBL)
Task 3	Dover 33	325,272	219,360	105,912	45,590	19,888
Task 4	Bagley	622,463	37,199	585,264	7,947	3,730
Task 4	Charlton 19	387,042	85,488	301,554	170,048	9,216
Task 4	Charlton 30/31	661,631	532,880	128,751	315,423	969,495
Task 4	Charlton 6	145,053	201,357	-56,304	34,592	2,239
Task 4	Chester 2	273,578	168,573	105,004	74,001	102,096
Task 4	Chester 5/6	224,303	34,821	189,482	117,743	1,852,096
Task 4	Dover 35	114,135	76,574	37,560	128,055	9,504
Task 4	Dover 36	504,639	520,844	-16,151	170,335	54,645
Task 5	Chester 16	155,657	0	155,657	0	0
	Total:	**3,413,824**	**1,877,097**	**1,536,727**	**1,063,734**	**3,022,910**

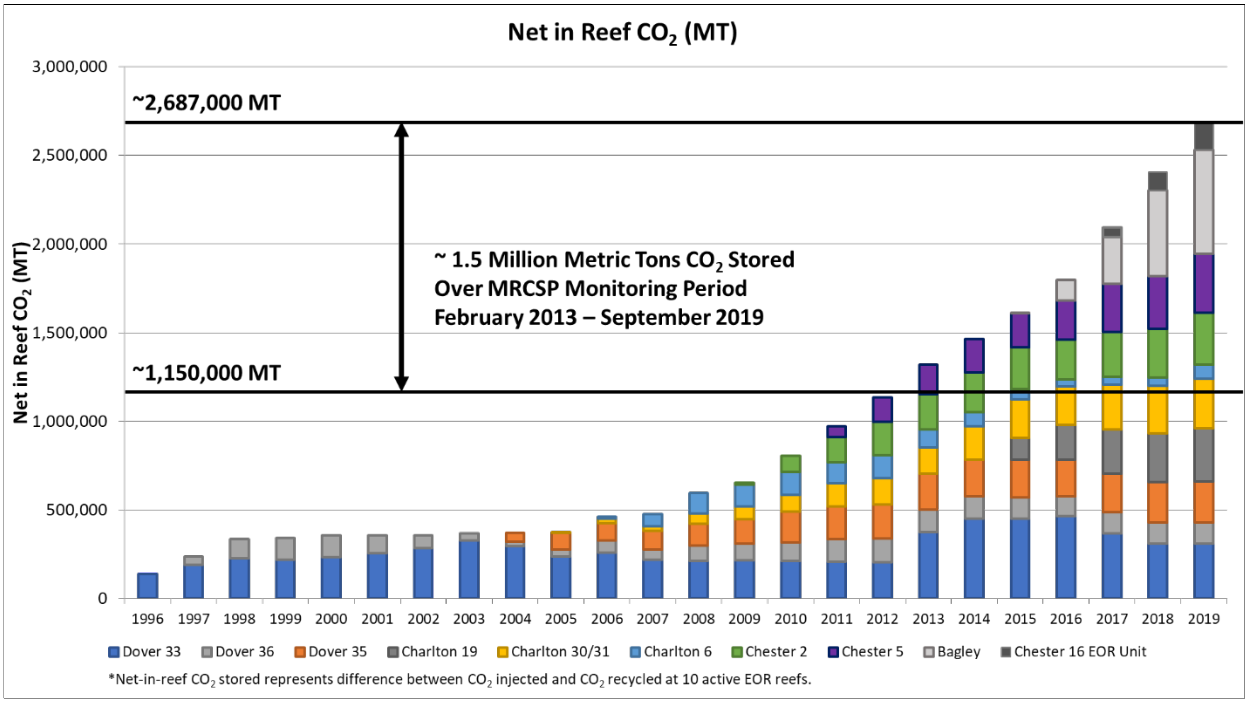


Figure 2-10. Net in-reef CO_2 over the life of secondary recovery within the MRCSP reef complex

2.3.3.2 Distributed Temperature Sensing (DTS)

- A fiber optic DTS cable was installed on the outside of casing in a CO_2 injection well and a monitoring well in the Chester 16 reef. DTS was performed continuously in both wells during the re-pressurization period (February 2017 through September 2019) when CO_2 was injected sans production.
- The DTS data from the injection well revealed the location of inflow zones where CO_2 entered the reservoir. The injection well had 7 perforated intervals of equal length but with differing injectivities as shown by the DTS data. A "warmback" analysis method (analyzing temperature change (increase) as a function of depth and time during shut-in following injection) was used to analyze time-series DTS data to detect inflow zones. Figure 2-11 shows an example waterfall plot of temperatures at the injection well for the injection period February through August 15, 2019. Here, the blue colored zone represents cooler temperatures, while red colored zones indicate warmer temperatures. During the injection the entire wellbore cools, but when injection is halted, the shallower formations above the injection reservoir (B Salt, A2 Carbonate and A2 Evaporite) quickly revert to reference reservoir temperatures. Similarly, near the bottom of Brown Niagaran formation, below the bottom-most perforated zone #7 at approximately 6,150 ft. shows no significant cooling indicating no migration of cooler CO_2, either during injection or the falloff period. This waterfall plot of temperature suggests that most injected CO_2 entered the reservoir within the target zone of injections, the A1 Carbonate and the Brown Niagaran Formations.

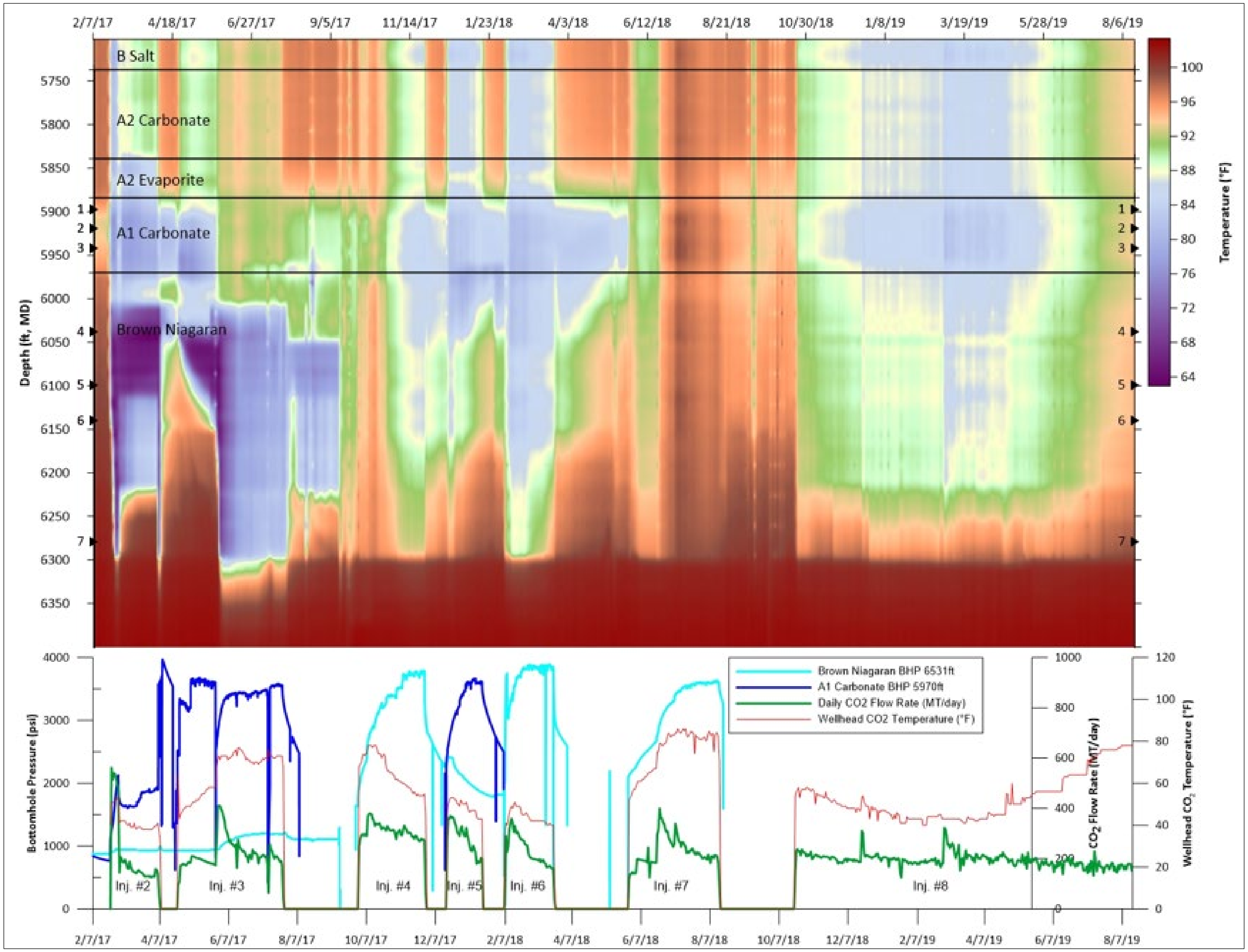


Figure 2-11. Waterfall plot of temperatures and bottomhole conditions in Chester 6-16 injection well

- The DTS data from the monitoring well revealed the vertical interval in the reservoir where CO_2 transport occurred, as indicated by a sustained decrease in temperature that started after CO_2 injection commenced (Figure 2-12). The depth interval where the cooling occurred corresponded with a zone where CO_2 was indicated by PNC logging (not shown) and an increase in pressure was recorded by multi-level pressure gauges in the monitoring well (not shown), thus supporting the claim that the cooling effect was caused by the arrival of injected CO_2 at the monitoring well.

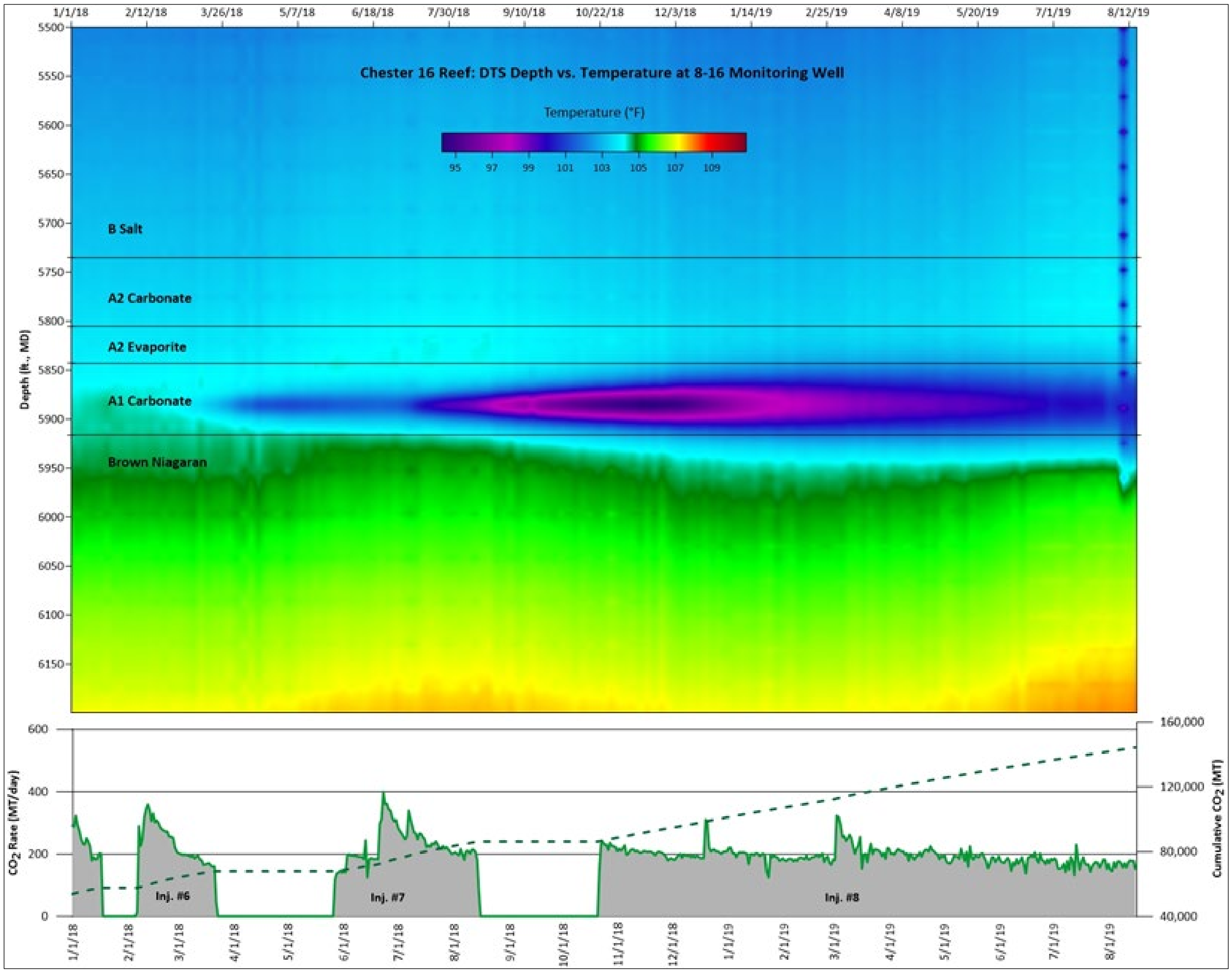


Figure 2-12. Waterfall plot of temperatures in the Chester 8-16 monitoring well showing vertical interval where CO_2 transport occurred.

- Table 2-5 summarizes key results of the DTS monitoring study, pros/cons of the technology, and an overall recommendation for using the technology to monitor CO_2 storage in Silurian pinnacle reefs of Northern Michigan.

Table 2-5. DTS Summary and Recommendations

DTS Summary and Recommendations	
Key Results of this study	• The technology useful for identifying inflow zones at the injection well and for detecting CO_2 breakthrough at the nearby 8-16 monitoring well. • The conditions at the Chester 16 reef were ideal for detecting CO_2 at the 8-16 monitoring well because it is close to the injection well (~1,100 ft) and the CO_2 moved laterally through a thin interval in the A-1 Carbonate which likely reduced temperature attenuation.
Pros	• Provides a continuous vertical profile of temperature along the length of the well at specified time interval. • Results are available in real time • Fiber optic DTS cable can be installed permanently behind (outside) casing (i.e., cemented in place), which allows the well to be used for other purposes; or it can be installed temporarily on a tubing string inside the well. • Ongoing continuous temperature monitoring can be configured to be done automatically and remotely.
Cons/Challenges	• The method is relatively expensive. For permanent systems the cost is due to the purchase cost of the fiber and installation (>$100K per well for a 5,000 ft deep well) plus the purchase cost of the surface data acquisition system (<$20K per well/event)
Overall recommendation	• DTS is recommended for CO_2 injection wells because of its usefulness for identifying inflow zones and vertical leakage. • DTS is generally not recommended for CO_2 plume tracking in monitoring wells unless site-specific modeling suggests there is high probability of seeing a temperature signal. However, if another fiber optic technology (e.g., DAS) is being installed in the monitoring well, the incremental cost of installing a companion DTS cable is very low.

2.3.3.3 Pulsed Neutron Capture (PNC) Logging

- Repeat PNC logging was performed in several wells in 4 different reefs to evaluate the use of PNC logging for detecting the arrival/presence of CO_2 at monitoring wells.
- The standard Sigma analysis method while useful for distinguishing water and hydrocarbons (oil, gas) is not sufficient for distinguishing CO_2 when hydrocarbons are present due to similar Sigma response by CH_4 and CO_2.
- To overcome this limitation, Battelle collaborated with Baker Hughes to develop a technique for computing multi-phase saturations, including oil, gas and water saturation, in cased wells. The technique (referred to as the Triangulation Method) uses the Sigma response and RATO13 response as input to Monte Carlo N-Particle (MCNP) simulations to generate theoretical pulsed neutron tool responses for the given well and reservoir conditions that are compared to actual tool response to estimate probable CO_2 saturations. Figure 2-13 shows the steps in the workflow for the Triangulation technique, which includes: 1) field logging and analysis of well logs to determine well conditions, 2) well condition data collection, 3) fluid properties analyses, and 4) analysis of finalized saturation profiles.

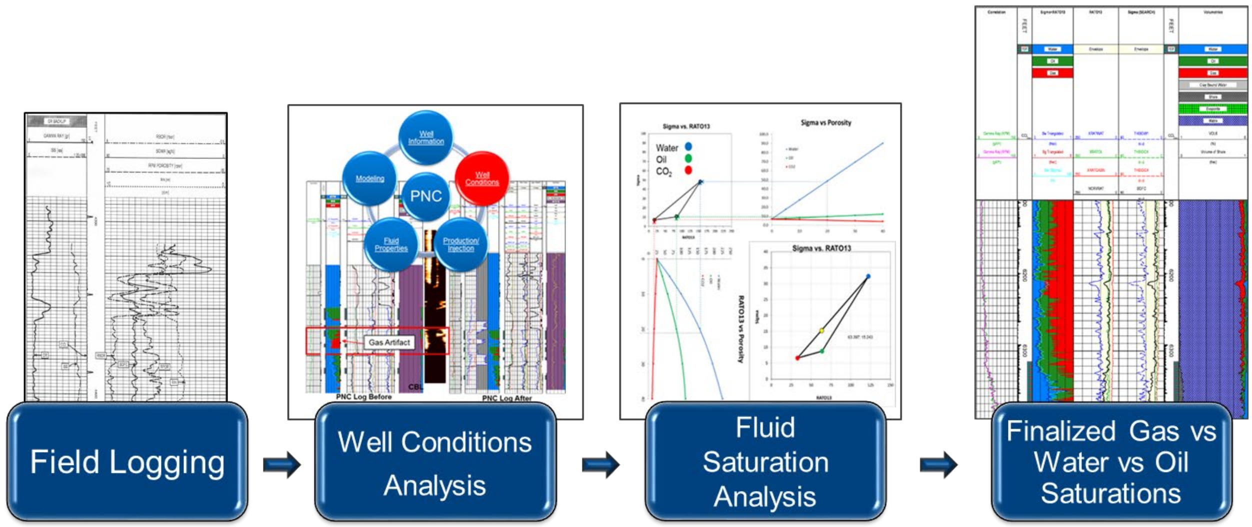


Figure 2-13. PNC Workflow – Analysis workflow steps for estimating saturation profiles

- An example of PNC logging results is shown in Figure 2-14. Wireline temperature data indicates there is a greater than 10° F temperature decrease between 5,861 t to 5,910 feet. This temperature decrease correlates strongly with the change in Sigma (SigR/SigB) and RPOR (RporR/RporB) from 2017 (baseline, before CO_2 injection) to 2018 (repeat, after CO_2 injection). Additionally, CO_2 breakthrough at the 8-16 well is indicated by an increase in gas saturation (GasR/GasB) that occurs in the same interval that undergoes cooling and the noticeable change in Sig and Rpor from the 2017 baseline event to the 2018 repeat event. Oil saturations show a considerable increase across this entire formation suggesting there is a pushing of oil due to injected CO_2.

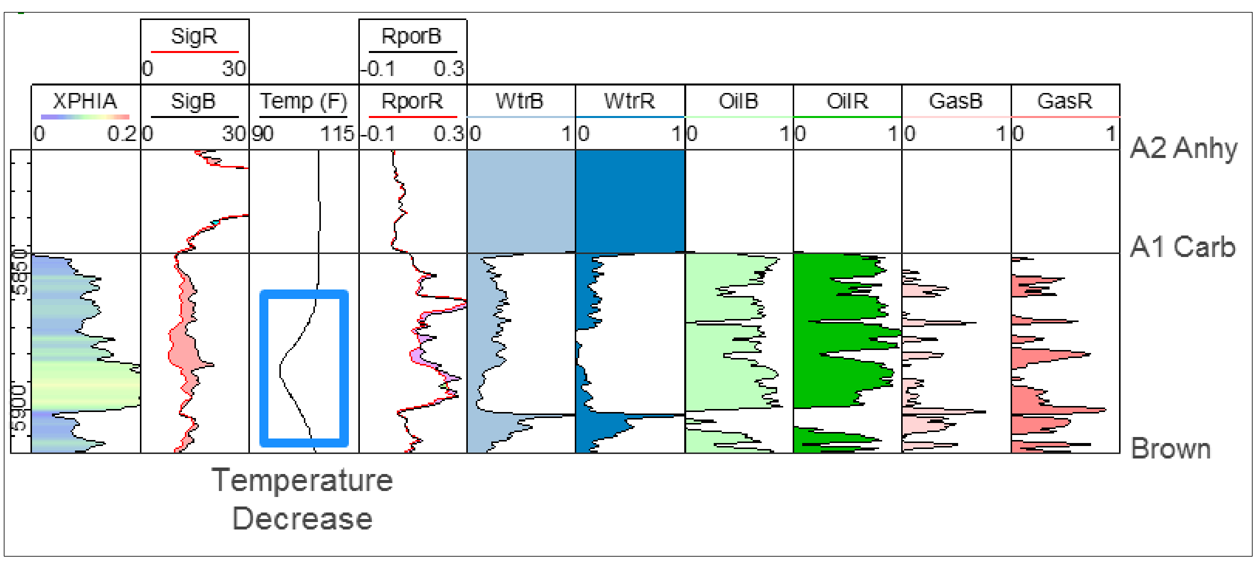


Figure 2-14. PNC signals (GAS, sigma and RPOR) in monitoring well 8-16 in the Chester 16 reef (located ~1,200 ft from the CO_2 injection well) indicate the arrival/presence of CO_2 in the same depth interval (5,861 MD feet to 5,910 MD feet) where a temperature decrease was detected with DTS.

- Table 2-6 summarizes key results of the PNC monitoring study, pros/cons of the technology, and an overall recommendation for using the technology to monitor CO_2 storage in Silurian pinnacle reefs of Northern Michigan.

Table 2-6. PNC Logging Summary and Recommendations

PNC Logging Summary and Recommendations	
Key Results of this study	• Collaboration between Battelle and Baker Hughes developed a novel "Triangulation" method to estimate %saturation of each component in a 3-phase (oil-water-CO_2) system • PNC results were useful for detecting breakthrough/arrival of CO_2 at the 8-16 monitoring well in the Chester 16 reef, which was corroborated by other monitoring data (DTS). Although other wells in other reefs were also included in the time-lapse PNC logging program, no other well provided similarly clear evidence of CO_2 breakthrough.
Pros	• The method is relatively inexpensive (<$20K per well/event) but cost multiples by number of wells logged and number of monitoring events so total cost can be high. Also, this assumes wells are already available. • Raw unprocessed field data (Sigma and Rpor) were shown to provide reliable indicator of CO_2, thus, in some cases it may not be necessary to implement the proprietary and complex Triangulation method developed in this study. • Requires specialized logging tools but they are commonly available from multiple oil-field service companies. • As an alternate use, PNC logging can be used to identify salt plugged intervals (which reduces storage capacity).
Cons/ Challenges	• Results are difficult to interpret – typically it amounts to visually comparing saturation curves collected at different times (e.g., baseline prior to CO_2 injection vs post-CO_2 injection). Interpretation of time-lapse results (% saturation vs depth curves) could benefit from calculating %saturation "difference curves" that quantify the change in saturation, rather than visually comparing curves collected at different times. • Limited to near wellbore • Does not differentiate between CH_4 and CO_2 • The method doesn't work well in low (<6%) porosity fields
Overall recommendation	• The technology has value in the Silurian carbonate formations that comprise the Michigan pinnacle reefs but low porosity can limit its usefulness. The primary value of the technology is to detect CO_2 breakthrough and delineate the vertical intervals where CO_2 is moving. • The method is recommended if monitoring wells are available or planned in the reef reservoir and provided a representative baseline measurement can be obtained before CO_2 injection commences.

2.3.3.4 Reservoir Pressure Monitoring

- Injection wells and monitoring wells in multiple reefs were instrumented with memory-style recording pressure gauges to record the pressure response within the reservoir resulting from CO_2 injection. Time varying pressure data allowed the following analyses:
    - ***Injection wells*** – these data together with injection rate data, determine (a) formation properties such as permeability using injection-falloff tests, and (b) permeability-thickness via injectivity index calculations using injectivity analysis.

- ***Monitoring wells –*** These data were used to analyzed to determine: (a) hydraulic diffusivity from the arrival time of the pressure pulse, and (b) permeability from the interference response.

- Traditional analysis of ***injection-falloff data*** using oil and gas industry workflows has been utilized in the context of monitoring of CCS/CCUS projects. However, what is new in this study is the use of (a) ***injectivity analysis*** and (b) ***arrival time analysis*** for further analysis of pressure and rate data obtained from injection and monitoring wells.

- An example injection fall-off analysis using the history matching (modeling) inverse method is shown in Figure 2-15 for a 9-day injection test (9-day injection period followed by 3-week fall-off period) in the 1-33 well within the Dove 33 reef. The analysis includes a cartesian-coordinate plot of measured vs modeled pressure data during injection and fall-off and 2) and a log-log plot of fall-off pressure and fall-off pressure derivative. For the 1-33 injection well, a match to the entire injection and fall-off pressure sequence and the fall-off pressure derivative was obtained with a three-zone radial composite gas model. The gas model is deemed more appropriate than a water-injection because CO_2 appears to have transitioned from a gas to a liquid or supercritical fluid during injection and then back to gas phase during fall-off (based on density values). The gas model yields permeability values of 27, 4, and 14 mD for the inner, middle, and outer zones, respectively with radii of these zones being 250, 515, and 1200 ft, respectively. There is some uncertainty associated with the outer zone estimates (i.e., reversal of derivative at late times) – hence the mobility of the middle zone is taken to be the most representative value.

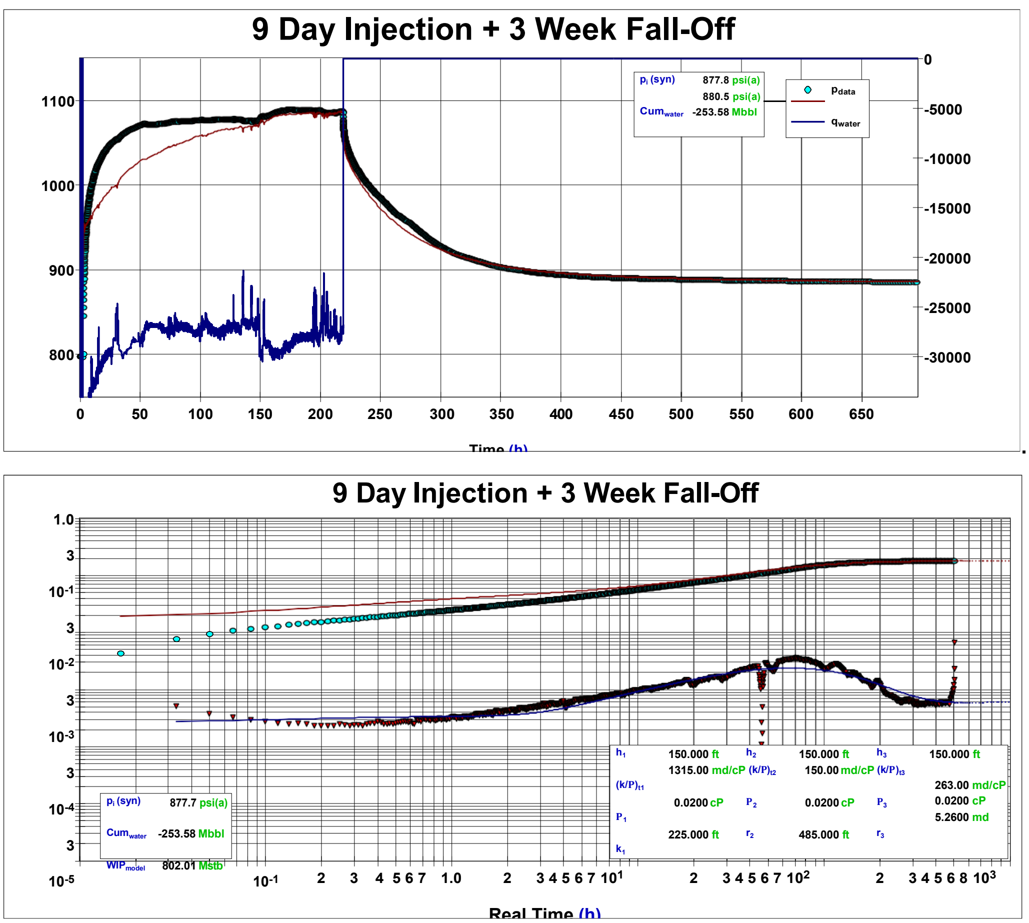


Figure 2-15. History-match for the nine-day test, pressure data, (top) cartesian plot of injection-falloff sequence, (bottom) log-log plot of falloff data, Dover 1-33 well

- An example injectivity index analysis is shown in Figure 2-16 and Figure 2-17 for approximately four months of injection data along with reservoir pressures observed at various multi-level pressure sensor locations. Of particular interest is the pressure response at 5865 ft, which is within the well's perforated interval from 5850 to 5900 ft in the A1 Carbonate formation. The flowing material balance plot corresponding to pressures at this depth are shown in Figure 2-17. Here, the rate-normalized pressure drop is plotted against material balance time, resulting in a strong linear trend (except the first few data points, which may be indicative of transient flow conditions prior to the onset of boundary effects). The strong linear trend is a clear indication of the pseudo-steady-state conditions caused by the bounded nature of the reef reservoir. Also, the success of the rate normalization approach in conjunction with material balance time is evident despite seven distinct rate variations in the period of interest. The injectivity index is readily calculated from the reciprocal of the intercept as 288 MT/yr-psi which in turn is converted to an equivalent-permeability thickness product and a corresponding permeability. In this case, a permeability of 15.8 mD was calculated assuming aa formation thickness of 50 ft.

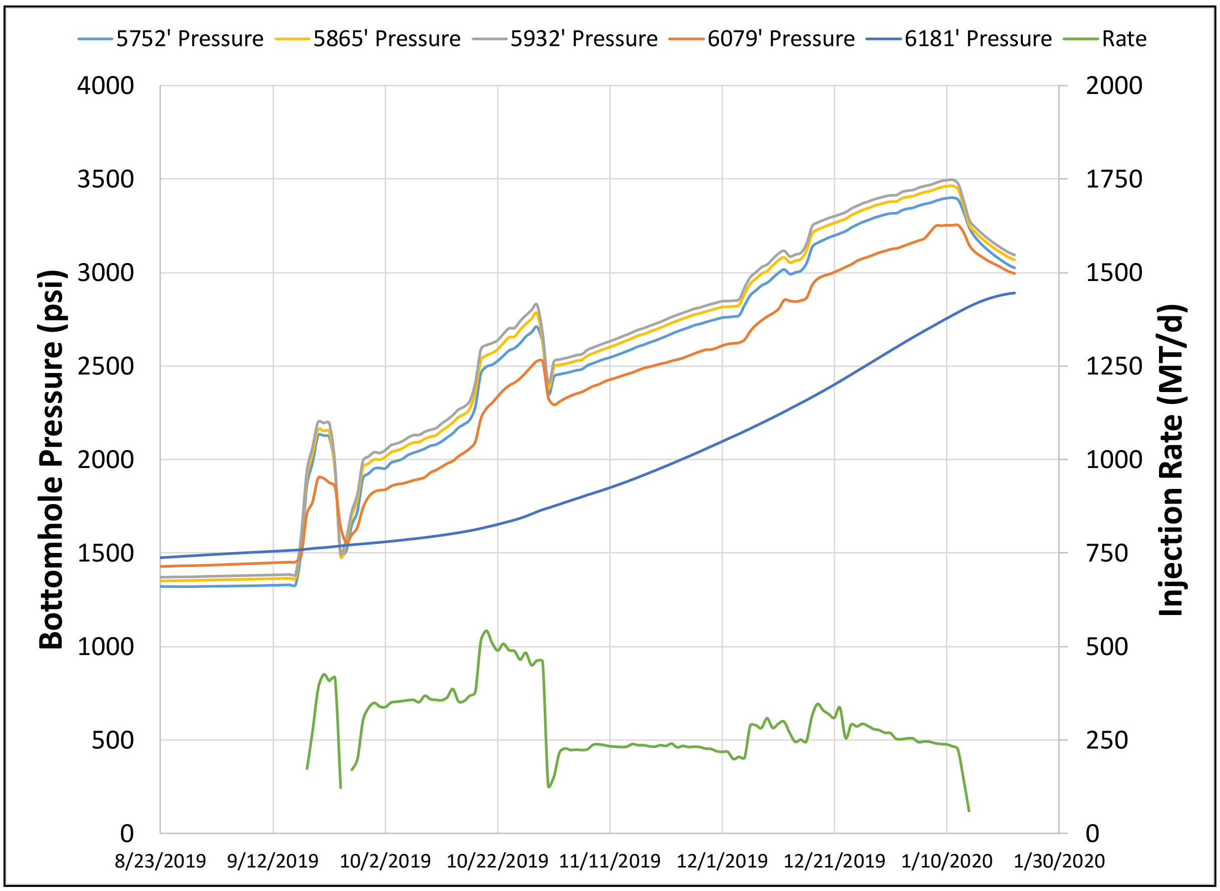


Figure 2-16. Injection rate (right axis) and pressure history (left axis) at the Chester 8-16 well

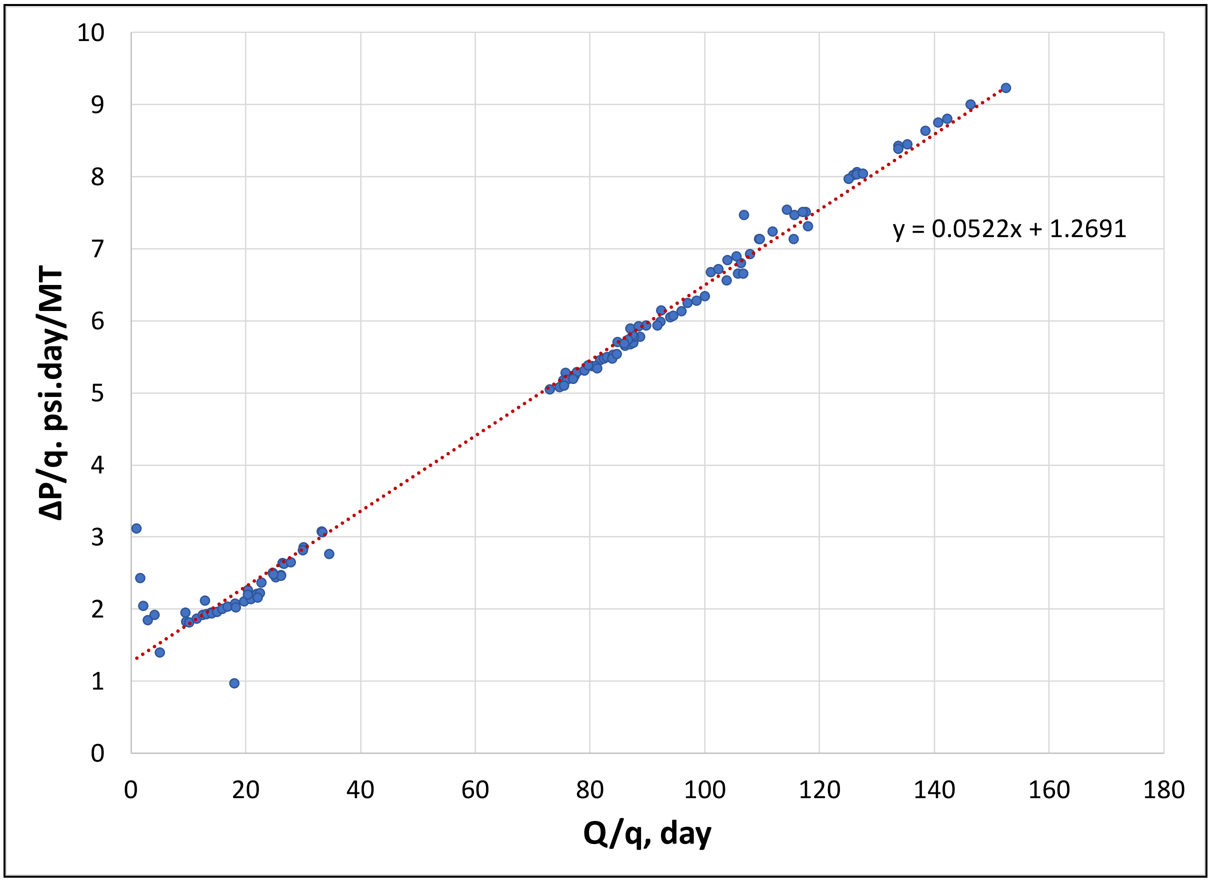


Figure 2-17. Flowing material balance plot corresponding to pressure gauge at 5865 ft, Chester 8-16 well

- The primary outcome of arrival time analysis is an estimate of hydraulic diffusivity η averaged over the region between the injection and observation wells. Associated outcomes are: (a) comparing the calculated value of diffusivity against those from other analysis carried out for the same reef as well for other reefs, (b) computing total compressibility c_t knowing total mobility λ_t (from injection-falloff analysis) using $\eta= \lambda_t/\phi c_t$ (where k is permeability, ϕ is porosity), or back-calculating λ_t based on assumed values for c_t. An example arrival time analysis using the pressure-pulse arrival times shown in Figure 2-18 for two monitoring wells located1200 ft (1-11) and 1482 ft (3-11) from the injection well (2-11) yielded diffusivity estimates of 3.8E6 (0.28) and 6.8E6 (0.49) (md-psi/cp)(ft^2/s), respectively. Permeability estimated from these values are 6 and 11 md using η=k/($\phi\mu c_t$) and μ = 0.05 cp, ϕ = 0. 08, and c_t = 4E-4 1/psi (based on independently derived information using core/log data and/or correlations) where μ is viscosity.

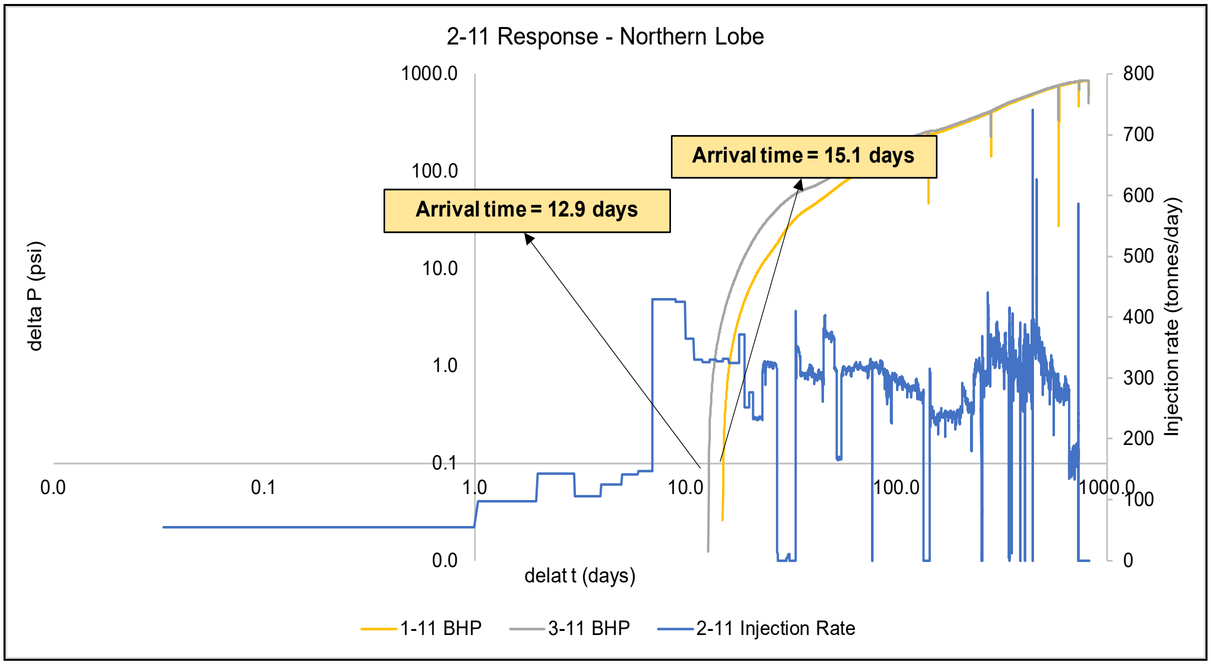


Figure 2-18. Arrival times, 2-11 injection response in the Bagley Northern lobe monitoring wells (1-11 and 3-11)

- Table 2-7 summarizes key results of the Reservoir-Pressure monitoring study, pros/cons of the technology, and an overall recommendation for conducting reservoir-pressure monitoring to monitor CO_2 storage in Silurian pinnacle reefs of Northern Michigan.

Table 2-7. Reservoir Pressure Monitoring Summary and Recommendations

Reservoir Pressure Monitoring Summary and Recommendations	
Key Results of this study	• This study demonstrated that pressure data can be used to characterize reservoir hydraulic properties vi injection falloff tests and arrival time analysis and for monitoring the change in a well's injectivity over time via injectivity index analysis.
Pros	• Useful for characterizing hydraulic properties of the reservoir including transmissivity, permeability (via injection-falloff analysis), diffusivity (via arrival time analysis) • Useful for quantifying injectivity of a CO_2 injection well (injectivity index) • Continuous pressure monitoring is inexpensive if it is done with memory-style pressure gauges; the primary cost is associated with retrieving and re-installing the gauges periodically, which is a slick-line operation. • Data acquisition and most data analysis and interpretation does not require highly specialized skills. Analysis of injection-falloff data does require specialized skills (reservoir engineer or hydrogeologist)
Cons/ Challenges	• Not a method for CO_2 plume tracking
Overall recommendation	• Reservoir pressure monitoring should be included in all CO_2 storage projects to aid in accurately defining reservoir hydraulic properties monitoring long-term performance of the storage reservoir

2.3.3.5 Interferometric Synthetic Aperture Radar (InSAR)

- Battelle used Interferometric Synthetic Aperture Radar (InSAR) to monitor potential land movement (uplift, subsidence) resulting from the injection of CO_2 into the Dover 33 reef. InSAR is a satellite-based technology that provides high-precision information on the movement of ground surface in areas with high radar coherence (e.g., roads, buildings, bare soils). In this study, artificial corner reflectors (ACR) were placed/installed throughout the study area to help monitor land movement because of the dense vegetation coverage which reduces radar coherence, and frequent snow coverage.
- Ground movement rates from ***natural radar reflectors*** over the Dover 33 reef in the full data set (i.e., 51 satellite images collected between 1992 to 2000 (historical period); 22 satellite images for a six-month from April 22, 2012 through October 23 (baseline period); and 76 satellite images acquired between April 22, 2012 and March 22, 2015 (operational period) showed little movement, with an average rate of -0.3 mm/yr (Figure 2-19). A cumulative displacement of 0.7 mm was measured by the natural reflectors over the full data set and 1.2 mm during the CO_2 injection phase. The results indicate there was slightly greater movement in the area above the reef during the injection period compared to the historical and baseline periods.

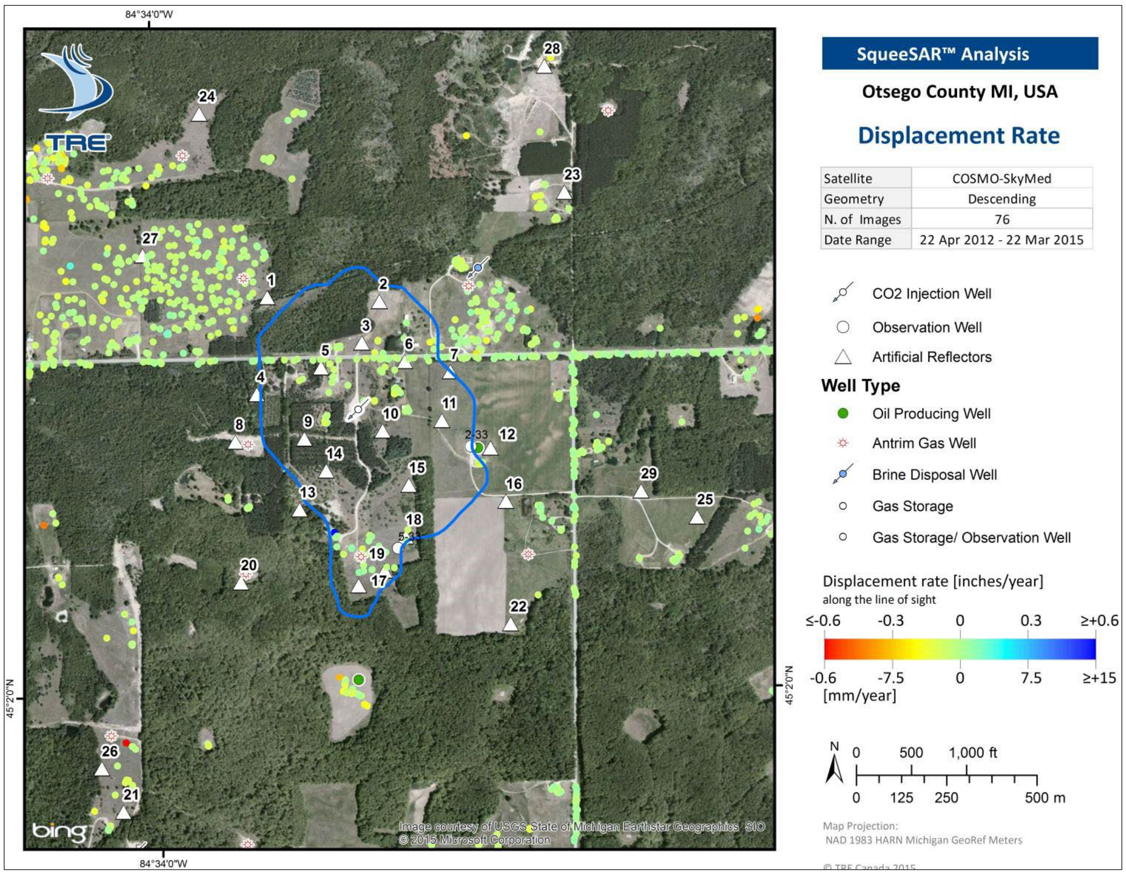


Figure 2-19. Land movement results calculated from the full (natural radar reflectors) data set (i.e., 51 satellite images collected between 1992 to 2000 (historical period); 22 satellite images for a six-month from April 22, 2012 through October 23 (baseline period); and 76 satellite images acquired between April 22, 2012 and March 22, 2015 (operational period) over the Dover 33 reef. Results are expressed as annual rate of movement calculated by dividing the total movement measured at each location during the monitoring period by the length of the monitoring period. Results were calculated using natural radar reflectors only; data from ACRs are excluded.

- Measurement of surface movement near the Dover 33 reef using ACRS installed in 2013 entailed processing 44 satellite images obtained from May 03, 2013 to March 22, 2015. Resulting movement rates over Dover 33 were between -0.1 and 3.9 mm/yr. An average movement rate of 1.1 mm/yr was obtained from the ACRs over Dover 33, while the average for all ACRs outside the reef was 0.01 mm/yr (Figure 2-20). The five ACRs closest to the injection well (ACR 3, 5, 6, 10, and 14) had movement rates ranging from +0.2 to +2.4 mm/yr. The results indicate there was slightly greater movement in the area above the reef compared to the area outside the reef during this period.

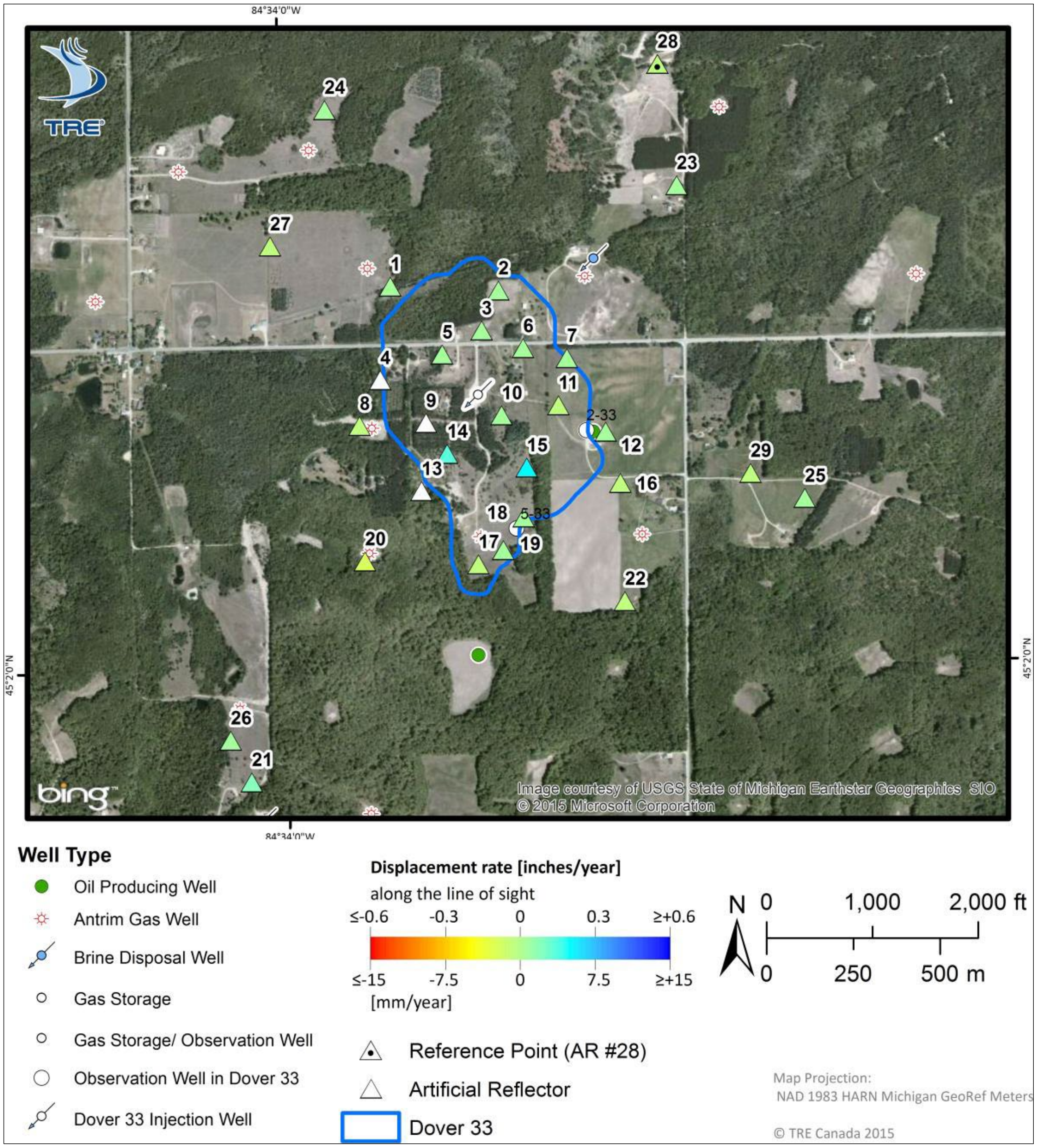


Figure 2-20. Displacement results obtained for all ACRs installed at the Dover 33 site. Three ACRs (shown in white) are not included in the analysis, as they were not visible to the satellite.

- A comparison between the surface movement and the reservoir pressure was performed to determine if there was a correlation between movement and reservoir pressure. Continuous CO_2 injection into the Dover 33 reef began in March 2013 and was halted in August 2014 after injecting 244,000 tonnes of CO_2 and reaching a bottom hole pressure of approximately 3,300 psi in the 1-33 injection well. Ground movement rates measured with the ACRs and natural reflectors during this time were within ±5 mm and no discernable correlation between surface deformation and reservoir pressure was determined.

- Table 2-8 summarizes key results of the InSAR monitoring study, pros/cons of the technology, and an overall recommendation for using the technology to monitor CO_2 storage in Silurian pinnacle reefs of Northern Michigan.

Table 2-8. INSAR Monitoring Summary and Recommendations

INSAR Monitoring Summary and Recommendations	
Key Results of this study	• No conclusive evidence was found for significant land displacement due to CO_2 injection (although some data [movement rates based on natural radar reflectors and ACRs] suggest the possibility of some amount of land displacement in the area overlying the Dover 33 reef), • Based on a weight of evidence approach, the preponderance of results indicate that CO_2 injection in the Niagaran pinnacle reefs ca be done safely without risk to surface and subsurface infrastructure
Pros	• Potentially useful for detecting land displacement (uplift) due to CO_2 injection • Relatively inexpensive • Capable of covering a large area • Data acquisition is streamlined because the method uses existing satellite data acquired by others
Cons/Challenges	• Data interpretation requires specialized skills • Requires relatively long monitoring period and large number of monitoring stations to be able to discern displacement due to CO_2 injection vs other causes of displacement (e.g., freeze-thaw) • Necessary to monitor a reference location (an area with similar land cover but without CO_2 injection) to be able to discern injection-induced displacement • A corroborative method can be useful for discerning injection-induced displacement (e.g., subsurface tiltmeters) • Not a method for CO_2 plume tracking
Overall recommendation	• Because the results obtained from this study are not unequivocal, INSAR should be implemented at a subset of future reefs where CO_2 storage is occurring to corroborate the results of this study. • Ambiguity in data interpretation can be reduced by using statistical methods to detect displacement.

2.3.3.6 Borehole Gravity Monitoring

- Borehole gravity (BHG) monitoring was carried out at the Dover 33 reef to determine the feasibility of BHG to detect the location of the injected CO_2 (i.e., CO_2 plume) over time. The injection of CO_2 and the redistribution of the fluids in the pore space result in changes in subsurface density that can be detected with surface and borehole gravity measurements. (Figure 2-21). The method is a passive measurement of the existing gravity field and it bridges the radius of investigation gap between the near-borehole examination by well logging tools and the larger volumes examined by many of the seismic methods. In a time-lapse mode, the method is responsive only to temporal density distribution changes, such as those associated with CO_2 injection and production.

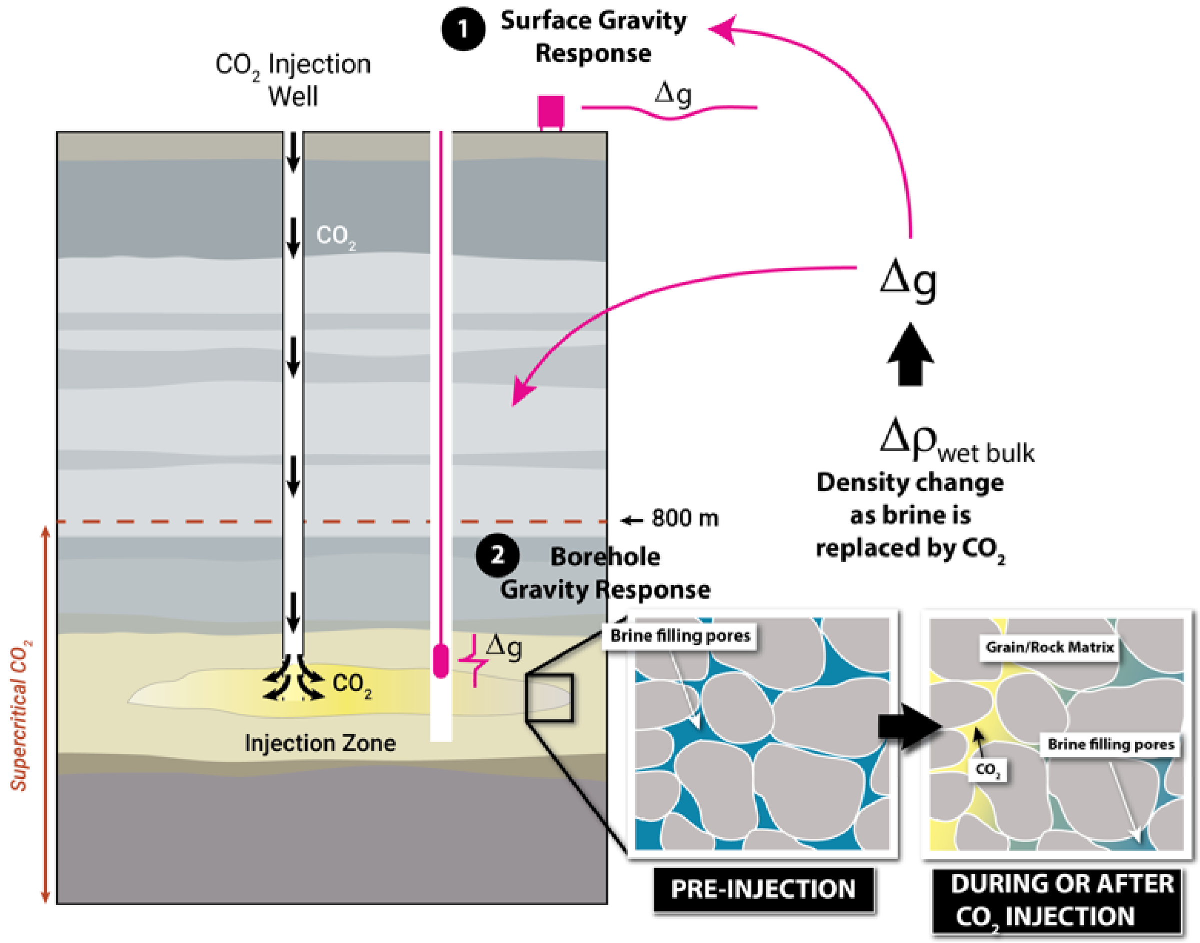


Figure 2-21. Principle of time-lapse gravity monitoring. The injection of CO_2 in the reservoir leads to the gradual replacement of original pore filling fluids by CO_2. This mass redistribution can be detected using surface gravity surveys (1), and borehole gravity survey (2) (from Appriou & Bonneville, 2020).

- Three BHG surveys were performed (2013, 2016, and 2018) to monitor the changes in gravity/density as a result of the injection of CO_2 into the reef (264,586 metric tons of CO_2 were injected between February 2013 and June 2016) and withdraw of CO_2 from the reef (136,271 tons of CO_2 were produced between July 2016 and July 2018 along with 4,243 metric tons of oil and 2,542 metric tons of brine) during this period. The first survey was conducted in February 2013 before commencing CO_2 injection; the second survey was conducted in June 2016 after CO_2 injection was completed; the final survey was conducted in June 2018 after a portion of the injected CO_2 had been removed.
- Time-lapse density changes between the surveys, calculated from the measured time-lapse gravity changes (Figure 2-22), clearly reflect where CO_2 injection and fluid production occurred. Within the reef, the density typically increases between the 2013 and 2016 surveys from the injection of CO_2 and then decreases between the 2016 and 2018 surveys as CO_2, oil, and water were produced from the reef. Often, the 2018 density lies between the densities calculated from the 2013 and 2016 survey data, which is the expected result given the intermediate mass of CO_2 in the reef at the time of the 2018 survey.

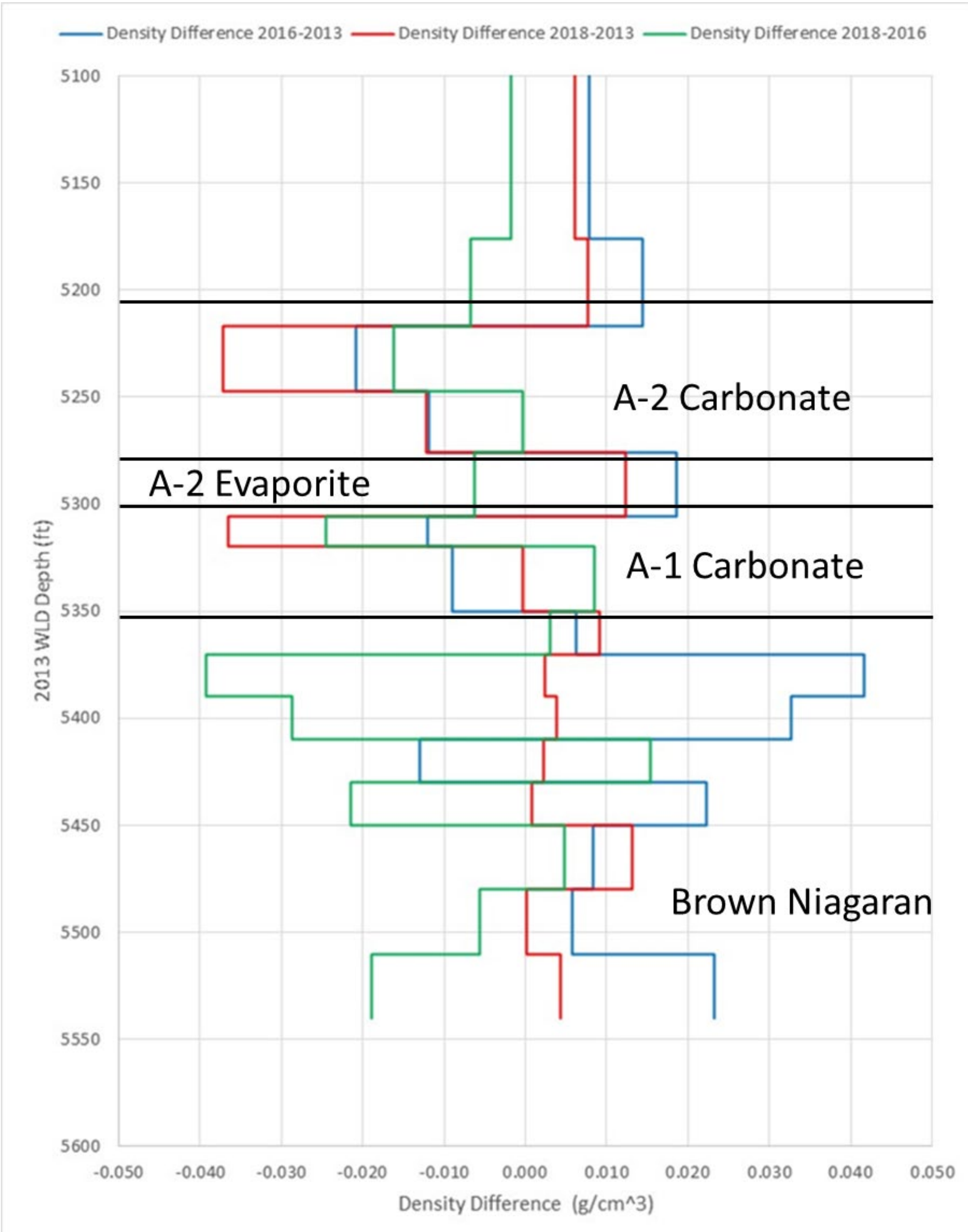


Figure 2-22. 4D Borehole Gravity Density Differences for Reservoir Interval (the plot extends from the A-2 Carbonate on top through upper part of Brown Niagaran on bottom; perforation interval is 5,309 – 5,460 ft).

- The gravity/density changes were modeled to determine the flow and storage zones of the injected CO_2 in the reef. The forward modeling method allows precise mapping of the areas of the reservoir that received most of the injected CO_2 and which zones are likely to have received less CO_2. The best fitting forward models correspond to CO_2 being stored primarily in the central and lower portions of the reef Figure 2-23 and Figure 2-24.

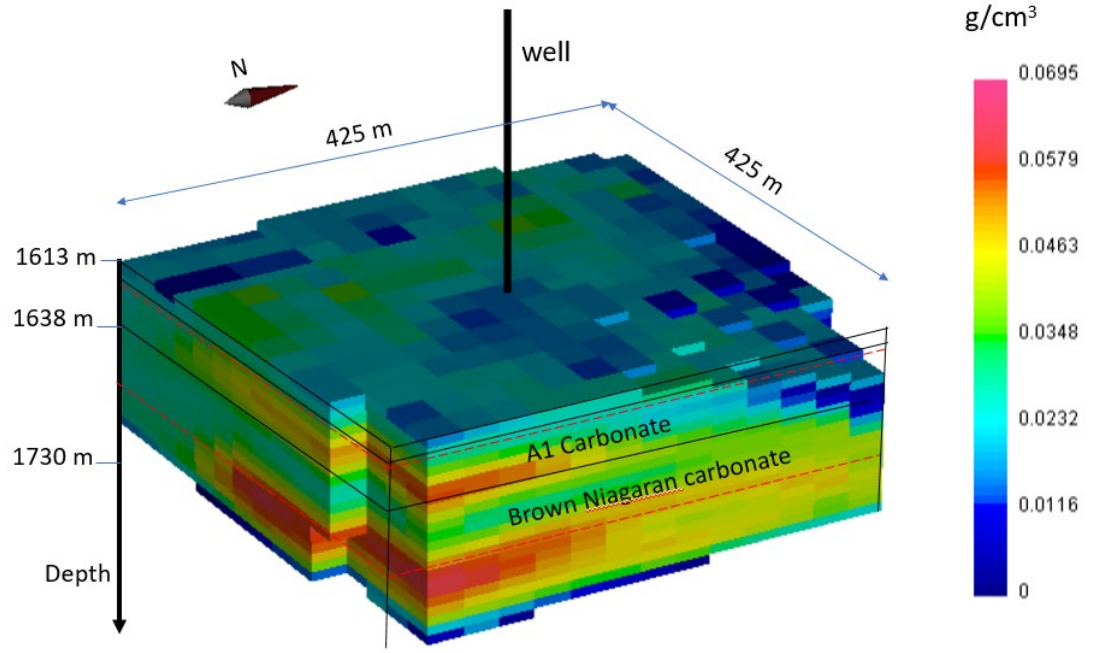


Figure 2-23. 2013-2016 injection period: three-dimensional perspective diagram of the modelled time-lapse density that represents the CO_2 plume in the reef for the best fitting solution K=0- R=300. The vertical black line represents the L-M 1-33 well. The horizontal black lines are the limits between the main geological units and the depth interval between the two horizontal red dashed lines is the perforated interval of the injection well.

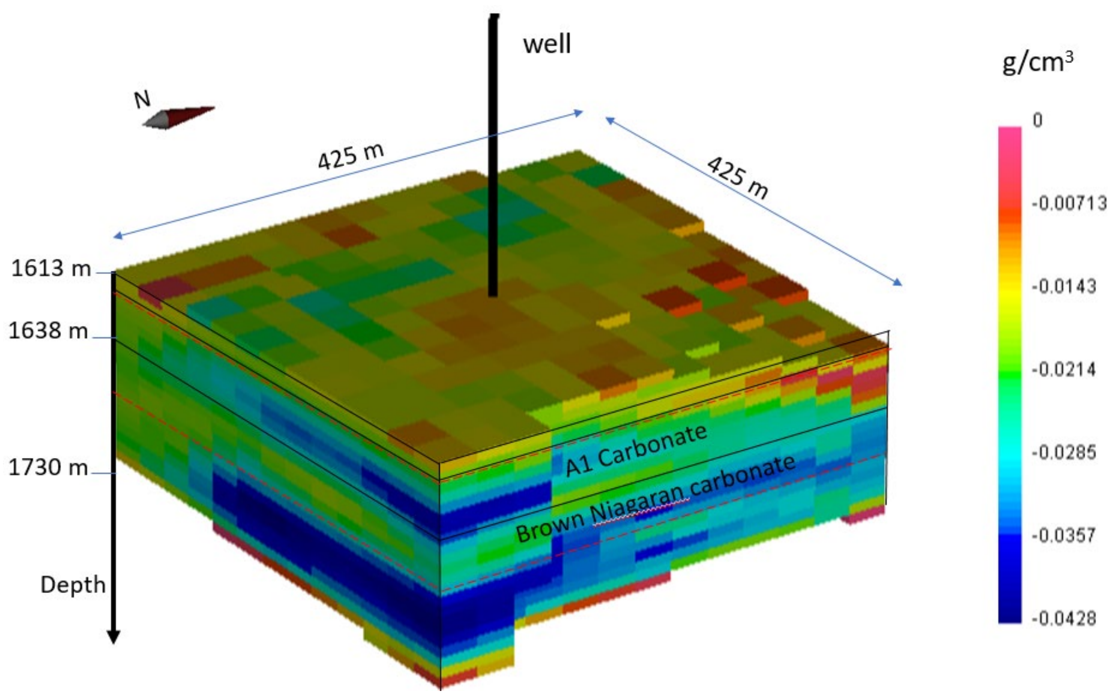


Figure 2-24. 2016-2018 production period: three-dimensional perspective diagram of the modelled time-lapse density in the reef for the best fitting solution K=0- R=300. The vertical black line represents the L-M 1-33 well. The horizontal black lines are the limits between the main geological units and the depth interval between the two horizontal red dashed lines is the perforated interval of the injection well.

- Table 2-9 summarizes key results of the borehole gravity monitoring study, pros/cons of the technology, and an overall recommendation for using the technology to monitor CO_2 storage in Silurian pinnacle reefs of Northern Michigan.

Table 2-9. Borehole Gravity Monitoring Summary and Recommendations

Borehole Gravity Monitoring Summary and Recommendations	
Key Results of this study	• Overall, the BHG study shows a plausible correlation between the reservoir CO_2 injection and production operations. The changes in gravity and density, generally correspond with the injection zone and the most pronounced changes are in the reservoir, rather than in the overlying 5,000+ feet; however, some intervals had an unexpected density/gravity response – both within the reservoir and outside the reservoir.
Pros	• The cost of this technology is moderate, with an acquisition cost of approximately $100,000 per monitoring event (not including the cost of the well). Cost for deploying this technology could potentially be reduced through standardization and more widespread use of the technology.
Cons/Challenges	• Acquisition and interpretation both require specialized services/skills. • the need for precise repetition of field procedures and measurement locations (because the technology relies on detecting very small changes in density). • The complexity of CO_2-EOR operations over time in fields such as Dover 33 is difficult to fully incorporate into the analyses or modeling.
Overall recommendation	• Borehole gravity can be a useful tool in monitoring CO_2 injection in depleted oil fields, including under CO_2-EOR conditions. • Evaluation of the lateral/extent of the CO_2 plume can be improved by deploying the technology in multiple wells rather than a single well as was done in this study. • The technology may be better suited for identifying thick intervals that underwent change in density due to CO_2 injection rather than thin intervals. • This technique may not be as useful for monitoring CO_2 plumes in saline reservoirs, because the contrast in density between brine and supercritical CO_2 isn't as great as the density increase created when a depleted reservoir (with pores mostly devoid of liquid) is filled with liquid CO_2. Increased usefulness in saline reservoirs may result from greater porosity values and increased lateral extent of the saline reservoirs over the closed-system reefs by magnifying the density changes caused by CO_2 substitution of the brine.

2.3.3.7 Geochemistry Monitoring

- A geochemistry monitoring program was implemented at three reefs (Dover 33, Charlton 19, and the Bagley Field) to determine geochemical processes/reactions occurring in the reefs because of CO_2 injection. Understanding the geochemical interactions between injected CO_2 and the reservoir solid and liquid phases is essential if geochemistry data is going to be used to monitor the vertical and lateral extent and behavior of the CO_2 plume.
- Brine, gas, and core samples were collected from the three reefs included in the geochemical study. Five wells in the Dover 33 reef were sampled for brine and four wells were sampled for gas; three wells in the Charlton 19 reef and two wells in the Bagley reef were sampled for both brine and gas; core was collected from one well (9-33) well in the Dover 33 reef. Table 2-10 lists the brine samples that were obtained from the wells in each of the three reefs, the sample dates, analyses performed,

and the reservoir pressure and cumulative CO_2 injected at the time of sampling. Thirty-two (32) gas samples were collected from 11 wells and from the Dover 36 gas processing facility (GPF) during the geochemical study (Table 2-11). Three core plugs were collected from the Brown Niagaran Formation above, at, and below the oil/water contact in the 9-33 well in the Dover 33 reef to investigate the presence of minerals that may have precipitated as the result of CO_2 injection in the reef, as suggested by geochemical equilibrium modeling. Core analyses (Table 2-12) were performed by Lawrence Livermore National Laboratory.

Table 2-10. Brine Samples Collected from the Three Reefs as Part of the Geochemistry Study

Reef	Well ID	Sample Date	Reservoir pressure (psi)	Cumulative CO_2 injected (MT)/stored	Analyses			
					Major Ions[d]	Trace Metals[e]	^{13}C DIC	other
Dover 33	L-M 1-33[a]	10/11/12	775	Before CO_2[b]	X	X	X	f
	L-M 1-33[a]	10/23/12	775	Before CO_2[b]	X	X	X	f
	L-M 2-33	11/7/12	775	Before CO_2[b]	X	X	X	f
	L-M 2-33	8/21/13	1270	96,100	X	X	X	f
	L-M 2-33	12/16/13	1455	166,500	X	X	X	f
	L-M 5-33	11/14/12	775	Before CO_2[b]	X	X	X	f
	L-M 5-33	8/23/13	1275	97,400	X	X	X	f
	Fieldstone 2-33	5/2/16	3040	259,300	X	X	X	f
Charlton 19	Lawnichak 9-33	12/7/16	~2500		-	-	X	f
	EMH 1-18	1/28/15	50	Before CO_2	X	X	X	f
	EMH 1-18A[c]	6/21/18	1190	290.000	X	-	X	f
	EMH 1-19D	2/6/15	50	Before CO_2	X	X	X	f
	EMH 1-19D	6/21/18	250	290,000	X	-	X	f
	EMH 2-18[c]	July 2018	1220	300,000				f
Bagley	J-M 1-11	10/14/15	50	Before CO_2	X	X	X	f
	J-S 3-11	10/12/15	50	Before CO_2	X	X	X	f

[a] CO_2 injection well
[b] From January 1996 through December 2008, prior to the MRCSP Phase III project, approximately 1.29
[c] million tonnes of CO_2 were injected into the reef and at the start of the MRCSP Phase III project, approximately 200,000 MT of this CO_2 were estimated to be retained in the reef.

The original EMH 1-18 vertical well was converted to horizontal well EMH 1-18A by sidetracking.

- **Anions (**Cl, SO_4, Br, F, NO_2, NO_3**); Total Metals by ICP (**Na, K, Ca, Mg, Fe, Mn, Li, Al)
- **Total Metals by ICPMS (**Sb, As, Ba, Be, B, Cd, Cr, Cu, Pb, Ni, Se, Ag, Sr, Ti, Zn)
- Alkalinity, Total Dissolved Solids, dissolved silica, specific gravity, pH,
- Scanning Electron Microscope (SEM) analysis was performed to examine the fine details of the core samples and to determine the chemical composition of the bulk rock and precipitates that filled pores, veins and vugs that had been identified.
- Samples were viewed under a polarizing light microscope to determine mineral phases and textures of the rock.

Table 2-11. Gas Samples Collected from the Three Reefs as Part of the Geochemistry Study

Reef	Well/Sample Location	Sample Date	Reservoir pressure (psi)	Cumulative CO_2 injected (MT)/stored	Analyses
Dover 33	L-M 1-33	5/6/13	1100	24,000	b
		7/20/13	1170	79,000	b
		10/3/13	1345	130,000	b
	L-M 2-33	5/6/13	1100	24,000	b
		7/30/13	1170	79,000	b
		8/21/13	1270	96,000	b
		10/3/13	1345	130,000	b
		12/13/13	1450	166,000	b
		11/14/12	775	Before CO_2	b
	L-M 5-33	5/6/13	1100	24,000	b
		7/30/13	1170	79,000	b
		8/20/13	1270	95,000	b
		10/3/13	1345	130,000	b
		12/18/13	1450	166,000	b
		12/7/17	~2500		b
	Lawn. 9-33	1/27/15	100	Before CO_2	b
Charlton 19	EMH 1-18(A)	8/4/17	1225	240.000	b
		6/18/18	1175	290,000	b
		12/31/14	100	Before CO_2	b
	EHM 2-18	2/20/15	100	Before CO_2	b
	EMH 1-19D	6/18/18	250	290,000	b
		6/19/18	900	370,000	b
Bagley Field	J-M 1-11	6/19/18	900	370,000	b
	J-S 3-11	6/19/18	1190	370,000	b
	Glass. 1-14	8/4/17	580	185,000	b
	Wrubel 1-14A	11/14/12	NA	NA	b
Dover 36 GPF	Pure[a]	5/6/13	NA	NA	b
	Recycled[a]	5/6/13	NA	NA	b
	Commingled[a]	11/14/12	NA	NA	b
		5/6/13	NA	NA	b

[a] These represent 'pure' CO_2 recovered from the Antrim Shale, gas that has passed through the reefs and subsequently been produced, and gas to be injected into the reefs, respectively.

[b] All gas samples were analyzed for isotopic composition ($\delta^{13}C_{CO2}$, $\delta^{13}C_{CH4}$, δD_{CH4}, and $\delta^{18}O_{CO2}$) and major gas constituents (He, H_2, Ar, O_2, CO_2, N_2, CO, CH_4, C_2, C_2H_4, C_3, C_3H_6, iC_4, nC_4, iC_5, nC_5, and C_6+).

Table 2-12. Core Analyses

Core Depth (ft.)	Core Type	Core Position Relative to OWC	SEM[a]	Light Microscope[b]	XRD[c]	XCT[d]	$\delta^{13}C$[e]
5,606.1	Plug	Above	✓	✓	✓	✓	✓
5,690.25	Plug	Near	✓	✓	✓	✓	✓
5,700	Plug	Below	✓	✓	✓	✓	✓
5,588	Trim Cut	Above	✓	✓	✓	✓	✓
5,630	Trim Cut	At oil water contact (OWC)	✓	✓	✓	✓	✓
5,655	Trim Cut	Transition	✓	✓	v	✓	✓

- X-Ray Diffraction (XRD) analyses were performed to determine the mineralogy/crystallography of the samples.
- micro- and macro- X-Ray Computed Tomography (XCT) analyses were performed to identify zones of the rock that may exhibit indications of dissolution or precipitation.
- $\delta^{13}C$ analyses were performed on select subsamples of the core to determine the isotopic values of the matrix carbonates and secondary mineral precipitates found in the rock
- samples of the rock matrix and vug-filling precipitates were analyzed with mass spectrometry to determine the isotopic compositions of these materials.
- Brine samples collected from the three reefs displayed comparable results for general geochemical properties. Overall, the brines have extremely high total dissolved solids (TDS) concentrations and are dominated by Ca, Mg, Na, and K for cations and Cl for anions, as may be expected from a brine in carbonate reef. The general geochemistry also displayed limited variation between the three reefs investigated, indicating there is not significant variation in the brine geochemistry over areal distribution of the reefs sampled. Also, the injection of CO_2 does not appear to change the general geochemistry (Figure 2-25).
- Carbon isotope values measured in the brine samples demonstrate that there was dissolution of the injected CO_2 into the brines within the reef. The injected CO_2 displays a unique $\delta^{13}C$ signature (approximately 20‰), which becomes increasingly heavier due to partitioning when the injected CO_2 is dissolved in water to form carbonic acid, bicarbonate and/or carbonate ions (approximately 30‰). Brine samples collected before CO_2 injection displayed $\delta^{13}C$ values ranging from approximately -7‰ to 10‰, but samples of the brine that collected after CO_2 injection displayed $\delta^{13}C$ values between approximately -20‰ 19 and 32‰ (Figure 2-26).
- The general chemical analyses and modeling indicate that the reef brines are supersaturated with respect to carbonate minerals (dolomite, calcite, huntite, and magnesite), and the likelihood of precipitation increases with the injection of CO_2.
- The gas analyses were primarily used to show the presence or absence of CO_2 at a sampled well (i.e. plume tracking). The concentration of CO_2 in the gas samples from the reefs significantly increased by the injection of the CO_2 (as expected). These results were used to qualitatively demonstrate the “amount” of CO_2 near the sampled wells over time.

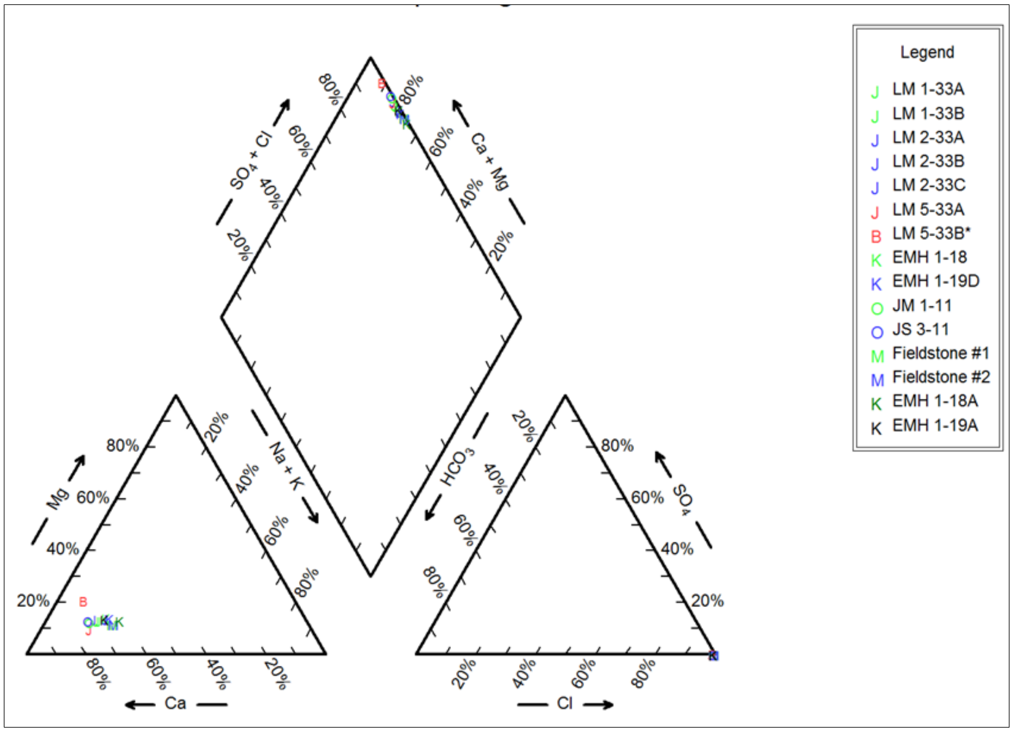


Figure 2-25. Piper diagram of the major cation/anion concentrations in the brine samples collected from the three reefs. There is no significant difference between samples collected before/after CO_2 injection.

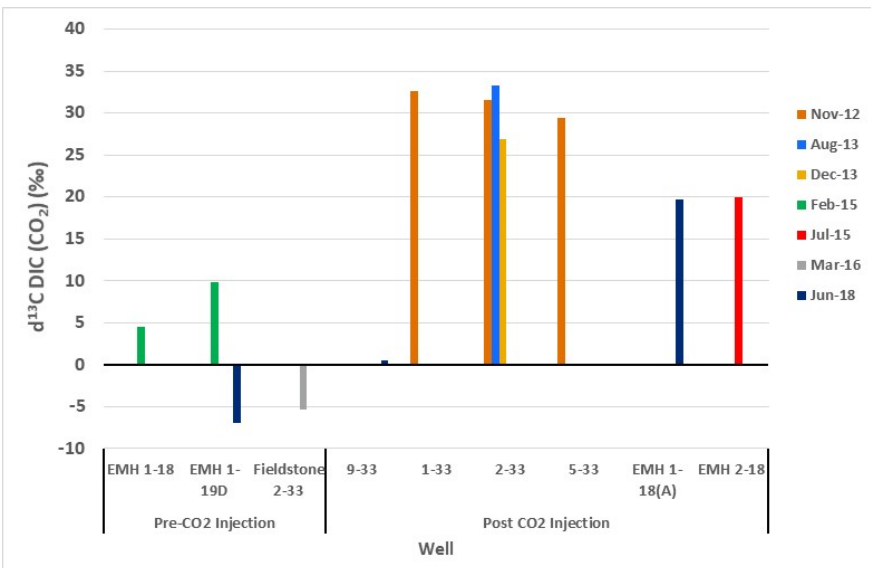


Figure 2-26. $\delta^{13}C$ of DIC in brine samples collected from the Dover 33, Charlton 19, and Bagley Field reefs, with wells without CO_2 interaction on the left and wells with CO_2 interaction on the right. Wells that have been exposed to significant injected CO_2 show relatively heavy $\delta^{13}C$ of DIC (between 19 and 32‰). The samples collected prior to the injection of CO_2 represent brines [EMH 1-19D, EMH 1-18 (baseline), and Fieldstone 2-33] exhibit lighter values (near 0‰) for $\delta^{13}C$ of DIC. One exception is the sample from L-M 9-33 well in the Dover 33 reef after significant CO_2 injection into the reef had $\delta^{13}C$ of DIC near 0‰ (i.e., similar to samples not exposed to CO_2); which could indicate that the CO_2 had not reached the area in the reef where the L-M 9-33 well is located. For reference, the injected CO_2 gas/supercritical fluid displays $\delta^{13}C$ values of approximately 20.5‰.

- While the geochemical equilibrium models suggest the precipitation of carbonate minerals and core sampled displayed evidence of carbonate, sulfate, and halide precipitation in the pores, vugs and fractures during the LS, SEM, XRD, and XCT analyses (secondary mineralization), it was not possible to correlate the timing of precipitation with the injection of the CO_2 in the core samples through the isotopic analyses (Figure 2-27 through Figure 2-30).

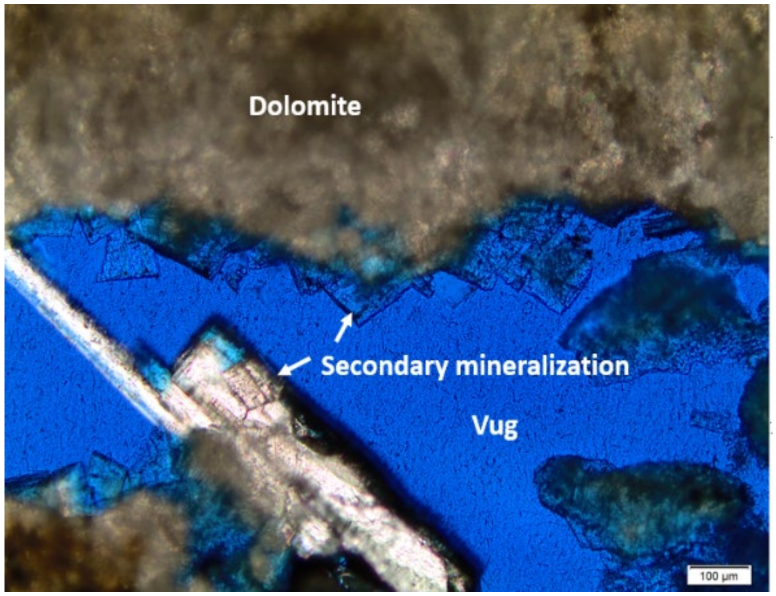


Figure 2-27. Digital light micrograph of thin section prepared from sidewall core trim sample 5,655 ft, in the oil-water transition zone. Blue dye epoxy highlights a vug with secondary mineralization lining the pore space, sample 5,655 ft. Large rectangular white crystal (arrowed, lower left) is anhydrite. Transparent rhombohedral crystals (carbonates) also line the vug (arrowed, center).

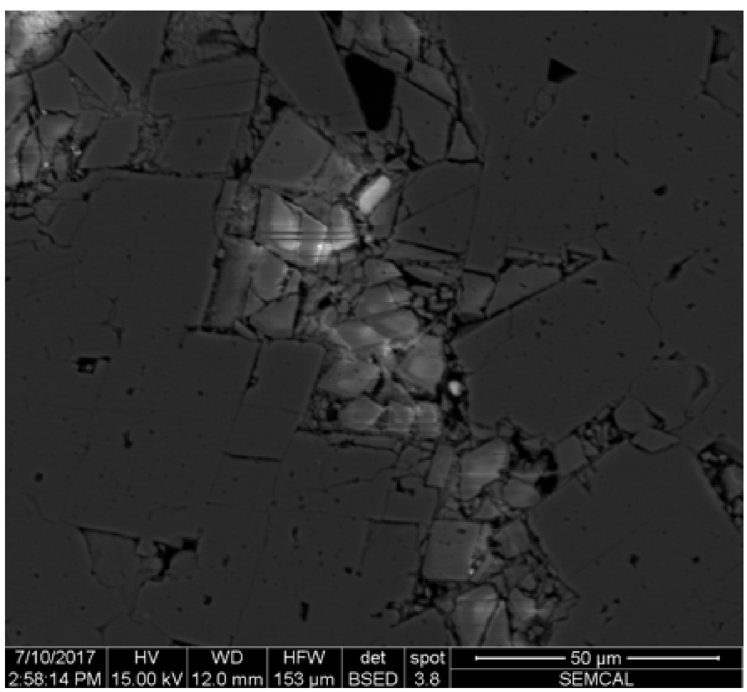


Figure 2-28. SEM BSE image of high-Mg carbonate mineral precipitate in a pore in the CO_2-EOR interval (from 5,655 ft).

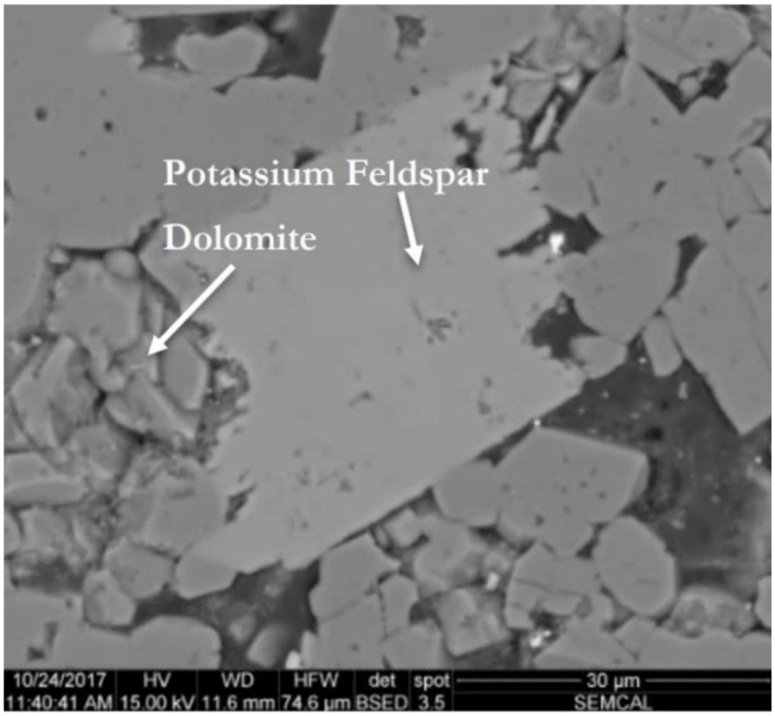


Figure 2-29. Backscattered SEM image of potassium feldspar adjacent to a vuggy pore containing dolomite. The potassium feldspar grain cleaves in a different geometry than the dolomite and displays a brighter BSE signal intensity. Some potassium feldspar grains contained euhedral dolomite inclusions.

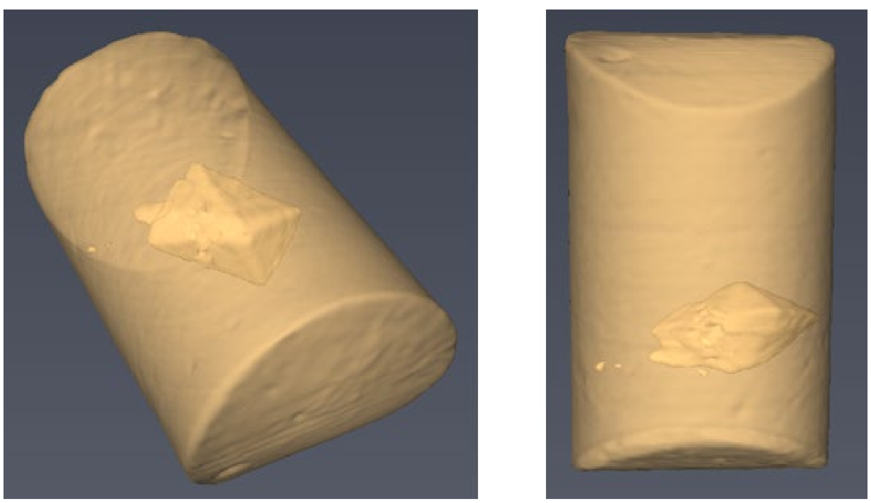


Figure 2-30. XCT scans of the core (5690.25'), a 3D image of the core and its inclusion was constructed for two different orientations. Aviso software was used to render a 3D image from XCT scans of sample 5690.25', including the partly infilled vug. XRD and SEM analyses of both matrix and vug inclusion material show that the core matrix is dolomite, whereas the material hand-picked from the vug consists of mostly dolomite and anhydrite, with minor halite, sylvite, and calcium chloride salt. The presence of these minerals within the vug and the interconnected fractures provide some evidence for fluid migration through the matrix and secondary precipitation of minerals elsewhere in the rock. The occurrence of the salts is likely attributed to post-sampling precipitation from desiccation of the sample.

- Table 2-13 summarizes key results of the geochemistry monitoring study, pros/cons of the technology, and an overall recommendation for using the technology to monitor CO_2 storage in Silurian pinnacle reefs of Northern Michigan.

Table 2-13. Geochemistry Monitoring Summary and Recommendations

Geochemistry Monitoring Summary and Recommendations	
Key Results of this study	• Overall, the geochemistry study was successful in demonstrating that the injected CO_2 mixed and/or reacted with the existing brine and reservoir matrix (solid). Evidence for mixing was provided by isotope data ($\delta^{13}C$ of DIC) because the injected CO_2 (derived from the Antrim Shale) has a unique isotopic signature which acts as a tracer in the brine. Evidence that the injected CO_2 reacted with the matrix was provided by analysis of the sold phase via light microscope, SEM, XRD, and SCT. Precipitates of several minerals were observed in pores that likely came from the reaction of the injected CO_2 with pore fluids and matrix. • The geochemical study was useful in predicting changes in the geochemical conditions of the carbonate reservoirs resulting from the injection of CO_2. Although the brine, gas, and core samples collected during the CO_2-EOR activities provide snapshot of the geochemical conditions over a relatively short period of time, the modeling of the data can be performed to predict changes over longer periods of time (i.e., well after CO_2 injection has stopped). • The general geochemistry parameters (major cations and anions) were not significantly affected by CO_2 injection; thus, these parameters were not useful for CO_2 plume tracking. • The gas-phase analyses were useful for identifying locations (i.e., wells) reached by injected CO_2 based on an observed increase in CO_2 in the gas samples. • The presence of CO_2 in the Dover 33 reef prior to the start of the MRCSP program made it difficult to discern behavior (transport, mixing, reaction) of newly injected CO_2 in this reef.
Pros	• Geochemistry monitoring is useful for CO_2 plume tracking and also characterizing fate/behavior (reactions, mixing) of CO_2 in the subsurface • The cost of this technology is low (assuming wells are available for sampling), with the main cost coming from sample collection, sample analysis, and data interpretation. • Data acquisition (analytical services) may require specialized services/skills but most of these are available through commercial laboratories.
Cons/ Challenges	• The collection of representative samples from CCS/CCUS sites for the analysis of geochemical parameter is complicated and can require significant field efforts (if samples are swabbed or the wells are under high pressures). Also, during the sampling process off-gassing of the CO_2 from the brine samples can result is field-related geochemical changes prior to analysis. • A large number of samples may be needed to perform statistical analysis on the analytical data and to be able to monitor changes over time. • Highly specialized laboratory analytical services required to characterize changes in solid (rock)-phase (e.g., SEM, XRD, XCT) may not be readily available from commercial laboratories and may require university involvement. • Data interpretation may require specialized skills (e.g., geochemical modeling).
Overall recommendation	• Geochemistry monitoring should be included in monitoring programs for CO_2 storage sites. It is a relatively low-cost technique (assuming wells are available) that can provide valuable insights into transport and behavior of CO_2 in a reservoir. • Geochemical monitoring is applicable to CO_2 sequestration in saline aquifers and the efforts likely would be simplified compared to studying the effects in a carbonate reservoir due to the reduction of chemical reactions with a quartz-based matrix.

Geochemistry Monitoring Summary and Recommendations	
	• The unique isotopic signature of the carbon in the injected CO_2 provided an opportunity to measure changes caused by the CO_2 injection. A unique isotopic signature is not likely to be encountered at many CCUS locations.

2.3.3.8 Vertical Seismic Profile Geophysical Monitoring

- A VSP study was conducted to test the effectiveness of time-lapse VSP for detecting and delineating a plume of more than 271,000 tonnes of CO_2 injected into the Brown Niagaran and A-1 Carbonate formations within the Dover 33 reef between March 2013 and September 2016. Five 2D walkaway VSP (WVSP) source lines were acquired by SIGMACUBED in September 2016 to investigate the possible time-lapse response in both P-wave and PS-wave seismic data. The data was compared to the same survey geometry acquired in March 2013 by SEISMIC RESERVOIR 2020 (SR2020) (Figure 2-31).
- P-wave and PS-wave reflection images were produced for each of the five source lines from both the 2013 baseline and 2016 monitor surveys. The images were then compared to look for changes in the reflectivity at and around the injection location that might indicate how the CO_2 has moved over this time period. It is difficult to identify any trends in the difference volume when displayed with standard interpretation color scaling (Figure 2-32). Figure 2-33 displays the P-wave amplitude difference plots only, this time with a color scale that emphasizes extreme values. Dashed ovals highlight large amplitude differences, such as those visible on the eastern flank of the reef and western half of the reef on the east-west trending line, or the core of the reef on the northeast-southwest trending line. Large amplitude differences are not, however, vertically or horizontally constrained by stratigraphic reservoir units, as would be expected if the image were capturing the signal of stored CO_2. Differences occur below the Cabot Head basal seal and within the B Salt. As it is geologically unreasonable to assume fluid flow through these units and/or CO_2 capture and storage in units with little or no pore space, this brings into question the validity of amplitude differences as CO_2 indicators within the reservoir. This technique revealed several localized areas with sizable impedance differences inside the reef where CO_2 would be expected; however, a large number of similar impedance "hotspots" were also detected outside the reef in areas where injected CO_2 would not be expected.
- A second analysis that involved calculating P-wave and S-wave travel time differences between the 2013 and 2016 VSPs was conducted to look for a change in travel time(s) that could have been caused by the CO_2 plume. Seismic wave modes measured in this study include 1) direct arrival P-waves from source to downhole receiver, 2) reflected PP-waves above and below the reservoir, and 3) reflected PS-(mode-converted) waves above and below the reservoir. However, the travel-time analysis indicated that the travel times in 2016 were not significantly different than the travel times in 2013 (differing only by a few milliseconds). Also, the difference in travel times was due in part to a small difference in the setting depth of the geophones between the 2013 and 2016 surveys. Figure 2-34 shows p-wave direct arrival time differences. Figure 2-35 shows reflected pp-wave travel time differences.

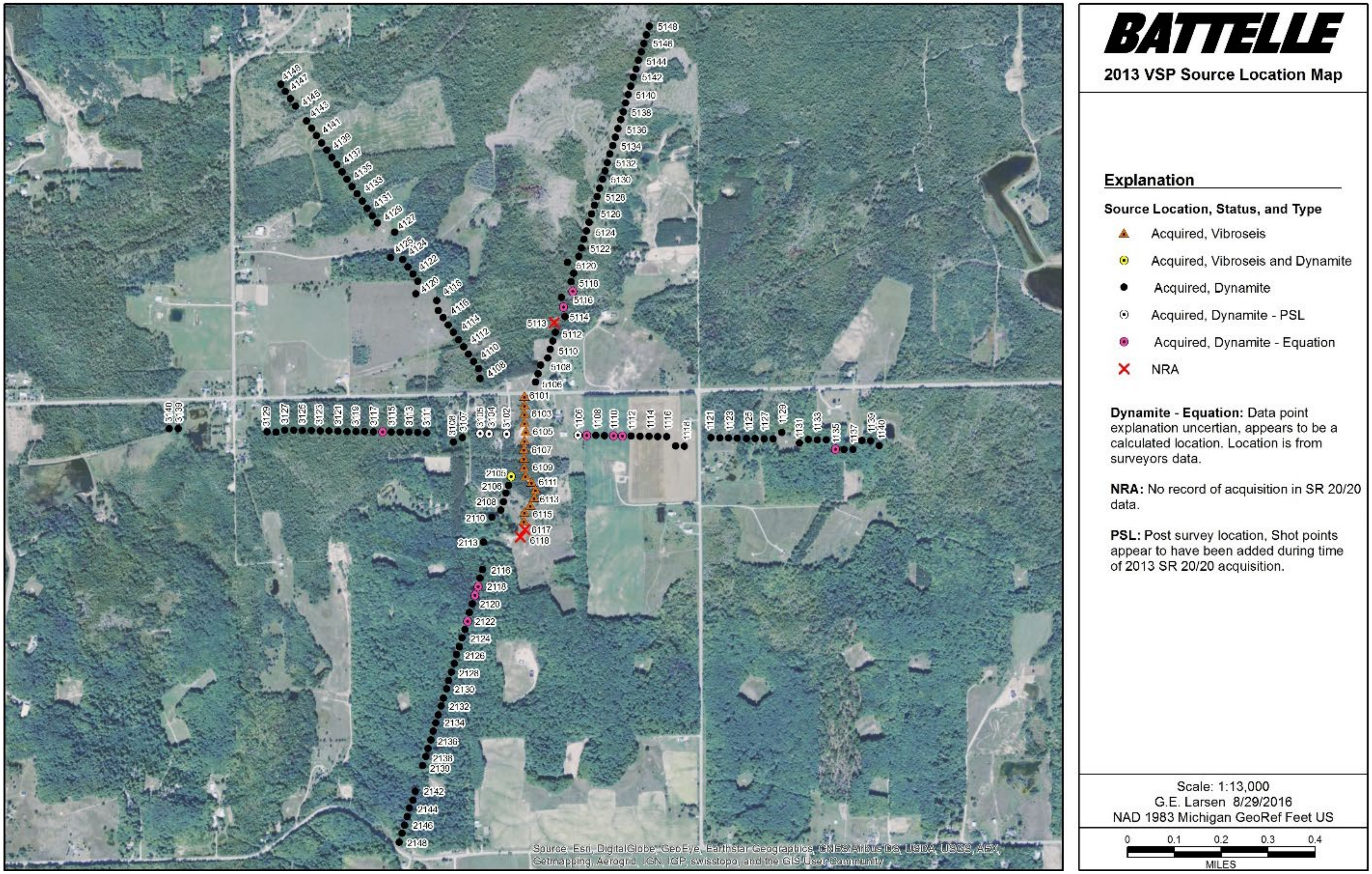


Figure 2-31. Source location map for 2013 baseline and 2016 repeat VSP surveys.

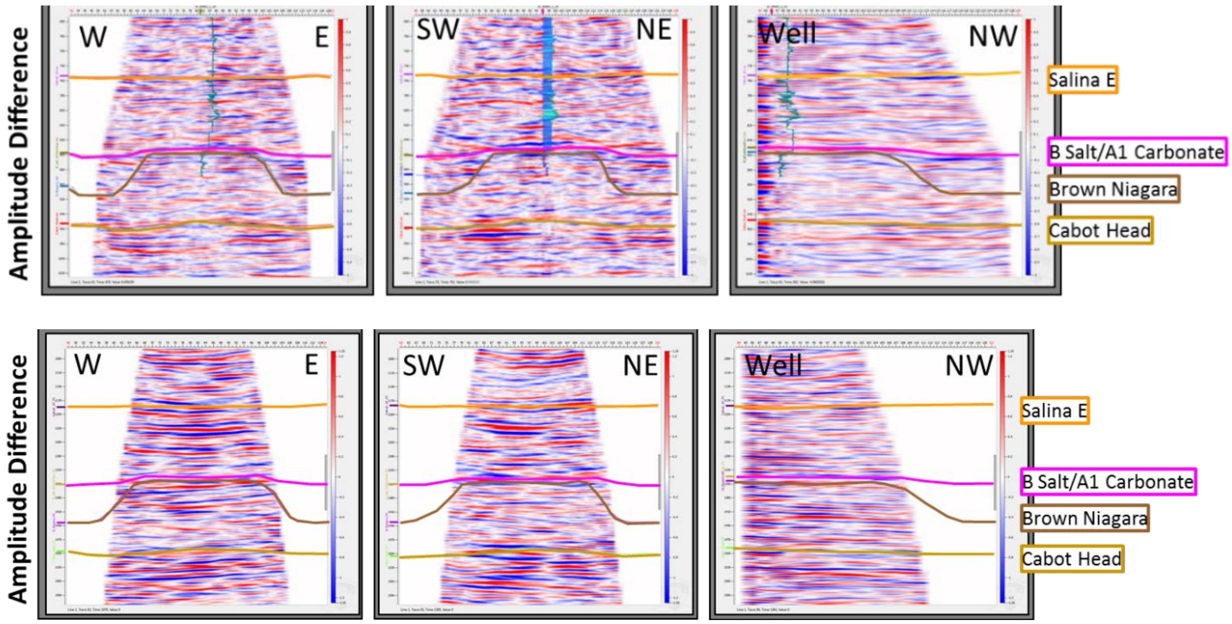


Figure 2-32. Images showing difference in PP-wave (top) and PS-wave (bottom) reflectivity-amplitude between the 2013 baseline survey and the 2016 repeat survey along three walkaway VSP transects.

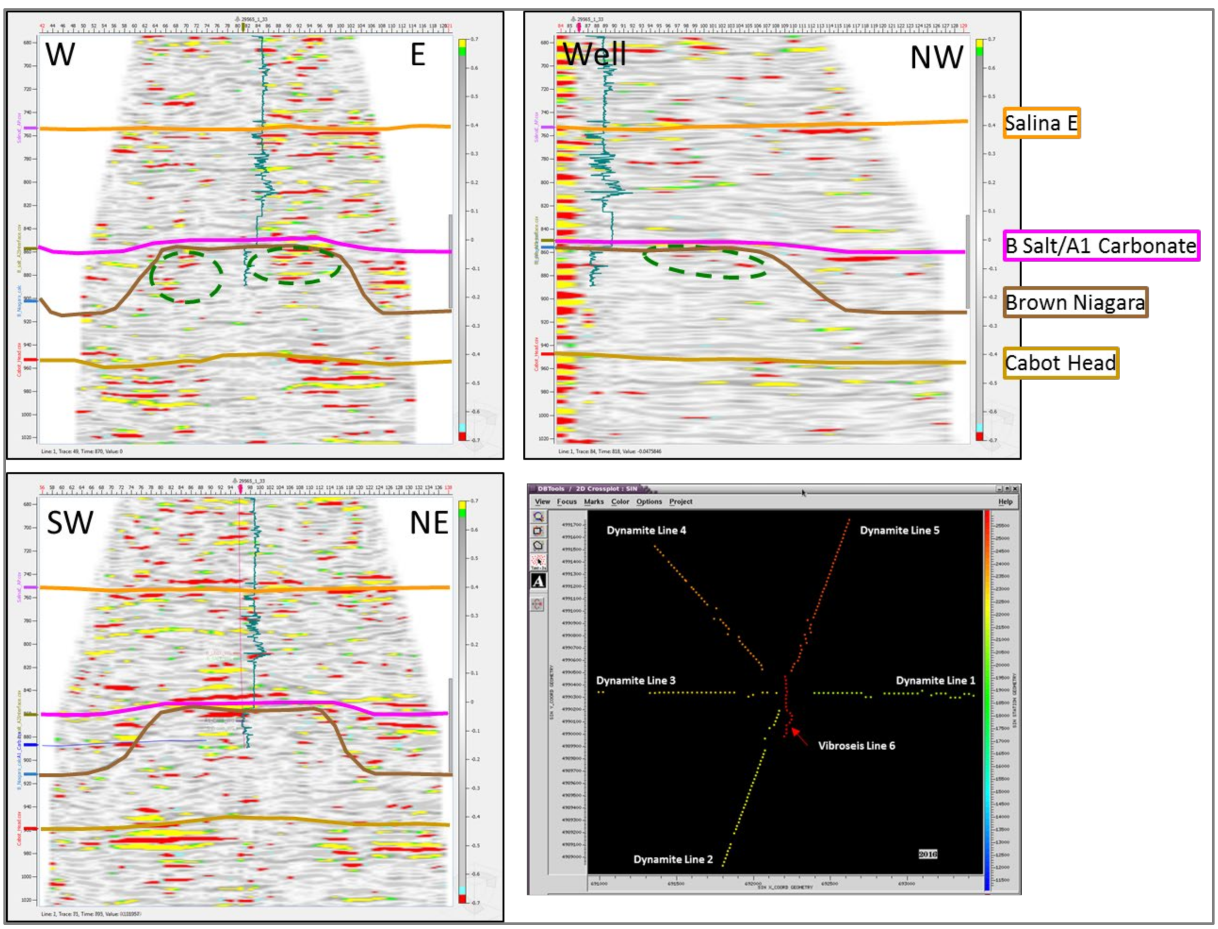


Figure 2-33. P-wave amplitude difference plots between the 2013 and 2016 VSP surveys (same data shown in Figure 2-32) with a color scale that emphasizes extreme values.

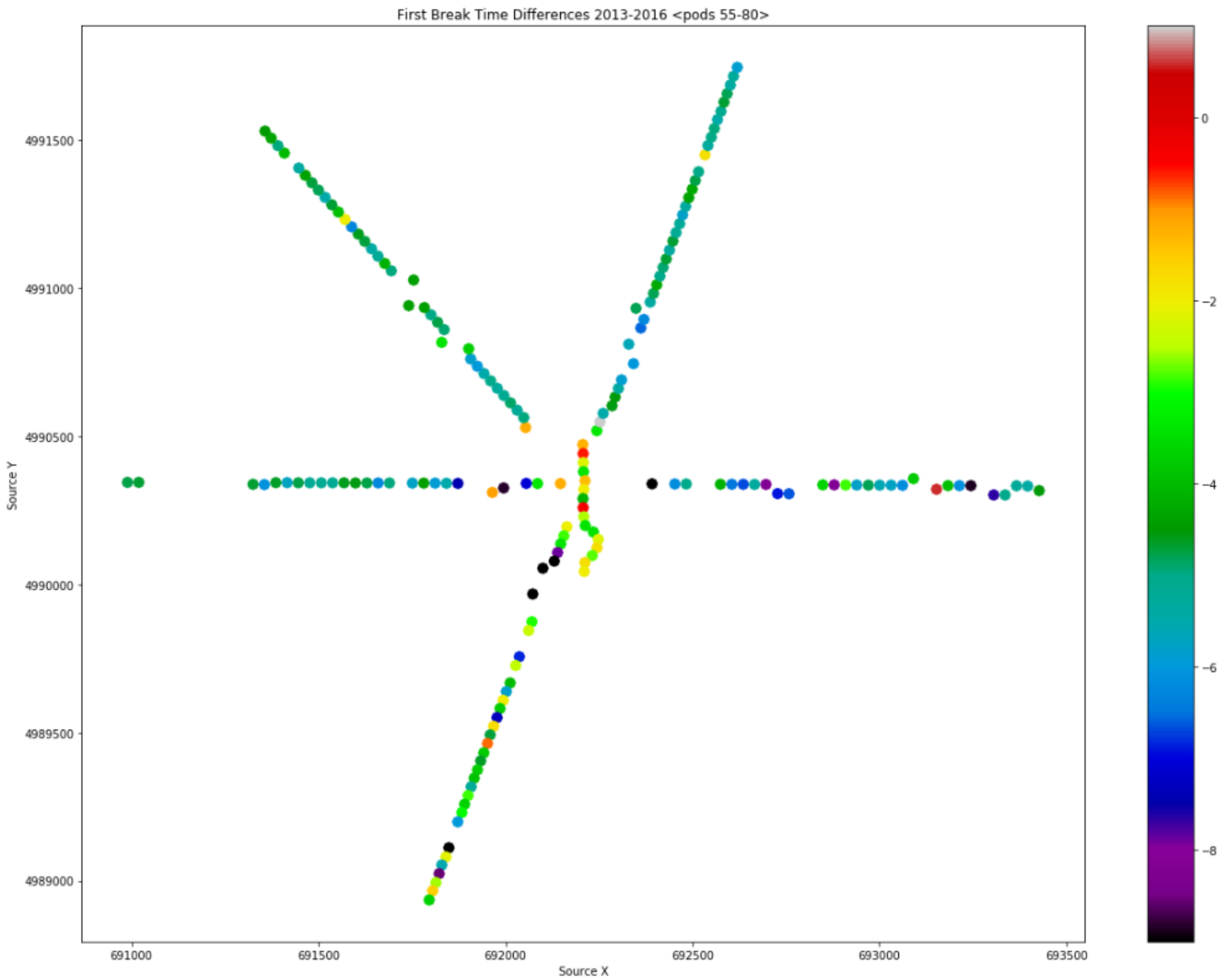


Figure 2-34. P- wave Direct arrival travel time difference between 2013 and 206 VSP surveys along each line of receivers showing no obvious spatial variation.

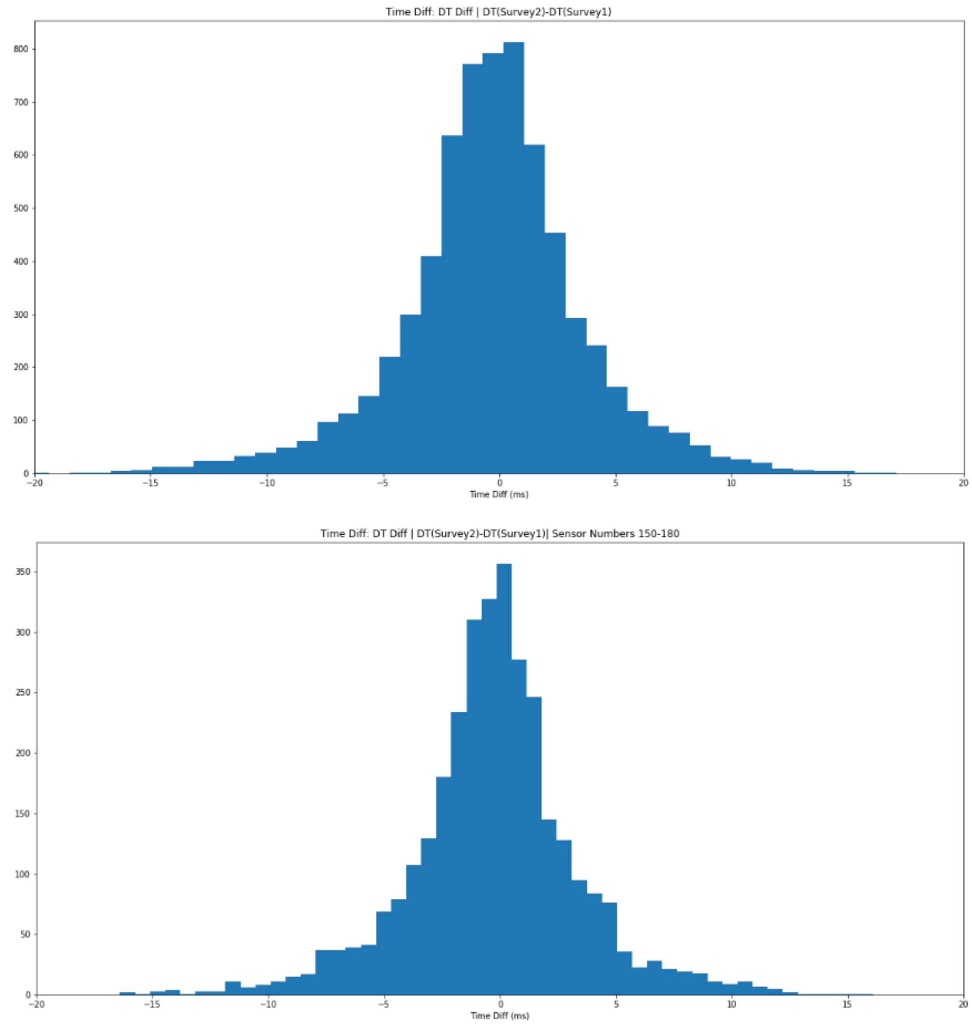
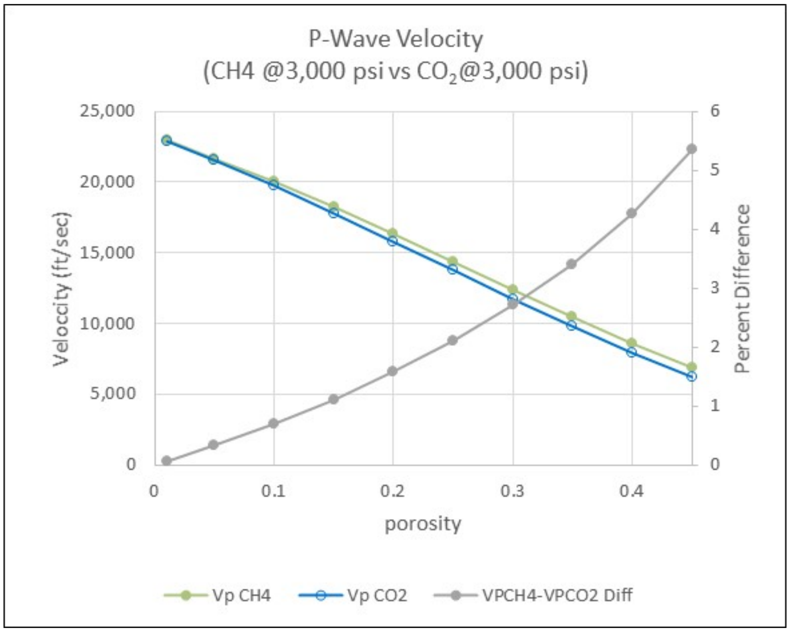


Figure 2-35. Histogram of the reflected PP-wave travel time differences between the top and base reflectors between 2016 and 2013 for all geophones (top) and deepest sensors emphasizing near-well region (bottom). Horizontal scale is the same on the two plots. There is no significant difference between near-wellbore region and entire image area.

- Three ancillary analyses were then undertaken to attempt to explain why the time-lapse VSP was not able to detect and delineate the 271,000-tonne CO_2 plume. These included 1) an analysis of signal-to-noise ratio (SNR); 2) a fluid substitution modeling analysis; and 3) a series of laboratory experiments that evaluated the effects of fluid substitution and pressure changes on acoustic velocities.
- The SNR analysis revealed that the 2013 VSP had a lower SNR compared to the 2016 survey. This indicates that the quality of the 2013 VSP survey was lower than the 2016 data. While attempts were made to equalize the frequency content of both surveys and filter out noise due to differing weather and shot conditions, the difference in SNR was large enough to adversely affect the amplitude difference images and picked travel times. In other words, the reliability of the 2013 VSP data was somewhat compromised which limited the usefulness of the data for making detailed comparisons to the 2016 data.
- Using fluid substitution modeling, the effect of CO_2 injection into the Dover 33 reef (modeled as 100% methane saturation at 805 psi changing to 100% CO_2 saturation at 3,3540 psi) on compressional-wave velocity was a decrease of less than 1% between the two VSP surveys (for a rock with 10%

porosity) (Figure 2-36).The estimated change in shear-wave velocity over the same period is also a decrease of similar magnitude (Figure 2-36). These results indicate that the effect of CO_2 injection into the Dover 33 reef on acoustic velocities will be very small. The predicted small changes may be below the level of detectability of seismic technologies.



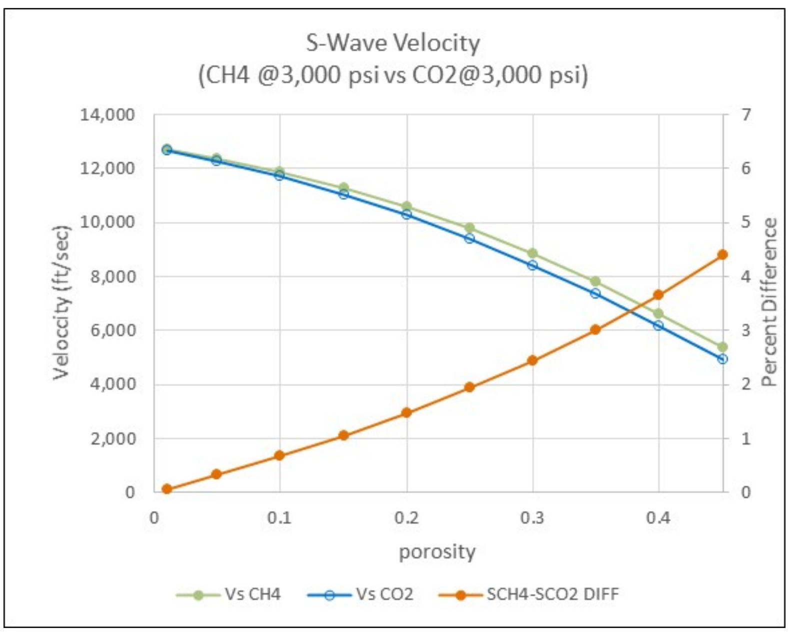


Figure 2-36. Modeled fluid substitution effects on Vp (top) and Vs (bottom) going from CH_4-saturated to CO_2-saturated.

- Three separate laboratory experiments were performed on core samples from a new well (9-33) in the Dover 33 reef to further assess acoustic velocity sensitivity to air-water saturation (air was used as a proxy for CO_2), effective pressure (stress), and brine-CO_2 saturations. Experiment #1 (Figure 2-37) indicates that Vp will decrease and Vs will increase as air (proxy for CO_2) replaces water assuming a constant value of effective pressure. The observed magnitude of change was -1.35% (Vp) and +1.3%

(Vs) (average of A-1 Carbonate and Brown Niagaran). Experiment #2 (stress sensitivity) (Figure 2-38) indicates that Vp and Vs will both decrease as effective pressure decreases (pore pressure increases). The observed magnitude of change was -2.6% (Vp) and -3.2% (Vs) (average of A-1 Carbonate and Brown Niagaran). Experiment #3 (sensitivity to CO_2 saturation) (Figure 2-39) indicates that Vp and Vs will both decrease as CO_2 saturation increases under a constant value of effective pressure (2,000 psi; 2,690 psi). The observed magnitude of change was -0.8% (Vp) and -3.3% (Vs) (both for the A-1 Carbonate). If stress sensitivity is included along with the fluid substitution effect, the results of experiments #1 and #3 would change as follows: the % decrease changes will get slightly larger and the % increase changes will get slightly smaller. Even after accounting for both fluid substitution and effective pressure changes, the predicted changes in Vp and Vs are still quite low (likely <5%) and may be below or near the level of detectability of the VSP technology. This is likely the key reason it wasn't possible to image the injected CO_2 plume.

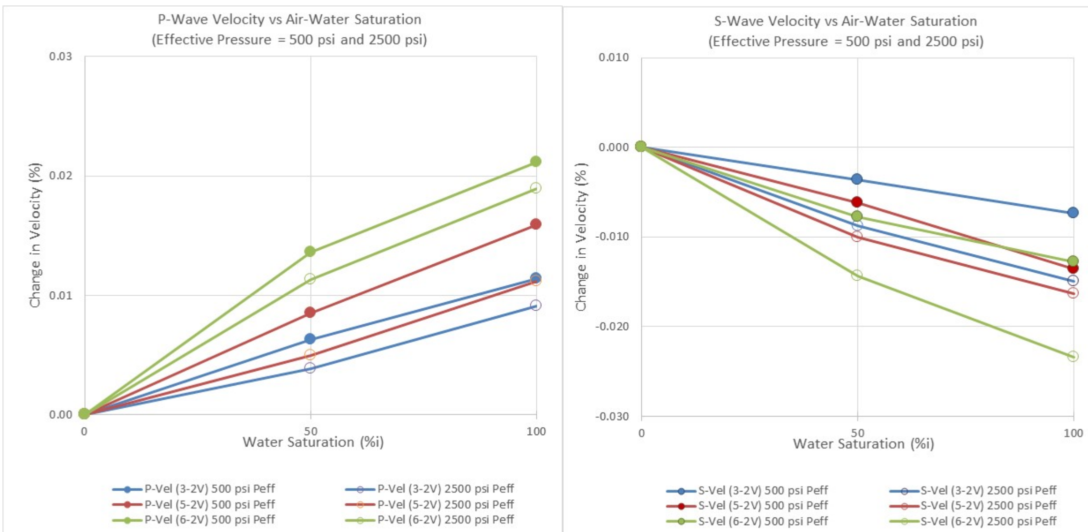


Figure 2-37. Percent change in Vp (left) and Vs (right) due to increase in water saturation (decrease in air saturation).

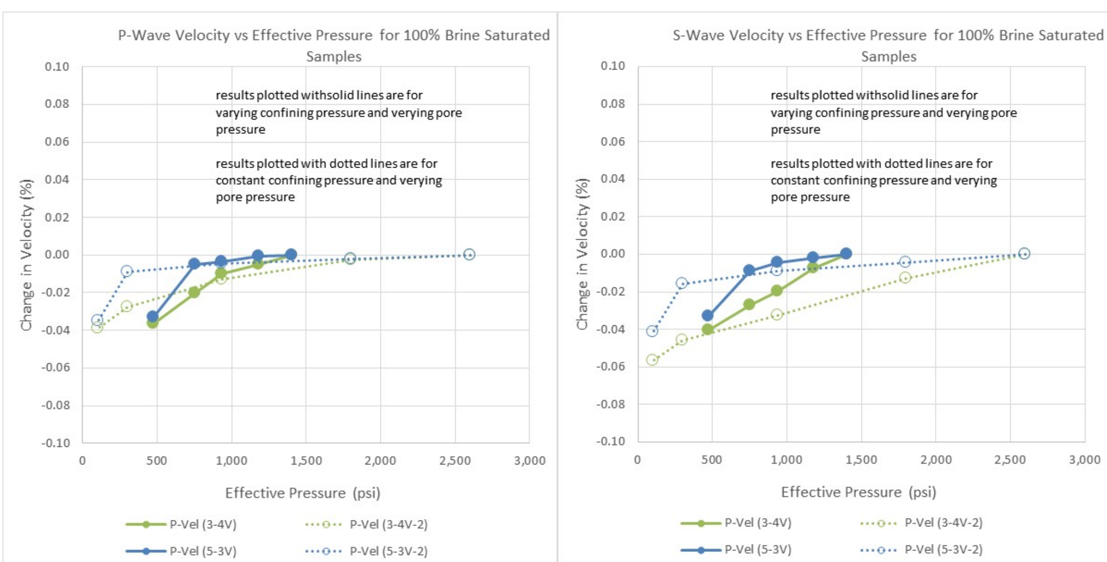


Figure 2-38. Percent change in Vp (left) and Vs (right) due to increase in effective pressure (stress) for the A-1 Carbonate (3-4V) and the Brown Niagaran (5-3V). Note: Pore pressure increases to the left.

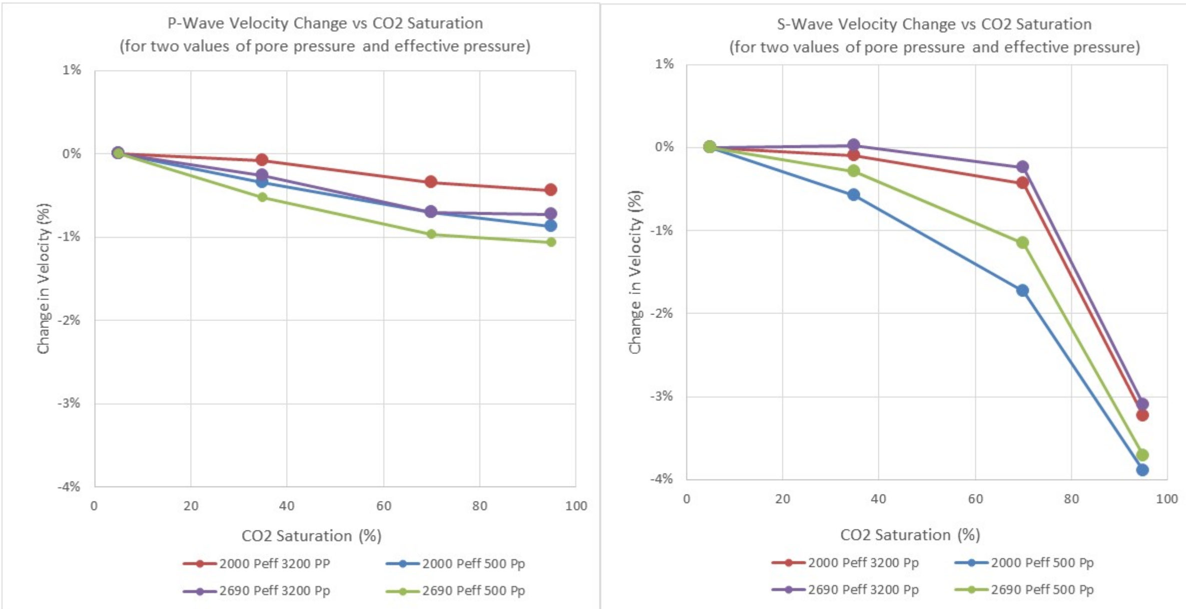


Figure 2-39. Percent change in Vp (left) and Vs (right) due to increase in CO_2 saturation.

- One other factor that made it difficult to discern the subsurface distribution of the injected CO_2 in the Dover 33 reef is the presence of CO_2 in the reservoir pore space at the time the baseline VSP survey was obtained (February 2013). The exact amount /concentration of residual CO_2 (left over from the initial CO_2-enhanced oil recovery efforts from 1996 to 2007 is not known, however, it is a fact that this would reduce the fluid substitution effect of CO_2 injection and make it more difficult to detect the CO_2 plume.
- Table 2-14 summarizes key results of the Dover 33 VSP monitoring study, pros/cons of the technology, and an overall recommendation for using the technology to monitor CO_2 storage in Silurian pinnacle reefs of Northern Michigan.

Table 2-14. Dover 33 VSP Monitoring Summary and Recommendations

	Dover 33 VSP Monitoring Summary and Recommendations
Key Results of this study	• The most common VSP analysis method for detecting CO_2 injected into deep geological formations (impedance-amplitude differencing) provided inconclusive results regarding the location of the injected CO_2 in the Dover 33 reef. Similarly, an analysis of travel-time differences (for both P-wave and S-waves) between the baseline and repeat surveys indicated that there is not a significant difference between the two surveys; thus, the travel-time method was not able to discern the CO_2 plume. • The lack of success with VSP is likely due to properties of the carbonate formations that comprise the reservoir and survey factors (low SNR of the 2013 baseline survey). Fluid substitution modeling shows that replacing pore fluids with CO_2 will cause very small changes in Vp and Vs, therefore corresponding changes in impedance will also be small. This was confirmed by laboratory experiments that measured the change in Vp and Vs due to CO_2 replacing pore fluids. The laboratory experiments also demonstrated that the change in stress that occurs as a reef is filled with CO_2 can cause a change in Vp and Vs that may mask the small change due to CO_2 replacing native pore fluids. • The presence of CO_2 in the reservoir prior to the start of CO_2 injection (as was the case for the Dover 33 reef) likely made detection of new CO_2 more difficult.

Dover 33 VSP Monitoring Summary and Recommendations	
Pros	• VSP has been widely shown to be effective for delineating horizontal and vertical extent of CO_2 in sandstone reservoirs with moderate to high porosity.
Cons/Challenges	• Low porosity, low compressibility carbonate rocks similar to those that comprise the Niagaran pinnacle reefs in northern Michigan are less conducive to VSP monitoring.
Overall recommendation	• VSP should be carefully evaluated prior to implementation by conducting a technical feasibility study that takes into account petrophysical properties of the reservoir (density, porosity, compressibility, velocity) and the current (pre-CO_2 injection) and anticipated future pressure/stress conditions on seismic velocities. Predicted velocity changes of 10% or greater are recommended in order to proceed with field implementation. The feasibility study should include fluid substitution modeling, augmented with laboratory experimentation if possible (e.g., velocity measurements on site-specific rock core for a range of fluid saturations and pressure/stress conditions).

2.3.3.9 Distributed Acoustic Sensing VSP

- Time-lapse DAS VSP was implemented at the Chester 16 reef to attempt to detect approximately 85,000 tonnes of CO_2 injected into the A-1 Carbonate and Brown Niagaran Formations. A baseline survey was conducted in February 2017 prior to injecting CO_2 and a repeat survey was conducted in August 2018. During the interim period between the baseline and repeat surveys, CO_2 was injected into the Chester 16 reef via the 6-16 injection well without production (withdrawal) of fluids from the reef.
- Pre-acquisition ray tracing was done to determine a set of source positions that would acceptably illuminate the reservoir zone in the target region. A grid of 181 source positions consisting of 44 vibrator positions, plus 137 dynamite shot locations, was used to give approximately continuous spatial coverage of the injection zone (A-1 Carbonate and upper Brown Niagaran) in the area between the two wells (Figure 2-40).

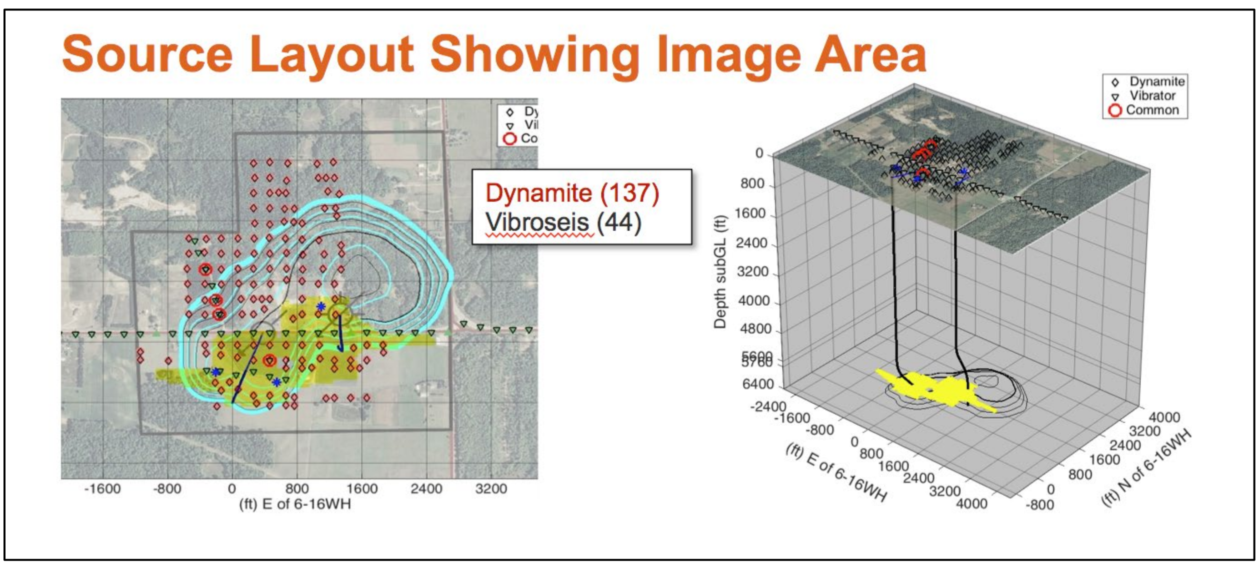


Figure 2-40. Plan view and perspective view showing the well trajectories, the reef topography interpreted from well logs and 3D surface seismic data, and the shotpoints that were chosen based on pre-job ray tracing.

- The processing approach implemented in this study focused on monitoring the change in the amplitude of the reflection coefficient (R) between the baseline and repeat surveys due to the introduction of CO_2. R, a property of the interface between two intervals, is affected by the acoustic impedance (AI) of the two intervals, where AI is the product of the bulk density and acoustic velocity of the rock-fluid system. Introduction of CO_2 into a layer can cause changes in density and velocity, resulting in a change in AI within the layer or interval receiving the CO_2. This can result in a change in the RC at the interface between the CO_2-containing layer and the overlying or underlying area that has not received CO_2. If the magnitude of the AI change is sufficiently large, the effect may be visually observed by comparing an image of the VSP monitor survey obtained after CO_2 injection to an image of a baseline VSP image obtained before CO_2 injection. Reflection coefficient is defined as follows:

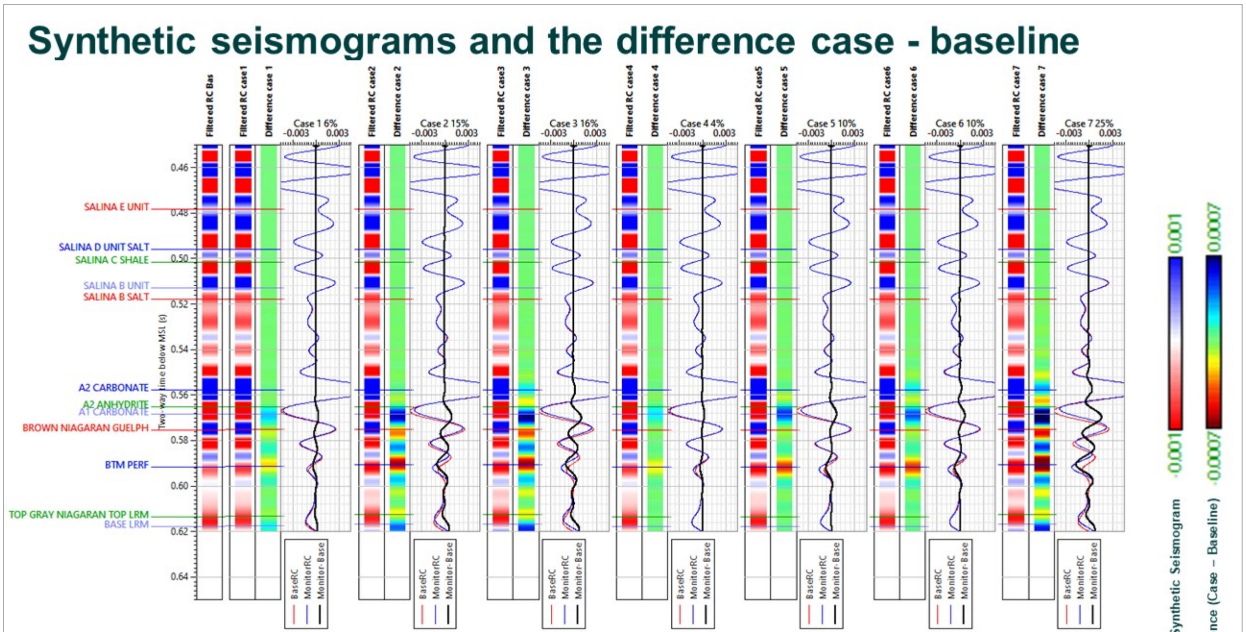
$$R = \frac{AI_1 - AI_2}{AI_1 + AI_2} = \frac{\rho_1 v_1 - \rho_2 v_2}{\rho_1 v_1 + \rho_2 v_2}$$

Equation 2-1

- The magnitude of change in DAS results (Reflection Coefficient) between the baseline and repeat surveys was predicted for seven different scenarios using a one-dimensional model where each scenario is defined as a different percent change in V and ρ for the A-1 Carbonate, Brown Niagaran, and A-2 Carbonate. Each of the seven scenarios included two cases, a and b. The “a” cases involved an increase in Vp and/or density between the baseline and repeat VSP. The “b” cases involved a decrease in Vp and/or an increase in density between the baseline and repeat VSP. The model scenarios are described in Table 2-15 and in Figure 2-41 (a cases) and Figure 2-42 (b cases). Values for ∆V used in the modeling were based on fluid substitution modeling and laboratory testing conducted for the Dover 33 reef VSP study *Dover 33 Time-Lapse Vertical Seismic Profiling [VSP] Study* (Kelley et al., 2020). An understanding of where (what layers) are most/least affected by the injection of CO_2 can be gleaned from the output of the 1D modeling shown in Figure 2-41 and Figure 2-42. These figures both use synthetic seismograms (colored profile) to show the modeled base case R profile (Track 1) plus for each of the seven model scenarios, the figures provide the modeled R profile and a difference R profile between the modeled R profile for that scenario and the modeled base case R profile. Blue and red shading (on the difference seismograms) correspond to the intervals with the largest positive and negative change in R, respectively, which varies from +0.007 to -0.007, respectively. Green indicates little/no change. The largest changes in R occur in the scenarios with a change in both velocity and density (e.g., compare Scenario 7 (change in velocity and density) to scenarios 3 (change in velocity only) and 6 (change in density only). The same information is displayed as a set of 3 curves for each scenario, where one curve represents the calculated base case R profile, a second curve represents the modeled R profile for the scenario, and a 3rd curve shows the difference.

Table 2-15. DAS VSP Model Scenarios

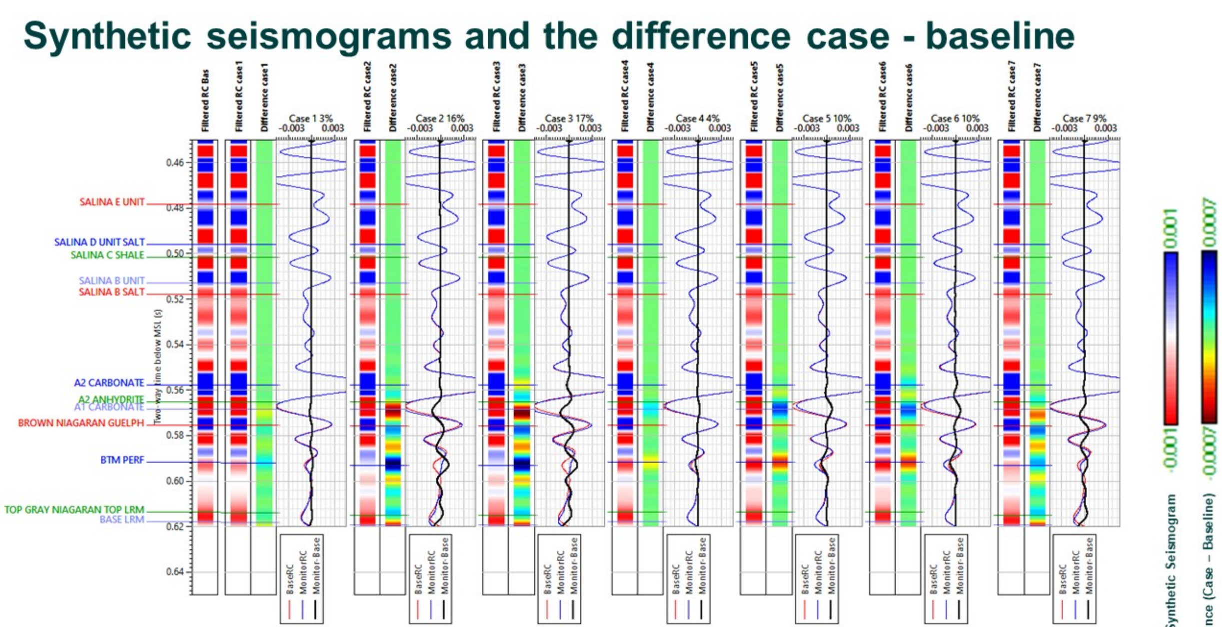
Title	Description[a]
Case 0	Baseline
Case 1a	+2% velocity change in A-1C and BN
1b	-1% velocity change in A-1C and BN
Case 2	+5% velocity change in A-1C and BN
2b	-6% velocity change in A-1C and BN
Case 3a	+5% velocity change in A-1C and BN and +1% velocity increase in A-2C
3b	-6% velocity change in A-1C and BN and -1% velocity change in A-2C
Case 4a	+2% density change in A-1C and BN
4b	+2% density change in A-1C and BN
Case 5a	+5% density change in A-1C and BN
5b	Same as 5a
Case 6a	+5% density change in A-1C and BN and +1% density change in A-2C
6b	Same as 5b
Case 7a	+5% velocity and density change in the A-1C and BN and a +1% change in velocity and density in A-2C
7b	-6% velocity change in the A-1C and BN and -1% velocity change in A-2C; +5% change in density in A-1C and BN and 1% change in density in A-2C



Name	Case 1a		Case 2a		Case 3a		Case 4a		Case 5a		Case 6a		Case 7a	
	Velocity	Density	Velocity	Density	Velocity	Density	Velocity	Density	Velocity	Density	Velocity	Density	Velocity	Density
	%	%	%	%	%	%	%	%	%	%	%	%	%	%
SALINA B UNIT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SALINA B SALT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
A2 CARBONATE	0	0	0	0	1	0	0	0	0	0	0	1	1	1
A2 ANHYDRITE	0	0	0	0	0	0	0	0	0	0	0	0	0	0
A1 CARBONATE	2	0	5	0	5	0	0	2	0	5	0	5	5	5
BROWN NIAGARAN/GUELPH	2	0	5	0	5	0	0	2	0	5	0	5	5	5
BTM PERF	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Fig. 13-1

Figure 2-41. Predicted change in R (shown in the upper part of the figure) for different changes in Vp and density (in these scenarios, all changes in Vp were positive).



Name	Case 1b		Case 2b		Case 3b		Case 4b		Case 5b		Case 6b		Case 7b	
	Velocity	Density	Velocity	Density	Velocity	Density	Velocity	Density	Velocity	Density	Velocity	Density	Velocity	Density
	%	%	%	%	%	%	%	%	%	%	%	%	%	%
SALINA B UNIT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SALINA B SALT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
A2 CARBONATE	0	0	0	0	-1	0	0	0	0	0	0	1	-1	1
A2 ANHYDRITE	0	0	0	0	0	0	0	0	0	0	0	0	0	0
A1 CARBONATE	-1	0	-6	0	-6	0	0	2	0	5	0	5	-6	5
BROWN NIAGARAN/GUELPH	-1	0	-6	0	-6	0	0	2	0	5	0	5	-6	5
BTM PERF	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Fig. 13-2

Figure 2-42. Predicted change in R (shown in the upper part of the figure) for different changes in Vp and density. In these scenarios, all changes in Vp were negative. Yellow shading indicates where input velocity is different.

- One method for displaying preliminary results of the DAS VSP surveys is to make figures showing pe-migration VSP single source point time-lapse results. Figure 2-43 shows such results. The figure shows a seismogram (tracks 1 and 3) and a corridor stack (tracks 2 and 4) for the baseline and repeat monitoring events for a single source location (101216) recorded at the 6-16 well. A corridor stack showing the difference between the baseline and repeat events for this location is shown in track 5 (labeled stack difference). For reference, the stack difference for a single scenario (in this case scenario 3b) is shown on the figure in track 6. The synthetic stack difference suggests the change in R should be confined to the reservoir-injection interval (the depth interval between ~1350 m (blue horizontal line representing top of A-1 Carbonate) and ~1450 m (depth corresponding to the bottom of perforated interval in injection well). In comparison, however, the actual stack difference shown in track 5 suggests there was a change not only in the reservoir but also in the layers above/below the reservoir. Therefore, these results are not unequivocal. It should be noted that Figure 2-43 is preliminary because it is based on pre-migration results for a single source point and therefore does not take advantage of all the source points.

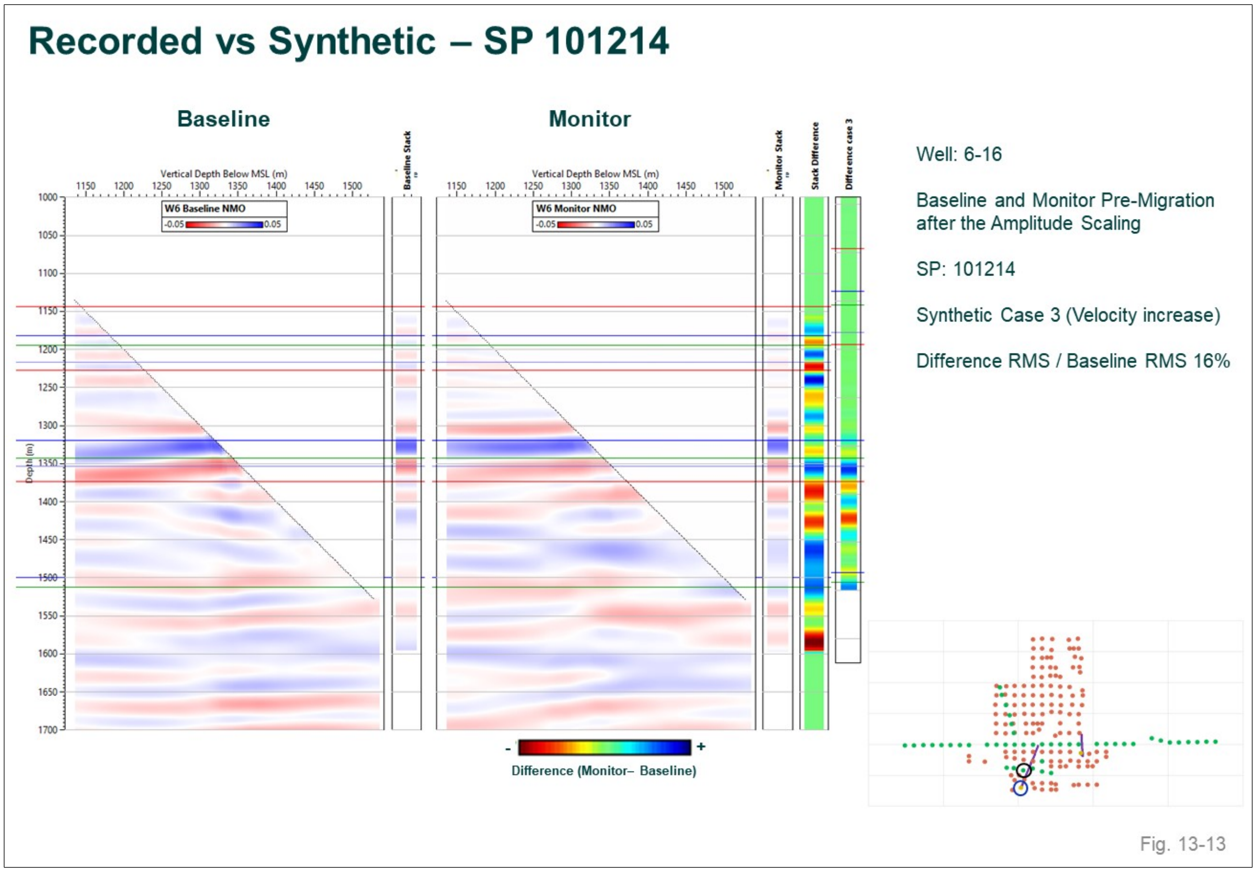


Figure 2-43. Difference between actual recorded repeat VSP minus baseline VSP for vibroseis source point SP 101214 recorded at well 6-16. Synthetic difference (model case 3a: 5 % velocity increase) is shown for reference. There is good agreement between the actual difference and the synthetic difference in the injection-reservoir interval but not outside this interval.

- Figure 2-44 shows a baseline and repeat vertical cross section image through each well, along with a (repeat survey minus baseline survey) “difference image” for each pair of time-lapse images. The images in Figure 2-44 represent post-migration results that combine data from multiple source locations. Ideally, the figures would have included data from all sources (i.e., vibroseis and dynamite) to provide the greatest spatial coverage of the reservoir. However, due to the low SNR of the dynamite data compared to the vibroseis data, the two source types were not combined and only vibroseis data were used in the migration process (i.e., to make the images). Consequently, the spatial coverage of the images is significantly smaller than the area that would have been imaged if dynamite data were included (but still larger than the area represented by the pre-migration (single source point) results. also, the well casings were not cemented completely to ground surface; consequently, only the cemented portion of the fiber optic DAS cable had sufficient acoustic coupling and provided useable data. This also reduced the image area compared to the originally planned image area. The images shown in Figure 2-44 cover an area close to the 6-16 injection well and the 8-16 monitor well. The imaged area near the injection well is particularly small. The difference image for the area near the 6-16 well shows difference features within the injection interval (A-1 Carbonate Crest and upper Brown Niagaran); however, difference features with similar magnitude also appear above and below the injection interval. Therefore, these results are encouraging but not unequivocal. The difference image for the 8-16 monitoring well does not show a pattern (clustering) of difference features associated with the injection interval.

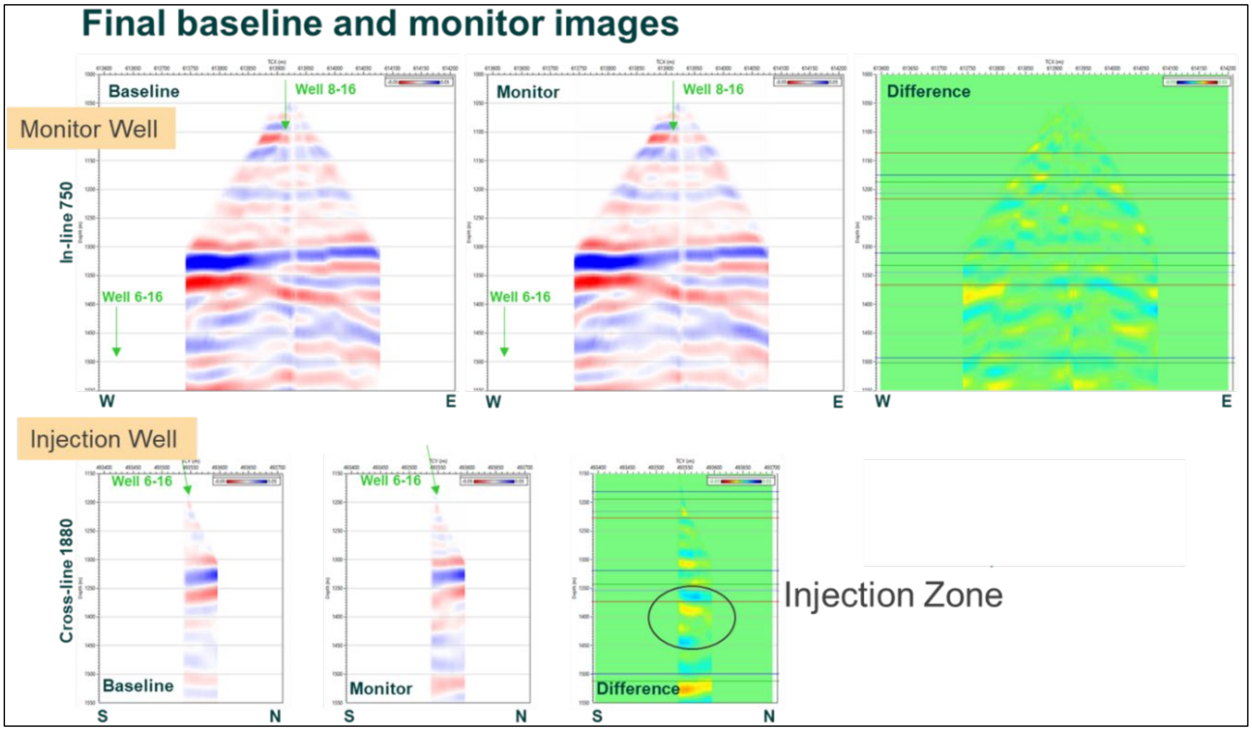


Figure 2-44. Final baseline and repeat migrated images from DAS data recorded at the 6-16 injection well and 8-16 monitoring well. These figures were made from vibroseis data only; dynamite data was excluded due to its low SNR). The difference image for the area near the 6-16 well shows difference features within the injection interval (A-1 Carbonate Crest and upper Brown Niagaran); however, difference features with similar magnitude also appear above and below the injection interval. Therefore, these results are encouraging but not unequivocal. The difference image for the 8-16 monitoring well does not show a pattern (clustering) of difference features associated with the injection interval.

- Table 2-16 summarizes key results of the Chester 16 DAS VSP monitoring study, pros/cons of the technology, and an overall recommendation for using the technology to monitor CO_2 storage in Silurian pinnacle reefs of Northern Michigan.

Table 2-16. DAS VSP Monitoring Summary and Recommendations

DAS VSP Monitoring Summary and Recommendations	
Key Results of this study	• The DAS VSP study was partially successful for detecting CO_2 injected into the Chester 16 pinnacle reef. The DAS data indicate a measurable change (decrease) in seismic Reflection coefficient in the A-1 Carbonate and Brown Niagaran Formation, the two injection intervals, and near the 6-16 injection well. However, difference features were also indicated in strata above and below the injection zone. Similarly, the DAS data also produced reflection difference features in the vicinity of the 8-16 monitoring well, both within the injection zone and outside the injection zone.
Pros	• DAS VSP has been shown to be effective for delineating horizontal and vertical extent of CO_2 in sandstone reservoirs with moderate to high porosity (similar to geophone-based VSP). • The method provides information at very closely-spaced interval along the fiber, which improves overall sensitivity. • DAS fiber-optic cable can be installed inside the well (e.g., on tubing) or outside the well casing. The external option is permanent but allows the well to be used for other purposes.
Cons/ Challenges	• In addition to the cons/challenges identified for VSP monitoring (e.g., low porosity, low compressibility carbonate rocks), DAS VSP is primarily sensitive to seismic energy that originates in the direction of the fiber. However, recent advances in fiber technology have been made that improves broadside sensitivity. • For DAS fiber-optic cables installed on the outside of casing, the cable should be encased in cement to achieve acoustic coupling with the formation. • The method generates a very large amount of data that must be processed/analyzed. This makes it difficult to conduct automated continuous monitoring.
Overall recommendation	• As with geophone-based VSP, DAS VSP should be carefully evaluated prior to implementation by conducting a technical feasibility study that takes into account special limitations of the DAS technology (e.g., directional sensitivity, casing cement, data volume) as well as effects of petrophysical properties of the reservoir (density, porosity, compressibility, velocity) the current (pre-CO_2 injection) and anticipated future pressure/stress conditions on seismic velocities. Predicted velocity changes of 10% or greater are recommended in order to proceed with field implementation. The feasibility study should include fluid substitution modeling, augmented with laboratory experimentation if possible (e.g., velocity measurements on site-specific rock core for a range of fluid saturations and pressure/stress conditions). • Ray-trace modeling is essential to design a source layout on surface that will illuminate the desired volume/area of the reservoir. • If both dynamite and vibroseis are to be used for sources, conduct testing with different loads and borehole depths as well as different vibroseis acquisition parameters to optimize SNR and ensure compatibility of both types of results.

2.3.3.10 Cross-Well Seismic Monitoring

- A cross-well seismic survey was acquired in the Chester 16 reef from September 9 to 14, 2018 to attempt to detect 85,000 tonnes of carbon dioxide (CO_2) that were injected into the A-1 Carbonate and Brown Niagaran Formations between February 2013 and September 2018. Conducting multiple cross-well seismic surveys over time (i.e., time-lapse cross-well seismic), which includes conducting a pre-CO_2 injection (baseline) survey, has been used elsewhere to monitor CO_2 injected into the subsurface. In this study, a baseline cross-well survey was not obtained; nevertheless, it was possible to generate an image that is a plausible, albeit not without anomalies, representation of the CO_2 plume. This conclusion is supported by other monitoring and modeling results from the Chester 16 reef that provide an independent indication about the likely position of the injected CO_2.
- The Chester 16 reef cross-well seismic survey was conducted between the 6-16 well, the CO_2 injection well for the Chester 16 reef, and the 8-16 well, an unperforated well located approximately 1,100 ft from the injection well that was used for monitoring. Over 19,000 (35 receiver geophones × 4 fans [positions] × 140 source locations per fan) traces were generated, which provided a dense seismic grid through the portion of the reef between the two wells. The study attempted to map the temporal change in acoustic velocity in the region between the two wells because fluid substitution involving replacement of pore fluids with CO_2 can alter the rock's velocity. This is referred to as cross-well seismic tomography because it produces images (velocity tomograms) of a vertical "slice" through the reef. Energy that propagates directly between wells without being scattered (i.e., direct arrivals) serves as the basis for constructing velocity images (tomograms). Reflection images (constructed from reflected energy rather than direct arrivals) were also produced to complement the tomograms. Reflection images illustrate reflectivity, which is a function of acoustic impedance (defined as velocity x density). Injected CO_2 can alter the reflectivity of the rock by altering both the velocity and density of the rock-fluid system. In this study, reflection images were not helpful in detecting the CO_2 plume because a baseline cross-well seismic survey was not conducted.
- The key results of the cross-well seismic survey are two figures illustrating the inferred CO_2 plume. Two figures are tomograms showing the interpreted CO_2 distribution based on the waveform tomography (i.e., full waveform inversion) results. Both figures are similar, except Figure 2-45 is based on a source frequency of 55 hertz (Hz), (i.e., using a wavelet with frequency of 55 Hz extracted from the actual cross-well seismic data) and the other is based on a source frequency of 75 Hz. The most obvious feature in both figures is a swirl pattern representing the area where a velocity change occurred due to injected CO_2. The swirl in each figure is made up of small discontinuous areas that are interpreted to be artifacts of the finite difference wavefield modeling, not real velocity changes. This same pattern is present in the third figure is based on the reverse time migration (RTM) imaging method, As is the case with the full waveform tomography method, the RTM algorithm also uses a finite difference process that propagates a wave. While the swirls appear to be anomalous, there is at least one zone that is plausibly due to the CO_2 plume. It is an area with a velocity decrease of 400 to 600 ms that occurs in the A-1 Carbonate just above the contact with the Brown Niagaran. The location of this large velocity difference (decrease) coincides with the interval where CO_2 was injected at the 6-16 injection well. Therefore, it is possible that this velocity feature represents CO_2. Also, this result is corroborated by other monitoring results (Distributed Temperature Sensing [DTS], pulsed-neutron-capture logging [PNC], and pressure monitoring) that indicate CO_2 is present in this interval. Thus, the results include both artificial features and some results that are plausible representations of CO_2.

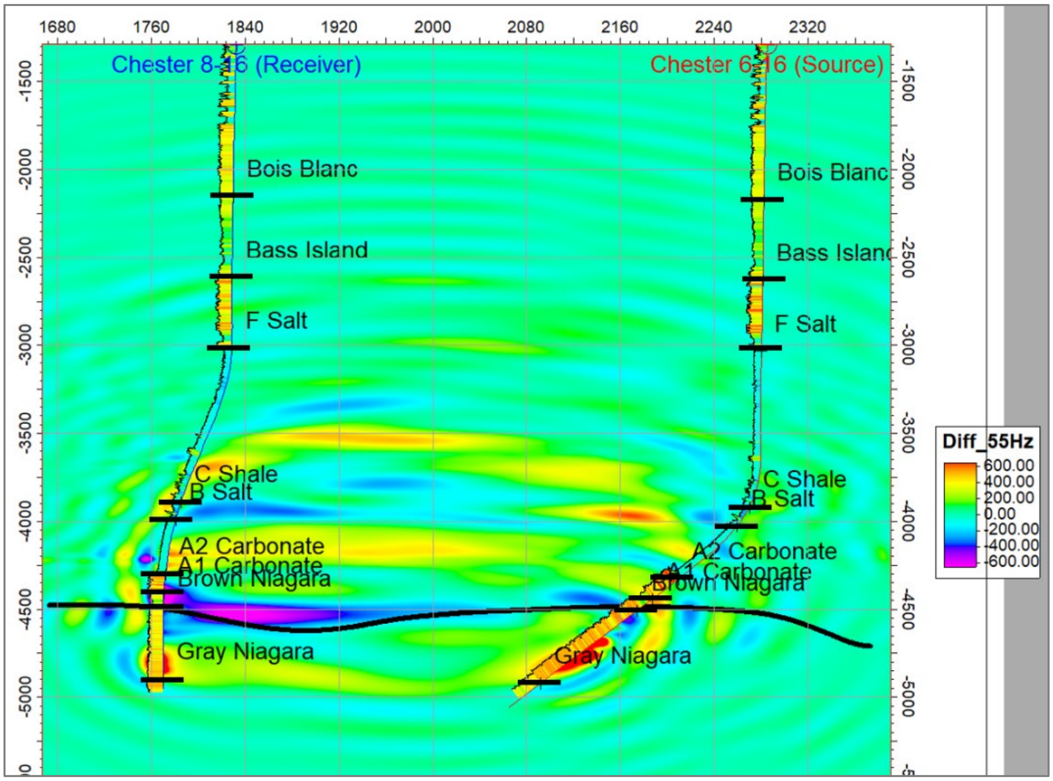


Figure 2-45. Velocity Difference Tomogram for 55 Hz Source Wavelet. Bold line is top of Brown Niagaran. Zone of major velocity change occurs in A-1 Carbonate.

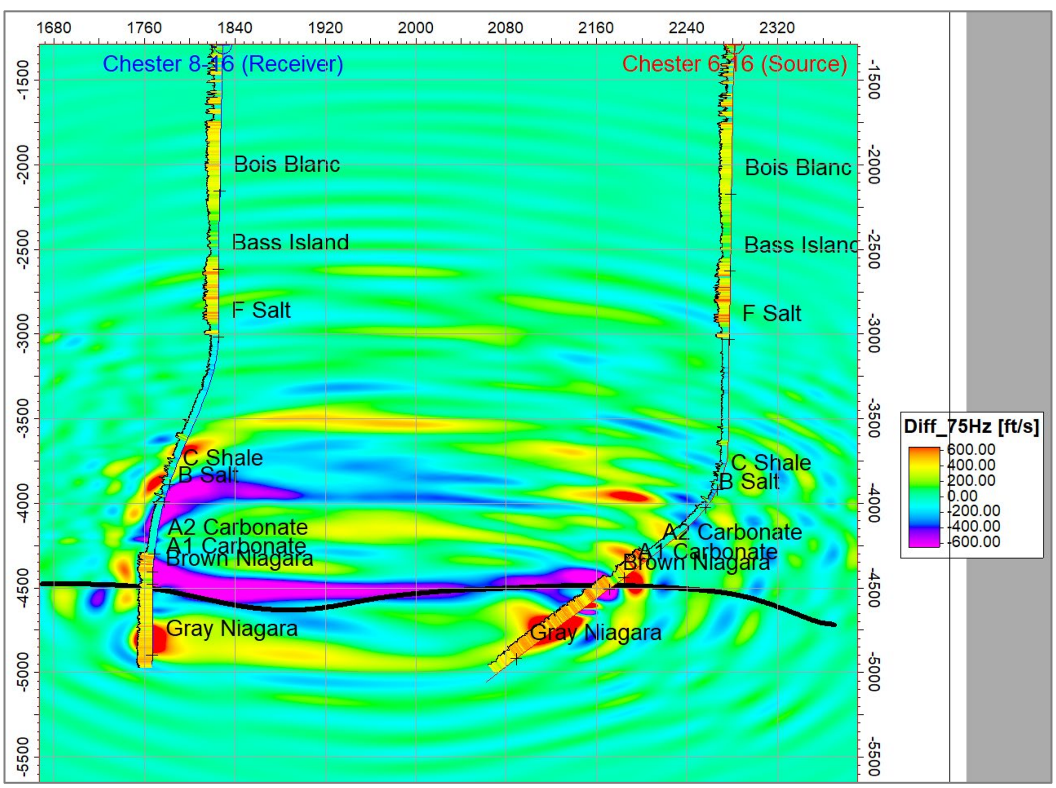


Figure 2-46. Compressional Velocity Difference Tomogram for 75 Hz Source Wavelet.

- Several factors made this project challenging, including the deviated well geometries and the complex structure of the reef. The lack of a pre-CO_2 injection (baseline) cross-well survey was another complicating factor. To compensate for this, a pseudo-baseline velocity model was generated using pre-injection well (sonic) logs. The Schlumberger standard cross-well seismic processing algorithm was ineffective, requiring a different approach for processing the data. As a result, an attempt was made to use an existing method for processing 3D Vertical Seismic Profile (VSP) data based on the Full Waveform Inversion (FWI) technique. The method produced results that are partially plausible, though there are ambiguities.
- Table 2-17 summarizes key results of the Chester 16 Cross-Well Seismic monitoring study, pros/cons of the technology, and an overall recommendation for using the technology to monitor CO_2 storage in Silurian pinnacle reefs of Northern Michigan.

Table 2-17. Cross-Well Seismic Monitoring Summary and Recommendations

Cross-Well Seismic Monitoring Summary and Recommendations	
Key Results of this study	• Normally, a baseline and repeat (post-CO_2 injection) cross-well survey is required to detect injected CO_2. However, in this study, a baseline cross-well survey was not obtained; nevertheless, it was still possible to generate an image (tomograms) that are a plausible representation of the CO_2 plume.
Pros	• Cross-well seismic has been shown to be effective for detecting CO_2 in deep geologic formations. • Cross-well seismic is capable of providing higher resolution results compared to surface seismic or VSP since the source is placed downhole and is typically much higher frequency than what is used with surface seismic methods, resulting in a significant increase in spatial resolution • Both tomograms (velocity images) and reflection images can be obtained; time-lapse tomograms are more useful for detecting areas where fluid substitution (CO_2 injection) has occurred • Time-lapse
Cons/Challenges	• Results are 2D • Deviated well geometries • complex structures • Spacing of wells can be a limitation • A baseline survey is recommended • Cross-well seismic is a complex technology • The success of time-lapse tomography for detecting CO_2 depends on petrophysical properties of the reservoir (density, porosity compressibility), and current and anticipated pressure and stress conditions in the reservoir • Cost is high (>$100K) to acquire/process a single cross-well survey (i.e., two wells).
Overall recommendation	• Cross-well seismic can be useful for delineating the lateral and vertical extent of the CO_2 plume and should be considered if well spacing and reservoir conditions are conducive. • A technical feasibility study should be conducted prior to implementing the survey (i.e., field acquisition). • Pre-job ray-trace modeling should be done to design the cross-well survey prior to acquiring the data.

2.3.3.11 Microseismic Monitoring

- Two microseismic monitoring events were conducted 39 months apart during re-pressurization of the Core Energy Dover 33 reef to evaluate the potential for CO_2-injection induced seismicity in Silurian-age carbonate reef depleted oil reservoirs. The first (baseline) monitoring event was conducted in March 2013 at the start of CO_2 injection under the MRCSP III project when the reservoir pressure was low (approximately 800 psi). The second (repeat) monitoring event was conducted in June/July 2016 after more than 285,000 tonnes of CO_2 had been injected and the reservoir pressure had increased to approximately 3,700 psi, which is near discovery pressure.
- The baseline survey was relatively unremarkable in terms of microseismic activity: only 12 of 34 events detected were determined to be actual microseismic events, and these events were located very close to the 5-33 monitoring well (the well used to house the geophone array). No events were detected within the reef where CO_2 injection was occurring or near the 1-16 injector well. The cause of the events is believed to be tube waves not injection induced seismicity.
- In sharp contrast to the baseline survey, thousands of events were detected during the repeat survey. The large number of detected events made data analysis/interpretation challenging. As a result, the data were analyzed by two groups: initially by Battelle and Paulsson and subsequently by NORSAR. The main aim of the data analysis was to determine if there is evidence of CO_2-injection induced seismicity.
- Microseismic data revealed evidence both for and against injection-induced microseismicity (Table 2-18).
- Magnitude of Events – Due to the lack of low-frequency content of the events, the ability to accurately determine the magnitude or moment tensor was limited. Ultimately, neither NORSAR nor Paulsson were able to quantify the magnitude of the events.
- Location of Events – Paulsson was able to locate five of the six string shots with reasonable accuracy. One of the six shots was not located correctly, likely because it was detonated from a location above the reef in a different geologic formation and Paulsson used a velocity model with a single constant velocity. Paulsson attempted to locate the Type 1 events that he believed were from subsurface well work in the 2-33 well. The locations of the mapped events clustered (laterally) near the 2-33 well but they were spread vertically over a very large distance. NORSAR determined that the locations of the events could not be reliably identified due to difficulties discriminating the arrivals of the P- and S-waves due to the long, high amplitude codas present in the data. In addition, the depths of events could not be identified due to the low SNR of the data. Ultimately, neither NORSAR nor Paulsson were able to determine the locations of the events.

Table 2-18. Evidence both for and against injection-induced microseismicity

Evidence supporting a CO_2 injection source	Evidence against a CO_2-injection source
• There is a very high degree of correlation between reservoir pressure and the cumulative number of events (Figure 2-47). • Furthermore, there was an abrupt increase in the occurrence rate of events shortly after the booster pump was started, which increased pressure in the injection well. This suggests injection pressure (or booster pump) somehow affects the occurrence of some microseismic events. • NORSAR observed that Times of high variance in injection rate very often coincide with higher activity of triggers in all classes (Figure 2-48).	• NORSAR found that each of their three event classes are detected during the injection phase and before CO_2 injection started and after CO_2 injection stopped (Figure 2-49). • Similarly, of the 11,000 events detected by Paulsson, approximately 4,000 events were detected during the installation of the array (i.e., while the array was positioned at 15 temporary setting positions) when no CO_2 injection was occurring. • Paulsson's Type I events are clustered into three days that coincide with times when work (pressure gauge removal and installation) was done in well 2-33 located on the same pad as the 5-33 well that hosted the microseismic array. This suggests well work may be the cause of a small number of events. • NORSAR identified significant noise contamination in the data. The relative amplitudes and the frequency content at the different sensors in the well showed problems that are likely due to instrumentation/cementation and/or electronics. A frequency analyses indicated that for both controlled and natural events the dominant frequency detected were near 1,500 Hz. The consistency of the dominant frequency could be related to the similar magnitude of the different events, or it could also be caused by the sensor response. Further evidence for sensor response or coupling issues with the microseismic array are the long codas that follow the first arrivals and the apparent damage to the lower-end frequencies that are attenuated before the higher frequency signals. There is no obvious explanation for the signal attenuation through wave propagation effects, rather these anomalies could be explained by coupling issues and/or sensor response (Figure 2-50 through Figure 2-54).

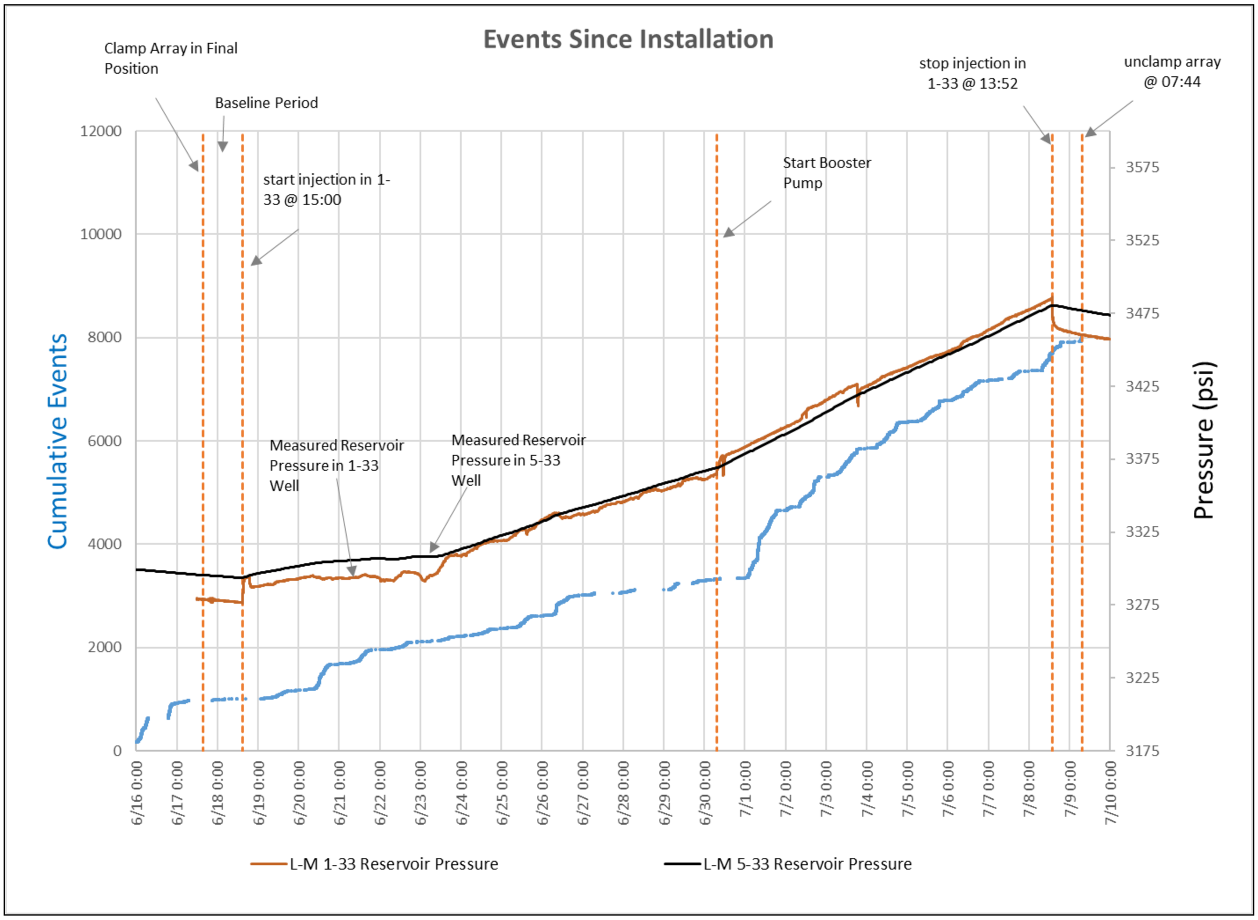


Figure 2-47. Cumulative events vs measured bottomhole (reservoir) pressure at the 1-33 injection well and the 5-33 monitor well (microseismic array was installed in the 5-33 well). Note that the pressures in the two wells have not been normalized to the same reference measurement elevation; thus it appears that the pressure in the monitoring well is greater than the pressure in the injection well. This slide is intended to show trends in reservoir pressure compared to the occurrence of microseismic events).

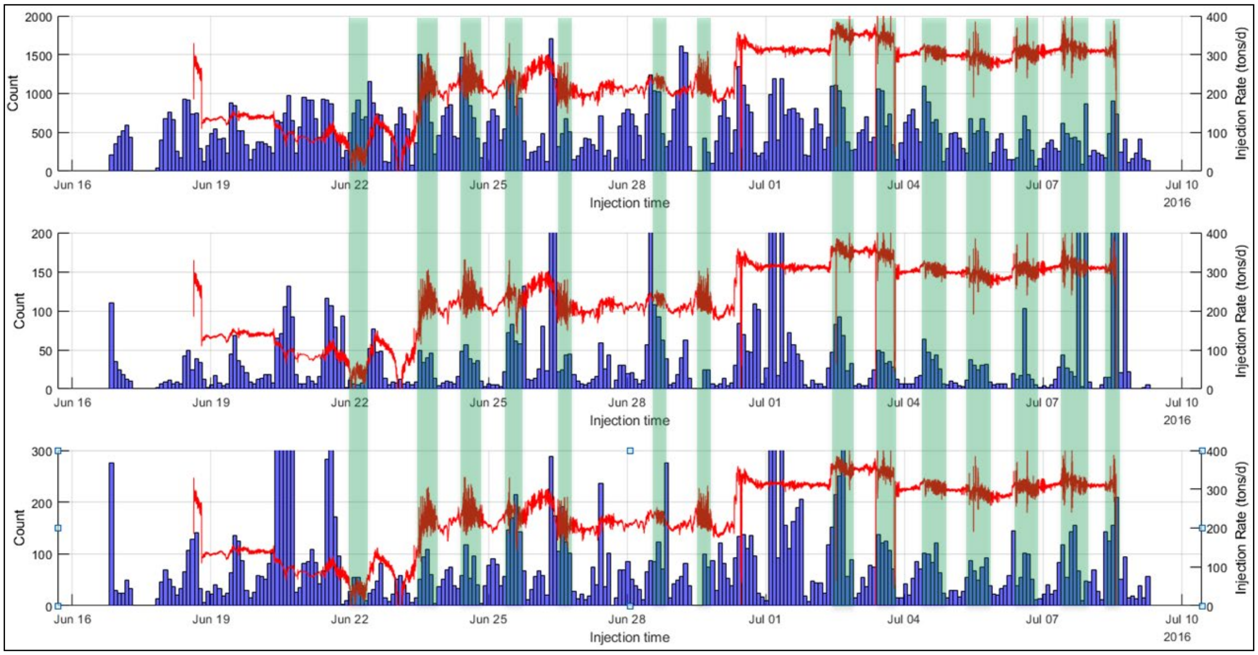


Figure 2-48. Occurrence of NORSAR's three types of triggers derived from raw features (distributions) and CO_2 injection rate. Green bars correspond to large variability in injection rate. Bars represent 2-hour increments.

Figure 2-49. Three classes of events derived from the raw features: peak frequency and frequency spectrum. Note that each of the three event classes are detected during the injection phase and before CO_2 injection started and after CO_2 injection stopped.

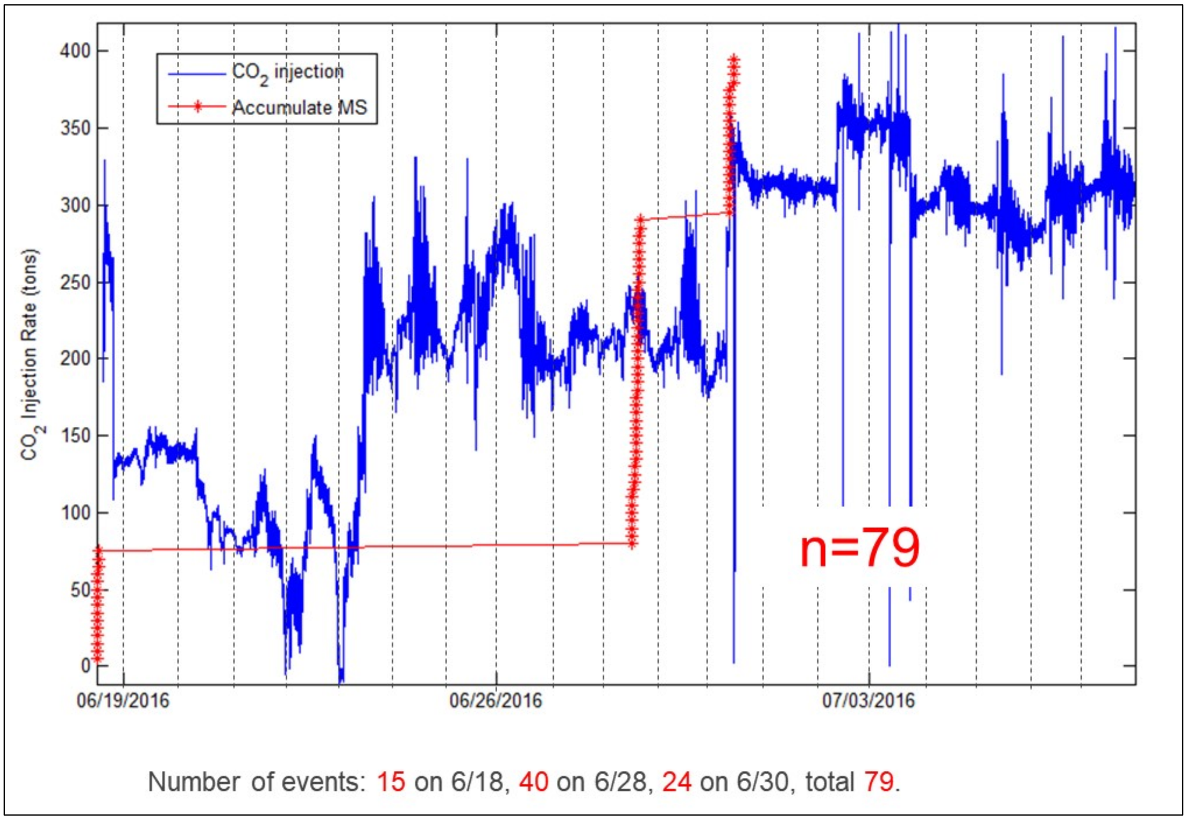


Figure 2-50. occurrence of Paulsson Type 1 events corresponds to three days when work was being conducted in the 2-33 well, located on the same well pad as the 5-33 well that housed the microseismic array.

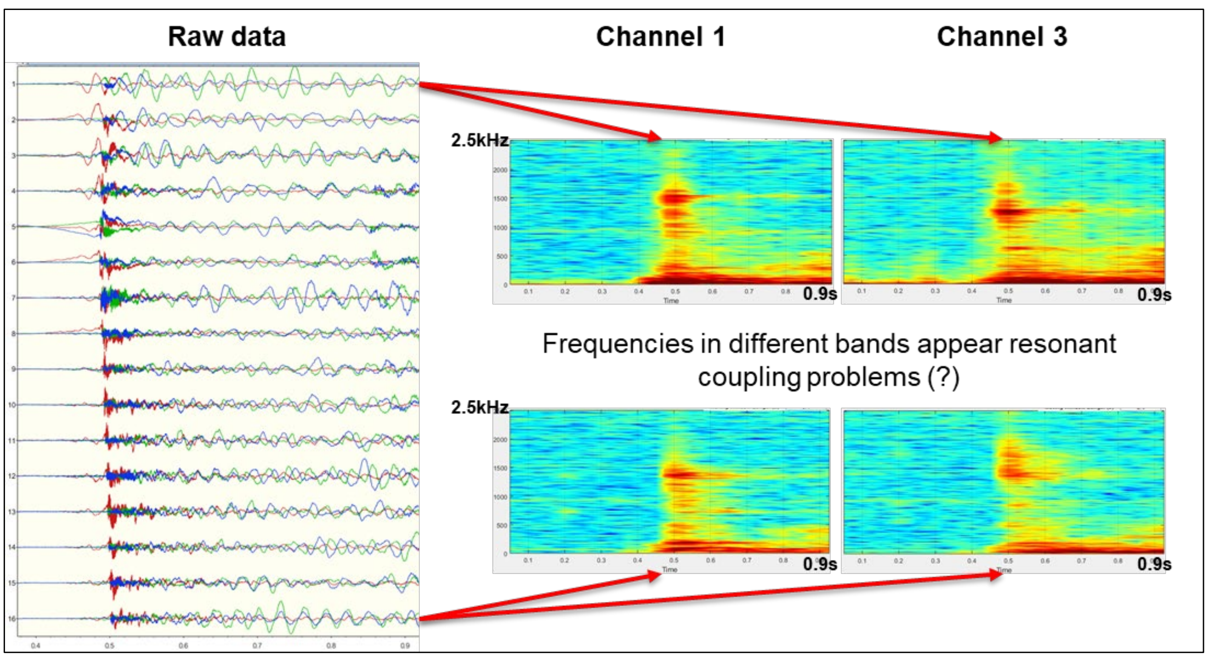


Figure 2-51. Frequency band detected by the top and bottom sensors during Orientation Shot #1 with the microseismic array clamped in the deepest position (Stage 16 – 5,572-5,947 ft). The microseismic data display a resonance effect.

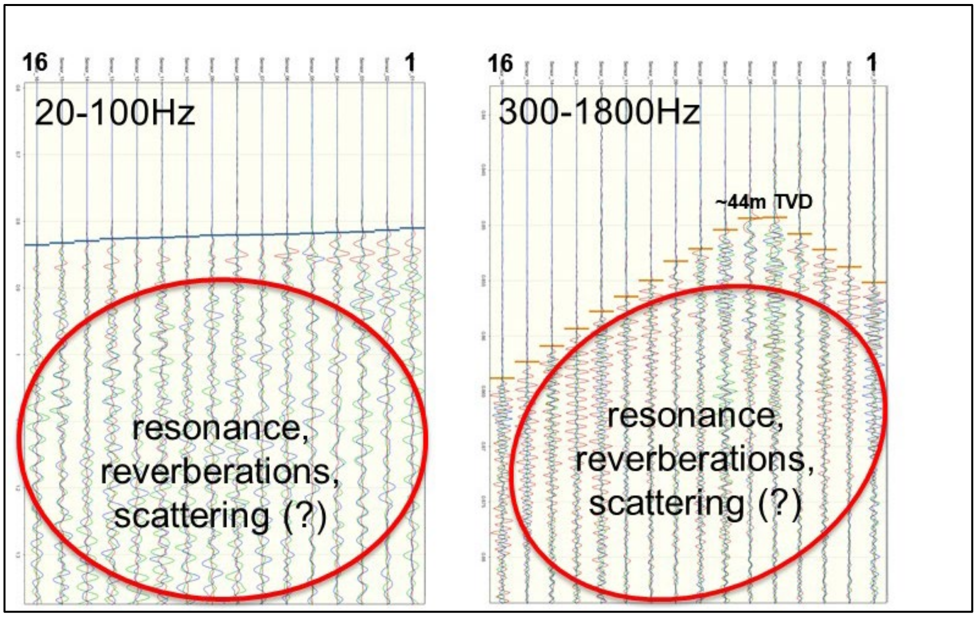


Figure 2-52. Waveforms from Orientation Shot #1 during the installatoin of the microsesmic array. First arrivals are followed by long codas. Dominant frequency is near 1.5kHz. Contributions to coda could come from scattering in unconsolidated formations near the surface, coupling issues and/or bad cement.

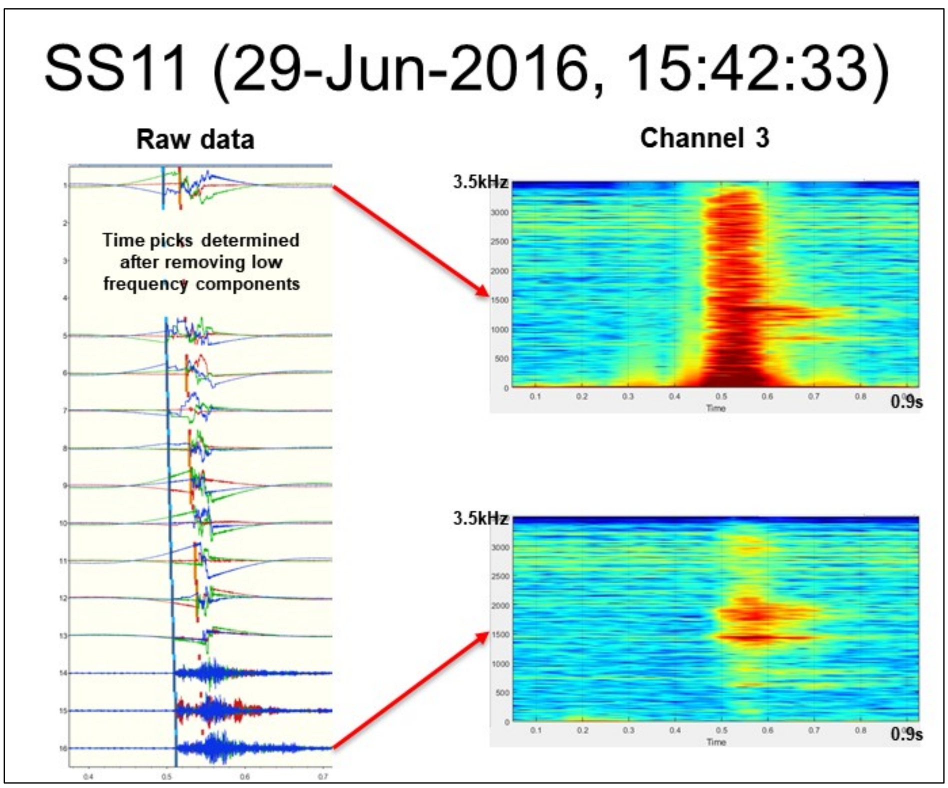


Figure 2-53. Freqency content of string shot #11 recorded by top and bottom sensors. Low frequencies are present but the time-domain representation suggests they are damaged. Band just under 1.5kHz is dominant and appears resonant; Low frequencies are attenuated before higher frequencies within the length of the array (~115m). This is atypical and possibly related to acquisition rather than wave propagation.

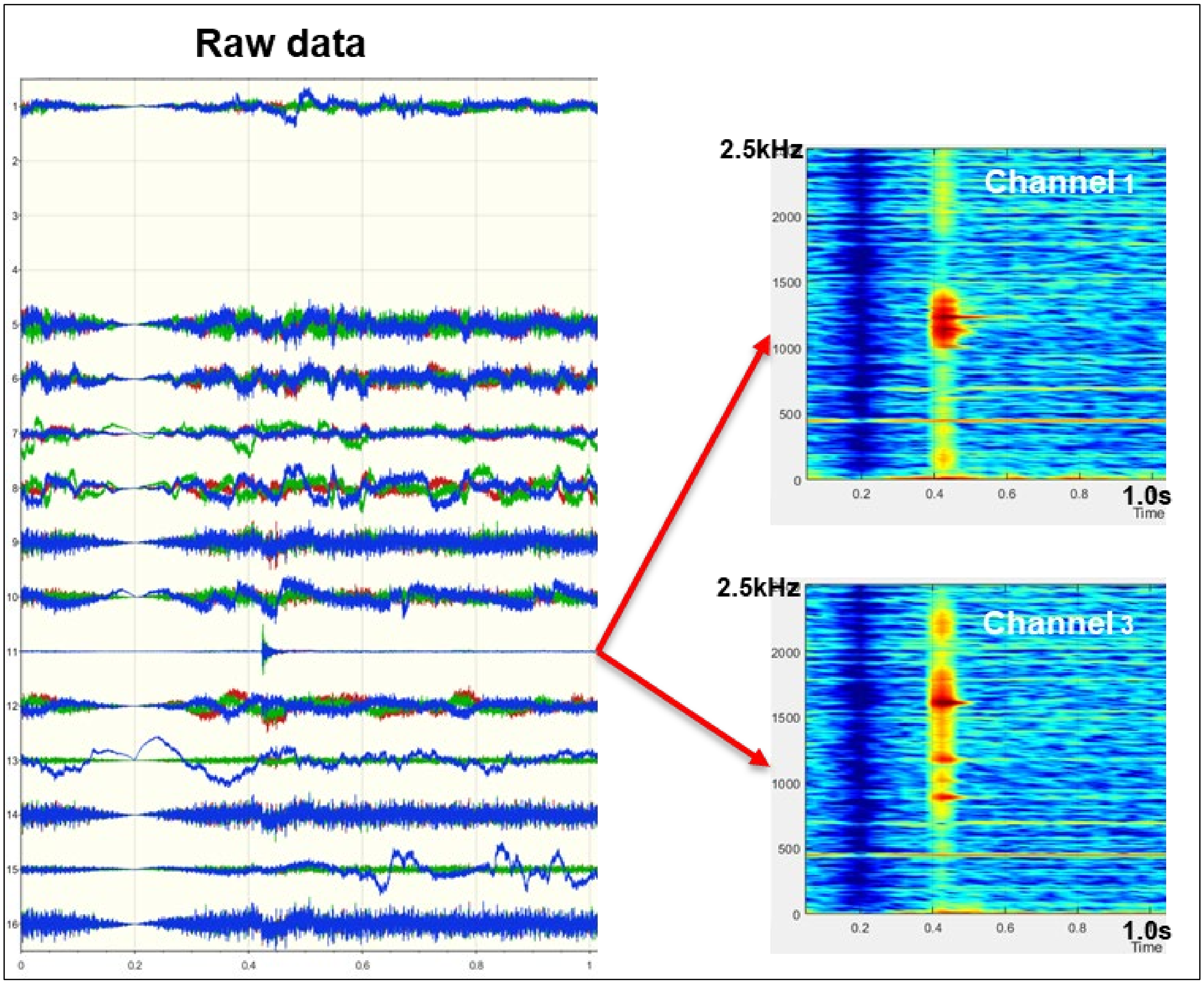


Figure 2-54. Microseismic data showing a different dominant frequency for different components of the same sensor. Arrival spectrum varies from one component to the other. Dominant frequency shifts from under 1.5kHz in channel 1 to over 1.5kHz in channel 3 in this detection. This produces inconsistency in the arrivals observed in different components.

- Table 2-19 summarizes key results of the Chester 16 Cross-Well Seismic monitoring study, pros/cons of the technology, and an overall recommendation for using the technology to monitor CO_2 storage in Silurian pinnacle reefs of Northern Michigan.

Table 2-19. Microseismic Monitoring Summary and Recommendations

Microseismic Monitoring Summary and Recommendations	
Key Results of this study	• This is the first documented microseismic study related to CO_2 injection/storage in a depleted carbonate pinnacle reef reservoir. • The Dover 33 microseismic monitoring study recorded a significant number of microseismic "events" during the repeat survey. Extensive data analysis was undertaken to determine the origin of the detected events, specifically to determine if any events are real microseismic events caused by injecting CO_2. • While there are indicators that support CO_2-injection (e.g., increase in pressure related to CO_2 injection) as the source of (some of) the events, the preponderance of data suggests that "noise", possibly related to the microseismic sensors or associated electronics, is the primary source of the of recorded events. • It was not possible to quantify the magnitude of the detected events or to locate the events. • In general, this study does not provide conclusive evidence that CO_2 injection is the cause of the recorded events; however, the results are not unequivocal.
Pros	• This technology has been used at many CO_2 storage sites to monitor injection-induced seismicity. • It is the only method capable of
Cons/ Challenges	• Microseismic monitoring generates a very large amount of data that has to be processed and interpreted. • Data interpretation is very complicated and requires highly specialized skills in signal processing, machine learning, etc.
Overall recommendation	• This study generally supports the use of the Silurian pinnacle reefs as reservoirs for long-term storage of CO_2. however, because the results are not unequivocal, microseismic monitoring is recommended at future CO_2 storage sites in Niagaran pinnacle reefs until a sufficient body of information is obtained that clearly demonstrates that CO_2 injection does not cause microseismicity. • Continuous microseismic monitoring should be done rather than conducting short/discrete monitoring events as was done in this study; however, this increases the data management burden. • New data management tools are needed to facilitate processing, review, and interpretation of the large volume of data that is generated by this technology.

2.3.4 Summary

As a result of the extensive body of monitoring data developed, new information was acquired about the effectiveness of the carbonate pinnacle reefs for long-term CO_2 storage. The major lessons learned are listed below.

- The carbonate reef reservoirs act as closed reservoirs because they are surrounded/overlain by low permeability carbonates and evaporites which prevent CO_2 leakage out of the reservoir, making them ideal geologic features for permanent CO_2 storage.
- It is possible to recover almost all CO_2 injected into a reef during CO_2-EOR. In other words, the reefs do not irreversibly sequester significant amounts of CO_2 during the EOR process.
- CO_2 injection into the pinnacle reef reservoirs does not appear to cause ***significant*** land displacement (uplift, subsidence) in the area overlying the reefs.

- CO_2 injection into the pinnacle reef reservoirs does not appear to cause ***significant*** seismic activity that could activate fractures and/or faults that could lead to CO_2 leakage out of the reservoir, even when reservoir pressure is near discovery pressure.
- The carbonate reef reservoirs may contain intervals/zones of salt plugging which reduces porosity and limits CO_2 storage capacity.
- Lateral migration of CO_2 within the carbonate pinnacle reef reservoirs away from the injection well may occur preferentially in thin intervals .
- The carbonate pinnacle reef reservoirs may occur as single isolated “pods” (e.g., Dove 33) or in groups of two or more closely-spaced/overlapping pods (e.g., Charlton 19, Chester 16, Bagley).
- The overall low porosity of the carbonate pinnacle-reef reservoirs presents a significant challenge for using borehole seismic monitoring methods to detect and delineate the injected CO_2.
- Fracture pressures (the pressure at which the formation will fracture) in depleted formations/intervals can be extremely low owing to the lowering of pore pressure below hydrostatic.
- Injection of CO_2 into the carbonate reef reservoirs increases the likelihood of precipitation of carbonate minerals (dolomite, calcite, huntite, and magnesite), owing to the extremely high concentrations of calcium, magnesium, sodium, potassium and chloride in the reef brines which causes them to be supersaturated with respect to these minerals.

2.4 Reservoir Modeling for CO_2 Injection in Reefs

The modeling process for simulating oil production, CO_2 injection, and associated storage in the reefs entailed two phases. The first phase, geologic framework modeling, integrated all pertinent geological and geophysical data (from logs, cores and seismic surveys) about reservoir structure, geometry, rock types, and property distributions (porosity, permeability, water saturation) into a 3-D distributed grid-based static earth model (SEM). The second phase, dynamic reservoir modeling, used the SEM as a platform to simulate the movement of oil, gas, water, and CO_2 within the reservoir during primary hydrocarbon production, as well as during subsequent phases such as CO_2-injection assisted EOR, plume migration, and associated storage. In addition, a simplified assessment of coupled process effects was also carried out, where the impacts of geochemical and geo-mechanical processes induced by CO_2 injection were studied. Figure 2-55 shows the modeling workflow.

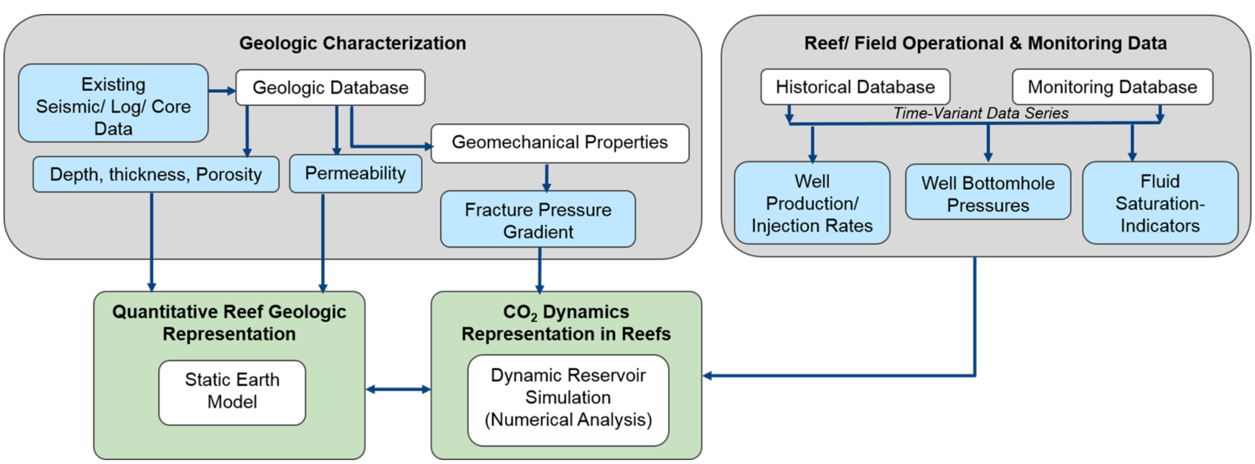


Figure 2-55. Simplified flow diagram of data integration into static and dynamic models showing the flow from geologic characterization and field operations/monitoring into modeling.

These modeling studies support several goals:

- Geologic system representation – data integration (e.g., integration of all reservoir characterization data into a geologic framework)
- Scientific – coupled process understanding (e.g., how does CO_2 move through the formation and interact with rock/oil/brine)
- Calibration – history matching (e.g., update description of subsurface by comparing model predictions to observations)
- Engineering – system design (e.g., how many wells are needed to meet injection targets and optimize oil recovery and associated storage)

Table 2-20 shows the various types of modeling applied to the four reefs of interest.

Table 2-20. Types of Modeling Applied to the Reefs of Interest

Reef	Data Integration (SEM)	History Matching	System Design	Coupled Process Understanding
Dover-33	x	x	x	x
Charlton-19	x	x		
Bagley	x	x		
Chester-16	x	x	x	

2.4.1 Static and Dynamic Modeling Approach

The overall flow of the modeling work consisted of analyzing and integrating geologic data to define the extent, depth, thickness, porosity, permeability, and water saturation of the reservoir(s). In conjunction with geologic characterization, field operational and monitoring data were compiled to develop the reef history that was used in history matching the dynamic model. The geologic characterization work then was used to develop a static earth model that was upscaled into a dynamic model. Figure 2-56 illustrates the workflow for SEM development.

The objectives for the dynamic modeling activity included evaluating CO_2 injectivity and assessing fluid migration in the reefs. The dynamic modeling activity aimed to validate the representativeness of the reef conceptual model (as implemented in the SEM) by history matching production (oil, water, gas) and pressure history during primary recovery period, and any secondary recovery (waterflooding, CO_2-EOR) periods as appropriate. The model was then applied to match the pressure response for the MRCSP Phase III injection period. History matching provided a validated representative model that captured the field observed response from primary production until the end of the Phase III CO_2 injection period. This representative reef model was then useful to simulate CO_2-injection assisted EOR, plume migration, and associated storage.

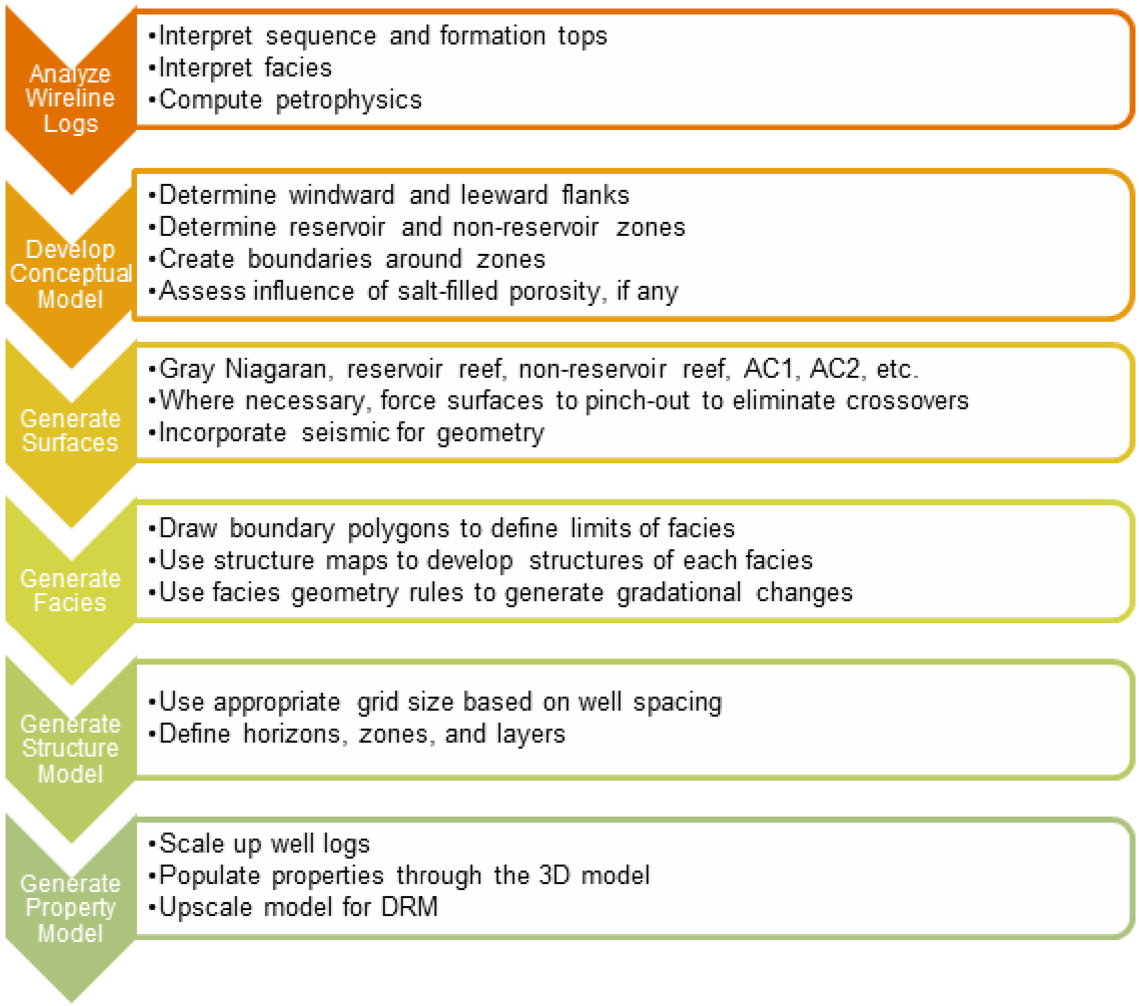


Figure 2-56. Workflow for building static earth models which integrates multiple data types and honors the geologic conceptual models.

For dynamic modeling, three different approaches with varying data and computation needs were used. These include:

- *Fully compositional*: In this grid-based modeling approach, detailed interaction between various (pseudo) components in the crude oil, CO_2 and water are captured using a Peng-Robinson equation-of-state (EOS) based component mass balance. The appearance/disappearance of all components in all phases (oil, gas, water) is strictly tracked. The coupled formulations are highly non-linear, require additional data regarding crude oil composition/EOS representation, and are computation intensive.

- *Pseudo-miscible*: This grid-based modeling approach involves modifying the physical properties and the flowing characteristic of the solvent (CO_2) and reservoir fluid in a three-phase black-oil simulator. Relative permeabilities and viscosity of different phases are also modified by solvent injection. A mixing parameter is used to determine the amount of mixing between the solvent and reservoir fluid within each grid block. This approach is popular in CO_2-EOR projects for obtaining rapid but reasonably accurate solutions.

- *Capacitance-resistance model* (CRM): In this lumped-parameter modeling approach, the goal is to develop a simplified physics model for the control volume surrounding an injection or production well, where the rate-pressure relationship can be represented via two parameters, (a) compressibilityweighted pore volume, and (b) injectivity/productivity index. This lumped parameter representation is widely used in waterflooding projects and is computationally very fast. However, it cannot resolve fluid movement within the control volume.

Coupled fluid-flow/geochemical and fluid-flow/geomechanical process models were also undertaken to understand: (a) the impact of geochemical reactions following CO_2 injection into the subsurface, and (b) the geomechanical changes resulting from pressure increase following CO_2 injection, respectively. The approach used for these specialized modeling tasks (along with their results) is described in the Integrated Modeling Report (Mishra et al., 2020).

2.4.2 Static and Dynamic Modeling Results

2.4.2.1 Modeling a Depleted Oil and Gas Field - Dover 33

Static Earth Model Results

The Dover-33 reef was initially interpreted and constructed into two models— Level 1 and Level 2. The Level 1 model contained two reef-associated layers (A1 carbonate and Brown Niagaran) based on lithostratigraphic formations. The Level 2 model used a sequence stratigraphic approach. With this approach, the individual sequence stratigraphic packages that make up the framework of the reef model were defined by geophysical log-data signatures that were correlated to regional sequence boundaries and interpreted lithofacies as defined in analog reef studies. Reservoir properties were distributed within the sequences and conditioned to the individual lithofacies. Early versions of the reef dynamic model were built from both the Level 1 and Level 2 SEMs; however, it was not possible to successfully match the entire primary production, secondary production, and the MRCSP Phase III CO_2 injection data with either model. Therefore, a new SEM based on depositional lithofacies (geobodies) approach described below was developed to attempt to produce a dynamic reservoir model that could accurately reproduce the primary, secondary production data and the Phase III CO_2 injection pressure data.

First, the surfaces corresponding to A-2 Carbonate, A-2 Evaporite, A-1 Carbonate, A-1 Salt, Brown Niagaran, and Gray Niagaran were defined. These were then tied to horizons and layers within Petrel to create a structural framework. Next, interpreted lithofacies (as discussed earlier) were used to define zones within a formation to represent individual compartments or “geobodies.” The lithofacies were divided to represent groups of facies with similar porosity and permeability distributions. This creates a heterogeneous model with more control during property modeling. The gridded SEM covers an area 700 m x 950 m, with a maximum height of ~160 m. Grid cells in the x- and y-direction were kept at 25 m with variable thickness in the vertical (z) direction, resulting in ~590,000 cells in the fine-scale model.

For property modeling, neutron porosity data from 15 wells were used, along with core measured porosity-permeability data from core samples. The A-1 Carbonate had a porosity range from 3.16% to 10.72% with a permeability range from 0.00 to 6.04 mD. The Brown Niagara had a porosity range from 1.51% to 7.14% with a permeability range from .00 to 204.28 mD. Power law transforms were fit to both sets of data. Kriging was applied to interpolate porosity values from upscaled neutron porosity logs for the Brown Niagaran and A1- Carbonate formations. All other zones were assigned an average value to represent the formation. The derived porosity to permeability transform was applied to the porosity model to predict permeability throughout the SEM for the Brown Niagaran and A-1 Carbonate. Maximum and minimum permeability observed in whole core were used to constrain the model limits. All other zones were assigned an average value to represent the formation. Water saturation was calculated from resistivity log data in seven wells using Archie’s equation. Moving average was used to interpolate water saturation throughout the SEM for the Brown Niagaran, A-1 Carbonate, and A-2 Carbonate zones using only three wells that were near initial reservoir conditions. Volumetric calculations for this fine-scale model yielded a pore volume of 2.7E+7 ft3, corresponding to an original oil in place of 3.28 million STB.

To create a computationally tractable grid for the dynamic reservoir modeling, it was necessary to create an upscaled (i.e., coarser) model that could reproduce the behavior of the fine-scale model with fewer cells. The Petrel plug-in CONNECT UpGrid™ was used to aid the upscaling process by optimizing the grouping of layers. This utility performs the optimum vertical upscaling design by minimizing the error on the pressure while combining vertical layers. The horizontal grid size remains unchanged. The 478-layer, fine-scale SEM served as input to the upscaling process, which resulted in a 64-layer model with ~68,000 cells (i.e., a reduction of more than 80%). A representative cross section with porosity and permeability distributions in the gridded upscaled model is shown in Figure 2-57.

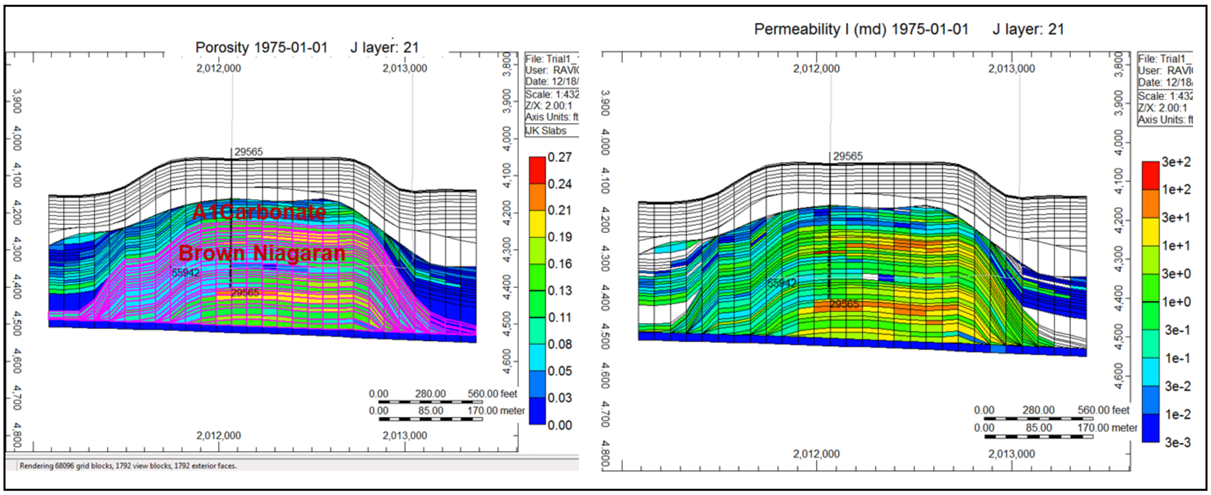


Figure 2-57. Cross section views of the porosity and permeability distributions in the Dover-33 Depositional Lithofacies SEM.

Dynamic Reservoir Model Results- Compositional

A compositional simulation framework was used for modeling the primary production, CO_2 injection for EOR, and purely CO_2 injection periods. This requires first characterizing the reservoir fluid using multiple pseudo-components for equation-of-state based fluid mixing calculations. A total of seven pseudo-components were defined so that the estimated fluid properties such as density and viscosity matched that of the original fluid sample. These pseudo-components and the corresponding mole percentages are: F1 (C1, N2) – 40.9%, F2 (CO_2) – 0.1%, F3 (C2-C4), 20.2%, F4 (C5-C9) – 17.4%, F5 (C10-C19) – 14.7%, F6 (C20-C24) – 2.8%, F6 (C25-C30+) – 3.9%.

The reservoir model was history matched to the primary production data and subsequent CO_2 injection for oil recovery and pressure changes during EOR periods. The goal was to manually adjust the permeability field and the relative permeability relationships to obtain a reasonable agreement between observed and model predicted values for cumulative fluid (oil, gas, water) production and average reservoir pressure. Figure 2-58 shows the history match that was obtained by adjusting the gas/oil relative permeability curves, and by modifying the permeability field to include: (1) a high-permeability streak in the core reservoir zone and (2) a vertical permeability baffle across this region and located ~2000 ft away from the injection well. The match with the cumulative oil and average pressure are quite good, while the errors in cumulative gas and cumulative water production appear to offset each other and preserve the overall reservoir voidage.

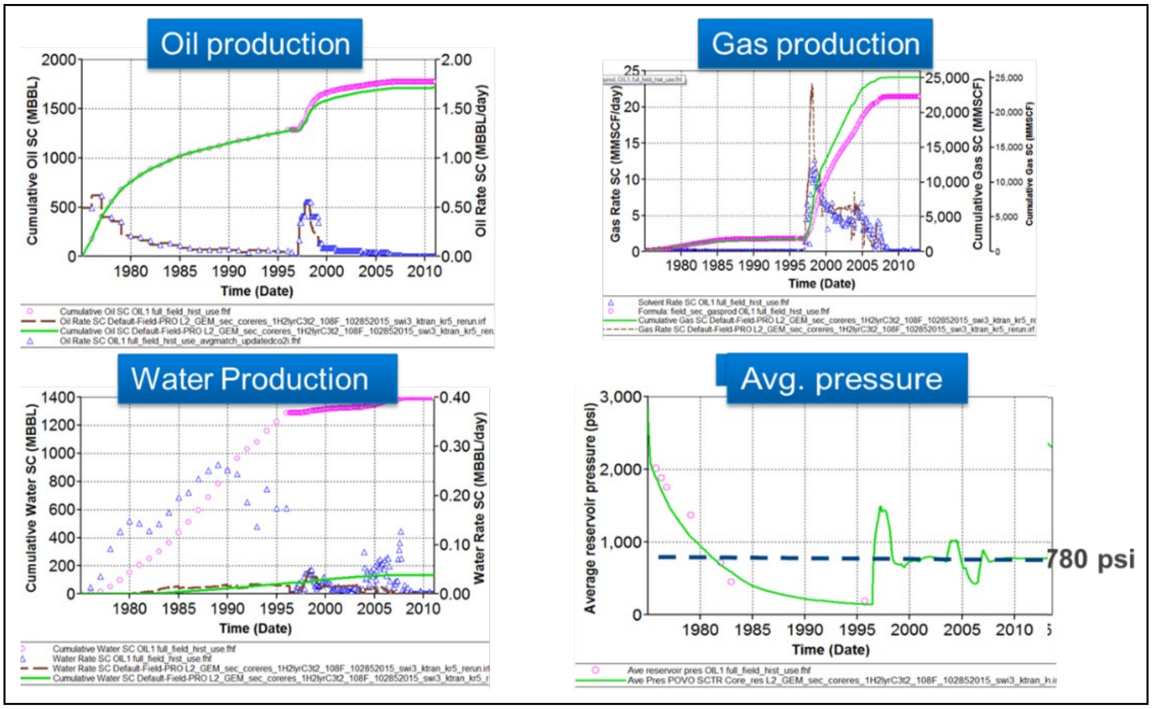


Figure 2-58. History-match results for: (a) oil production; (b) gas production; (c) water production; and (d) average reservoir pressure. The symbols represent field data and the lines show the model outputs.

This model was also applied in a blind prediction mode to compare predictions for the final CO_2 injection phase (without any oil production). Figure 2-59 shows that the overall amplitude of the pressure increases during the variable-rate injection periods, and the subsequent fall-off periods, are broadly captured. The trends in pressure change with time are not perfectly captured by the model. This could be due to subtle time-dependent (and hence pressure dependent behavior) potentially caused by geochemical reactions or geomechanical changes that have not been captured by the current model.

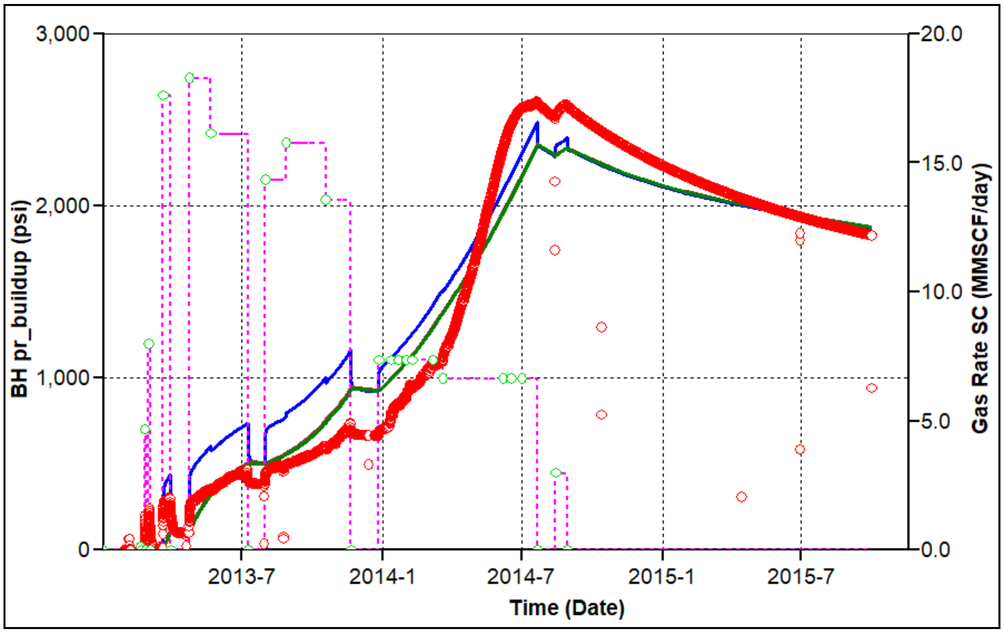


Figure 2-59. Modeled pressure response during the MRCSP Phase III CO_2 injection period. Here, the red circles represent observed bottom-hole pressure data, green circles represent simplified field CO_2 injection rate data, magenta lines are the modeled CO_2 injection rate, blue curve is the modeled injector bottom-hole pressure buildup and the brown and green curves are the modeled monitoring wells bottom-hole pressure buildup.

2.4.2.2 Modeling a New EOR Field – Charlton 19

Static Earth Model Results

All available geologic data, petrophysical analyses, and interpretations were used as input into the SEM. A 2D depositional model was used to guide the development of the model's structural framework. 3D seismic data was used to define the boundary and geometry of the reef. Surfaces for facies were created to subdivide the reservoirs into key zones. These zones were subsequently layered and followed by well log upscaling and property modeling.

The uppermost SEM zone for the Charlton-19 reef was the A-2 Carbonate, which gently slopes off-reef. The A-1 Carbonate follows the underlying Brown Niagaran Formation. Locally, the Brown Niagaran was comprised of two pinnacle reefs and a small reefal high in the saddle region between the two pods. The Gray Niagaran was relatively flat throughout the study area deepening to the southeast. These surfaces were defined from seismic data and well log-based formation top picks, and then tied to horizons and layers within Petrel to create a structural framework. Next, interpreted lithofacies (reef flank, windward, leeward, reef core) were used to define zones within the Brown Niagaran to represent individual compartments or "geobodies." The lithofacies were divided to represent groups of facies with similar porosity and permeability distributions. This creates a heterogeneous model with more control during property modeling. The gridded SEM covers an area 1580 m x 680 m, with a maximum height of ~200 m. Grid cells in the x- and y-direction were kept at 20 m with variable thickness in the vertical (z) direction, resulting in ~960,000 cells in the fine-scale model.

For property modeling, neutron porosity data from five wells were used, along with core measured porosity-permeability data from core samples in the Dover-33 reef due to lack of Charlton-19 samples. The Dover-33 reef was used as an analog because of its proximity and similar dolomitic reef lithology. Power law transforms were fit to the observed porosity-permeability relationships for the A-1 carbonate and Brown Niagaran formations. The A-1 Carbonate had an average porosity 5% and an average permeability of 0.35 mD. The Brown Niagaran had an average porosity of 7.9% with an average permeability of 3 mD. Gaussian Random Function Simulation method was applied to interpolate porosity values from upscaled neutron porosity logs for the Brown Niagaran and A-1 Carbonate formations. The derived porosity to permeability transform was applied to the porosity model to predict permeability throughout the SEM for the Brown Niagaran and A-1 Carbonate. Maximum and minimum permeability observed in whole core were used to constrain the model limits. Porosity and permeability values for all other zones were assigned a zone-specific average value. Figure 2-60 shows porosity and permeability distributions calculated for a representative cross section. An average initial water saturation of 11.35% was estimated from material balance calculations. Volumetric calculations for this 357-layer fine-scale model yielded a pore volume of 2.4E+7 ft3, corresponding to an original oil in place of 2.6 million STB.

There was no upscaling step applied to this fine-scale model as there was no detailed dynamic reservoir modeling done for the Charlton-19 reef.

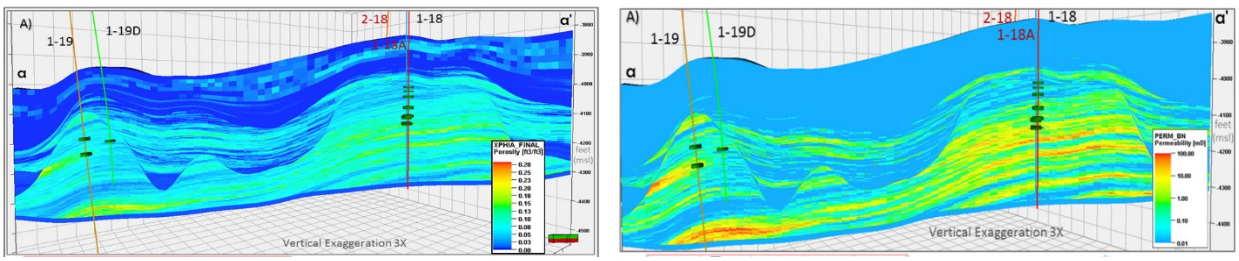


Figure 2-60. Cross section views of the porosity and permeability distributions in Charlton-19 model.

Capacitance Resistance Model

The objectives for the dynamic modeling activity included evaluating CO_2 injectivity and assessing pore volume in this complex reef structure using the simplified CRM approach with available field data. Data were taken from the CO_2 injection-only period, from February 2015 through June 2017. This data was filtered to eliminate point outlier values of injection rate. Figure 2-61 shows the filtered rate and bottomhole pressure data from the injection well during this period. This data was formatted and used as the input for the CRM.

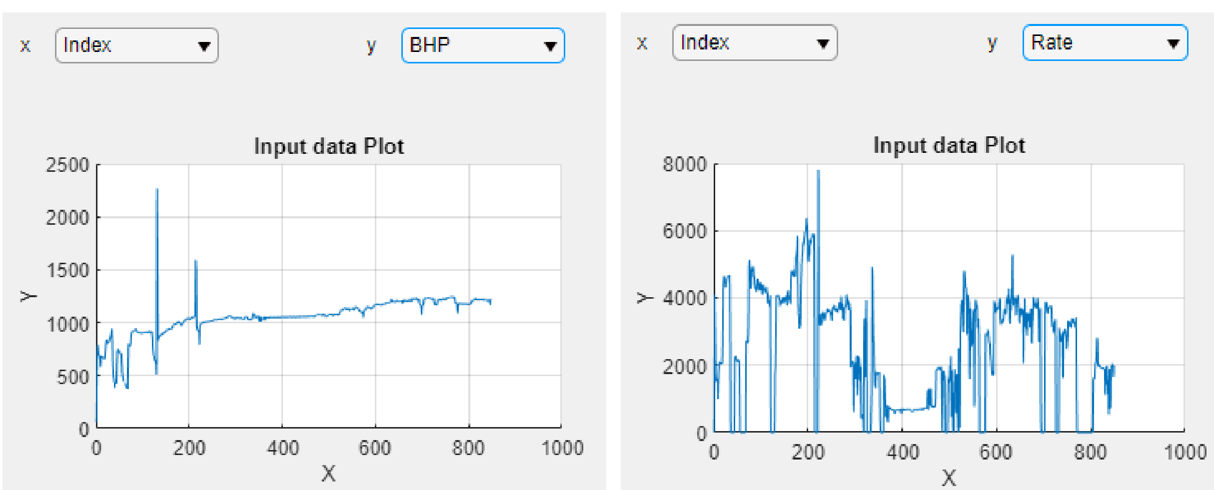


Figure 2-61. Filtered bottomhole pressure (left panel; psi units) and injection rate (right panel; rbbl/day units) data from the injection well during the CO_2 injection-only period being evaluated.

The CRM tool uses multi-variate regression analysis to minimize the difference between the predicted and field observed cumulative injected CO_2 volume to estimate two fitting parameters: (a) injectivity index, and (b) total compressible pore volume. The model is calibrated by assuming an initial pressure value based on the field history. Since this value was not known with certainty (following the end of primary production), a range of realistic initial pressure assumptions, bound by field data, is used to evaluate the performance of the CRM model. As shown in Figure 2-62, the optimal value for the initial pressure is found to be 700 psi, which corresponds to the best overall fit. The corresponding estimated model parameters are: compressible pore volume (Ct.PV) = 3423 rbbl/psi, and injectivity index, J = 62 rbbl/day.psi.

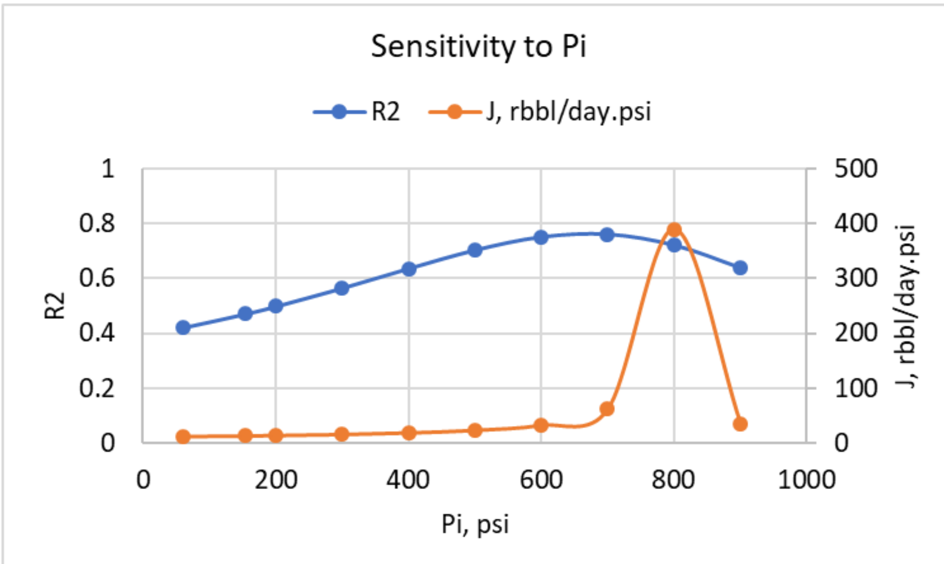


Figure 2-62. Resulting coefficient of regression (R^2) and injectivity index (J) values for different initial pressure assumptions. The initial pressure value of 700 psi is seen to achieve the best fit or highest R^2 with a corresponding J value of 62 rbbl/day.psi.

For an average bottomhole CO_2 density of 48 lb/ft3 corresponding to prevailing bottomhole pressure and temperature conditions during CO_2 injection, J is recalculated as 7.58 MT/day-psi. This compares very well with the previously determined injectivity index value of 2694 MT/yr.psi or 7.38 MT/day.psi using flowing material balance calculations. Also, given a hydrocarbon pore volume of 4.38E6 rbbl from material balance calculations, the total compressibility is calculated to be 7.8E-4 1/psi, which is consistent with the order of magnitude of total compressibility typical of oil and gas systems.

2.4.2.3 Modeling a Multiple Lobe Field - Bagley

Static Earth Model Results

Geological parameters, including reservoir thickness and reservoir depth, were provided using geological contour maps for Brown Niagaran, Grey Niagaran, and A-1 carbonate formations. These maps were then used to generate three-dimensional grids for each formation.

Unlike other reefs, extra surfaces were not prepared to delineate the distinct lithofacies within the Brown Niagaran because (1) the diagenesis is significant in carbonate reef that make presence of lithofacies meaningless, and (2) there is not enough evidence (such as seismic data) to support presence of lithofacies in Bagley reef. As a result, single zones (intervals between two horizons) were created for each formation in the Bagley reef. A 3-D model of the entire Bagley study area is shown in Figure 2-63.

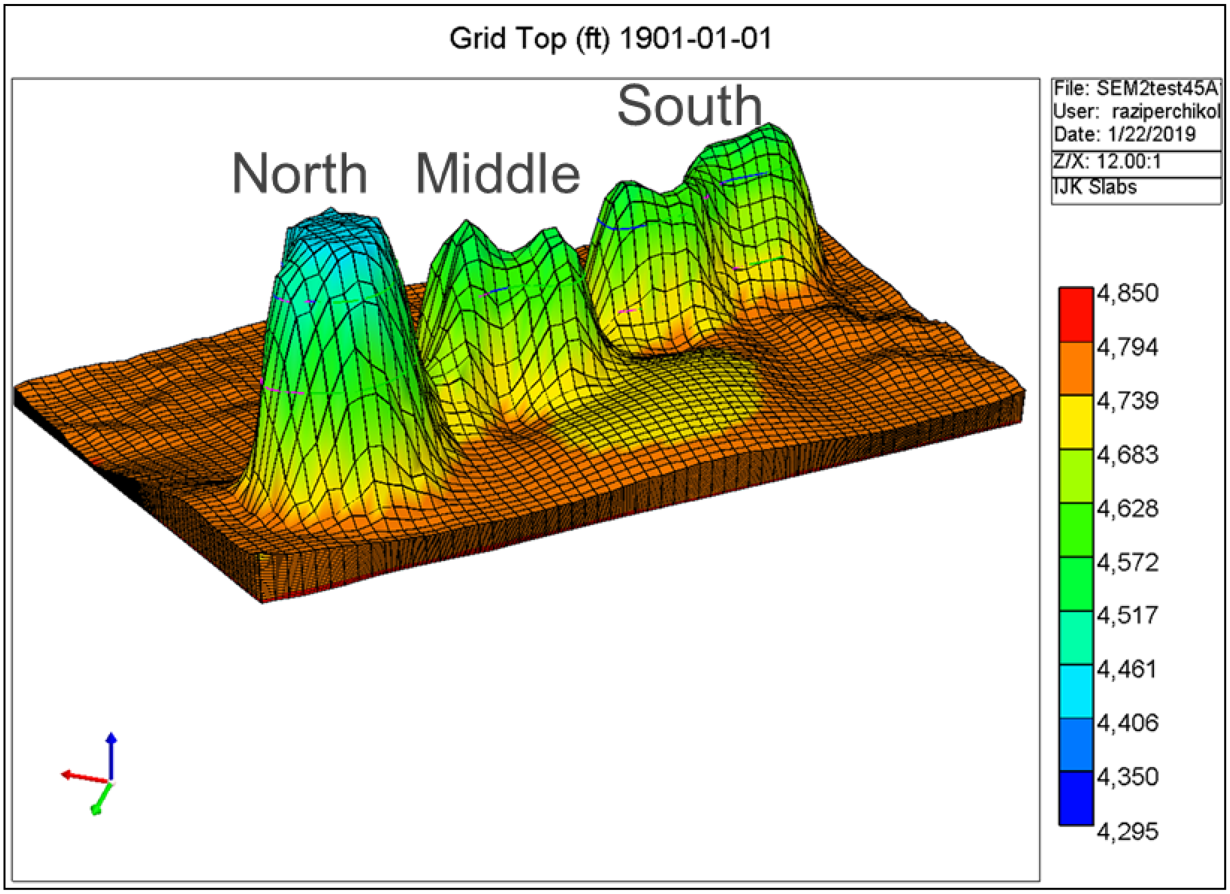


Figure 2-63. The grid system for Bagley reef: The upper panel shows the top of A1-Carbonate. The lower panel shows the top of Brown Niagaran formation.

For dynamic modeling, a sector model corresponding to the Northern lobe was extracted. This model used a 60 x 60 x 30 grid system and contained ~110,000 cells. The property modeling included assigning porosity and water saturation values to the model. Because the Bagley task is divided into two subtasks, a single porosity model was used to develop the CRM and limited simplified history matched model. The histogram of neutron porosity from well-log data for the Bagley northern lobe has a range 0.05-0.20, with an average of 0.1034 which is used for the Brown Niagaran formation. A connate water saturation of 0.2 is used in the oil zone. Volumetric calculations for this yielded a pore volume of 5.3E+9 ft3, corresponding to an original oil in place of 9.6 million STB for the entire Bagley field.

Dynamic Reservoir Model Results

Starting with the static model for the Northern lobe, different scenarios were used during the history match process to adjust the model parameters in order to match: (a) primary production response (i.e., oil and gas rates or equivalently, the corresponding cumulative production volumes), (b) average reservoir pressure during primary production, and (c) pressure buildup during the CO_2 injection period.

Model calibration involved adjusting both intrinsic permeability and relative permeability relationships. A constant permeability model was used for history match process. The cumulative oil production was used as the primary constraint for history match. Thus, the history match is primarily against the cumulative gas production, which is reasonably honored (Figure 2-64). The mismatch with the cumulative water production is greater, which results in a misfit against the average reservoir pressure. With a simplified permeability field, it was not possible to meet both water and oil production constraints.

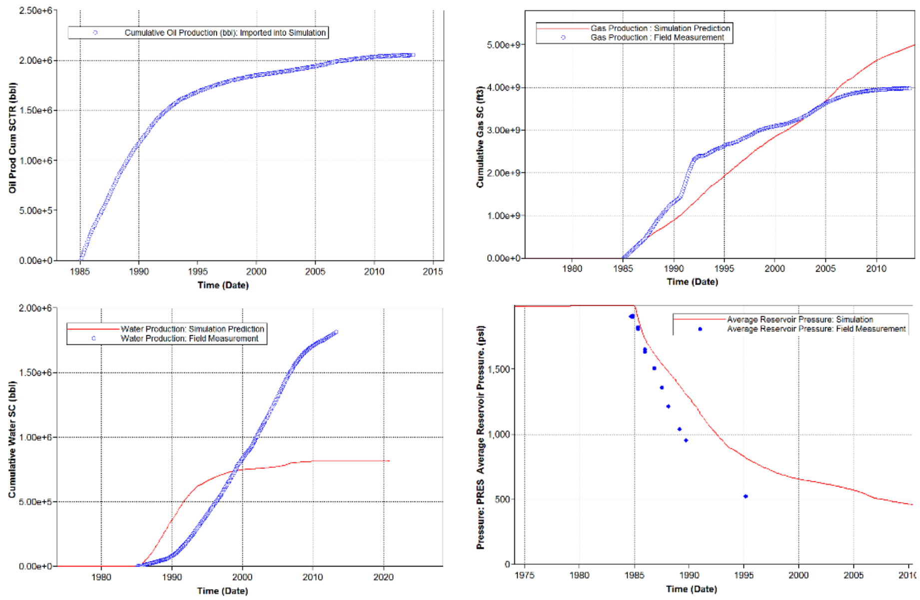


Figure 2-64. Predicted and measured average reservoir pressure.

Next, the CO_2 injection rate was used as a constraint for history match of CO_2 storage phase. The model was able to predict pressure response of injector (Figure 2-65) with good accuracy. This required using a skin factor of six for the injector well in order to achieve the pressure history match, suggesting some wellbore damage that has been corroborated from operational records. A reef permeability of 15 md was used to history match primary production and CO_2 storage phase. Both the oil-water and gas-oil relative curves were also adjusted for the history match.

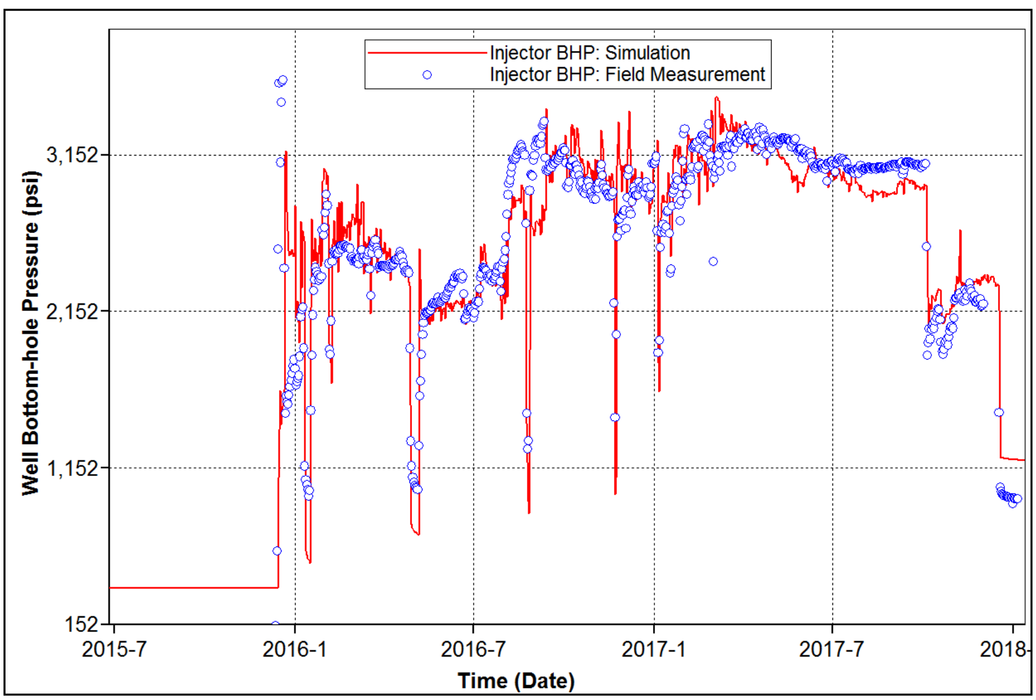


Figure 2-65. Injector Well (2-11) BHP comparison between field measurement and simulation.

Capacitance Resistance Model

The CRM model was applied to the injection data from the Northern, Middle and Southern Lobes of the Bagley reef. Cross plots of field versus cumulative CO_2 injection volume were used to evaluate the goodness of fit.

For the Middle Lobe, the R^2 for the CRM analysis is 0.89, which shows the simplified model is able to explain injection related data (Figure 2-66) and estimate fitted parameters (J and Ct*PV) with higher confidence (Figure 2-67). Initial pressure of 600 psi is used as an input for the model. The total compressibility times pore volume of the model is 2727 rbbl/psi, and estimated injectivity index is 4.89 rbbl/(day*psi).

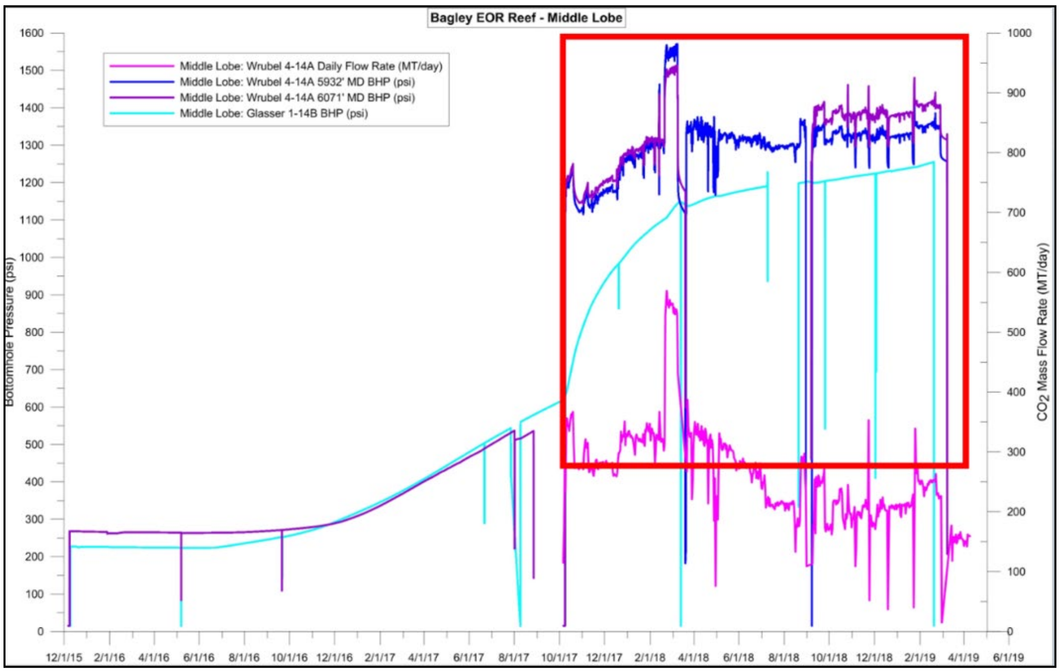


Figure 2-66. BHP and CO_2 injection rate for well 4-14 in Middle Lobe. The red box shows the time interval used for importing CRM model.

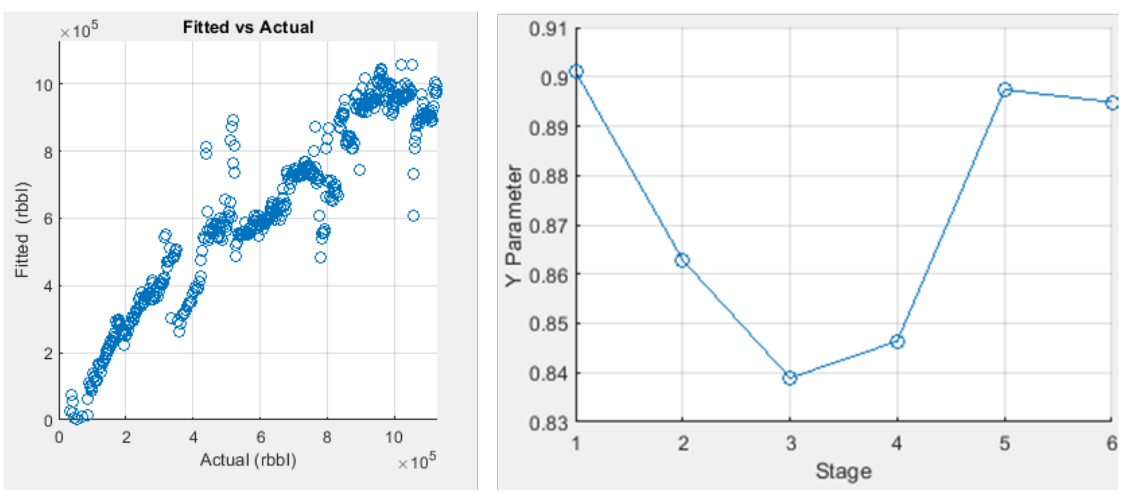


Figure 2-67. (A) Actual (field) CO_2 injection volume versus fitted data using simplified model (B) estimation of R^2 in different time interval.

However, for the Northern Lobe, the R^2 for the CRM analysis was found to be only 0.37, which shows the simplified model is unable to explain injection related data and estimate fitted parameters (J and Ct*PV) accurately. Changing the initial pressure as a control parameter does not improve R^2 of the model. The low R^2 in this model could be because of additional wellbore effect (such as skin factor) in the injection well of North Lobe.

Although not shown here, the R^2 for the CRM analysis of the Southern Lobe was found to be 0.76 showing the simplified model is able to explain injection related data and estimate fitted parameters (J and Ct*PV). Initial pressure of 500 psi is used as an input into the model. The total compressibility times pore volume of the model is 1310 rbbl/psi, and estimated injectivity index is 7.15 rbbl/(day*psi).

2.4.2.4 Modeling a Two-Lobe, New EOR Field – Chester 16

Static Earth Model Results

The Chester-16 static model construction follows a similar workflow to that of the other reefs. The geologic data and interpretations and petrophysical analyses were used as input into the SEM. A 2D depositional model interpretation was used to guide the development of the model's structural framework. 3D seismic data was used to define the boundary and geometry of the reef. The first step was to generate structural surfaces. The uppermost SEM zone for the Chester-16 reef was the A-2 Carbonate, which has a higher elevation over the Northern Lobe and gently slopes off-reef. The A-1 Carbonate follows the underlying Brown Niagaran Formation and is divided into three subunits: (a) Flank - which occupies the space adjacent to the reef and is relatively tight, (b) Crest – the oil-bearing portion that drapes over the reefal pods, and (c) Saddle – which occupies the saddle region between the two reef pod with poorly constrained properties. Locally, the Brown Niagaran was comprised of two pinnacle reefs, with the northeastern pod being the taller. The Gray Niagaran was relatively flat within the study area.

Next, surfaces for facies were created to subdivide the reservoirs into key zones. For this modeling effort, extra surfaces were prepared to delineate the distinct lithofacies within the Brown Niagaran, i.e., Flank, Windward, Leeward, and Reef Core. The gridded SEM covers an area 1200 m x 700 m, with a maximum height of ~180 m. Grid cells in the x- and y-directions were kept at 25 m, with variable thickness in the vertical (z) direction, resulting in a fine-scale 2853-layer model containing ~4,000,000 cells.

For property modeling, neutron porosity logs from seven wells were used, along with core-measured porosity-permeability data from core samples. The A-1 Carbonate had a porosity range from 3.16% to 10.72% with a permeability range from 0.00 to 6.04 mD. The Brown Niagara had a porosity range from 1.51% to 7.14% with a permeability range from .00 to 204.28 mD. Power law transforms were fit to both sets of data. The fine-scale 2,853-layer geologic framework was used with scaled-up log properties to build porosity and permeability property models. During this exercise, both porosity and derived permeability logs were sampled to the grid resolution and subjected to variogram analysis to characterize vertical heterogeneity in oil-bearing zones like the A-1 Carbonate Crest and the Brown Niagaran. The variogram model, along with well logs, were then used in a conditional simulation algorithm to populate the 3D SEM with the key petrophysical rock properties. This process required interpolating the upscaled log porosity and permeability values across the entire 3D model grid. The GRFS method was used for these models. The GRFS is a stochastic method that honors the full range and variability of the input data. Each run creates one equiprobable distribution of a property throughout a model zone based on a model variogram and upscaled well logs.

The permeability modeling effort focused on GRFS for the oil-bearing zones, which include the A-1 Carbonate Crest, A-1 Carb Flank, and Brown Niagaran reef. Starting from the core-based porosity-permeability transform for these zones, a permeability log is computed from the neutron porosity log. This method characterizes the permeability residuals and then, through conditional simulation, adds the permeability residuals to the basic transform. The resulting transform is conducted along the cells penetrated by the well trajectory. Permeability values at the off-well grid cells were distributed via GRFS via collocated co-kriging with the porosity model. The permeability model was simplified for the non-oil-bearing zones by using average values from core measurements. These zones include the Gray Niagaran, A-1 Salt, A-2 Evaporite, and the A-2 Carbonate. For modeling purposes, permeability for these zones are homogeneous.

Upscaling was then performed on the fine-scale model to create a tractable model for dynamic reservoir simulations using the Petrel plug-in called CONNECT UpGrid™. The optimal coarse-scale grid, which preserves an appropriate level of heterogeneity, was determined to be one with 79-layers containing 110,000 grid cells. Figure 2-68 shows the porosity and permeability distributions for a representative cross section in this upscaled model.

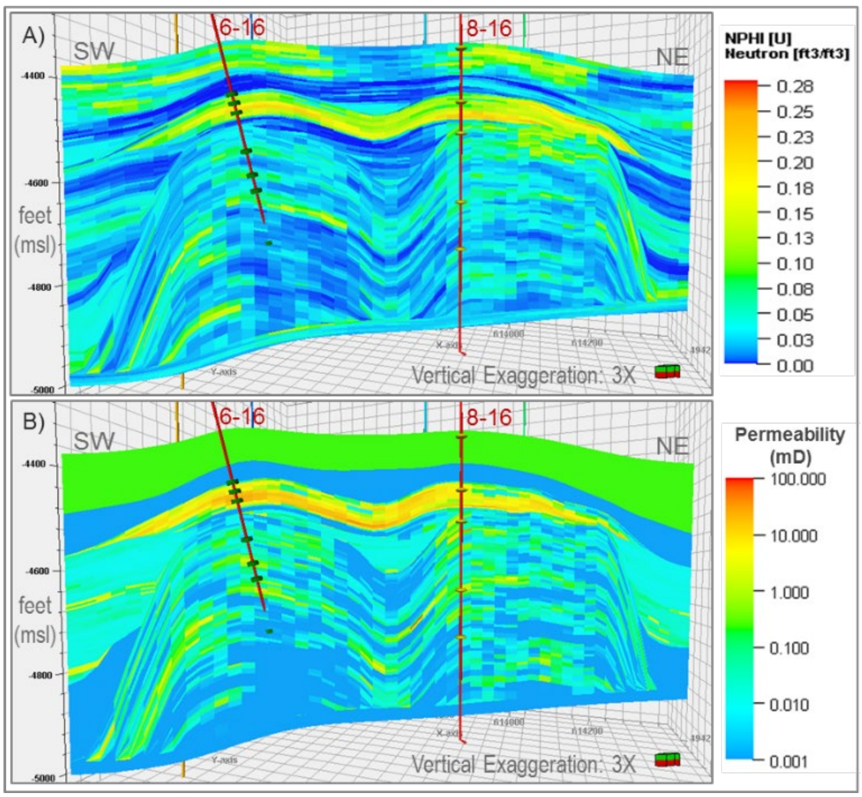


Figure 2-69. SEM upscaling results for the the 79-layer model. A) Porosity model. B) Permeability model.

Water saturation was calculated from resistivity log data in seven wells using Archie's equation. The distribution of water saturation in the model was separated into three regions. The lower third of the reef structure was assumed to be water saturated. Formations outside the oil-bearing zones were also assigned a value of Sw = 1. The oil-bearing zones, A-1 Carb Crest, the Brown Niagaran reef, and the A-1 Carb Flank (saddle region) are recognized as oil-bearing. Water saturation versus height above OWC was plotted individually for these zones. The Brown Niagaran employed a split on the basis of low (<3%) and high (>3%) porosity (or a pseudo rock-type), with the implication that the higher-porosity rock had a residual water saturation of around 0.15, while the lower porosity rock had an average residual water saturation of around 0.25. Most of the rock was of the low-porosity type and a curve fit of water saturation as a function of square-root of k/phi ($Sw=SQRT(k/\Phi)$) was used to model saturations for this region.

Volumetric calculations for this model yielded a pore volume of 5.2E7 ft^3, corresponding to an oil in place of 9.2 MM STB.

Dynamic Reservoir Modeling Results

All simulations were done in CMG's IMEX module, which assumes black-oil and pseudo-miscibility of CO_2. Performing simulations with this module is a computationally efficient alternative to full blown compositional simulation (CMG-GEM), where the mass transport associated with each individual component of the reservoir fluid is calculated on the gridded domain. The black-oil option simplifies the numerical model by capturing the volumetric expansion of only oil, gas, and water in each grid block and calculates the mobility of these fluid at a given pressure.

Per the objectives of this project and the uncertainties inherent in the modelling, we are satisfied learning about the general movement or extent of the CO_2 plume, the average pressure response, associated oil production rates and gross CO_2-storage capacity of Chester-16 with injection-production configuration. The data availability and computational-time constraints forced a trade-off where we chose general accuracy (pseudo-miscible mixing of CO_2 and oil via IMEX) over precision (fully compositional simulation via GEM) in this modelling effort.

Since laboratory measured fluid compositional data was unavailable, industry-standard correlations were used to generate black-oil properties (formation volume factors of oil and gas, solution gas-oil-ratio, oil and gas viscosity) as a function of pressure for the simulation. Inputs for applying these correlations are bubble-point pressure (~1800 psi), initial producing gas-oil-ratio (~650 scf/stb), stock-tank oil density (51.2 lb/ft3) and gas-gravity (0.83). In CMG-IMEX's pseudo-miscible module, CO_2 is assumed to be insoluble with formation water but assigned an omega (mixing) parameter of 0.7 at the miscibility pressure of 1,300 psi and above, and a 0 at sub-miscible pressures.

The objectives (performance indicators) of the history match were to: (1) honor all individual well oil production rates via the oil constraints, (2) honor individual water injection and CO_2 injection rates, (3) reproduce the pressure decline history recorded from the primary production period and at abandonment after waterflooding, and (4) reproduce the pressure deflections recorded at the various depths (gauges) of the 8-16 monitoring well during CO_2 injection through the 6-16 injection well.

History matching of the Chester-16 reservoir model was a highly iterative process, assessing model sensitivity to individual parameters via numerous forward simulations testing various parameter combinations in trial-and-error. Meeting objectives (1) to (3) involved revising the permeability field through the various layers. Significant uncertainty exists as to the allocation of the CO_2 injection rates between A1 Carbonate and the Brown Niagaran. As a result, meeting objective (4) required estimating the CO_2 injection volumetric split between the A-1 Carbonate and the Brown Niagaran that could reproduce the appropriate pressure deflections at various depths.

A significant component of the history matching workflow involved adjustment of permeability values. After extensive manual trial-and-error attempts, a total of 17 regions of permeability modification/enhancement were implemented. Three permeability groups were identified in the A-1 carbonate from the SEM, generally representing permeability within two orders of magnitude. The Brown Niagaran on the other hand, is a generally more heterogeneous rock and thus had more permeability groups representing a much wider range (four orders of magnitude). Well testing data also pointed toward a thin but contrastingly low-permeability region at the base of the A-1 Carbonate (a baffle), in between the saddle region and the A-1 carbonate. This layer was assigned a low permeability of 0.01 md. Finally, the well-test also suggested that the saddle region itself had a very low overall permeability of 0.001 md. All other rock layers – the Gray Niagaran and all the outermost flank layers to the Brown Niagaran — retained the very low permeabilities assumed in the original.

A uniform permeability high perm streak was introduced to the middle of the Brown Niagaran to meet oil production constraints with a model that retained the heterogeneity. While the porosity distribution in those layers was retained, the permeability heterogeneity in these layers was removed in favor of a uniform and layer-wide homogeneous permeability of 40md. Additionally, some gridblocks were manually assigned a permeability value, depending on their porosity value. The history matching process has (1) lowered the overall heterogeneity in the entire model, (2) consistently increased permeability in the entire model by at least one order of magnitude, and (3) introduced a horizontal permeability streak in the Brown Niagaran that is surrounded by a low background permeability.

Figure 2-69 shows that the history matched model adequately captures the average reservoir pressure decline even though continuous pressure decline data was unavailable. The model correctly predicts a post-waterflood, abandonment pressure of around 500 psi. With updated permeability field, the model was able to meet the oil production constraints for all five wells to match the field cumulative production. The model's prediction of gas production captures both the global trend in gas production as well as the overall cumulative produced volume. Water production data for the life of the field was unavailable.

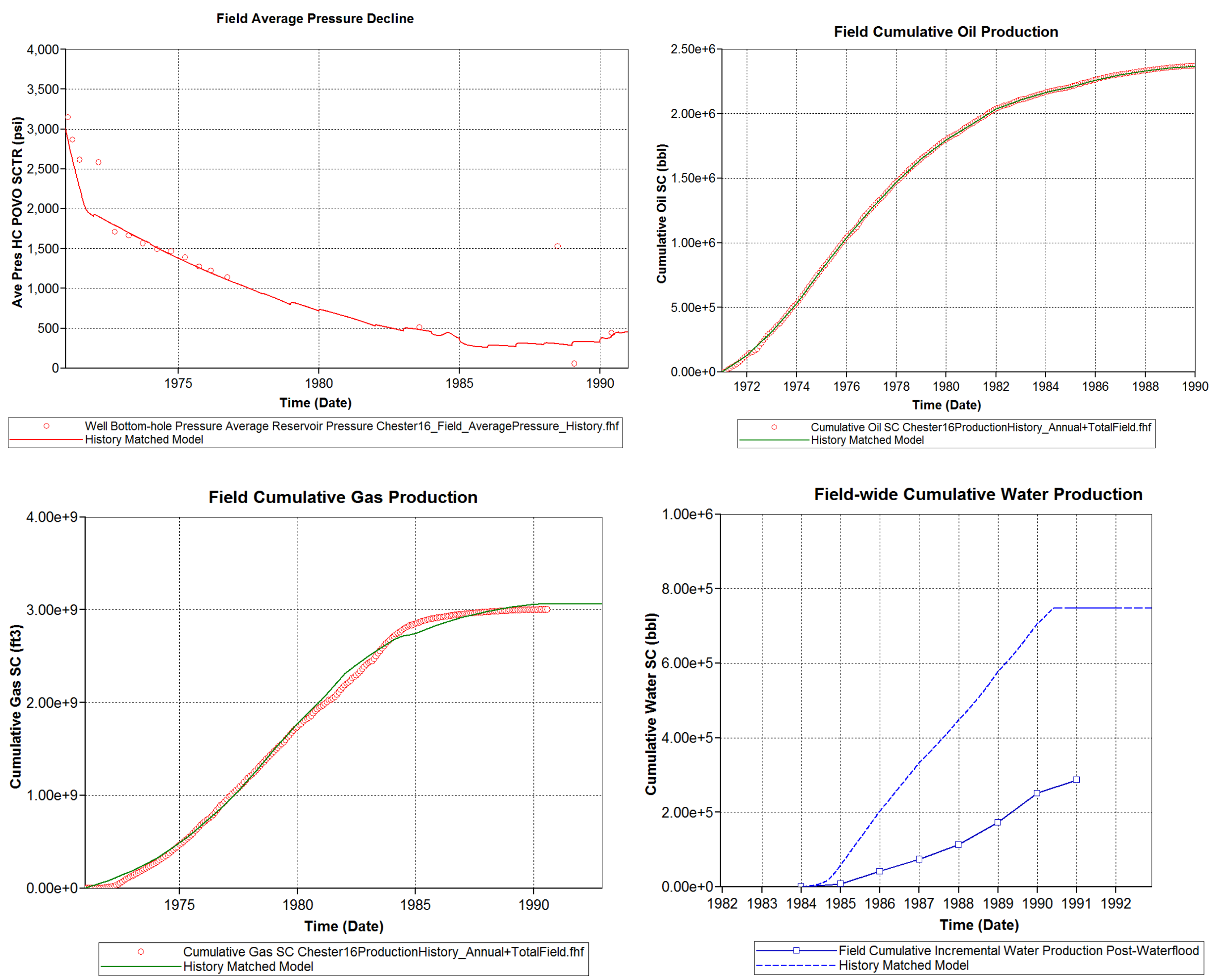


Figure 2-70. (A) Actual (field) CO_2 injection volume versus fitted data using simplified model (B) estimation of R^2 in different time interval.

Although incremental water production data from after the waterflood was available, it is still a source of uncertainty. The current model overpredicts the water production from this period considerably. Attempts to match this level of water production by lowering water-oil relative permeability endpoint was not successful as it results in lower oil production and higher average pressure.

The quality of the match during the CO_2 fill up phase is an indication of the reliability of the permeability field and the CO_2 injection rates allocated to the individual formations (and perforations). The match to the bottomhole pressure data at various depths in the location of the 8-16 well is the primary performance indicator. Several different rate allocations were attempted in trial-and-error, due to the non-uniqueness of the history matching problem.

Figure 2-70 (left) shows that the match to the pressure in the middle of the A-1 Carbonate at the 8-16 well is good. The initial pressure prior to CO_2 injection has been matched nearly exactly. The model also captures the timing of the first arrival of the pressure pulse from the injection closely. The pressure at the end of injection has also been matched nearly exactly. However, the transition from the initial condition to the final has not been fully replicated. Figure 2-70 (right) also shows the match to the pressure in the middle of the Brown Niagaran at the 8-16 well. The initial pressure prior to CO_2 injection has been matched within 50 psi, although the pressure at the end of injection is off by around 150 psi. However, the transition from the initial condition to the final has not been replicated, nor has the pressure pulse arrival time. Because (1) the Brown Niagaran is over 300 ft thick and highly heterogeneous and the A-1 Carbonate is relatively thin homogeneous rock in comparison, and (2) the simulator employs a less rigorous pseudo-miscible black-oil model, such that matches for the Brown Niagaran are not expected to be as good.

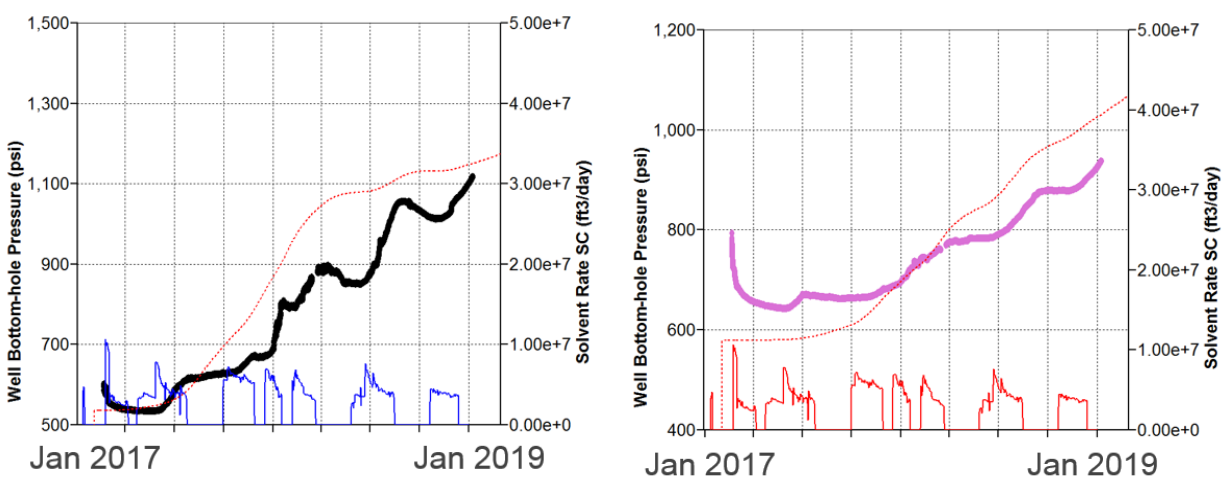


Figure 2-71. History match to the pressure response at the top of the Brown Niagaran, as measured at the 8-16 gauge.

Next, several "what-if" scenarios were investigated for the CO_2-EOR period after the reef was pressurized beyond the minimum miscibility pressure target of 1300 psi. These 10 scenarios collectively investigated the use of vertical versus horizontal wells, production of A-1 Carbonate versus Brown Niagaran, and location of injectors/producers. The forward simulation for each scenario used an injection rate constraint that was capped at 6 MMSCFD, and a maximum bottom-hole pressure of 4000 psi. Also, total fluid rates of the injected and produced volumes were to be kept approximately equal for pressure maintenance.

Figure 2-71 summarizes the performance of these scenarios, with each metric normalized to the highest quantity observed across all 10 scenarios. Scenarios 3, 8, 9, and 10 stand out for producing the most oil while accompanied with the lowest levels of CO_2 injection required. From these, Scenario 9 ranks best in terms of needing the lowest amount of CO_2 injected, and yet storing the most CO_2. Scenario 9 thus appears to be optimal for both CCUS and CO_2-EOR from this ranking analysis, followed by Scenario 3.

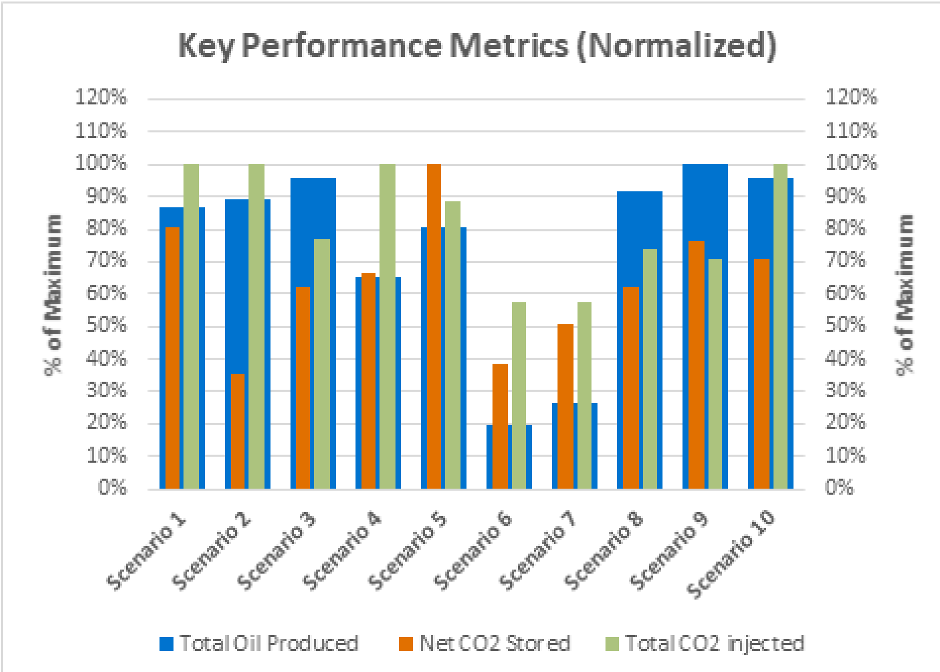


Figure 2-72. Comparison of all scenarios against each other in terms of oil recovery, CO_2 injection and CO_2 stored. Each performance metric is expressed as a percentage of the maximum observed across all 10 scenarios.

2.4.3 Coupled Process Modeling

2.4.3.1 Geochemical

This task was performed as part of the dynamic modeling activities for the Dover-33 reef to demonstrate capability to model geochemical effects of CO_2 injection within a dynamic modeling framework. This task aimed to implement multicomponent flow simulation coupled with phase and chemical equilibrium and rate-dependent mineral dissolution/precipitation to evaluate effects of geochemical processes on short-term observed pressure response during the injection period as well as longer-term behavior associated with CO_2 storage processes.

Methodology

The system of interest considered for the current study was a simplified equivalent coupled flow-geochemical model in CMG-GEM® consisting of a core reservoir region with an overlying low permeability zone and an underlying water column with logarithmically increased grid spacing in the radial direction to ensure more resolution closer to the well where most of the dynamic processes would be centered. This radial model was set up in a fully compositional setting to represent a depleted oil reservoir with one vertical CO_2 injection well to incorporate relevant field data. It was subject to an assumed CO_2 injection period to assess the impact of geochemical reactions on the observed pressure buildup during injection and the fate of the CO_2 through an extended 1000 year post-injection monitoring period.

The methodology involved the following key steps:

1. The reference simplified representative model involving CO_2 injection in a depleted oil reservoir without geochemistry was implemented in CMG-GEM®.
2. Required geochemistry-related input data such as minerology and fluid sampling data from the field, as well as previous equilibrium model considerations for the Dover-33 reef, were collected.
3. The geochemical module was included and set up in GEM for the CO_2 injection period and the simplified representative reef model was re-initialized.
4. Basic numerical sensitivity analyses were run to observe impact of geochemical reactions during and after the defined CO_2 injection period in the depleted oil reservoir and the coupled flow-geochemical model was compared with the reference model without geochemistry.

The geochemical modeling under CO_2 injection conditions considered the following important factors affecting CO_2 sequestration: (1) the kinetics of chemical interactions between the host rock minerals and the aqueous phase, (2) CO_2 solubility dependence on pressure, temperature, and salinity of the system, and (3) redox processes that could be important in deep subsurface environments.

Results

For the given system, the pressure response and propagating CO_2 front show minimal differences during the period of CO_2 injection between the reference and coupled models. During later times in the post-injection period however, there are noticeable differences in the results between the models with respect to the movement of the gas front and reservoir pressure. The effect of considering the aqueous and mineral reactions in the system of interest thus impacted the longer-term pressure response (Figure 2-72) and the plume progression during the 1000-year post- CO_2 injection period. The phase distribution of CO_2 in the system was studied as the system worked to retain a new equilibrium during the post-injection period with the CO_2 in the system slowly moving into more stable dissolved phases.

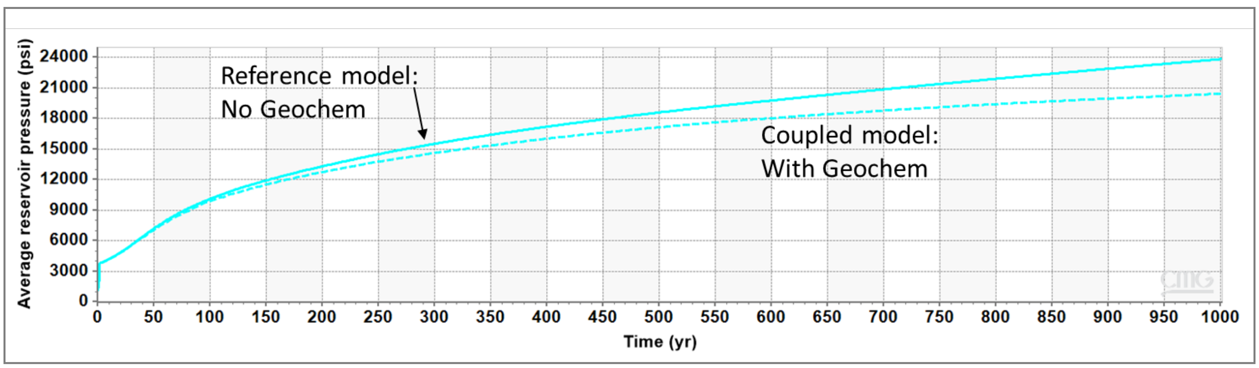


Figure 2-73. Comparison of the average model pressure until the end of the post-injection period. The reference model with no geochemistry is shown as continuous curves while the geochemistry-coupled model for the CO_2 injection period is shown as dashed curves. The effect of these geochemical reactions can be seen by the divergence in the average pressures post 100-years of injection.

Figure 2-73 shows the evolution of the total moles of HCO_3^-, CO_2 in dense phase, and dissolved CO_2 in the system of interest. The presence of low pH brine with high Cl- in the assumed minerology results in a negative saturation index that drives the dissolution of dolomite and calcite present in the reservoir rock. However, the extent of this dissolution occurring in the chosen system of interest was not seen to significantly impact the porosity or hence the permeability of the rock. Basic sensitivity analyses to reservoir permeability and brine pH were performed to investigate the potential impact of basic reservoir and in-situ brine properties on the rate of aqueous and mineral reaction rates in the system of interest.

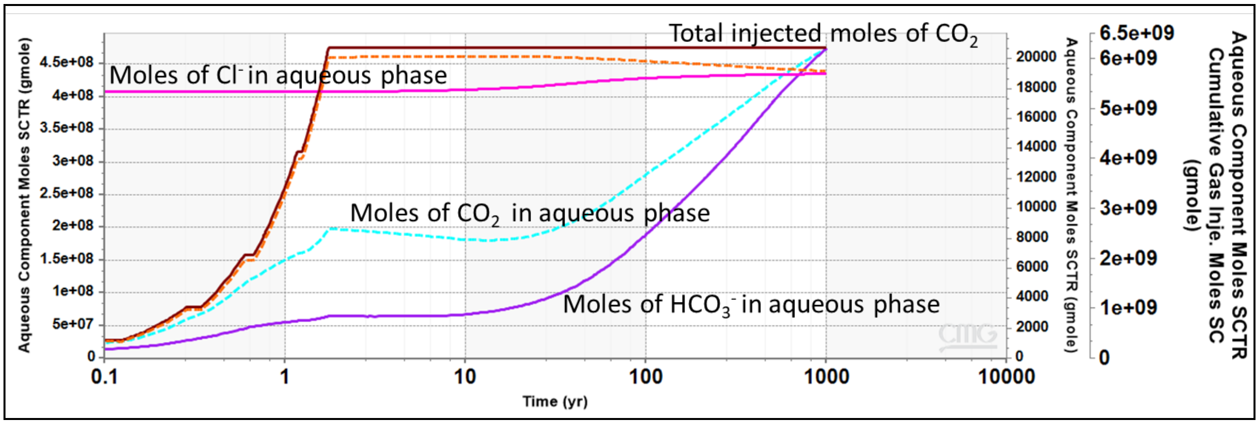


Figure 2-74. Evolution of CO_2, HCO_3^- and Cl^- until the end of 1000 years in the coupled model. After the injection period, the moles of dissolved CO_2 increase as more CO_2 goes into solution with decreasing moles of CO_2 in the supercritical phase (orange dashed line).

Coupled reservoir models are useful to simulate many relevant subsurface processes as demonstrated in the reef modeling exercises, with the brine composition and minerology determining the longer-term system response. The input parameters, however, need to represent in situ field conditions and need validation through detailed site-specific field testing for these models to be as accurate and reliable as possible in practical applications.

2.4.3.2 Geomechanical Modeling

Understanding the geomechanical outcomes of CO_2 storage into geological formations is necessary since it affects CO_2 injectivity, reservoir mechanical integrity, and safety of the potential injection site. To ensure that the mechanical integrity of the reservoir caprock system is maintained during injection, in-situ stress changes caused by pore pressure changes (i.e., poroelastic effect of injection) should be investigated. Poroelastic effects of injection determine the final stress state in the reservoir as a precursor for evaluating tensile and shear failure potential. The final in-situ stress also limits practical injectivity of the reservoirs. Ground surface uplift and induced seismicity, which could have a detrimental effect on the safety of the injection site and its surrounding area, also depends on the poroelastic effect of injection. The main goal of the geomechanical modeling is to investigate the poroelastic response of CO_2 injection into the Niagaran carbonate reef system. The poroelastic effects, investigated in this work, include stress changes, reservoir deformation, and surface uplift due to CO_2 injection into the reservoir.

Methodology

Statistical-based models were developed to provide a quick tool to evaluate the poroelastic effect of injection. A combination of experimental design for seven independent parameters (depth, caprock and reservoir Young's modulus, caprock and reservoir Poisson's ratio, pressure, and Biot's coefficient) and response surface modeling was used to develop statistical-based reduced-order models. We performed 147 numerical simulations to develop simplified models for the reefs. The poroelastic model responses were captured using a standard quadratic model with full interaction terms, as well as a reduced model with only statistically significant coefficients. Reduced-order models were then combined with a Monte Carlo simulation to perform poroelastic uncertainty analyses and better understand the poroelastic performance of CO_2 storage in the closed carbonate system of the Michigan basin. We also used coupled hydromechanical simulations as a second objective of the geomechanical modeling to estimate stress changes and surface uplift due to injection into a depleted reef (i.e., Dover-33 reef).

Results

Four poroelastic responses, evaluated using statistical based modeling, include: I-stress (horizontal stress) increment, K-stress (vertical stress) increment, reservoir vertical displacement, and surface uplift. Figure 2-74 shows the response surface plot for various combinations of reservoir block pressure and reservoir depth using statistical based models. When pressure increases, surface uplift increases. Decreasing depth causes surface uplift increase. The result of the statistical based modeling shows that each reservoir type has different control parameters for each performance metric. The pressure increase is the main parameter that controls stress increase, reservoir displacement, and surface uplift. While the reservoir depth is a significant parameter to predict surface uplift, Biot's coefficient is the main parameter to evaluate horizontal stress increase.

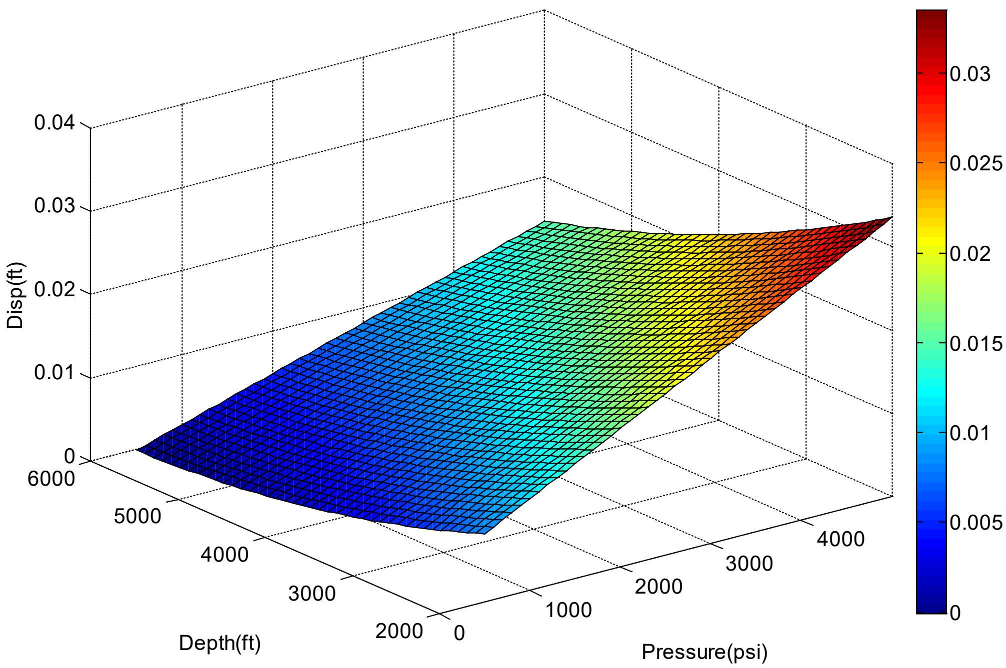


Figure 2-75. Surface uplift response surface based on reduced order model to estimate surface uplift

A stress independent constant Biot's Coefficient has typically been used to estimate poroelastic response of injection such as surface uplift modeling, reservoir stress path prediction, and fault activation. Numerical hydromechanical models were used to estimate the poroelastic response of injection by considering Biot's Coefficient dependency to the effective stress (as the second objective of geomechanical modeling). The modeling results demonstrated how the assumption of a constant Biot's Coefficient affect geomechanical responses of the subsurface injection. Modeling results showed that using a constant Biot's Coefficient would be inaccurate since effective stress changes cause Biot's Coefficient increase.

Coupled hydromechanical modeling is typically used to evaluate the poroelastic effect of injection as well as the resulting geomechanical outcomes. Solving several equations over many grid blocks numerically can be computationally expensive. As a result, statistical-based models were developed to provide a quick tool to evaluate the poroelastic effect of injection. Using the simple statistical based mechanical model, the screening process to select the best site for CO_2 sequestration, in terms of mechanical integrity, could be more efficient.

2.4.4 Key Findings from Modeling

2.4.4.1 Static Earth Modeling

A SEM workflow common in the oil and gas industry has been used in these studies using the Petrel software. The geologic framework was first established from seismic and geophysical log analysis. Property modeling for porosity and permeability involved geostatistical simulations using porosity-permeability transforms. Several lithofacies were identified from geological considerations, but the geometry and properties of some of the lithofacies can be highly uncertain because of limited sampling via wells and/or cores and the heterogeneous nature of the geological deposition of the pinnacle reefs. Water saturation data were derived from geophysical logs or modeled using capillary pressure and Leverett J-function concepts. Volumetric calculations for original oil in place were cross-checked against material balance analysis results to verify the property modeling. Another key feature was SEM upscaling (coarsening of the geocellular grid) using CONNECT UpGrid™, a Petrel plug-in. This application, which scales the grid-based on the vertical distribution of porosity, is an enhancement over arbitrarily changing a model's layer count through the standard proportional layering method independent of the variation in rock properties. Model cell counts can be reduced by ~80% while preserving the key patterns of geologic heterogeneity. In the Chester 16 reef, a porosity cube inferred from seismic inversion was used to update and condition property models. In general, it was possible to repeat the workflow across multiple reefs, subject to the availability of well log data, core data, and seismic inversions (when available) that spanned each of the reefs (and the lithofacies therein) in a representative manner.

- ***What we did***: developed static earth models using standard oil and gas workflows including geophysical log and seismic data integration and rock property modeling
- ***What was new and improved***: geostatistical porosity-permeability modeling; grid upscaling to reduce cell size, porosity cube from seismic inversion
- ***What were remaining uncertainties***: geometry and location of lithofacies, constraints on inter-well property estimates from seismic inversion

2.4.4.2 Dynamic Reservoir Modeling

Two types of grid-based dynamic simulations were carried out: (a) compositional simulations (Dover 33), and (b) pseudo-miscible black-oil calculations (Bagley, Chester 16). Computation intensive compositional simulations require detailed oil sample characterization and experimental data on fluid properties as well as equation of -state based fluid property modeling. The pseudo-miscible option is computationally efficient, requires only a few adjustable parameters, and is reasonably accurate. History matching of the primary production and subsequent CO_2 injection history with both modeling options generally involves significant adjustment to the initial permeability field (often derived from porosity to -permeability transform functions derived from laboratory porosity and permeability data). This suggests that the small-scale core-derived porosity-permeability transforms may not be a good representation of field-scale permeability distribution, especially in a carbonate reservoir setting. Nonetheless, the history matching process was able to suggest large-scale permeability trends in Dover 33 and Chester 16 that appear to be geologically reasonable (albeit unsampled because of limited number of wells).

Data availability can also impact the quality of history matching because of issues such as: (a) limited static bottomhole pressure data from the historical primary production period, (b) questionable water production data that have an impact on reservoir voidage calculations, and (c) uncertain apportionment of injection volume between multiple permeable zones. In addition, pressure volume temperature (PVT) data from each reef was not always available, and data from the best analog reef was used as a proxy.

This is also another source of uncertainty. Finally, oil-water and oil-gas relative permeability relationships are generally not available and have to be assumed. Even a limited number of laboratory experiments would be useful in constraining end point saturations, end point relative permeabilities and the curvature of the relationships.

The application of the history matched model for forecasting CO_2 EOR and associated scenarios in Chester 16 was helpful in elucidating the relative efficacy of vertical versus horizontal wells, location of producers versus injectors, and incremental recovery versus associated CO_2 storage.

In Bagley, a simple homogenous model is used to history match the primary production data, as opposed to having an unnecessarily complex heterogenous complex static geological model. The simple model can also match the CO_2 injection pressure history. This suggests that production and pressure response can be represented using a simple reservoir model. The uncertainty for the modeling comes from the lack of input data like seismic data.

In order to conduct a rapid, simplified analysis of the reservoir injectivity and capacity, the lumped parameter CRM was successfully applied for the CO_2-injection only period of the MRCSP injection in the reef. CO_2 injectivity in closed, depleted oil reservoirs is affected by the phase changes and interactions with the existing fluid phases as well as with the rock itself. The average representative injectivity index (stabilized flow rate normalized by pressure buildup) from the CRM was found to concur with an independent injectivity analysis done for the reef. The model also addressed uncertainty in the initial pressure estimate for the reef with the resulting compressible pore volume found to be consistent with total system compressibility representative of typical oil and gas systems. In addition, the resulting fitted model has the potential to serve as a rapid forecasting tool for a quick prediction of the pressure buildup or rate for a desired target injection scenario in the future.

- ***What we did***: dynamic grid-based simulations using compositional and pseudo-miscible modeling approaches based on the SEMs developed in this project and lumped parameter capacitance-resistance modeling to match pressure-production/injection data
- ***What we learned***: manual history matching can be tedious and non-unique, initial permeability fields (generated from core porosity-permeability transforms) may need to be significantly adjusted, calibrated models can be useful for evaluating EOR related well-placement options, and CRM models can be useful forecasting tools with limited data
- ***What were remaining uncertainties***: availability of pressure data during primary production, quality of water production data, lack of experimental PVT data, and relative permeability information

2.4.4.3 Coupled Process Modeling

The coupled flow-geochemical modeling task successfully utilized a simplified 2-D radial model using relevant rock and fluid data from the field to generate synthetic pressure responses following CO_2 injection into a depleted oil reservoir. The brine composition and minerology determine the tendency and rate of mineral dissolution/ precipitation. The effect of considering the aqueous and mineral reactions in the system of interest impacted the longer-term (post 100-years of injection) pressure response and the plume progression during the 1000-year post- CO_2 injection period. The CO_2 injected in the system slowly moved into more stable dissolved phases in the post-injected period to attain a new system equilibrium. The accuracy of such coupled models depends upon input parameters representative of in situ conditions and need validation through detailed site-specific field testing to provide practical and relevant results.

Geomechanical processes associated with CO_2 sequestration should be investigated to ensure long-term safe storage of CO_2. To that end, impacts such as surface uplift, reservoir expansion, and in situ stress changes have been studied using statistical based reduced order models (developed from coupled flow and geomechanics model results). This approach provides a tool to evaluate the poroelastic response of injection whenever practical limitations (budget and time) require a quick response. A key insight from these studies was that fracture pressure increases during injection due to poroelastic effects. In fact, the main reason that hydraulic fracture test shows such a low fracture pressure is that minifrac test was performed when the reef was depleted from primary oil production to low pore pressure (~500 psi). Data limitations are a major challenge for geomechanical studies. Therefore, additional field and laboratory data should be collected on geomechanical properties of the overburden and the formation.

- ***What we did***: coupled fluid flow and geochemical modeling to understand chemical reactions after CO_2 injection, developed statistical proxy models based on coupled fluid flow and geomechanical modeling to predict surface uplift, reservoir expansion, and in situ stress changes from CO_2 injection
- ***What we learned***: aqueous and mineral reactions are slow but can impact pressure response in ~100 year time frame and plume progression in the ~1000 year time, fracture pressure increases during injection due to poroelastic effects, proxy models can capture the behavior of full-physics geomechanical models with good accuracy.
- ***What were remaining uncertainties***: reactive transport parameters representative of in situ conditions, availability of in situ field testing for modeling model validation, field and laboratory data collection to provide formation geomechanical properties.

2.5 Moving towards Commercialization

As Phase III of MRCSP drew to a close, the partnership was working to lay the groundwork for future CCUS projects. This work will apply lessons learned in the demonstration project to develop strategies for scaling up and commercializing CCUS across the region.

The final phase of the MRCSP project has been focused on addressing critical challenges for commercial-scale CCUS and EOR in the region. Some of these include:

- Translating the success of the 1 MMT demonstration project at the Northern Niagaran Pinnacle Reef Trend to the whole region to drive a net reduction of regional greenhouse gas emissions.
- Overcoming the barriers and challenges to successful CCUS and CO_2-EOR in the region, including challenges related to technology, economics, policy, regulation and stakeholder acceptance.

The MRSCP team conducted a Greenhouse Gas Emissions lifecycle analysis (GHG LCA) to determine the net emissions and success of the demonstration project. Additionally, they used the information learned through field activities, geologic characterization, modeling, and monitoring to help develop a successful, EPA approved monitoring, reporting, and verification plan for the project operator (Core Energy, LLC). The results of these two studies are summarized in this section.

2.5.1 Measuring the Success of CCUS: Greenhouse Gas Lifecycle Analysis for CO_2-EOR in the Northern Niagaran Pinnacle Reef Trend

To evaluate the feasibility of scaling up CCUS and EOR across the region, MRCSP addressed two critical questions about the outcomes of the Michigan Basin demonstration project:

- What is the *net* volume of CO_2 stored during CCUS-EOR activities, after considering the greenhouse gas emissions generated during capture, gate-to-gate CO_2-EOR operations and downstream activities?
- When considering emissions across the entire lifecycle, did the project meet its goal of reducing overall greenhouse gas emissions?

To answer these questions, MRCSP completed a GHG LCA of CO_2-EOR activities in the NNPRT in the Task 3,4, and 5 reefs. The LCA analysis spanned EOR activities from 1996 to 2017, including both the MRCSP project and prior EOR activities in the NNPRT. The analysis looked at greenhouse gas emissions generated vs. carbon stored for all stages of the EOR lifecycle (Figure 2-75).

- Upstream (CO_2 capture from Antrum shale gas fields)
- Gate-to-Gate (CO_2 compression, dehydration, pipeline transport, injection, oil processing)
- Downstream (Crude oil refining, fuel transport, combustion of fuel produced through EOR activities)

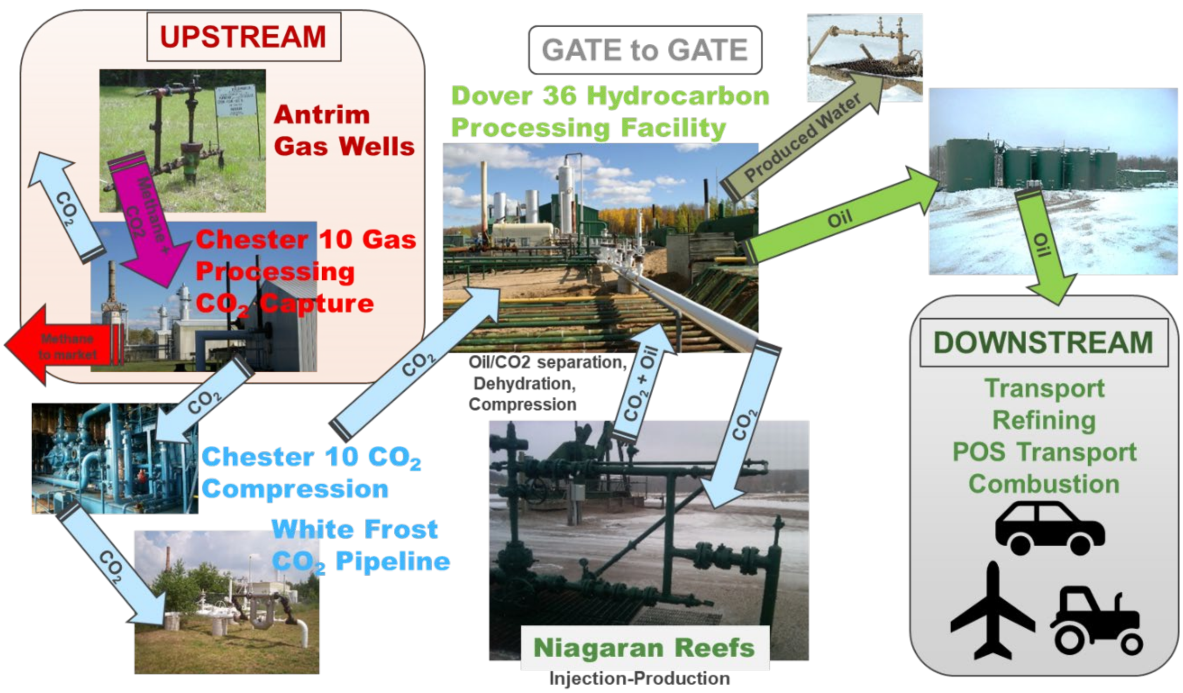


Figure 2-76. Illustration of key components contributing to the net CO_2 emissions from upstream to downstream.

The goals of the LCA were to:

- Analyze emission factors across all stages of lifecycle for CO_2-EOR operations in the NNPRT (Figure 2-76).
- Determine cumulative greenhouse gas emissions for 22 years of CO_2-EOR operations.
- Calculate net emissions (emissions from “cradle to grave” operations – CO_2 stored via CCUS) for CO_2-EOR activities.
- Find opportunities to further reduce emissions at different stages of the lifecycle.

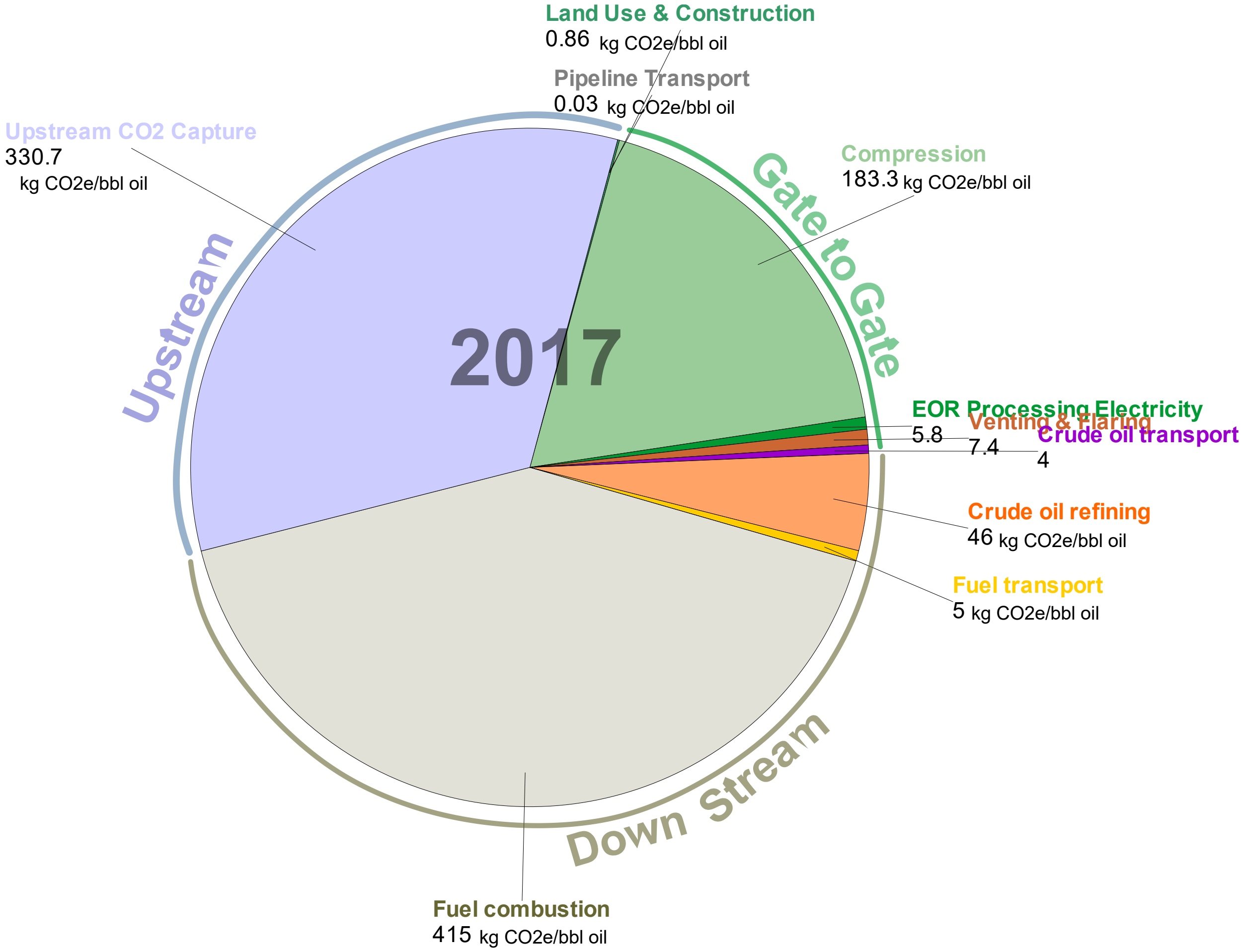


Figure 2-77. Summary of emission factors for 2017 Lifecycle Analysis for Northern Niagaran Pinnacle Reef Trend CCUS-EOR Operations. In 2017, 64,443 metric tons of CO_2 were emitted during upstream capture, 38,495 metric tons of CO_2 were emitted during EOR operations, and 91,614 metric tons of CO_2 were emitted during downstream oil transport, refining, and combustion. 298,010 metric tons were stored via CCUS, resulting in net CO_2 emissions of -103,468 metric tons.

The analysis showed that more CO_2 was stored than emitted over the course of CO_2-EOR operations in the NNPRT, resulting in a net reduction in greenhouse gas emissions of ~160 kt (Figure 2-77). In other words, EOR activities reduced overall emissions in the region even when accounting for the emissions produced during operations and as a result of combusting oil that would otherwise not have been captured. This suggests that CCUS and EOR provide a viable option for reducing overall greenhouse gas emissions in the Midwest region while at the same time increasing oil production from existing wells.

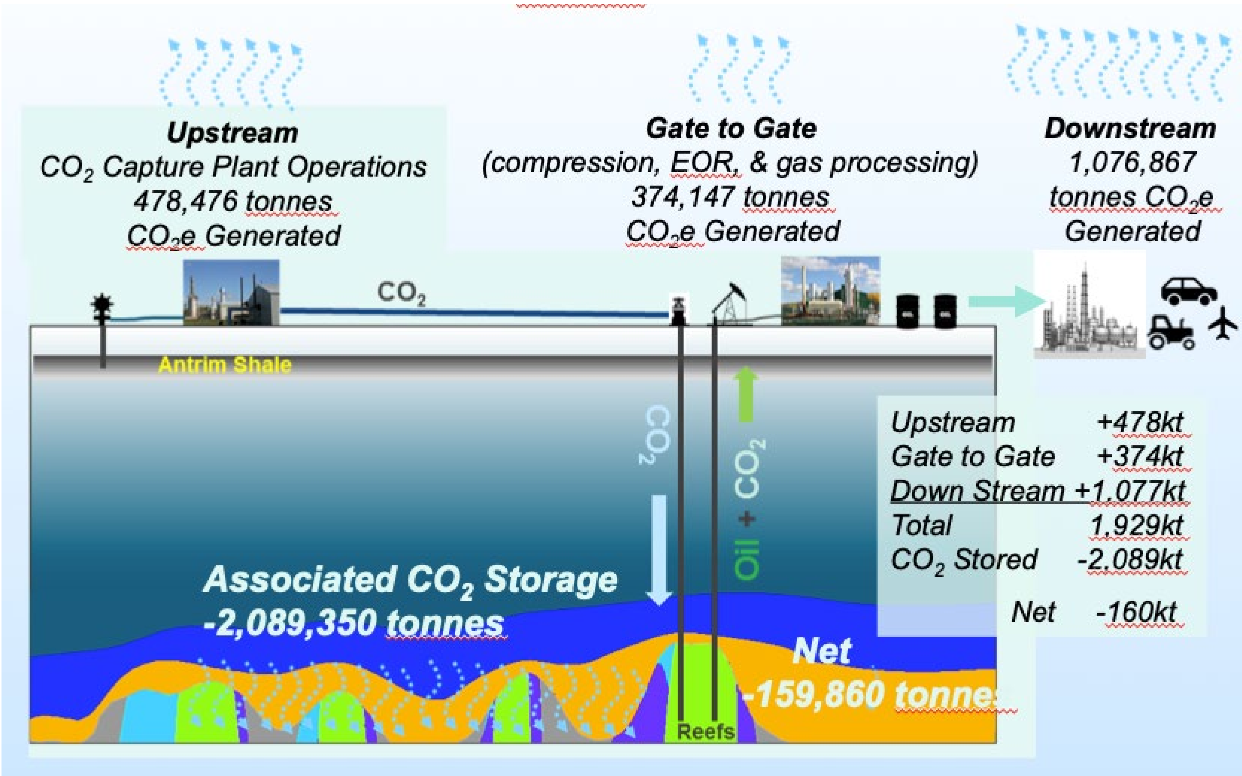


Figure 2-78. Total LCA Results, 1996 – 2017. Over this time period, 2,089,350 metric tons of CO_2 were stored via CCUS. Total emissions across the lifecycle—including upstream, gate-to-gate, and downstream activities—were 1,929,443 metric tons, resulting in net emissions of -159,907 tons.

2.5.2 Monitoring, Reporting, and Verification Plan (MRV) for Greenhouse Gas Reporting

The Greenhouse Gas Reporting Program (GHGRP) was developed to track greenhouse gas data and other information from emission sources, fuel and industrial gas suppliers, and CO_2 injection sites. As part of this program, methodologies were developed to quantify and account for emissions and stored CO_2. One such method is through Subpart RR, for the geologic sequestration of carbon dioxide. This rule is complementary to the EPA's requirements for UIC Class VI wells and can be used to meet the requirements for the 45Q Tax credits.

As part of MRCSP, Battelle supported Core Energy's efforts to develop a Monitoring, Reporting, and Verification Plan (MRV) to meet the GHGRP requirements. The MRV plan went through multiple iterations with formal and informal meetings with the EPA. The plan was accepted in December 2018. Figure 2-78 illustrates the process of creating the MRV plan.

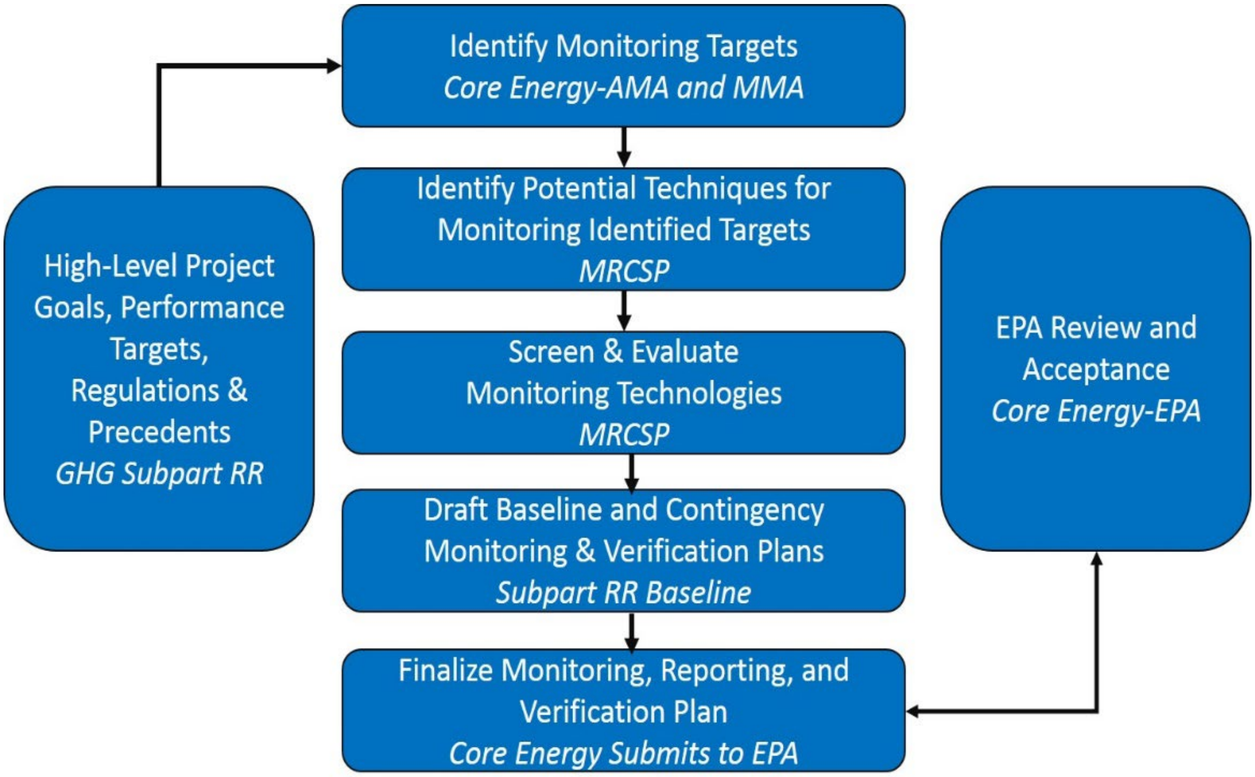


Figure 2-79. Simplified flow diagram of the process for developing an accepted MRV plan.

To qualify for the 45 Q tax credit, captured CO_2 must be safely and permanently stored in secure geologic formations or utilized in other projects that permanently sequester the CO_2. Entities seeking to claim the credit for CCUS projects must:

- Identify a suitable storage site.
- Conduct characterization and modeling to demonstrate that the site has sufficient storage potential and will safely and permanently sequester the CO_2.
- Have an EPA-approved MRV plan to ensure that CO_2 is staying in the formation and not migrating back out to the atmosphere.

The MRV plan includes seven components:

1. A delineation of the maximum monitoring area (MMA) and active monitoring area (AMA)
2. Identification of potential surface leakage pathways
3. A strategy for detecting surface leakage
4. A strategy for determining monitoring baselines
5. A discussion of any site-specific variables needed for the mass balance calculations
6. Identification numbers for UIC permitted wells
7. The planned start date for reporting

EPA requires the following information to be included in the MRV plan and to be reported annually:

1. The mass of CO_2 injected into the subsurface.
2. The mass of CO_2 produced from oil or gas production wells or from other fluid wells.
3. The mass of CO_2 emitted from surface leakage.
4. The mass of CO_2 emissions from equipment leaks and from vented emissions of CO_2 sources between the injection flow meter and the injection wellhead and between the production flow meter and the production wellhead.
5. The mass of CO_2 sequestered in subsurface geologic formations, calculated by subtracting total CO_2 emissions from CO_2 injected in the reporting year.
6. The cumulative mass of CO_2 reported as sequestered in subsurface geologic formations in all years since the facility became subject to Subpart RR.

2.5.2.1 Active and Maximum Monitoring Areas

The modeling and extensive history of oil and gas production in the NNPRT have demonstrated the varying degree of compartmentalization of the reefs and the efficiency of the overlying evaporites and carbonates as seals. The reefs act as a closed reservoir system, which provides excellent conditions for CO_2-EOR operations. Thus, the AMA is defined as the boundary of each reef. The MMA at a minimum has to be defined as a ½ mile buffer around the AMA. In this case, the MMA was defined as a ½ mile buffer around the entire NNPRT which allows for future growth (Figure 2-79).

2.5.2.2 Identification of Potential Leakage Pathways

Knowledge gained through the long history of oil and gas production in the Niagaran reefs coupled with the regional geological characterization conducted were used to identify and assess potential pathways for leakage of CO_2 to the surface (www.MRCSP.org). The following potential pathways were reviewed, and the results summarized:

- Existing wellbores- a systematic wellbore integrity evaluation showed that while leakage through a wellbore was possible, the wells were constructed ideally to prevent such leakage. Routine monitoring of active wellbores through the use of bottom hole pressure and wellhead inspections are used to identify any potential active leaks.
- Faults and fractures- Northern Michigan has few identified faults, all of which are deep basement faults, 100s of feet below the injection zone and do not influence the integrity of the seal system.
- Natural and induced seismic activity- The region is structurally stable with no recorded seismic events and a low risk. The 2D and 3D seismic data show no immediate structural concerns and microseismic monitoring showed no meaningful events.
- Lateral migration outside of a reef- The reefs are laterally sealed by non-porous evaporites (salt and anhydrite), shale, and carbonate. Monitoring and modeling activities demonstrate there is no lateral migration.
- Diffuse leakage through the seal- The reefs are overlain by thick deposits of evaporites, shales, and carbonates, which is hundreds of feet thick. That along with the history of successful oil and gas production demonstrate the low probability of diffuse leakage through the seal.
- Pipeline/surface equipment- Leakage through pipeline and surface equipment is a potential risk. This is minimized by routine maintenance, daily inspections, and mass balance accounting.

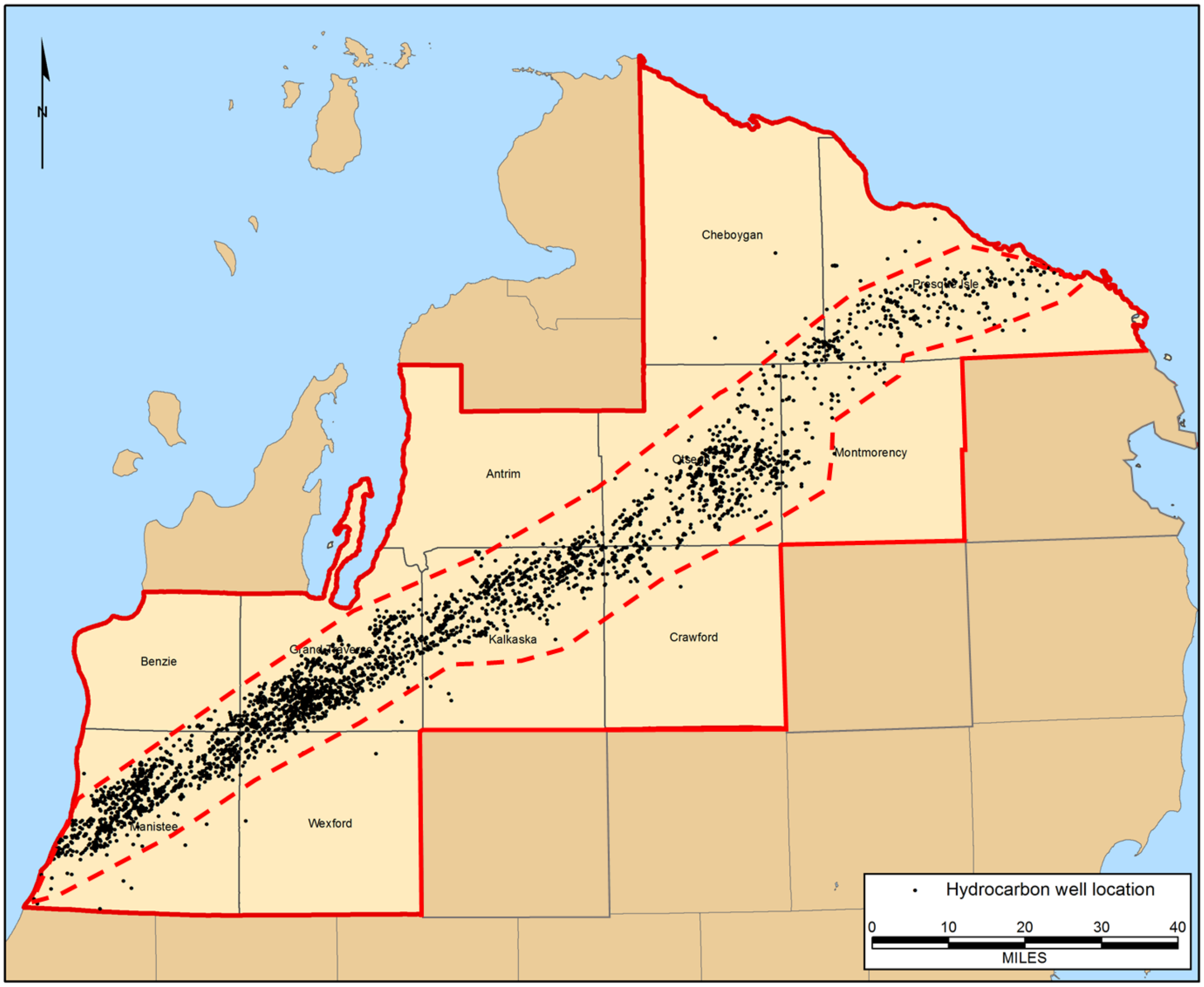


Figure 2-80. Areal extent of the maximum monitoring area (MMA) shown as the dashed red line, which includes the hydrocarbon bearing pinnacle reefs in the NNPRT.

2.5.2.3 Mass Balance Accounting for Monitoring and CO_2 Quantification

As part of its ongoing operations, Core Energy monitors and collects flow, pressure, and gas composition data from each reef in the central HMI computer system. Core Energy uses a mass balance approach with a set of flow meters to monitor multiple locations along the operations path including the processing plant, pipeline, and well heads. The quantities of CO_2 injected and produced are recorded along with estimates of CO_2 losses. The mass of CO_2 sequestered annually and the cumulative is reported following Equation RR-11 from Subpart RR.

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

Equation 2-2

where:

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

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

CO_{2P} = Total annual CO_2 mass produced (metric tons) net of CO_2 entrained in oil in the reporting year.

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

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead in the reporting year, calculated as provided in subpart W.

CO_{2FP} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity in the reporting year, calculated as in Subpart W and including the metered CO_2 measurements at the wet and dry vents attached to the separators.

2.5.2.4 Reporting and Verification

Sequestered CO_2 and estimated CO_2 losses are accounted quarterly and reported annually through the GHGRP system. Verification is accomplished through self-verification and by EPA review.

2.5.2.5 Conclusions

The collaboration between MRCSP and Core Energy has generated increased confidence in geologic certainty and the safe storage of CO_2 through their CO_2-EOR operations. The rich history of oil and gas production, EOR and CO_2-EOR demonstrates the effectiveness of the reservoir and seals. The compartmentalization of the reefs creased ideal storage compartments. The monitoring plan with flow meters and gauges created an accurate method for measurements for accounting and reporting. All of these factors allowed for the successful demonstration of a safe CO_2-EOR operation which resulted in a successful and approved MRV plan[3]

2.6 Summary

The MRCSP large-scale CCUS test incorporated all facets of CO_2 storage assessment in an actively growing CO_2-EOR complex of carbonate reef systems in the Michigan Basin. The growth in the number of small fields under EOR since 2012 start of the test, helped MRCSP in adapting the characterization, modeling, and monitoring efforts over time. This is shown in the portfolio of geologic analysis, monitoring, and modeling used initially in the Dover 33 reef (mainly based on limited existing geologic data) to the more advanced assessments with new geologic data and fiber optic monitoring in the Chester 16 field. Within the constraints of the monitoring systems deployed, it is apparent that the CO_2 injection is working as anticipated, in terms of injectivity, containment, and capacity for storage. This work, conducted on a local scale, helped develop the methodologies and approaches needed to expand the analyses to a regional scale. Chapter 3.0, covers the results of the regional analyses.

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[3] https://www.epa.gov/sites/production/files/2018-10/documents/coreenergyniagaran_decision.pdf

3.0 MRCSP Regional Geology Analyses

3.1 Introduction

To support regional upscale efforts, MRCSP has developed a knowledge base that future partnerships will be able to build on as they plan and execute new CCUS projects which spans multiple states and geologic provinces (Figure 3-1). This included regional characterization activities to extend the characterization work completed for the Michigan Basin project. Regional characterization included:

- Development of a first-of-its-kind reef atlas with detailed information for the 850+ reefs in the Northern Niagaran Pinnacle Reef Trend to upscale from the large-scale injection test to the entire NNPRT to assess the full feasibility of the reefs.
- Further analysis of characterization data to build a better understanding of regional trends in geology which will be a valuable resource to identifying key areas for CCUS.
- Estimating CO_2 resources, storage potential and EOR potential across the region

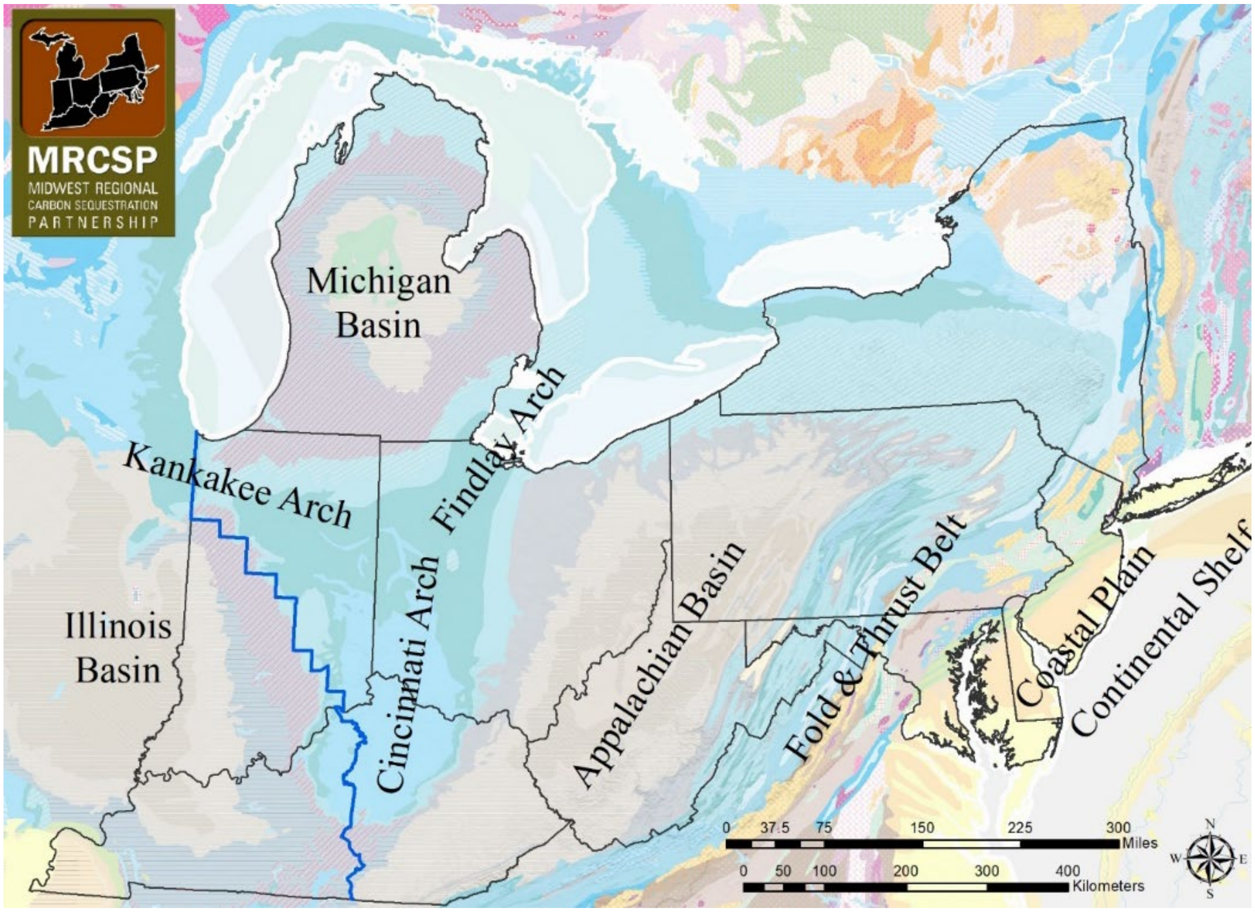


Figure 3-1. Map of the MRCSP region and geologic provinces covered.

Multiple studies spanned from these efforts as are summarized in a series of technical reports listed in Table 3-1.

Table 3-1. List of regional technical reports and the citations

Report Name	Citation
Regional Assessment for the CO_2 Storage Potential in Northern Niagaran Pinnacle Reef Trend	Haagsma, A., Goodman, W., Larsen, G., Cotter, Z., Scharenberg, M., Keister, L., Hawkins, J., Main, J., Pasumarti, A., Valluri, M., Conner, A., and Gupta, N. 2020. Regional Assessment for the CO_2 Storage Potential in Northern Niagaran Pinnacle Reef Trend. MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH
Regional Geology Capstone Report for the Midwestern Regional Carbon Sequestration Partnership	Sminchak, J., Haagsma, A., Hawkins, J., Carter, K., and Gupta, N. 2020. Regional Geology Capstone Report for the Midwestern Regional Carbon Sequestration Partnership MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH
Regional Geologic Cross Sections for Potential Storage and Containment Zones in the MRCSP Region	Dinterman, P., Greb, S., Lewis, E., Schmelz, W., Sparks, T., Solis, M., Medina, C., Carter, K., Barnes, D., Harper, J., Harrison, W., Moore, J., Miller, K., Hickman, J., Riley, R., McDowell, R., Rupp, J., Browning, J., and Gupta, N. 2020. Regional Geologic Cross Sections for Potential Storage and Containment Zones in the MRCSP Region. MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH
Appalachian Basin: Enhanced Recovery Opportunities	Carter, K., Moore, J., Lewis, E., Nuttall, B., Dinterman, P., Daft, G., Anthony, R., Schmid, K., Dunst, B., Sparks, T., Greb, S., Solis, M., McDonald, J., Ortt, R., and Gupta, N. 2020. Enhanced Recovery Opportunities in the Appalachian Basin. MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH
Michigan Basin: Assessment of Enhanced Oil Recovery Using Carbon Dioxide in Silurian Pinnacle Reefs	Harrison, W., Barnes, D., Caruthers, A., Rine, M., Garret, J., Nadhim, Z., Suhami, A., Al-Musawi, M., and Gupta, N. 2020. Assessment of Enhanced Oil Recovery using Carbon Dioxide in Michigan Basin Silurian Pinnacle Reefs. MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH
Mid-Atlantic Coastal Plain and Adjacent Offshore Region: Characterization of Carbon Storage Targets	Baldwin, K., Fukai, I., Miller, K., and Schmelz, K. 2020. Mid-Atlantic Coastal Plain and Adjacent Offshore Region: Characterization of Carbon Storage Targets, MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH
Ordovician-Cambrian Units: Hierarchical Evaluation of Geologic Carbon Storage Resource Estimates	Medina, C., Rupp, J., Ellet, K., and Gupta, N. 2020. Ordovician-Cambrian Units: Hierarchical Evaluation of Geologic Carbon Storage Resource Estimates. MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH
Upper Silurian to Middle Devonian Strata of Ohio: Structural Characterization of Potential CO_2 Reservoirs and Adjacent Strata	Ohio Division of Geological Survey.2020. Upper Silurian to Middle Devonian Strata of Ohio: Structural Characterization of Potential CO_2 Reservoirs and Adjacent Strata. MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH
Triassic Rift Basins: Preliminary Study of Long-Term CO_2 Storage Potential	Brezinksi, D., Adams, R., and Gupta, N. 2020. Triassic Rift Basins: Preliminary Study of Long-Term CO_2 Storage Potential. MRCSP topical report prepared for DOE-NETL project DE-FC26-05NT42589, Battelle Memorial Institute, Columbus, OH

The results of the regional studies are summarized in this section. Additionally, synergistic projects that worked with MRCSP are summarized.

3.2 Regional Characterization and Resources Estimates of the Northern Niagaran Pinnacle Reef Trend (NNPRT)

The goal of this task was to perform an initial assessment of the geologic storage capacity and injectivity of the Northern Fairway of Michigan's Niagaran Reef Trend. This was achieved through three main objectives: 1) development of a reef atlas, 2) understanding the regional trends in geology, and 3) estimating CO_2 and CO_2-EOR resources trend-wide. The task was divided into the subtasks described in Table 3-2.

Table 3-2. Summary of subtasks and objectives

Subtask Name	Objective(s)
Reef catalog	Identify all reefs in the NNPRT and associated publicly available information
Anecdotal mapping	Compile anecdotal information from well records and mudlogs to identify key trends in the NNPRT
Cross sections	Generate regional cross sections to capture changes in reefs and off reef across the NNPRT
Structure and isopach maps	Generate regional structure and isopach maps to capture changes in formation thicknesses and structural trends
Wireline log and whole core analyses	Compile and digitize wireline and core data to assess trends in reservoir properties
Diagenesis analysis	Analyze 3D computed tomography (CT) scan data to better understand diagenesis and implications for reservoir properties; develop predictions
Residual oil zone (ROZ) analysis	Assess the existence of ROZs and the potential for associated storage and resources
Geochemical modeling	Compile geochemistry data from key formations and model the influence of introduced CO_2 to assess stability
Geomechanics analysis	Compile acoustic data and laboratory measurements to assess geomechanical trends and implications for safely storing CO_2
Resource estimates from fluid substitution	Utilize databases to compute baseline storage resources using fluid substitution methodology
Simplified modeling	Utilize databases to refine storage resource estimates and potential oil recovery in CO_2-EOR viable fields

3.2.1.1 Development of a Reef Atlas

Data collected across multiple subtasks were integrated into a mappable database that could be accessed from many of the leading software. This included the following for over 850 reefs:

- Reef field name, location, and production status
- Number of wells penetrating the reef, well identification, and well status
- Cumulative oil, gas, water, additional fluids, and category (primarily gas, oil, water, or tight)
- Pressure, pressure gradient, and maximum reef height
- Current operator and additional notes
- Estimated top of reef structure based on well tops and thicknesses
- Fluid contacts (oil-water, oil-gas, gas-water, etc.) and fluid properties (API gravity for liquids and specific gravity for natural gas)
- Lithology: limestone, dolostone, or mixed
- Salt and anhydrite plugging: depth and thickness of noted occurrences
- Gas and oil shows, and dead oil: depth of noted occurrences

- Presence of vugs and fractures: depths
- Sour gas: whether it was detected
- Lost circulation: depth
- Measured and estimated porosity and permeability
- Estimated secondary porosity through vugs and fractures
- Geomechanical properties

3.2.1.2 Understanding Regional Geologic Trends

The reef atlas was used to map the reefs and associated characteristics across the entire NNPRT. This included the following:

- First of a kind regional structure and isopach maps which captured the regional changes in reef height, size, and structure
- Regional mapping of key reservoir properties such as pressure, temperature, and fluid properties showed influence of depth
- Regional mapping of reservoir quality properties such as porosity, permeability, secondary porosity helped identify potentially high performing reefs
- Regional mapping of confining units helped demonstrate the continuity and robustness of the caprocks

3.2.1.3 CO_2 and CO_2-EOR Resources Estimates

Several methodologies were explored to estimate the CO_2 and CO_2-EOR resources across the trend which included three scenarios: 1) storage only using fluid substitution and volumetric estimations, 2) CO_2-EOR which applied proximity analysis concepts and measured performance metrics from the Core Energy reefs to predict performance at all oil reefs, and 3) enhanced storage scenario which combined CO_2-EOR with fluid substitution to represent maximized storage after completion of CO_2-EOR (Figure 3-2). Under scenario 1, more than 230 million MT of CO_2 storage is possible, with 73 million MT in oil reefs and 160+ million MT in gas reefs. Scenario 2 explored traditional CO_2-EOR, which would store 49 million MT at the end of the life cycle. Finally, scenario 3 would consider repressurizing a reef following CO_2-EOR to maximize CO_2 storage, resulting in nearly 250 million MT of possible storage (Figure 3-3).

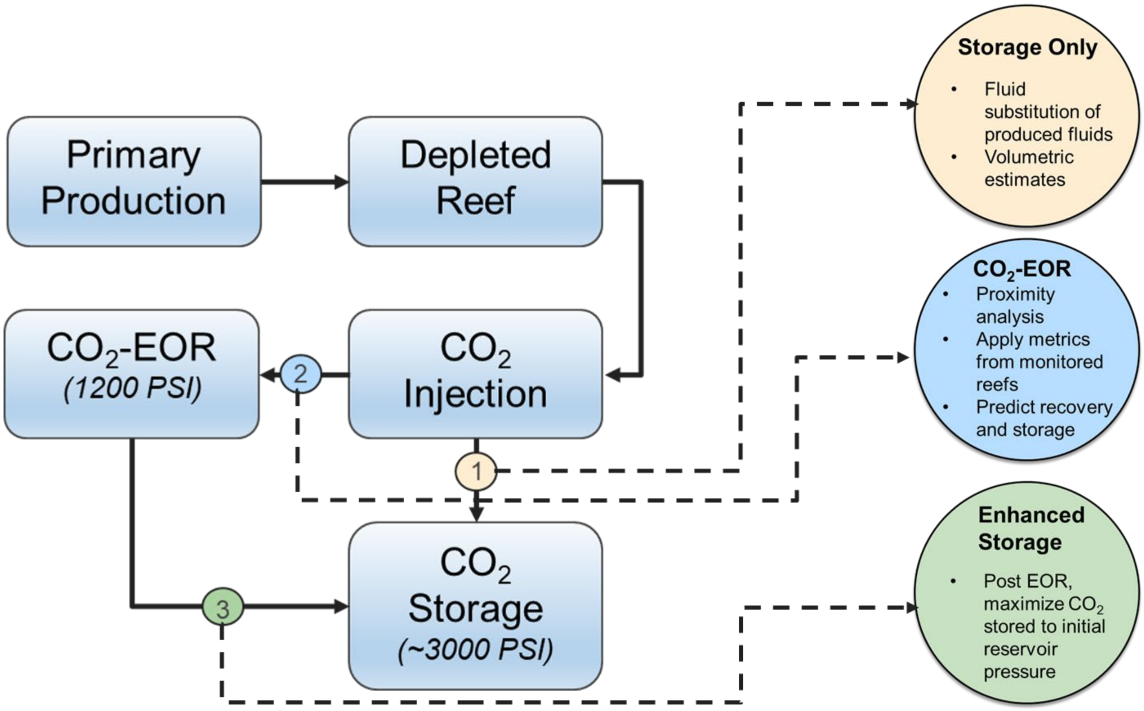
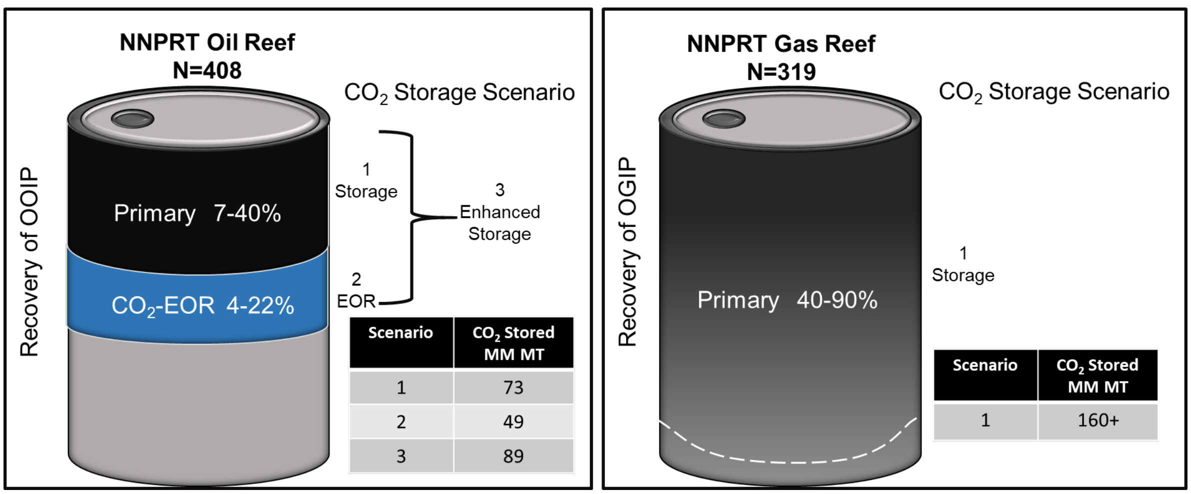


Figure 3-2. Simplified flow diagram illustrating the three scenarios analyzed for resource estimates across the NNPRT and where they occur during the CO_2-EOR production lifecycle.



Scenario	CO_2 Stored MM MT
1	73
2	49
3	89

Scenario	CO_2 Stored MM MT
1	160+

Figure 3-3. Summary of CCUS scenarios for oil and gas reefs in the NNPRT, where N is the number of reefs classified as oil or gas. A possible 89 million tons of CO_2 storage in oil reefs and 160+ million tons in gas reefs for a total of 250+ million tons of CO_2 storage.

3.3 Geoteam Summary

Since 2003, the MRCSP Geoteam has characterized the CO_2 storage potential in deep rock formations in the diverse geologic settings of the Midwest to Mid-Atlantic United States. The Geoteam members included many researchers from Delaware, Indiana, Kentucky, Michigan, New Jersey, New York, Ohio, Pennsylvania, and West Virginia state geological surveys and other organizations (Figure 3-4). The regional characterization focused on four major geological subregions: Michigan Basin, Arches Province, Appalachian Basin, and Coastal Plain/Mid-Atlantic Offshore.

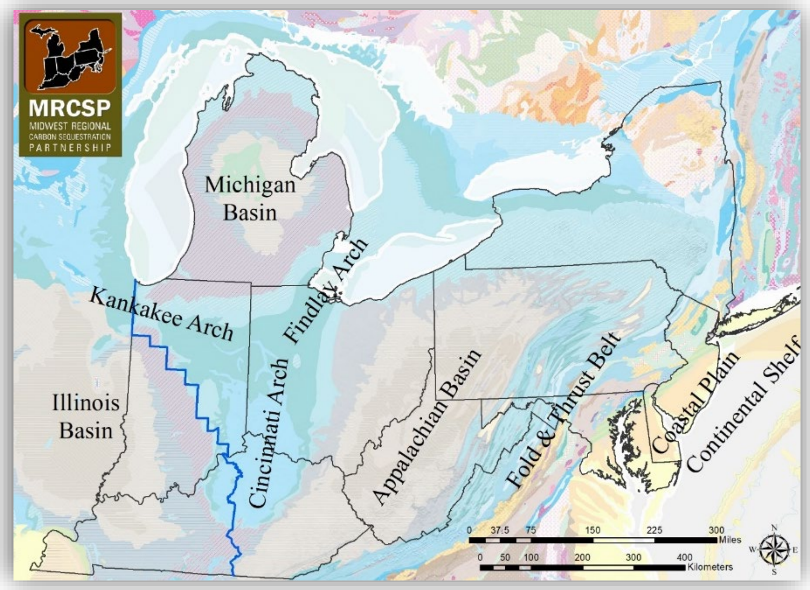


Figure 3-4. Regional extent of the MRCSP geoteams and photographs from team meetings.

Over the 16+ years of research, the MRCSP Geoteams have progressed from identification of geologic storage intervals in Phase I, to characterization of key storage zones in Phase II, and more focused delineation of geotechnical parameters for storage resource definition in Phase III. The Geoteam effort involved ten states working together for the first time, tackling mapping efforts for more than one Basin. The teams developed digital data compiled into consistent format, a comprehensive GIS database (>50 maps), and first-of-a-kind regional maps for key CO_2 storage rock formations, depleted oil & gas reservoirs, and caprocks (Figure 3-5). Some key products developed by the Geoteams include:

- Phase I Characterization of Geologic Sequestration Opportunities in the MRCSP Region (2005)
- Appalachian Basin Oil and Gas Fields Map (2005)
- Tuscarawas County, Ohio, CO_2 Stratigraphic Test Well (2007)
- CO_2-EOR Prospects for the Appalachian and Michigan Basins (2005-2010)
- Phase III regional characterization of key geologic storage aspects in the MRCSP region:
- Regional geologic cross sections of CO_2 storage zones and caprocks,
- Database of MRCSP Depleted Petroleum Fields (2019);
- Analysis of Cambro-Ordovician Storage Potential;
- Assessment of CO_2 Storage Potential along East Coast Offshore, Onshore Storage, and Triassic Rift Basins;
- Silurian Pinnacle Reef CO_2-EOR Reservoirs;
- CCUS Opportunities in the Appalachian Basin;
- Storage and Enhanced Gas Recovery for Organic-Rich Shale;
- Ohio-Pennsylvania-West Virginia Tri-state case studies on stacked CCUS potential.

Together, the regional characterization effort developed useful products to support project developers, policy makers and other stakeholders in the MRCSP region seeking to understand where potential storage exists relative to large stationary sources of CO_2 emissions.

The MRCSP Phase III regional geologic characterization task completed research on important topics identified in previous MRCSP efforts. The description of enhanced oil recovery opportunities, storage targets along the Atlantic Coast, and storage resources in key rock formations provides a foundation for establishing CCUS applications in the MRCSP region. There is a great deal of detailed geotechnical information in the Geoteam reports. They also contain products like regional geologic cross sections and maps that help portray the nature of CO_2 storage zones for decision makers, stakeholders, and the general public. The information compiled by the MRCSP Geoteams is embedded in the geological surveys and research organizations. This allows an ongoing mechanism to support future CCUS development (Sminchak et al., 2020).

Key conclusions for the Phase III regional geologic characterization research are provided below:

Regional Geologic Cross Sections- The five regional geologic cross sections produced by the Geoteams illustrate the arrangement of geologic structures, CO_2 storage intervals, organic rich shales, and caprocks throughout the MRCSP region (Figure 3-6) (Dinterman et al., 2020). Each cross section uses 15 to 25 deep wells and other geologic information to illustrate the relative depth, thickness and location of rock units in the subsurface. The cross sections correlate local stratigraphic units across multiple states as stand-alone individual plates to be distributed for outreach, research, and education. These products help stakeholders understand the geologic framework for CO_2 storage near their locations.

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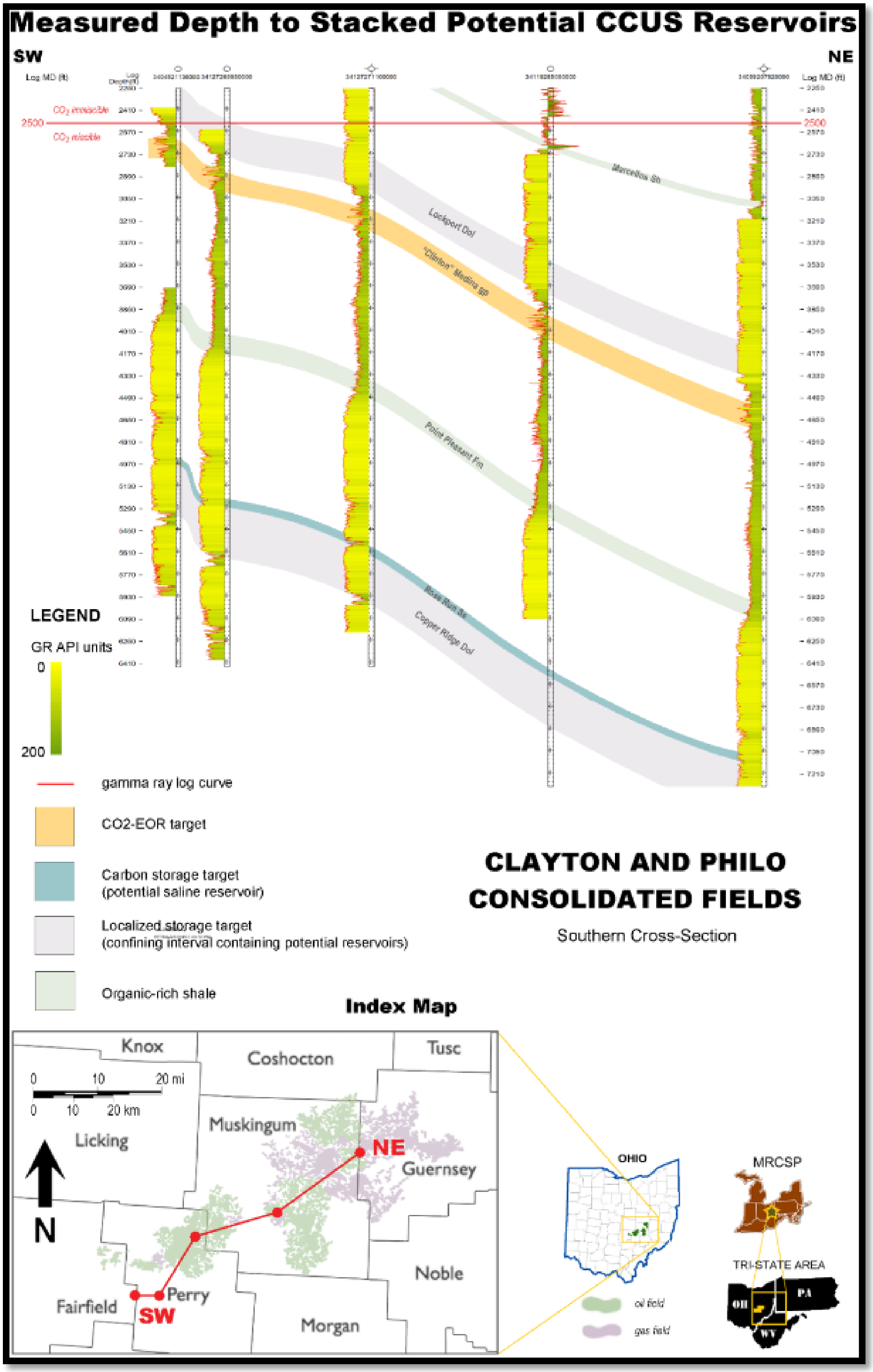

Figure 3-5. Example cross section resulting from geoteam research efforts.

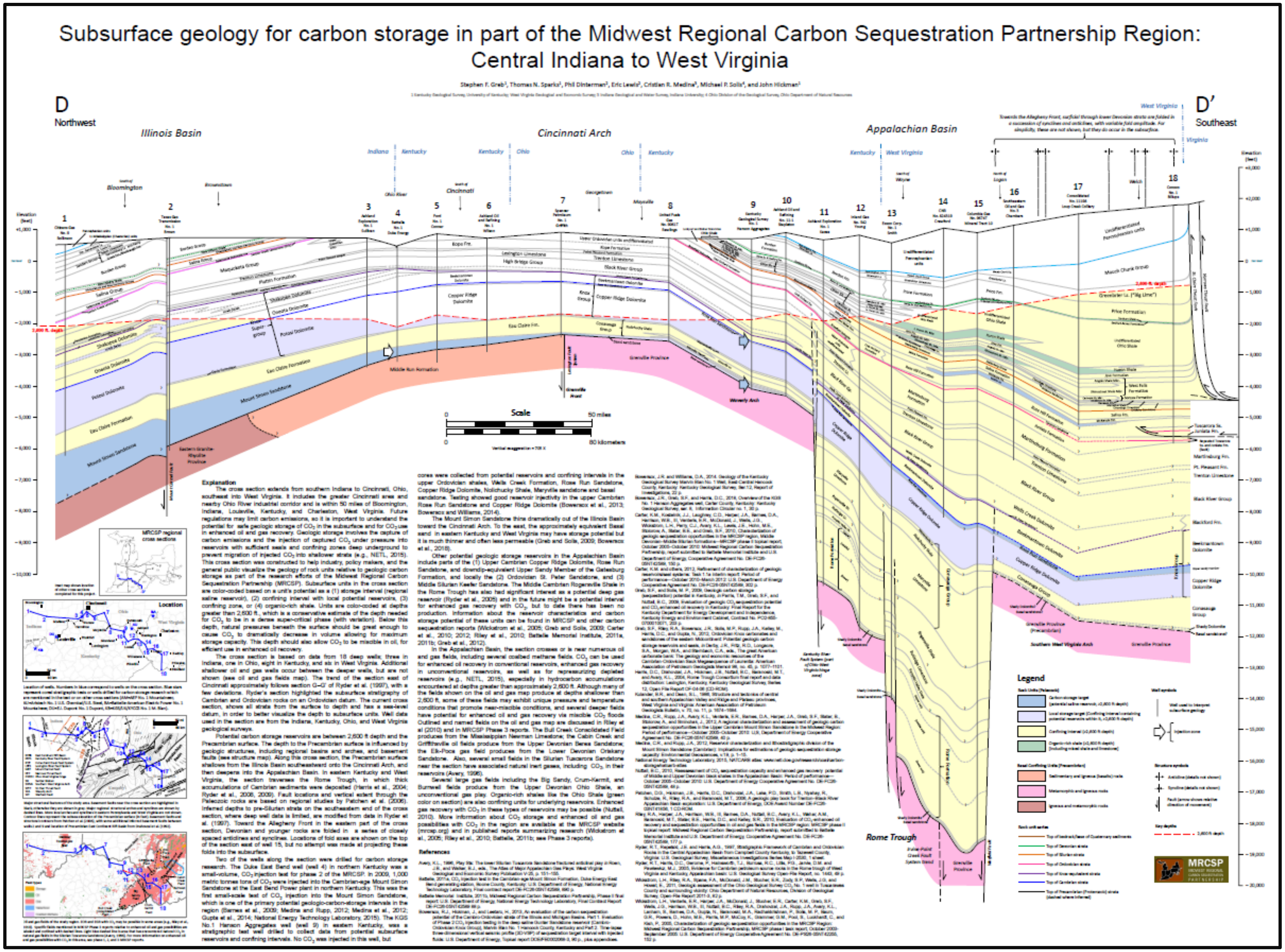

Figure 3-6. Example regional cross section D-D' which passes through central Indiana to West Virginia. Colored sections represent rocks deeper than 2600 feet measured depth to ensure critical phase of CO_2.

Appalachian Basin: Enhanced Recovery Opportunities- The Appalachian Basin EOR task assessed the potential for CO_2-EOR, enhanced gas recovery (EGR) from organic-rich shales, and CCUS project integration in the Appalachian Basin (Figure 3-7) (Carter et al., 2020). Stacked reservoirs, with the potential to incorporate CO_2-EOR and saline storage, exist in much of the Appalachian Basin (Figure 3-8). The total storage capacity for all oilfields in the Region ranged from 423 Mt to 1,286 Mt with the most likely storage potential being 701 Mt. While oilfields provide the potential for income with incremental oil recovery through CO_2-EOR, gas fields in the Region have a higher most likely total storage capacity, exceeding that of the oilfields by more than an order of magnitude (9,708 Mt). Stacked storage has the potential to increase the capacity with saline storage. EGR in the organic-rich Marcellus and Utica/Point Pleasant have storage capacities ranging from 804 Mt to 2,680 Mt and 1,880 Mt to 6,266 Mt, respectively, adding an additional target for CO_2 in the region. The case studies in the Ohio, Pennsylvania, and West Virginia provide specific information on key depleted oil and gas fields in this important industrial corridor of the MRCSP region. Challenges to implementing CCUS in the Appalachian Basin include legacy wells, modern horizontal drilling, pipeline infrastructure, prospective reservoir size and reservoir data gaps. Opportunities for implementing CCUS in the Appalachian Basin can be augmented using methods and datasets of this topical report.

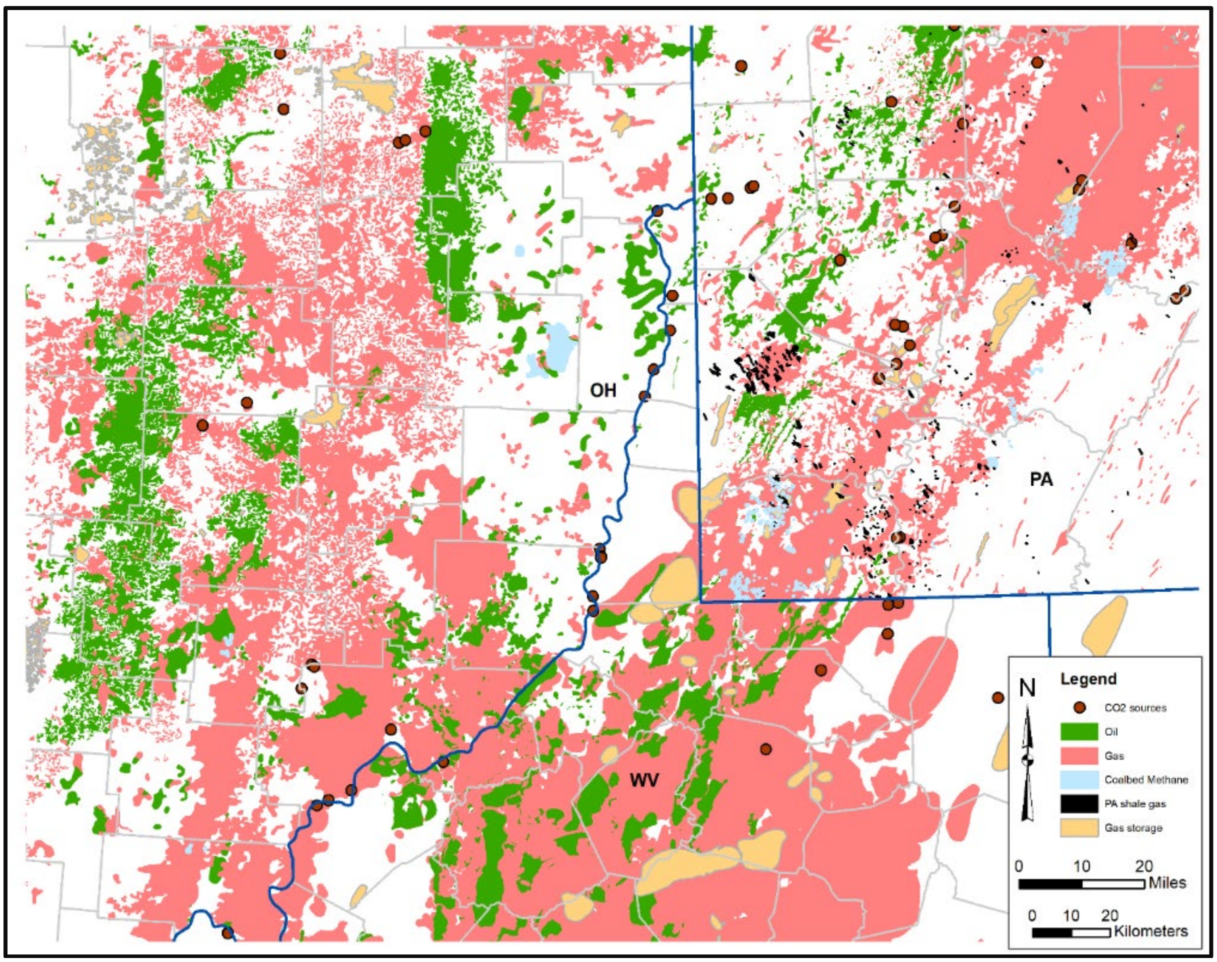

Figure 3-7. Map of major oil and gas fields in eastern Ohio, West Virginia, and Pennsylvania and location of major CO_2 sources.

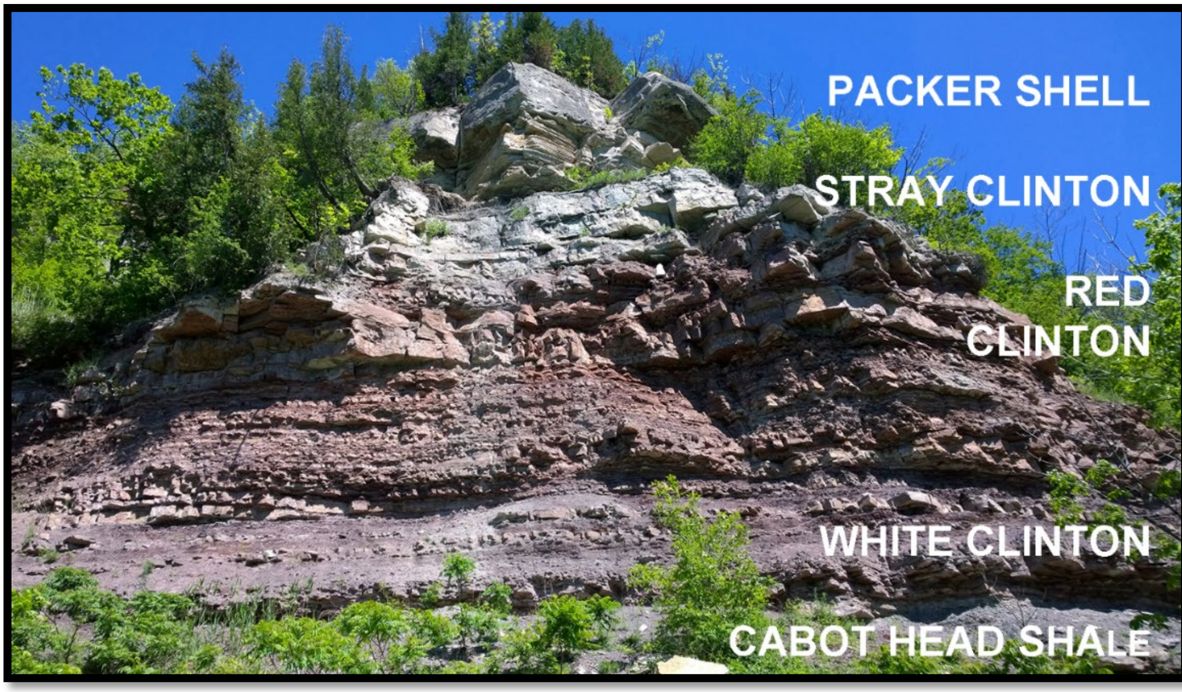

Figure 3-8. Outcrop example of potential reservoirs and caprocks studied in the Appalachian Basin region. Outcrops help the geologist understand important features and characteristics of reservoirs and caprocks to better relate them to subsurface data and develop conceptual models.

Michigan Basin: Assessment of Enhanced Oil Recovery Using Carbon Dioxide in Silurian Pinnacle Reefs- The Michigan task analyzed relevant data about reservoir properties in the Silurian pinnacle Reefs to define lithologic and depositional characteristics of the reservoir formations and porosity and fluid flow properties (Figure 3-9) (Harrison et al., 2020). Models of the geological facies and physical characteristics of the reservoir and seal system were integrated with the history of production, secondary recovery, and tertiary recovery. Core samples and core analysis data were examined from five fields in the Southern Pinnacle Reef Trend and from 14 fields in the Northern Pinnacle Reef Trend. These observations and data helped constrain the geologic models produced in this study. Geologically realistic and quantitative 3-D static models were developed for Niagara–Lower Salina reef complex reservoirs to inform operational decisions on CO_2-EOR fields of interest in Otsego County, Michigan. A workflow was developed to prepare Pinnacle reef models based on: 1) construction a robust geological model using the new asymmetrical reef model and any core/seismic/wire-line log data available in the field, 2) incorporation of diagenetic observations, 3) wire-long log analysis to identify facies within the reef complex, 4) definition of flow zones based groups of petrophysically similar rock types/flow zones, 5) population of flow zones with normal distribution curves developed for facies related porosity and permeability, 6) and validation of the reservoir model with uncertainty analysis.

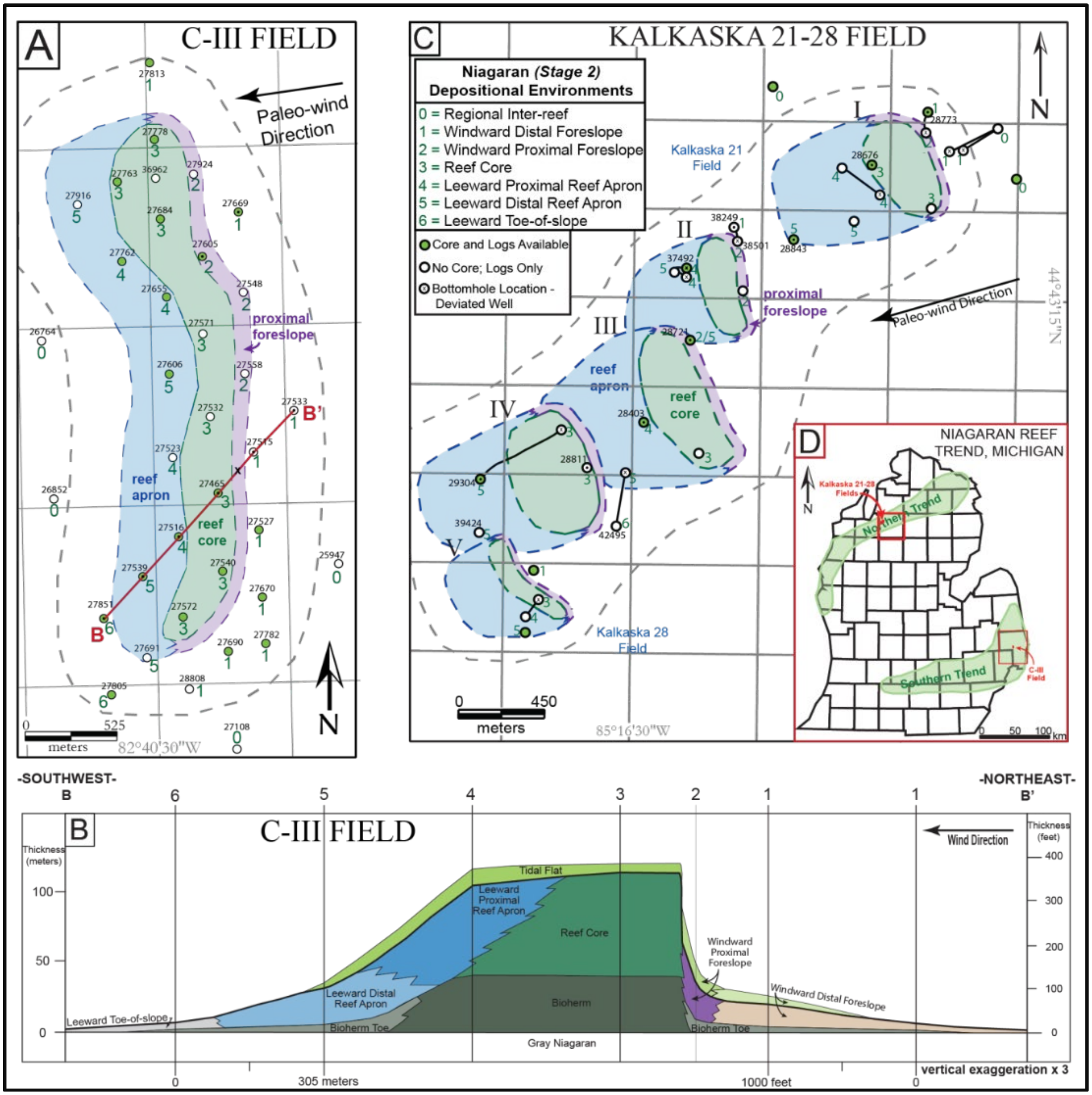

Figure 3-9. Example case studies of reefs from the Niagaran Pinnacle Reef trends illustrating the interpreted lithofacies.

Mid-Atlantic Coastal Plain and Adjacent Offshore Region: Characterization of Carbon Storage Targets- The Mid-Atlantic Coastal Plain and Offshore Region study completed a regional characterization of geologic CO_2 storage systems in the Delaware, Maryland, and New Jersey coast and offshore areas based on sequence stratigraphic framework (Baldwin et al., 2020). Saline reservoirs were identified in the onshore lower-to-mid Cretaceous Waste Gate and Potomac formations and correlative offshore Logan Canyon Formation using sequence chronostratigraphy, biostratigraphy, core/log analysis, and seismic evaluation (Figure 3-10). The analysis indicates that there is potential for storage of large volumes of CO_2 (8.4 to 33.5 Gt CO_2) in the onshore Waste Gate-Potomac I in the subsurface of the Mid-Atlantic Coastal Plain. The greatest targets for offshore carbon storage are in the nearshore areas of Maryland in the Waste Gate-Potomac I sequence and in the Logan Canyon Sands on the Great Stone Dome. The potential exists for future implementation of carbon storage in the Mid-Atlantic Coastal Plain and offshore region.

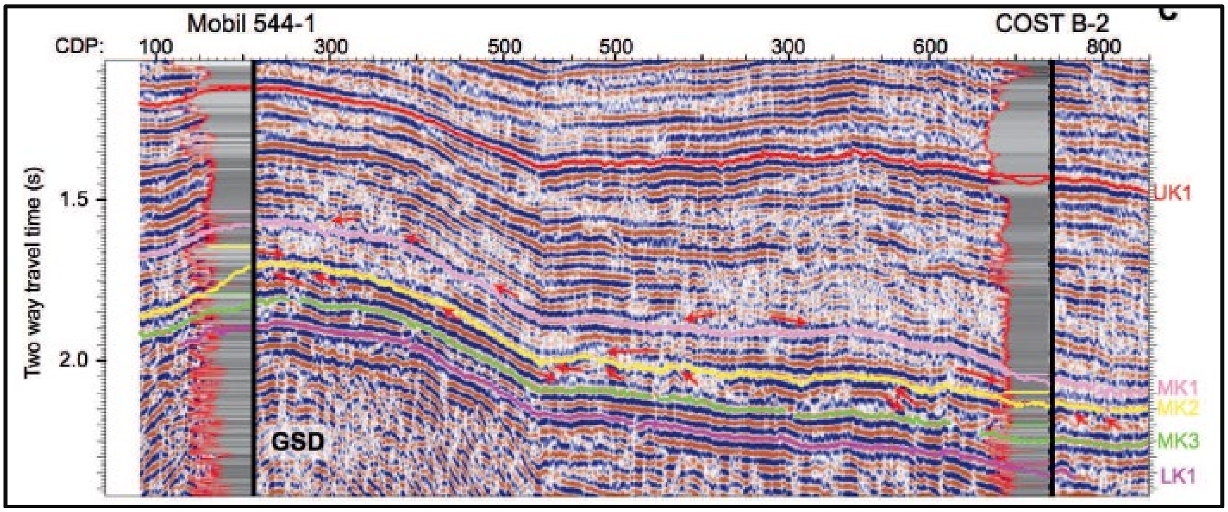

Figure 3-10. Example seismic line highlighting key horizons of study.

Ordovician-Cambrian Units: Hierarchical Evaluation of Geologic Carbon Storage Resource Estimates- The regional distribution and storage capacity estimates (SREs) for Ordovician-Cambrian stratigraphic units located within the MRCSP region was based on a comprehensive set of wireline logs and petrophysical data (Figure 3-11) (Medina et al, 2020). SREs were calculated for limestone and dolostone from the Upper Ordovician Trenton Limestone/Black River Group and equivalent units, the Middle Ordovician St. Peter Sandstone, and reservoir rocks of the Lower Ordovician and Upper Cambrian Knox Supergroup and equivalent units. Six different methodologies were used in the SRE calculations to show the spatial variance of estimates from each methodology and depict areas with the greatest total storage potential estimates. SREs developed under the task suggest there is sufficient storage capacity in the carbonate reservoirs of the Ordovician-Cambrian to for 100+ years of storage based on CO_2 emissions from stationary sources in the MRCSP region. Regional scale SREs could benefit from the use of efficiency factors that incorporate regional or basin-specific data for reservoir area, thickness, and porosity. Results from this study indicate higher SREs where the reservoir-units occur at depths of 2,500-8,000 ft measured depth.

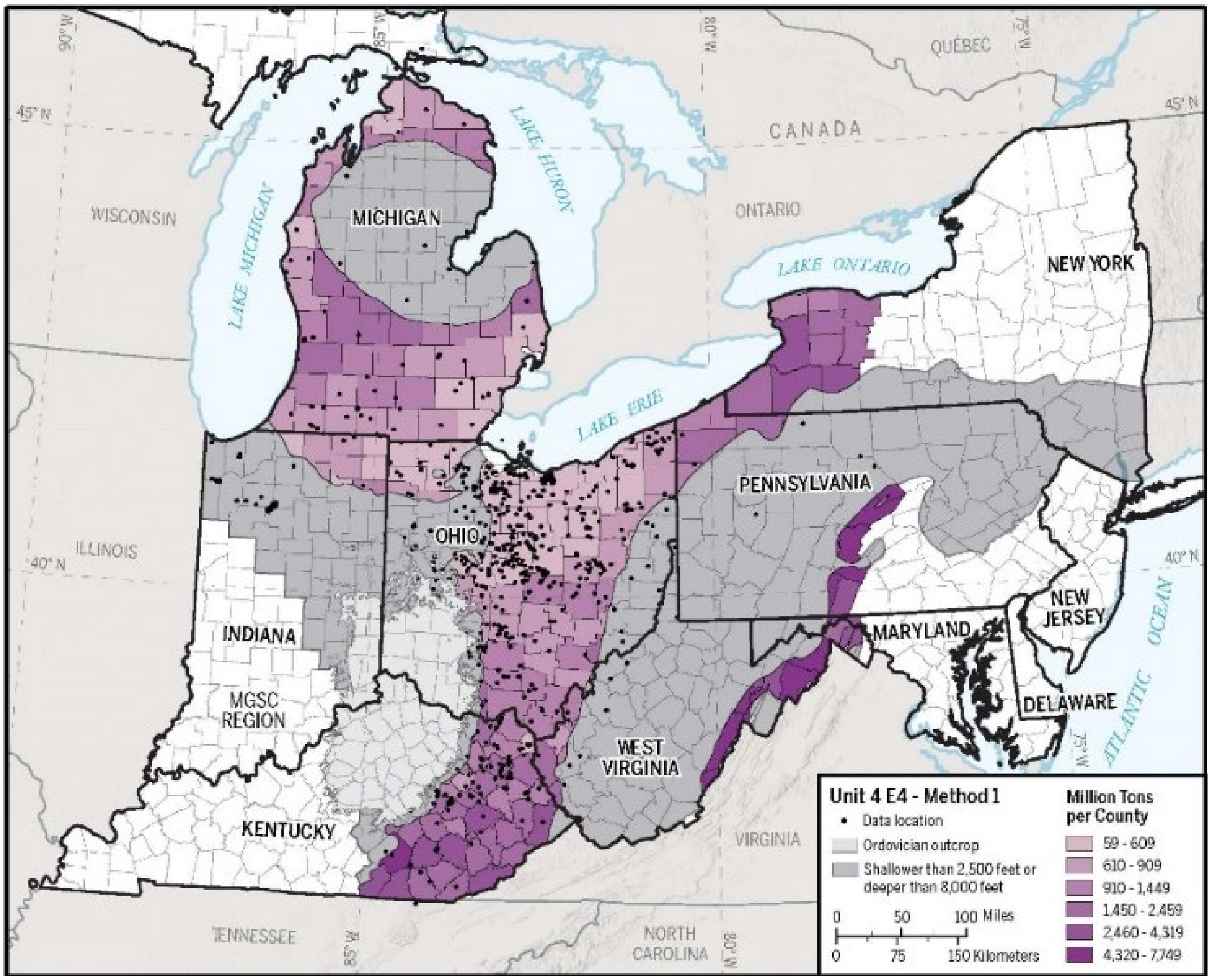

Figure 3-11. Example map illustrating the potential storage resources by county and extent.

Upper Silurian to Middle Devonian Strata of Ohio: Structural Characterization of Potential CO_2 Reservoirs and Adjacent Strata- Nine Upper Silurian to Middle Devonian age rock formations in the Appalachian Basin of Ohio were evaluated to assess CO_2 storage reservoirs, seal integrity, and CO_2 migration pathways based on 2200 oil and gas wells and associated wireline logs (Figure 3-12) (ODGS, 2020). This study focused on the units within the Llandovery Silurian to Middle Devonian interval which included: Medina Group, Lockport Dolomite, Bass Islands Dolomite and Oriskany Sandstone. Tops of formations of interest were identified and used to develop structure and isochore maps. These detailed formation maps show varying thicknesses of 0 to 1,100 ft in the formations. The maps illustrate structural influences, fracture and fault trends, and trapping mechanisms in the rock formations, which are key considerations for CO_2 storage.

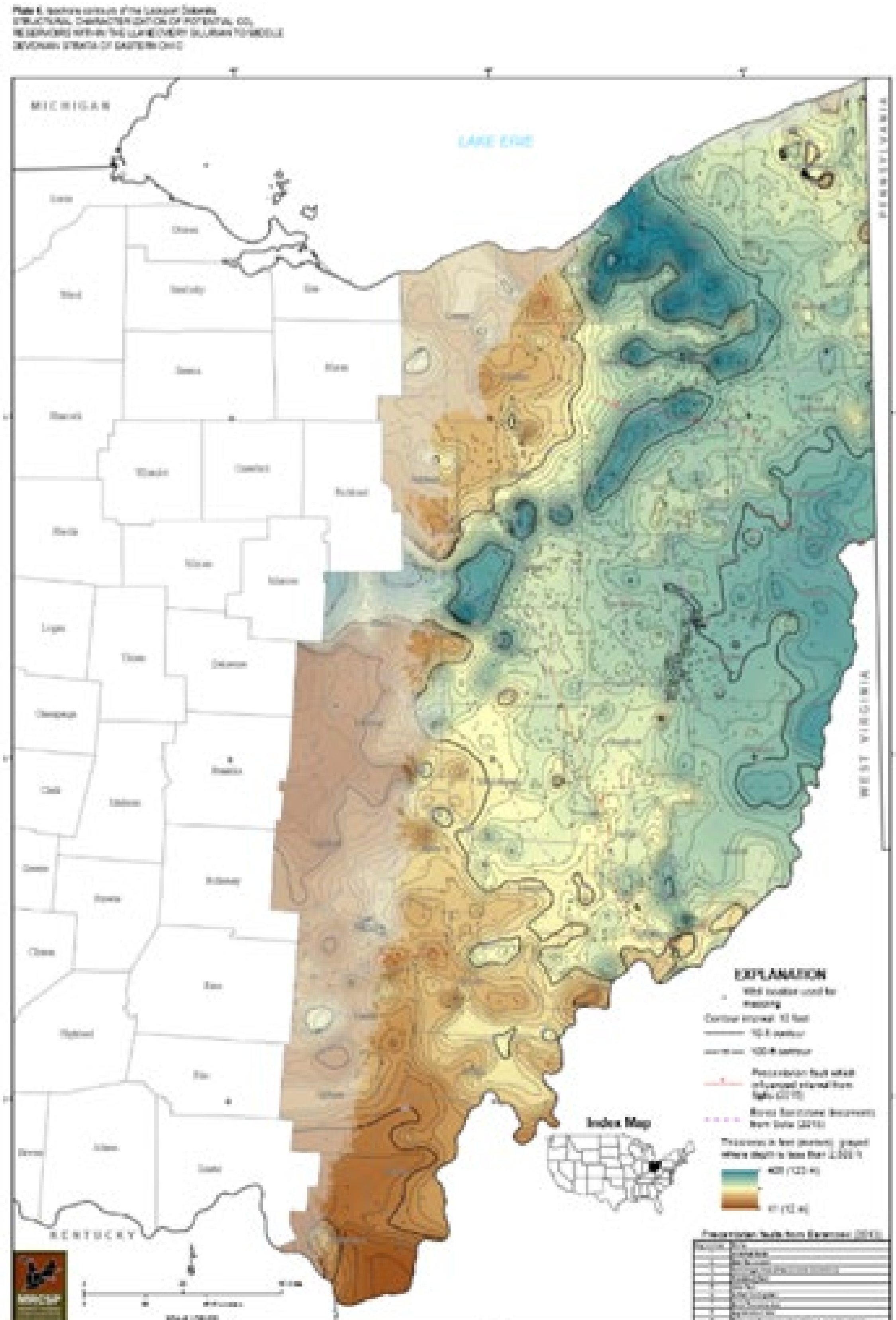

Figure 3-12. Example thickness map of the Lockport Dolomite in Eastern Ohio.

Triassic Rift Basins: Preliminary Study of Long-Term CO_2 Storage Potential – The Triassic Rift Basin research characterized Triassic rift basins along the Mid-Atlantic coast for permanent CO_2 storage potential. The task examined rock exposed at the surface in the Taylorsville, Culpeper, and Gettysburg Basins to establish lithofacies associations and estimate rock properties in the deeper portions of the basins (Brezinski et al., 2020). Well data demonstrated that up to 8,000 feet of fluvial and lacustrine rocks are preserved near the basin centers. The MRCSP research indicated that the arrangement of coarse-grained fluvial facies and fine-grained lacustrine facies differ substantially between the basin center and basin margin. Triassic mafic igneous rocks are also present in Triassic Rift Basins in the eastern MRCSP region. These igneous rock formations have primary porosity, fracture porosity, and CO_2 mineralization potential for CO_2 storage.

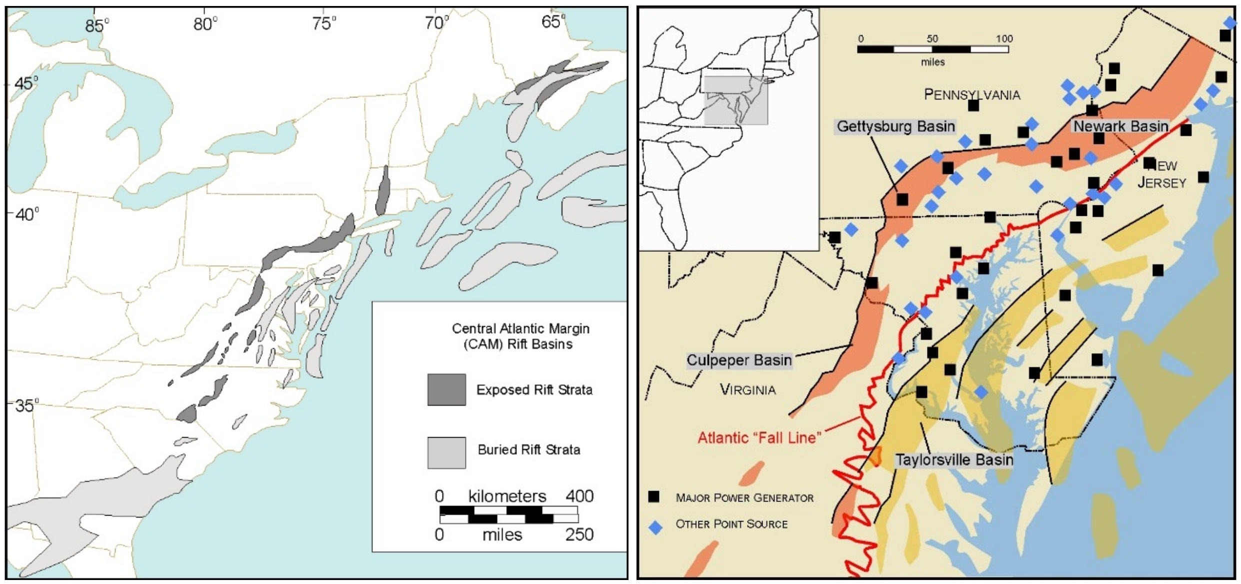

Figure 3-13. Example maps of the study area of the Triassic rift Basins.

Overall, these research topics found that stacked storage options are an important consideration for the MRCSP. Multiple deep saline and depleted oil and gas reservoirs are available in much of the MRCSP region. There is also potential to utilize storage in organic rich shales, but little experience on CO_2 injection into these types of rocks. The hierarchical examination of CO_2 storage resource estimates highlights the value of local versus regional data. The offshore and Triassic rift basin research depicts geologic intervals available in these Mid-Atlantic coastal areas with limited history of oil and gas exploration.

3.4 Synergistic Studies

MRCSP provided cost share for multiple projects in the region to expand the regional characterization efforts and improve understanding of CO_2-EOR potential. These included four Ohio Coal Development Office (OCDO) funded projects:

1. Conducting Research to Better Define the Sequestration Options in Eastern Ohio and the Appalachian Basin (CDO-D-1007a)
2. CO_2 Storage Resources and Containment Assessment in the Cambrian and Ordovician Formations of Eastern Ohio (OOE-CDO-D-13-22)
3. CO_2 Utilization for Enhanced Oil Recovery and Geologic Storage in Ohio (OOE-CDO-D-13-24)
4. CO_2 Utilization for Enhanced Oil Recovery and Geologic Storage in Ohio (OER-CDO-D-15-08)

Section 3.4.1 summarized the work conducted under the first two projects as part of the geologic characterization efforts. Section 3.4.2 summarizes the work conducted under the last two projects as part of EOR characterization efforts.

Additionally, the work and partnerships generated under MRCP has led to several new projects within the region. This includes CarbonSafe Phase I projects in both the Appalachian and Michigan Basins, and an advanced CO_2-EOR project in the Trenton Black River play in Southern Michigan. Section 3.5 and Section 3.6 summarizes these efforts.

MRCSP helped fund several piggyback wells in Ohio and West Virginia to better characterize deep formations for storage (Figure 3-14) in conjunction with the OCDO projects. Basic and advanced wireline log data was collected in the wells along with sidewall cores. Additionally, hydraulic testing (flowmeter logging and injection tests) were conducted to evaluate the injectivity of a formation and identify flow zones.

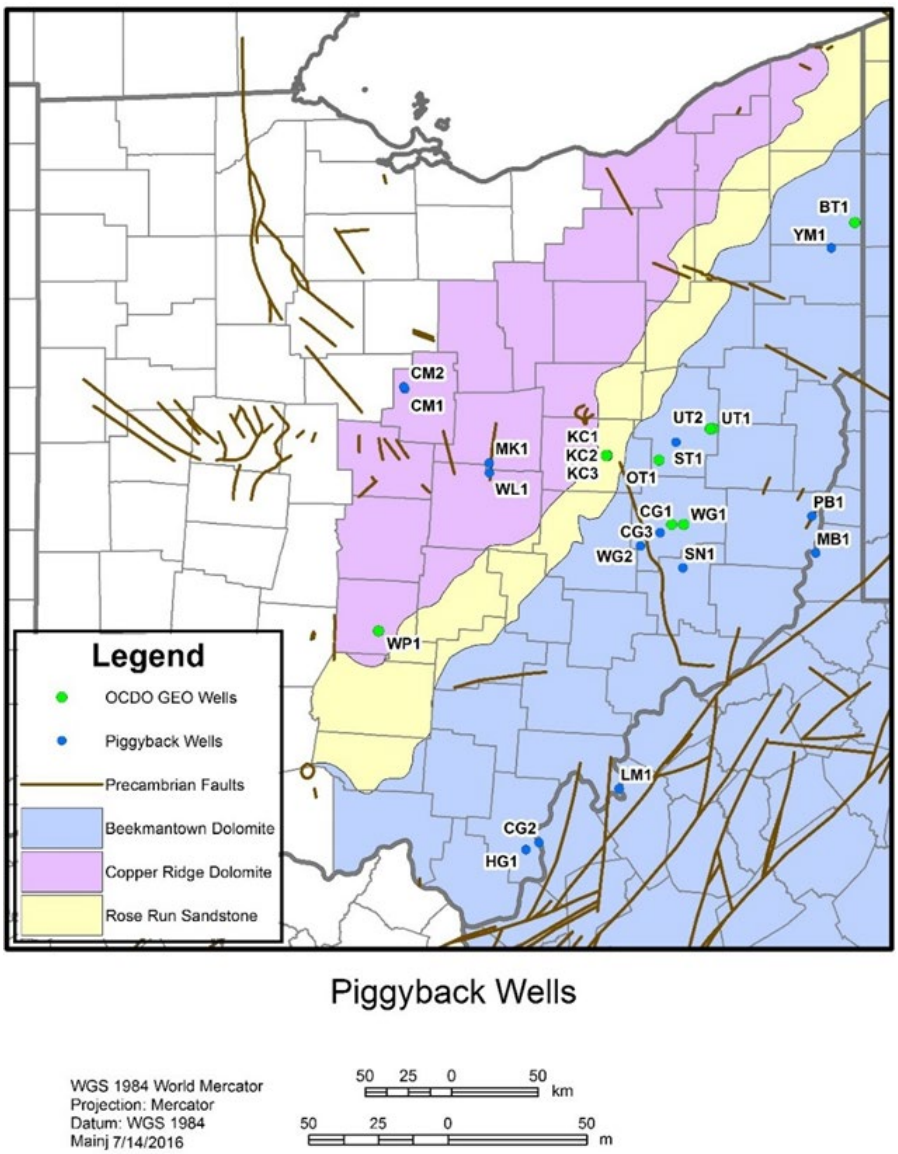

Figure 3-14. Map showing piggyback well locations drilled during synergistic projects.

3.4.1 OCDO Geologic Characterization Projects (CDO-D-1007a and OOE-CDO-D-13-22)

The first phase of the OCDO funded geologic characterization efforts focused on data collection and review to identify potential reservoirs which were deep enough and had storage potential in Eastern Ohio. The study primarily focused on deep Ordovician-Cambrian “sub-Knox” intervals due to sufficient depth and lack of local exploration (Battelle, 2018, and Battelle, 2013).

Key findings from the OCDO Phase I project included:

- Regional geologic analysis of wireline log and core data, along with preliminary interpretations of 280 miles of seismic reflection data, identified and defined several lower Ordovician and Cambrian carbonate and sandstone formations with sufficient areal extent and thickness to justify interest as possible CO_2 reservoirs for the eastern Ohio/Upper Ohio River Valley region.
- Below the Knox Unconformity the lower Ordovician Beekmantown dolomite has developed secondary vuggy and karstic porosity from subaerial exposure. Most of the presently known reservoirs occur in erosional remnants with limited areal extent, and these remnants can produce oil, gas, or water. High resolution seismic mapping may help delineate areas of local tectonic warping and development of greater weathering or karsting.
- The sandstone reservoir storage potential and lateral continuity appear to be in the Copper Ridge “B” dolomite and Krysik sandstone in northeast Ohio. The Copper Ridge “B” is a silty dolomite that contains several sandstone lenses that show good reservoir characteristics on wireline logs. An injection test in the No.1 Northstar well in Youngstown, Ohio showed the Copper Ridge “B” to have at least modest injectivity. The Krysik sandstone appears to be stratigraphically equivalent to the Copper Ridge “B.” The Krysik sandstone produces gas in the Birmingham-Erie field in Erie and Lorain, Huron and Richland Counties.
- Reservoir scale porosity can also develop in weathered Copper Ridge “B” carbonate lithofacies, beneath the Knox unconformity subcrop. At the Knox unconformity subcrop, the Copper Ridge “B” porosity is sealed by the Wells Creek shale, and the Gull River, Black River, and Trenton limestones. To the east and away from the subcrop, the Upper Copper Ridge and Beekmantown carbonates provide additional seal capacity.
- The Lower Copper Ridge dolomite was first recognized as a potential reservoir in southeastern Ohio in 2003 in the AEP test well drilled at the Mountaineer plant in Mason Co., West Virginia opposite Pomeroy, Ohio. Its potential was subsequently confirmed through logging, coring, and testing during CO_2 injection at the site. The data from the AEP Mountaineer site provided the initial set of formation characteristics used for evaluating the regional extent of porosity along Ohio Valley. The Lower Copper Ridge was subsequently identified in the Jarrell No. 1 and McKelvey No.3 wells, strongly intimated in the CO_2 No.1and Devco No.1 wells, and injection tested in the Silcor No.1 SOS-D well. The integrated analysis of these data conducted in this OCDO project shows that the Lower Copper Ridge represents a primary injection target along a NNE-SSE trend south of Stark and Columbiana Counties.
- The Rome dolomite displays subtle features that will be important to characterize for mapping and quantifying storage potential. Lithologically, the Rome represents a diverse suite of rocks with the likelihood of numerous facies changes throughout the study area. Flow tests conducted on the Rome in the PFM Adams No. 1 and Silcor No. 1 SOS-D wells has yielded moderate to excellent injectivity. Thus, the Rome is identified here as having possible reservoir potential in several wells throughout the study area. The Rome trend appears to be co-incident with that of the shallower Lower Copper Ridge dolomite.

The second phase of the OCDO funded geologic characterization efforts focused on a sub-regional investigation for the Appalachian Basin region of Ohio. The key objectives were to review existing data and collect new data from deep wells to identify potential CO_2 storage reservoirs and prepare a sub-regional estimate for prospective storage resources. New characterization and operational data was obtained from several deep wells drilled for brine disposal in eastern Ohio. Existing seismic data from shale gas exploration was also licensed for evaluate geologic continuity and structures. Reservoir feasibility was assessed using simulations of CO_2 injection in promising zones. CO_2 containment potential was assessed using data from the caprock layers and simulating scenarios to determine likelihood of fracturing caprocks.

Key findings and highlights from the OCDO Phase II projected included:

- Strong relationships were established with industry partners that are invaluable for knowledge sharing and potential for future work/opportunities.
- Advanced wireline log data was critical in the identification of reservoir facies and zones in formations that were not typically considered reservoir (i.e. Nolichucky shale, Maryville).
- Advanced wireline log data was used to correlate to basic log data to identify key signatures and trace features well to well (i.e., arkosic sandstone, vuggy dolomite).
- Injection tests showed multiple formations were susceptible to injection. Some zones were correlated across test wells indicating potential for regional continuity (Figure 3-15).
- Injection tests showed high potential for carbonate reservoirs that were not easily identifiable on wireline log data. Traditional methods for characterizing reservoirs underestimate the storage potential of carbonates. The development of the vug prediction tool aided in advanced characterization, but there is need to develop more methods to better define storage in carbonates.
- A regional SEM was constructed to conceptualize the geologic storage framework of nine deep Cambrian-Ordovician saline formations over a 23,500 mi^2 (61,000 km^2) area in eastern Ohio.
- Static estimation of CO_2 storage potential for each deep saline formation quantified in terms of Theoretical Maximum CO_2 Storage Resource, Prospective CO_2 Storage Resource, and CO_2 storage efficiency.
- Of the nine formations evaluated in the study area, the Maryville formation, the Upper Copper Ridge dolomite, the basal Cambrian sandstone, and the Lower Copper Ridge dolomite have the highest static storage resource, with each having an estimated 3-4 gigatonnes (Gt) of Prospective CO_2 Storage Resource (P50) (Figure 3-16).
- Favorable areas for CO_2 storage were identified and some areas/formations were ruled-out. Results suggest there are several locations in Ohio (e.g. northeastern Ohio, east-central Ohio, and south-central Ohio) where vertically stacked reservoir injection/storage scenarios could potentially be implemented to facilitate large-scale storage.
- Stress analysis was completed for immediate caprocks (Wells Creek and Black River) and secondary caprocks (underlying layers) to incorporate into a complete model.
- Modeling was used to assess caprock performance such as the mechanical integrity and sealing effectiveness.
- Primary/immediate caprocks were found to be robust and difficult to generate caprock failure. The identified caprocks will be effective seals.
- The caprock feasibility assessment was the first of its kind study in the regional leading to a detailed understanding of the caprock systems.

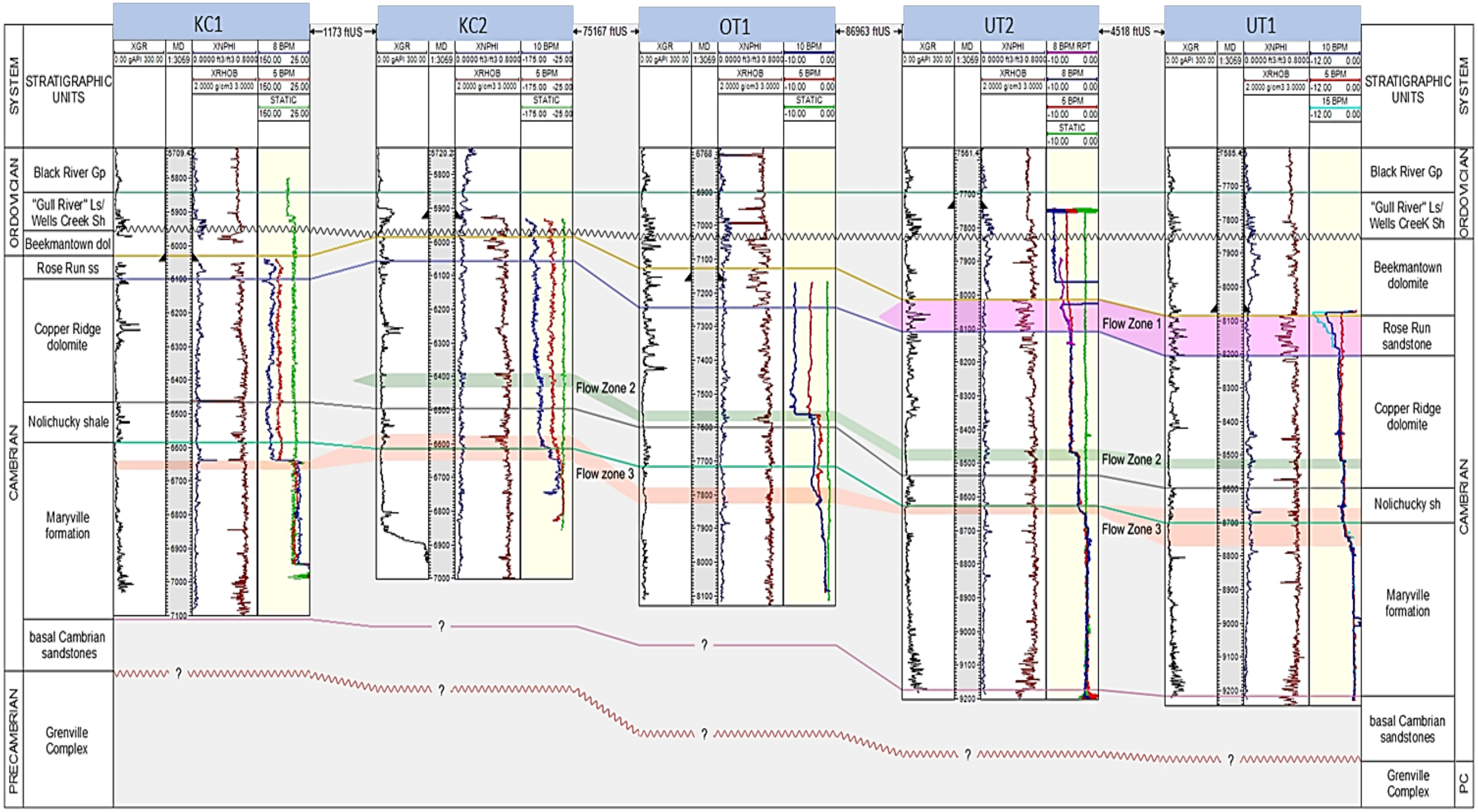

Figure 3-15. Cross section of piggyback wells with flowmeter data showing continuity of identified inflow zones in the Rose Run, Lower Copper Ridge, and Nolichucky/Maryville interface (Conasauga/Rome)

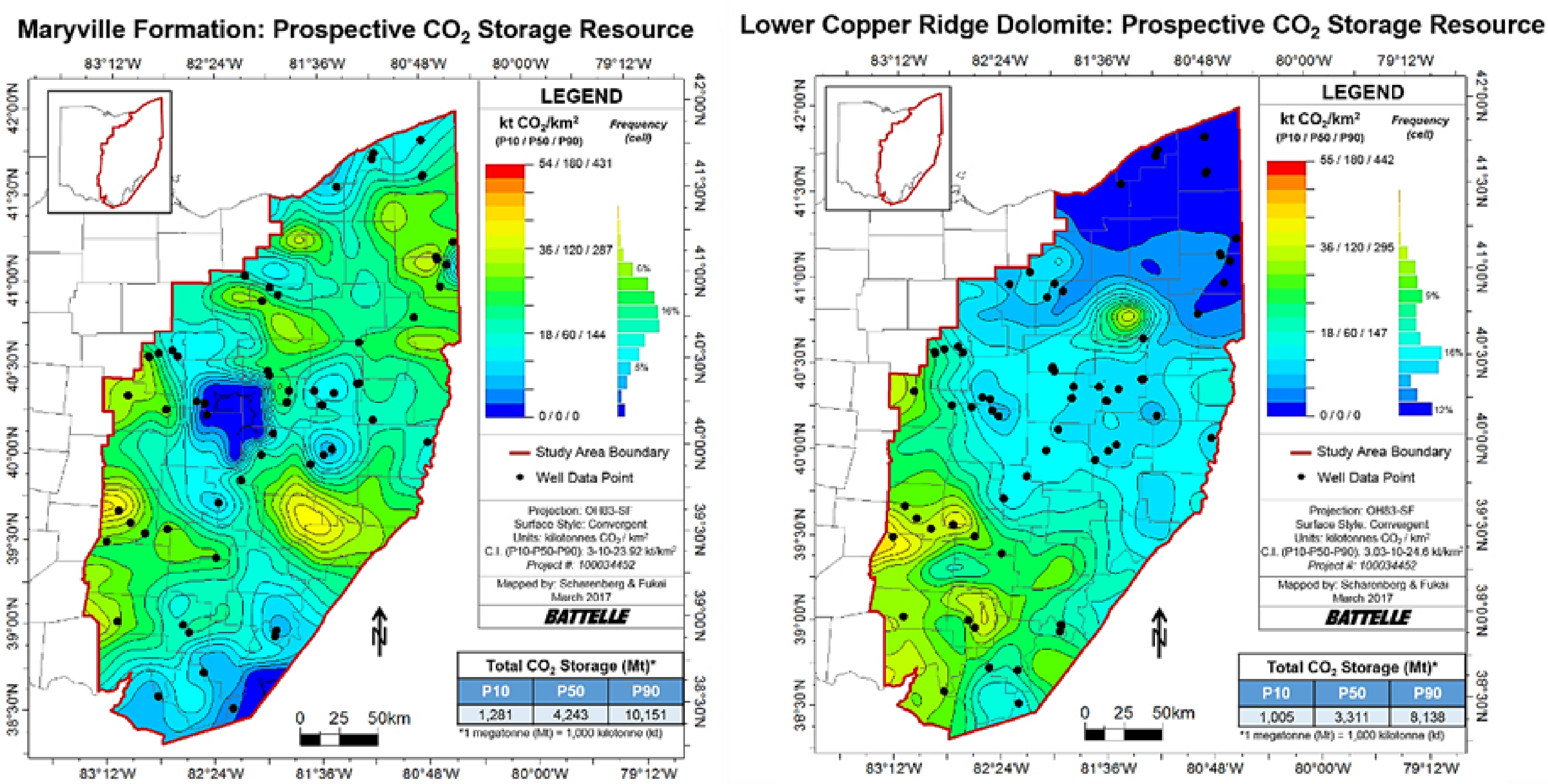

Figure 3-16. Maryville formation (left) and Lower Copper Ridge static CO_2 storage resource estimates in kilotonnes per square kilometer (kt/km²).

Overall, the work completed through these projects provided a detailed assessment of reservoirs and caprocks. Sandstones and carbonates are both viable options for CO_2 storage, however carbonates are greatly underestimated using traditional methods. Injection data provided by operators through proved injection potential in the deep reservoirs. Detailed mapping and capacity estimates narrowed down candidate storage areas. Feasibility studies emphasized that the stacked reservoir scenario is necessary for commercial scale storage and that well/field configuration is key for success. Additionally, the caprock feasibility studies have established that the primary caprocks are sufficient to prevent CO_2 leakage from the reservoir into higher formations.

The geologic framework (reservoirs and caprocks) shows suitable options for CO_2 storage in eastern Ohio. There are also many sources for CO_2 that would make potential capture locations. The regional analysis was the first step towards successful CCUS in Ohio.

3.4.2 OCDO Enhanced Oil Recovery Projects (OOE-CDO-D-13-24 and OER-CDO-D-15-08)

The first phase of the OCDO EOR efforts focused on the development of process understanding and an evaluation technical and economic feasibility of CO_2-EOR in Ohio. The focus was on depleted oil fields in the Clinton Sandstone (Eastern Ohio) and the Knox Dolomite Group (North-Central Ohio). These fields are promising candidates for CO_2-assisted EOR because of poor primary recovery efficiency that leaves behind approximately 80–90% of the original oil in place. A systematic assessment of EOR and co-sequestration potential for CO_2 in these depleted oil fields has not been undertaken to date – which is the objective of this research project (Battelle, 2015 and Battelle, 2019). Key findings from the project were:

- CO_2 sequestration potential in the 30 major oilfields of Ohio was found to be 878 million metric tons based on replacement of void space created by historical oil and gas production (Figure 3-17),

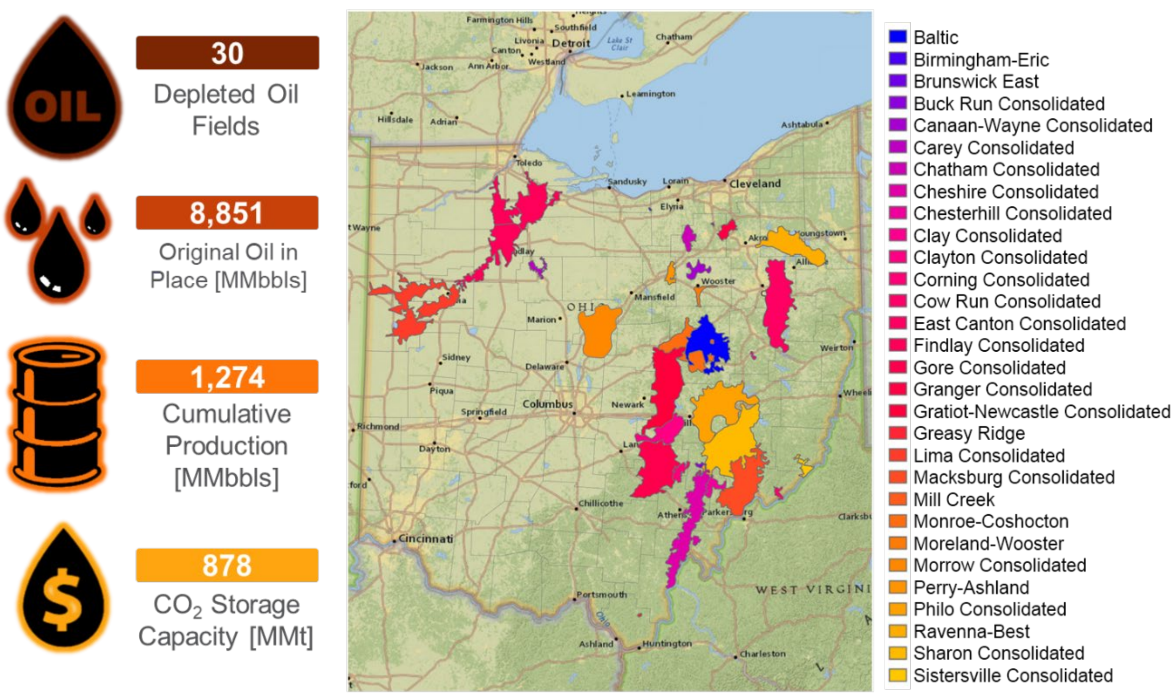

Figure 3-17. Oilfields in Ohio studied under the OCDO-EOR Phase I project totaling 1,274 MMbbls produced with an equivalent of 878 MMt of CO_2 storage potential.

- Integration of well-log and core analysis data was utilized to create geologic framework models for two "reference" reservoirs in the Clinton and Knox formations (i.e., East Canton and Morrow oil fields) for input into dynamic reservoir simulation models,
- A reservoir fluid prediction toolbox was created to generate tables of oil, gas, water, and CO_2 PVT properties based on empirical correlations,
- Reservoir simulation studies were carried out using the geologic framework models to better understand the interplay between incremental oil recovery from CO_2 injection and CO_2 storage,
- Key emissions sources from Ohio were identified as emitting 123 million metric tons of CO_2, and the location of these was mapped with respect to the depleted oil fields, along with the selection of optimal pipeline routes from the sources to the two reference oil fields, and
- A cost-benefit analysis methodology including Ohio specific well costs was developed and applied to the East Canton and Morrow oil fields for a range of CO_2 cost and oil price scenarios.

The second phase of the OCDO EOR funded research focused on the continued development of the methodology and knowledge base to facilitate linking operators of coal-fired power plants with small producers in Ohio, along with the key accomplishments listed below:

- ***Characterization of oil fields with limited data*** – a methodology has been developed that enables the rapid estimation of geologic properties based on characteristics of geologically similar regions for performing assessments of CO_2-enhanced oil recovery (EOR) and geologic storage feasibility.
- ***Identification of fractures from well-log data with machine learning*** – a machine learning based approach has been developed for predicting fractures from common well log signatures which can be a powerful reservoir characterization tool when advanced logs and/or core samples are not available.
- ***Prediction of permeability with greater accuracy*** – new porosity-permeability transforms have been developed with larger data sets for both the Clinton sandstone and Copper Ridge dolomite oil-bearing formations to enable improved prediction of permeability for carrying out dynamic reservoir assessments.
- ***Prediction of CO_2-oil MMP with greater accuracy*** – a new statistical correlation for minimum miscibility pressure (MMP), i.e., optimal operating pressure for CO_2 floods, as a function of reservoir temperature and oil gravity has been developed to better estimate MMP without running detailed laboratory experiments.
- ***Understanding of core floods under CO_2 injection*** – first-of-a-kind laboratory experiments with core samples from the Clinton sandstone and Copper Ridge dolomite formations provide process understanding of CO_2-oil interaction in-situ without the interference from field-scale heterogeneities.
- ***Simplified tools for CCUS reservoir performance*** – a material balance toolbox and a simplified rate model have been developed to perform rapid assessments (i.e., in the project screening phase) of the impacts of CO_2 injection into depleted oil fields.
- ***Factors affecting fractured reservoir CCUS performance*** – detailed numerical simulations have been carried out to quantify the impact of natural fractures on CO_2 injection associated improved oil recovery and geologic storage volumes for the Clinton sandstone formation (Figure 3-18).

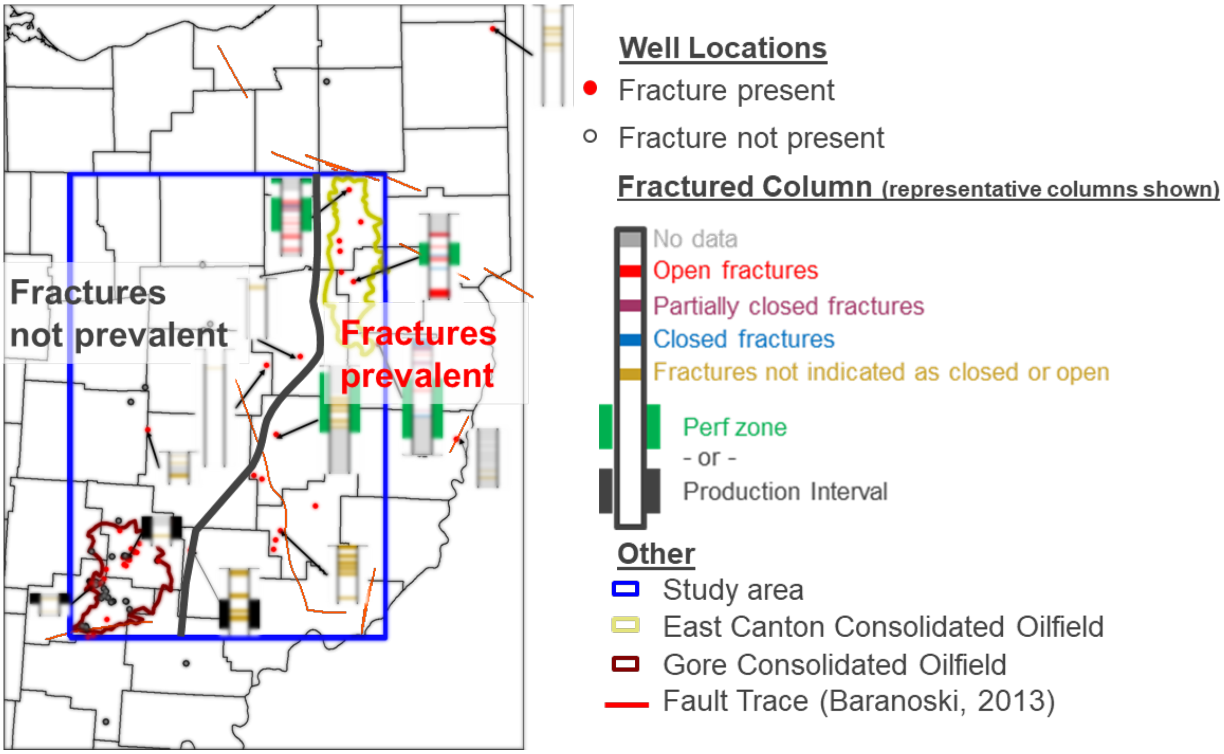

Figure 3-18. Example of fracture mapping in the Clinton Sandstone

- ***Detailed mapping of CO_2 sources and sinks in Ohio*** – a detailed mapping of power plants (sources) and proximal oilfields (sinks) has been carried out for the largest coal-fired power plants in Ohio that helps identify promising candidates for a CCUS project.
- ***Techno-economic analysis of CCUS projects in Ohio*** – a detailed techno-economic analysis has been carried out for a representative source-sink pair that (a) shows how CO_2 storage credits can be critical for CCUS economics, and (b) identifies several feasible scenarios for which CO_2 capture costs can be offset from CO_2-EOR revenues.
- ***Framework for calculating risks from wellbore integrity issues*** – a detailed approach has been developed and applied to several depleted oilfields in Ohio to quantify wellbore integrity driven risks of CO_2 leakage and their associated cost impacts.
- ***CO_2 injection into two different formations*** – CO_2 was successfully injected into one well in the Clinton sandstone formation and one well in the Copper Ridge dolomite formation – thus demonstrating acceptable injectivity and providing useful lessons on operational and cost issues associated with site preparation and monitoring.
- ***Analysis of pressure-production data*** – calibration of single-well models for primary production and CO_2-injection induced pressure response provides valuable insights into the representation of key processes and parameters in field-scale models.

3.5 CarbonSAFE Programs in MRCSP Region

One of the key gaps in the critical path toward CCS deployment is the development of commercial-scale (50+ million metric tons CO_2) geologic storage sites for CO_2 from industrial sources. There has been relatively little effort by the private sector to identify and certify (i.e., regulatory permit) geologic storage sites that are capable of storing commercial-scale volumes of CO_2, primarily because of the lack of immediate economic incentives. As a result, commercial-scale CO_2 sources that want to develop CCS projects face the risk of not finding a suitable saline storage site for their captured CO_2.

Carbon Storage Assurance Facility Enterprise (CarbonSAFE) is a U.S. Department of Energy (DOE)-sponsored effort to develop an integrated CCS storage complex constructed and permitted for operation in the 2025 timeframe over a series of sequential phases of development: Integrated CCS Pre-Feasibility, Storage Complex Feasibility, Site Characterization, and Permitting and Construction. Subject to availability of funds, a series of funding opportunity announcements (FOAs) are planned to accomplish this mission.

The work conducted under MRCSP led to two Phase 1 CarbonSAFE projects. One in the northern Michigan Basin and the second in the central Appalachian Basin. This section summarizes the key findings in the regions.

3.5.1 Northern Michigan Basin CarbonSAFE

The objective of this project was to take the first step in developing an integrated commercial geologic CO_2 storage complex in the Northern Michigan Basin, herein referred to as the CarbonSAFE – Northern Michigan Basin (CS-NMB) storage complex. This includes demonstrating that the storage sites within the complex have the potential to store more than 50 MMT of industrially sourced CO_2 emissions safely, permanently and economically (Battelle, 2018). To achieve the overall objective of the Phase I pre-feasibility study, FOA-1584 required three activities:

- Perform a high-level technical sub-basinal evaluation to identify a potential storage complex with storage site(s), including a description of the geology and risks associated with the potential storage site; identify and evaluate potential CO_2 sources.
- Develop a plan for the storage complex and storage site(s) including a strategy that would enable an integrated capture and storage project to be economically feasible and publicly acceptable.
- Form a CCS coordination team capable of addressing regulatory, legislative, technical, public policy, commercial, financial, etc. challenges specific to commercial-scale deployment of the CO_2 storage project.

The high-level sub-basinal evaluation focused on assessing the lateral extent, thickness, structure, properties, and CO_2 storage capacity for two saline reservoirs: the St. Peter sandstone and Bass Islands dolomite. Additionally, a catalog of Niagaran reefs was used in collaboration with the MRCSP regional characterization task to identify top targets for CO_2-EOR. This study also included an evaluation of risks and identification of land usage.

Next, all the collected and interpreted data was integrated with source locations to identify potential regionals for commercial-scale CCS. The modeling analysis demonstrated 50 MMT of CO_2 could be injected into the St. Peter Sandstone and that 82 reefs were needed to reach a goal of a combined commercial storage volume (Figure 3-19).

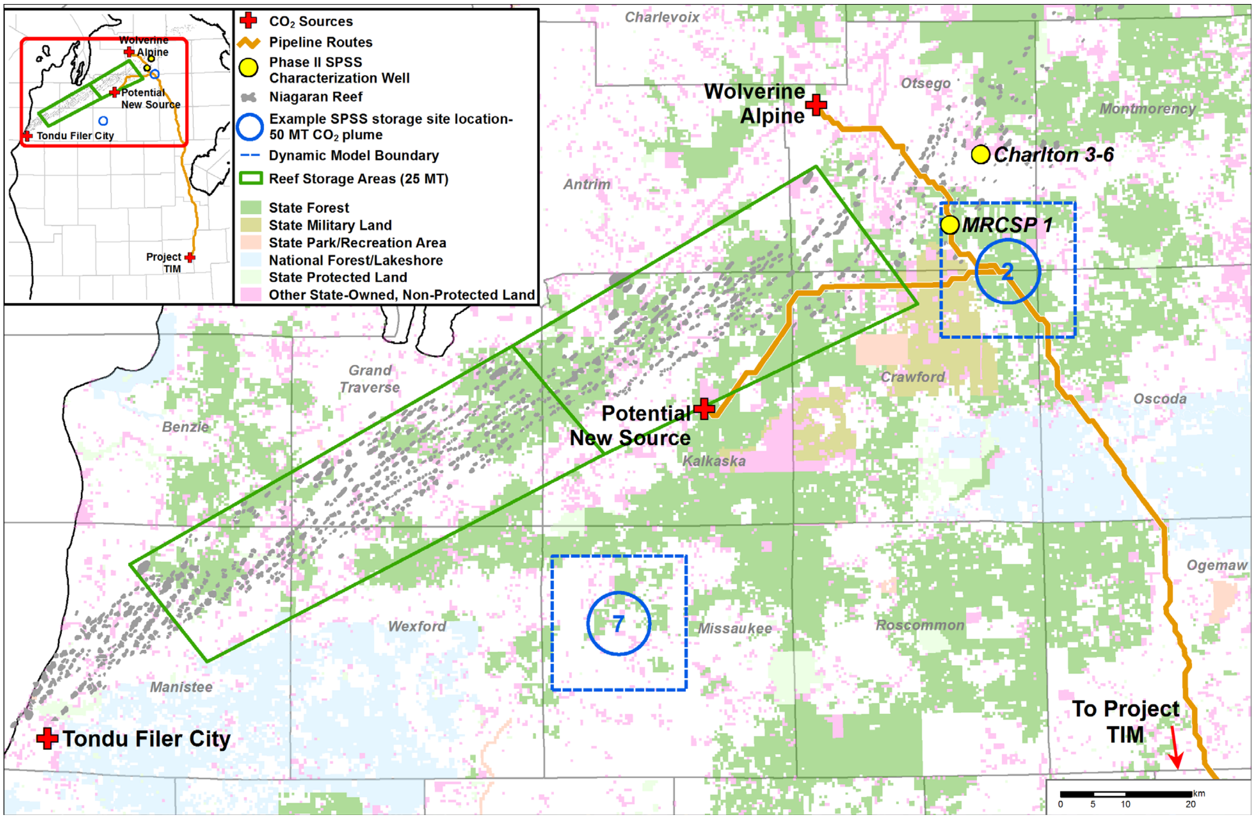

Figure 3-19. Summary of the CarbonSAFE Northern Michigan Basin project showing top sources and sinks.

Lastly, the project successfully formed a CCS coordinate team which consisted of industry partners, geoscience experts, legal and regulatory experts, outreach coordinators, and financial analysis experts. The team consisted of all critical expertise needed to develop a commercial CCS project in the region.

3.5.2 Central Appalachian Basin

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 (Battelle, 2018b).The key activities and findings are summarized below:

- 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.
- 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 (Figure 3-20).

- The project definition, including project dimensions, infrastructure requirements, mineral and property rights, and site screening for a commercial-scale CCUS project, was determined.
- Project integration factors including economic, regulatory/political/technology issues, permitting, public outreach, and project liability of a commercial-scale CCS project were evaluated.
- Team building involved the creation of a team of experts to provide the necessary expertise to support a successful CCUS project.

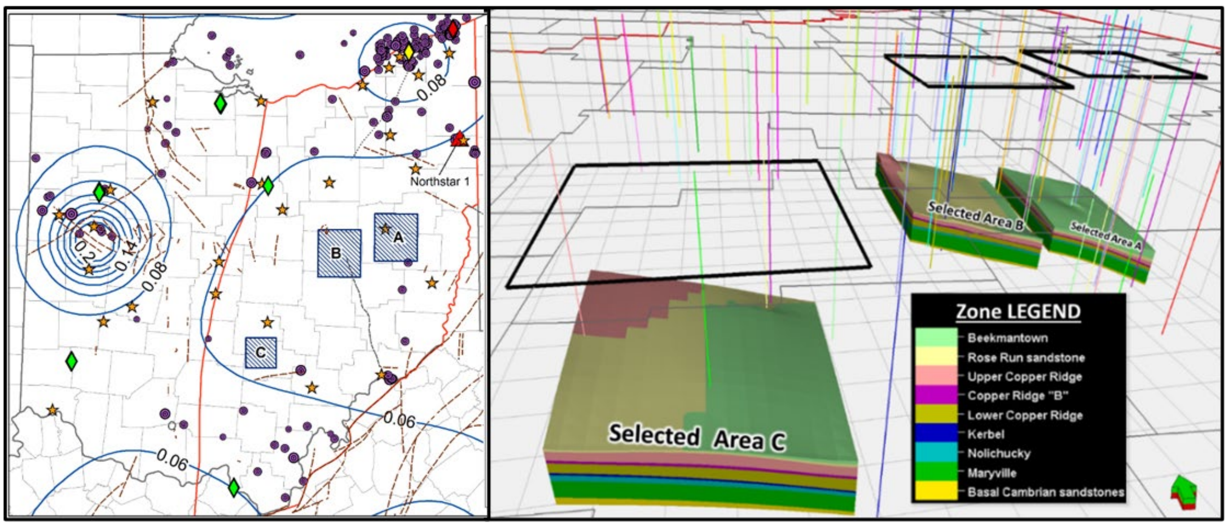

Figure 3-20. Down selected study areas (left) for advanced modeling and analyses (right).

3.6 Advanced CO_2-EOR Program in Southern Michigan

The work conducted MRCSP generated valuable research and industry partnerships that provided the framework for new opportunities in the region. One of these opportunities, is a new project titled *Chemically Enabled CO_2-Enhanced Oil Recovery in Multi-Porosity, Hydrothermally Altered Carbonates in the Southern Michigan Basin (*DOE-FOA-0001988), which focuses on experimental design, field testing, and development of CO_2-EOR in the Trenton Black River play (Figure 3-21).

The research concept involves integration of multiple data types to evaluate fields in the study area that have the lowest technical and environmental risk and optimal setting for EOR. Laboratory experiments will be used to optimize a CO_2 flood composition specific to hydrothermal dolomite (HTD) rock properties, and subsequently design and simulate injection scenarios that offer wettability alteration, foaming, and reduced surface tension. This work will improve oil recovery from matrix porosity and mitigate the impact of fracture zones. The optimized design will be implemented and tested in a Trenton/Black River field. The results will provide strategies to improve oil recovery in complex carbonate formations in the Michigan Basin as well as in other carbonate plays. The key risks include working with data vintages; data availability; assessment of complex HTD systems, including thief zones and conformance issues; wellbore integrity of old wells; and cost and sourcing of CO_2 for field tests. The identified risks will be mitigated through the developed methodologies and partnerships under laboratory experiments, characterization, and machine learning tasks, and by field test planning.

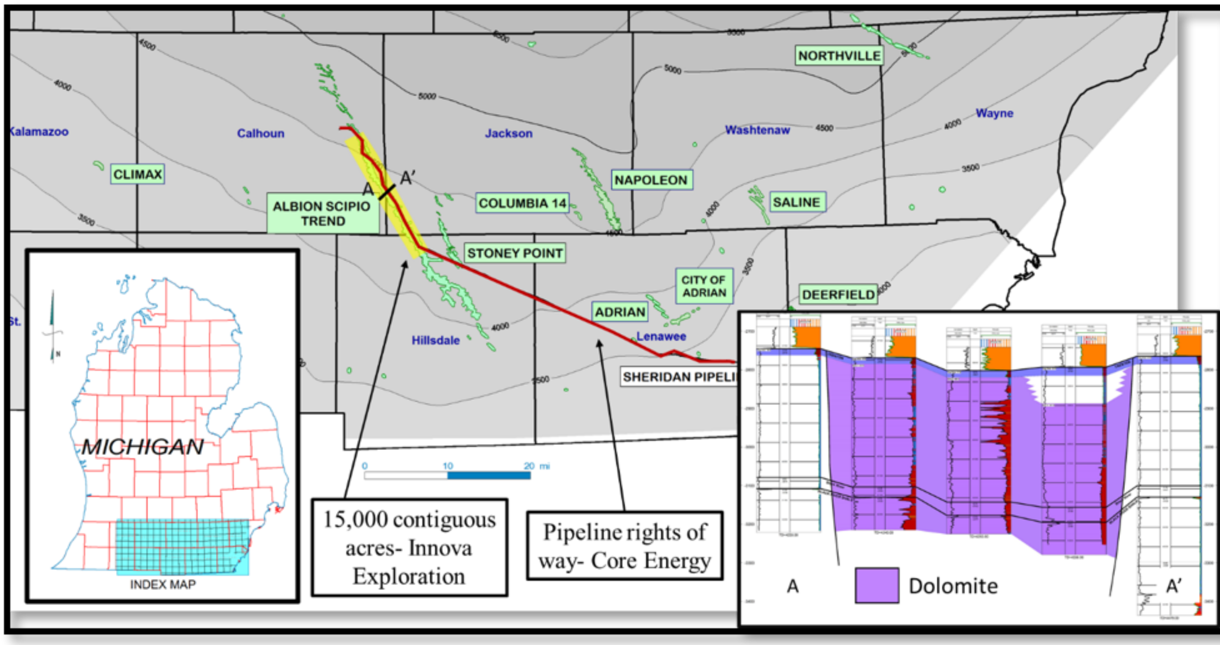

Figure 3-21. Project study area for the CO_2-EOR project in the Trenton Black River play in Southern Michigan.

The project will help reinvigorate depleted oil fields in HTD type reservoirs in the Michigan Basin, with technical transferability to other similar basins. Without DOE funding, the small producers that operate most fields in Midwestern and Appalachian regions will not be able to use advanced EOR technologies customized for their needs, leaving significant stranded oil. The HTD reservoirs are also a prominent play throughout the eastern United States and Canada, with documented production in Indiana, Ohio, New York, West Virginia, and southwestern Ontario. Additionally, there are more than 35 documented HTD plays worldwide, which make up approximately 20 percent of carbonate reservoirs. While project funding will initiate CO_2-EOR infrastructure in the Midwest, it will also lay the groundwork for future work.

4.0 Technical and Public Outreach

A key goal of the MRCSP and the other Regional Carbon Sequestration Partnerships (RCSP) Program was to engage in public outreach and education, to facilitate achievement of the technical goals, dissemination of the results, and to gauge and develop awareness of the CCS technologies as one of the options for carbon mitigation. These goals were achieved through local and regional outreach related to the field projects and technical knowledge sharing through MRCSP meetings, conferences, workshops, Best Practice Manuals, and journal publications. This chapter provides an overview of the outreach work undertaken by MRCSP during its entire performance period (i.e., Phases I, II and III).

4.1 Introduction and Stakeholder Change Over Project Timespan

The social landscape for CCS changed dramatically during the course of the MRCSP project due to the efforts of MRCSP, the other regional carbon sequestration partnerships (RCSP), and numerous other CCS projects as well as external influences. When the MRCSP was launched in 2003, the main research objective could be informally described as "would CCS prove to be a viable technology for addressing climate change?" Now, almost 20 years later, the answer to that question is a clear yes and the focus has shifted to figuring out how to commercialize deployment of the technology in in the MRCSP region and globally. During that time, we have learned a great deal about how to effectively engage the public on this topic.

The core contribution from MRCSP and the other RCSP projects has been the development of a substantial body of technical knowledge and practical experience in CCS. As indicated in the following summary of outreach activities, MRCSP has shared this information with diverse groups of stakeholders at the local, regional, state, federal, and international level. The result of these information sharing efforts, and those of the RCSPs and other research projects, is that there much greater certainty about the viability of CCS technology.

One key stakeholder group is project developers and CO_2 emitters. The MRCSP has both gained experience and developed products that are useful to developers. Experience in site development, project design, permitting, monitoring, and accounting for the CO_2 all facilitate the development of future CCS projects. The MRCP has also developed communication tools designed to inform the public about CCS and address common public concerns and perceptions of the technology.

Another key stakeholder group is policy makers and regulators. Experience from the RCSPs informed the development of Underground Injection Control (UIC) regulations for sequestration wells (Class VI). The US EPA has issued Class VI permits and has already delegated implementation primacy to one state with others in process. There is also a reporting rule in the US that allows all CO_2 injection projects to quantify the amount of CO_2 stored; the Phase III MRCSP project reports under this rule. National and state incentive programs that provide tax credits, funding, and other support for CCS are designed to further assist the business case. Notable among these are the federal tax credit for CCS known as "45Q," several state severance tax relief programs for the use of anthropogenic CO_2 in EOR, and the California protocol to enable CCS projects to deliver CO_2 reductions into the state's Low Carbon Fuel Standard (LCFS) program.

Other countries have also promulgated regulations for CCS. An indication that there is widespread support for and confidence in CCS is that the International Standards Organization (ISO) is engaged in creating standards for CO_2 capture, transport, storage, quantification, and EOR. That effort has already published eight standards and has four under development.

Another important stakeholder group includes environmental NGOs and other civic groups. The MRCSP and other RCSP projects have diligently worked to share technical information with these stakeholders. The result has been a deeper substantive understanding of CCS. Some groups have become strongly supportive of the role of CCS in addressing climate change. This includes constructive efforts to shape regulations and incentive policies. Not all civic groups support CCS. There are concerns about the potential to prolong reliance on fossil fuels and there have been concerns that not enough deployment is taking place to make a difference. The important thing is the debate has tended to focus more on the policy choices rather than the question of whether CCS works.

A number of external factors have also influenced public attitudes towards CCS. One of the most important to recognize is the polarized debate about climate change itself. When the MRCSP was launched, the US was involved in the Kyoto Protocol and had seemed to be on a course to take policy action that would provide a significant driver for CCS. The elections in 2000, 2008, and 2016; the tragedy of the terrorist attacks in 2001; the real estate market collapse; the global recession; and the shale gas boom all contributed to a changing and polarized view of climate change that impacted the potential for policy drivers, such as regulations, that would require CCS. As the science of climate change has continued to emerge, a recognition of the value of having technology options like CCS has contributed to ongoing interest, if not outright support, for CCS by civic groups.

Another factor is change in the energy field including technology development and energy markets. The shale gas boom put competitive pressure on coal combustion but at the same time, opened markets for exported LNG and stimulated demand for CO_2 for use in EOR. As CCS technology has been proven and improved, some costs have begun to drop. As serious financial incentive programs have emerged, private companies are taking advantage of these programs. The section 45Q tax credit for CCS was passed in 2008, amended in 2009, it provided \$10-20/tonne for EOR and saline storage. The program was significantly expanded in 2018 to include, among other changes, a new rate of up to \$35-50/tonne. As of May 2018, credits resulting from nearly 60 million tonnes of CO_2 storage had been claimed at the original rate and the number of claims is expected to rise under the new pricing. The newest program to emerge is the LCFS program in California. Private companies that capture and sequester CO_2 can partner with transportation fuel providers to offset carbon emissions. There is a market within California to trade such reductions and the current trading price is roughly \$180/tonne. These incentives are motivating companies to develop and document CCS projects. This private sector push is, in turn, further improving stakeholder attitudes towards CCS.

While there is still work to be done to commercialize CCS, the advances in technology and public awareness provide a solid foundation for the full potential of CCS to be realized.

4.2 Summary of Outreach Activities

Technology transfer was a key aspect of MRCSP's work. The MRCSP team has coordinated numerous workshops, technical conferences, stakeholder outreach open houses, technical advisory committee meetings, and industry meetings for CCUS and environmental applications. These education and outreach activities have raised awareness of CCUS and helped stakeholders understand the technical, economic, regulatory and safety considerations for CCUS and EOR projects. Additionally, MRCSP participated in providing content for the Best Practices Manuals and Carbon Atlases. By sharing the knowledge and expertise gained over the course of the MRCSP projects, we have set the stage for others to continue this work and bring CCUS and EOR into widespread use.

4.2.1 Annual Partners Meeting

MRCSP engaged program partners and stakeholders each year in its annual Partners Meeting (Figure 4-1), which attracted up to 100 attendees. These meetings showcased MRCSP technical progress, meaningful panel discussions on topical issues, and upcoming work. The program aimed to reach out to stakeholders across the region by hosting the meeting at different locations including Columbus, Baltimore, Washington DC, Traverse City, Cincinnati, and Annapolis.

Figure 4-1. Photographs from the 2019 MRCSP partners meeting in Columbus, Ohio.

4.2.2 Technical Workshops

MRCSP participated in hands-on technical workshops to engage and educate decision makers and end-users of CCUS technologies (Figure 4-2). The workshops focused on building consensus between stakeholders including industry, technical researchers, vendors, regulators, financial institutions, legal, government, local communities, and non-government organizations. They emphasized applied research for CCUS—including site characterization, permitting, operations and monitoring—with practical examples of technology deployment in the field.

- International Energy Agency Greenhouse Gas Program (IEAGHG)
- International Energy Agency (IEA)
- U.S. Environment Protection Agency (EPA)
- U.S. Department of Energy
- U.S. Energy Association
- Carbon Sequestration Leadership Forum (CSLF)
- U.S.-Japan Bilateral
- North American Energy Ministers CCS working group
- Groundwater protection council (GWPC)
- Various state agencies and industrial group workshops

Figure 4-2. IEAGHG workshop site visit in Traverse City, Michigan.

4.2.3 Technical Conference Presentations

The technical team has given numerous presentations at national, regional, and international conferences, including:

- Greenhouse Gas Technology (GHGT)
- Petroleum Technology Transfer Council (PTTC)
- American Association of Petroleum Geologists AAPG (sectional and regional)
- Society of Petroleum Engineers - SPE (section and regional)
- American Institute of Chemical Engineers (AiCHE)
- Annual CCUS conference
- American Geophysical Union (AGU)

4.2.4 Papers and Publications

The technical team has produced a large volume of peer-reviewed papers in leading scientific journals along with participation in technical books (provided in bibliography). Journals include:

- AAPG Explorer
- AAPG Environmental Geosciences
- Greenhouse Gas Science and Technology
- International Journal of Greenhouse Gas Control
- Petroleum Science and Engineering
- Society of Petroleum Engineers
- Energy Procedia

4.2.5 Field Site Tours

MRCSP has provided several tours of active CO_2 injection operations for interested stakeholders, such as hosting researchers from China, MRCSP partners meeting, and through the IEAGHG working group workshop. These events allow stakeholders to see injection operations in action so they can better understand how CCUS works.

4.2.6 STEM Outreach

MRCSP recognized the importance of conducting Science, Technology, Engineering, and Math (STEM) outreach for children and young adults. These outreach programs involved planning and running experiments related to CO_2 emissions and CCUS.

- American Association of University Women (AAUW) (Gaylord, Michigan) (Figure 4-3)
- BeWISE STEM Camp (Central Ohio)

Figure 4-3. AAUW bicycle pump demonstration

5.0 Conclusions

This Final Technical Report along with the series of companion Topical Reports and published papers are intended to document the CCUS research conducted by Battelle and team members under the MRCSP program. As demonstrated through these documents and the underlying data, MRCSP has been successful in accomplishing all the expected outcomes over its 17 years of operations.

When MRCSP started, the CCUS technology and its awareness were in its infancy. There were no climate policies or incentives, but there was a significant interest from the policymakers and industry in the role of CCUS in the emerging consensus around the need to address carbon emissions. Shale gas production enabled with hydraulic fracturing was still in early development stages and the power generation was highly reliant on coal as the primary energy source. All this is reflected in the significant interest from the MRCSP founding sponsors, who included all major utilities in the study region along with several oil companies.

Starting in 2003, the **MRCSP Phase I** assessed the initial landscape for CCUS in the study area, including a review of CO_2 sources, possibilities of storage in geologic and terrestrial sinks, and the regulatory, policy, and stakeholder setting at that time. Phase I also set the stage for identifying candidate locations and willing host sites for the field pilot studies for development in Phase II.

The **MRCSP Phase II** started in 2005 and was completed in 2011, with a primary emphasis in conducting multiple pilot-scale field injection tests to evaluate the basic concepts of CO_2 storage and foster stakeholder awareness and acceptance. The MRCSP geologic storage tests were conducted at sites hosted by Duke Energy, First Energy, DTE, and Core Energy. In addition, MRCSP terrestrial storage team conducted four tests of carbon storage in shallower terrestrial systems. There was strong industry and stakeholder support for all the tests. During the Phase II work, a key stakeholder and observer was the USEPA, who permitted the field tests under Class V experimental injection well category. The lessons learned from the pilot geological storage tests were used by the USEPA for development of the Class VI injection well category for CO_2 storage well. Overall, the Phase II geologic pilot tests validated that CO_2 could be effectively injected in deep saline formations, contained within the intended subsurface zones, and monitored for its retention and migration within the subsurface. Phase II tests also showed that injectivity and storage capacity are not uniform and therefore more detailed geologic exploration and storage capacity assessments are needed prior to making massive investments in a CCUS facility.

The **MRCSP Phase III** was funded in 2008 and completed in 2020, with the primary objective of conducting a large-scale test (>1 million metric tons) of CO_2 injection within the MRCSP region, with the intent of evaluating scalability and deployment aspects of CCUS. In addition, MRCSP continued working with its Geology Team members to assess selected regional aspects of CO_2 storage across the study area. The large-scale test objective required access to cost effective source of CO_2, suitable geology, a willing host site, and an appropriate stakeholder and policy setting. The low-cost CO_2 sources in the study area were ethanol and natural gas processing plants. The initial location for the test, an ethanol plant in western Ohio, was deemed to be not viable due to stakeholder concerns in the area, which would have taken too long to address. As a result, the test was moved to a northern Michigan location, which was also the host site for Phase II, with CO_2 from natural gas processing. However, the new USEPA requirements for the Class VI injection wells were too onerous for a research program and therefore, the drilling of the test well for this site was suspended in 2011. MRCSP was able to quickly shift to the current location, within the same Michigan Basin study area. This new location allowed leveraging the ongoing and expanding CO_2-EOR activities by Core Energy in the carbonate reef complex. This experience in having to change the large-scale injection project twice reflects the real-life stakeholder situations that must be addressed and the value in having alternative options available.

The **MRCSP Michigan Basin** large-scale test in the CO_2-EOR setting started in late 2011. The test was designed to be highly synergistic with Core Energy's expanding EOR operations in the study area enabling MRCSP to evolve as Core added new fields to their operations. The program included assessment of CO_2 injection operations across the entire facility which grew from 5 to 10 fields during the MRCSP work. The research was organized according the EOR stage of the fields – a late-stage field that was already near to end of EOR operations; active EOR fields undergoing injection and production; and newly added fields without prior injection activity. The MRCSP characterization, modeling, and monitoring evolved over time with the growth in fields, resulting in a portfolio approach of technology assessment. Some key outcomes of the large-scale test include:

- The overall objective of injection and monitoring at least 1 million metric tons of CO_2 was greatly exceeded, based on monitoring of CO-EOR operations between 2012 and 2019.
- A complete mass balance evaluation of all current and historical injection, production, processing, and recycling showed that within measurement uncertainties, all the CO_2 can be accounted. The accounting framework and CO_2 mass balance analysis were accepted under the USEPA Greenhouse Gas Reporting program. The mass balance data were also used for the Life-Cycle Analysis, which showed that CO_2-EOR operations in this setting can produce oil with net negative emissions.
- The geologic characterization using both previous exploration data and newly collected seismic and wellbore data, showed that the carbonate reef geology is highly conducive to CO_2 injection, storage, and retention. However, within each reef, there is a great deal of internal heterogeneity, leading to differences in permeability, injectivity, and the zones with preferential flow of CO_2. Some reefs have internal compartmentalization or may be semi-connected with adjacent reefs. The degree of dolomitization can also affect injectivity. Despite these geologic challenges, overall reef system showed that there is sufficient injectivity and the storage capacity in the individual fields for the intended purposes. Furthermore, the overlying anhydrite and salt layers make the reefs excellent containers for retention of CO_2. The geologic data collected under MRCSP was useful in further optimizing the injection and EOR operations at the site.
- A portfolio of commercial and emerging monitoring options was deployed across the facility with the dual intent of evaluating CO_2 storage and migration within the reefs and evaluating the effectiveness of monitoring technologies in this geologic setting. The monitoring showed that standard downhole pressure and temperature are essential for understanding reservoir behavior and storage potential. Advanced monitoring technologies, especially the borehole seismic methods, had limited use due to the physical properties of the carbonate rocks. However, there is potential to improve their applicability for specific geologic settings with further research. The fiber-optic DTS was also very useful in determining the CO_2 flow zones in the reservoir. Other technologies such as surface deformation with InSar, borehole microgravity, pulse neutron logging, and geochemistry provide useful insights into specific aspects of injection and storage.
- The reservoir modeling also used a portfolio approach to test various modeling approaches, develop new concepts, and evaluate the ability of models to simulate the field observations. While it was generally possible to conduct a reasonable history match with the models, it was fairly challenging to fully match all phases (primary production, fill-up with CO_2, EOR production, post-EOR injection) of the EOR life-cycle with the available data. This is in part due to complex internal geology of the carbonate systems. However, the gross behavior of each reef in terms of pressure buildup, injectivity, and storage capacity was sufficiently understood with models to indicate that the EOR operations are working as anticipated. The models were also used to evaluate relative merits of various engineering decisions to accelerate or improve field injection operations.

- The overall stakeholder and enabling regulatory environment in Michigan is very favorable for large-scale deployment. There were no stakeholder concerns during the large-scale test, based on the excellent working relations between Core Energy and residents in the project area. The Michigan regulations allow for synergistic use of subsurface resources on State lands, while being protective of the environment.
- Overall, no significant technical risk factors were identified that could hinder further development of CCUS in conjunction with the EOR operations in the study area.

The **MRCSP Regional geology** work supplemented the large-scale test during phase III. The key outcomes are summarized in Chapter 3 of the report and detailed in the companion regional geology reports. The regional work covered specific geologic settings. A few key highlights include:

- The scale-up in the Michigan Basin from the large-scale test in 10 reefs to the entire northern reef complex indicated several hundred million tons of storage potential combined with commercial benefit of incremental oil production. The current CO_2-EOR operations in the area can be significantly expanded using the Core Energy experience, if additional CO_2 was available.
- The largest CO_2 sinks in the MRCSP region remain the Mt. Simon Sandstone in the western areas (Michigan, Ohio, Kentucky, and Indiana). This will be the workhorse for development of regional saline storage complexes.
- Deeper in the basins, the Mt. Simon Sandstone or basal sandstones can lose injectivity. However, additional zones, especially the vuggy carbonates (Knox Dolomite) can provide significant storage potential, subject to more detailed characterization. As an example, monitoring in several produced water injection wells in eastern Ohio indicates commercial scale injectivity in carbonate zones overlying basal sandstone. Deeper sections of the Appalachian Basin (eastern Ohio, western Pennsylvania, and West Virginia) and central Michigan Basin will require expanded characterization to qualify storage resources.
- The largest storage potential likely exists in the offshore reservoirs along Atlantic coasts. This needs to be further characterized and developed as it maybe that best carbon mitigation options for current or future sources along east coast and even in the Appalachian Basin.
- Significant CO_2-EOR potential also exists in the Appalachian Basin and Michigan Basin depleted oil and gas fields. However, for large-scale sources, it may be best to develop stacked storage systems with EOR and saline formation storage in the same CCUS complexes. In addition, many of the larger oil fields in the Appalachian Basin tend to be low permeability and may have a large number of existing wells, requiring well integrity assessments prior to injection.
- There are several localized storage candidates in region, including rift basins along the east coast, sedimentary layers in the coast planes, and Silurian and Devonian sequences in eastern Ohio.
- The unconventional oil and gas reservoirs, such as Utica and Marcellus shale may offer future options for storage and enhanced recovery. However, the challenge of low injectivity needs to be addressed for any commercial-scale long-term storage in these low permeability zones.

The above highlights indicate that the MRCSP Phase III program was successful in meeting all the objectives laid out at the beginning of the program. In the process, MRCSP collected enormous amounts of data relevant to future deployment of CCUS and built a significant knowledge base. All of the MRCSP data has been archived at the DOE EDX site for future use. These data are already being used for the DOE’s Initiative for machine learning (SMART) and National Risk Assessment Partnership (NRAP).

MRCSP work has also resulted in development of human capital and expertise at Battelle, geological surveys, universities, and in partner companies. This expertise is already being used for additional demonstrations and commercial project development, which will lead to deployment of CCUS. The synergistic projects being undertaken by MRCSP include work on CarbonSAFE, Coal FIRST, and Southern Michigan EOR projects. The Battelle MRCSP team has also worked on international projects funded by the World Bank and Asian Development Bank I China, Mexico, Indonesia, Mongolia, and South Africa. Finally, the subsurface data and expertise are being used to support the assessments of brine disposal and geothermal energy.

MRCSP program has proven the technical viability of CCUS in the region. It has also demonstrated availability of large CO_2 storage resources. However, the next challenges deal with scaling up to full commercial scale projects. This will require continued efforts to characterize and qualify reservoirs that can guarantee availability of large-scale, long-term storage and injection capacity. Work is also needed for developing optimized monitoring approaches for various geologic settings. This should be combined with addressing of remaining policy gaps, including access to pore space, unitization, infrastructure, and regulatory certainty.

During the MRCSP performance period, the outlook for CCUS underwent several up and down cycles. This has been affected by the likelihood of carbon mitigation regulations, economic conditions, replacement of coal by natural gas, reduction in prices for renewables, and industry interest. During the last two years, the expanded 45Q tax credit system has led to a major increase in commercial and industry interest in deployment CCUS. Furthermore, the carbon regulations, especially the California Low Carbon Fuel Standards have raised carbon prices significantly for fuel sales in California market. All this is especially conducive for high purity sources that can likely benefit from the 45Q credit limits. For the larger-scale sources, such as power plants, additional improvements in capture costs and further government support maybe needed for deployment. Finally, there is an increasing emphasis on integration of CCUS with emerging themes including, stacked storge systems, direct air captures, biologically enhanced CCUS, hydrogen economy, and combined renewable and CCUS systems.

To address the remaining technical and institutional aspects in an accelerated manner, DOE has already funded the four new Regional Initiatives for deployment of CCUS (Figure 5-1). The MRCSP study region in this new initiative called the **Midwest Regional Carbon Initiative (MRCI)** new program has been expanded 20 states in the Midwest and northeastern USA and includes the Midwestern Geological Sequestration Consortium (MGSC) region of Illinois Basin. The MRCI is jointly led be Battelle and University of Illinois. The MRCI program addresses key technical challenges using existing and new data and evaluates infrastructure needs for large-scale deployment. Above all the Initiative is a resource for industry and other stakeholders interested in deployment.

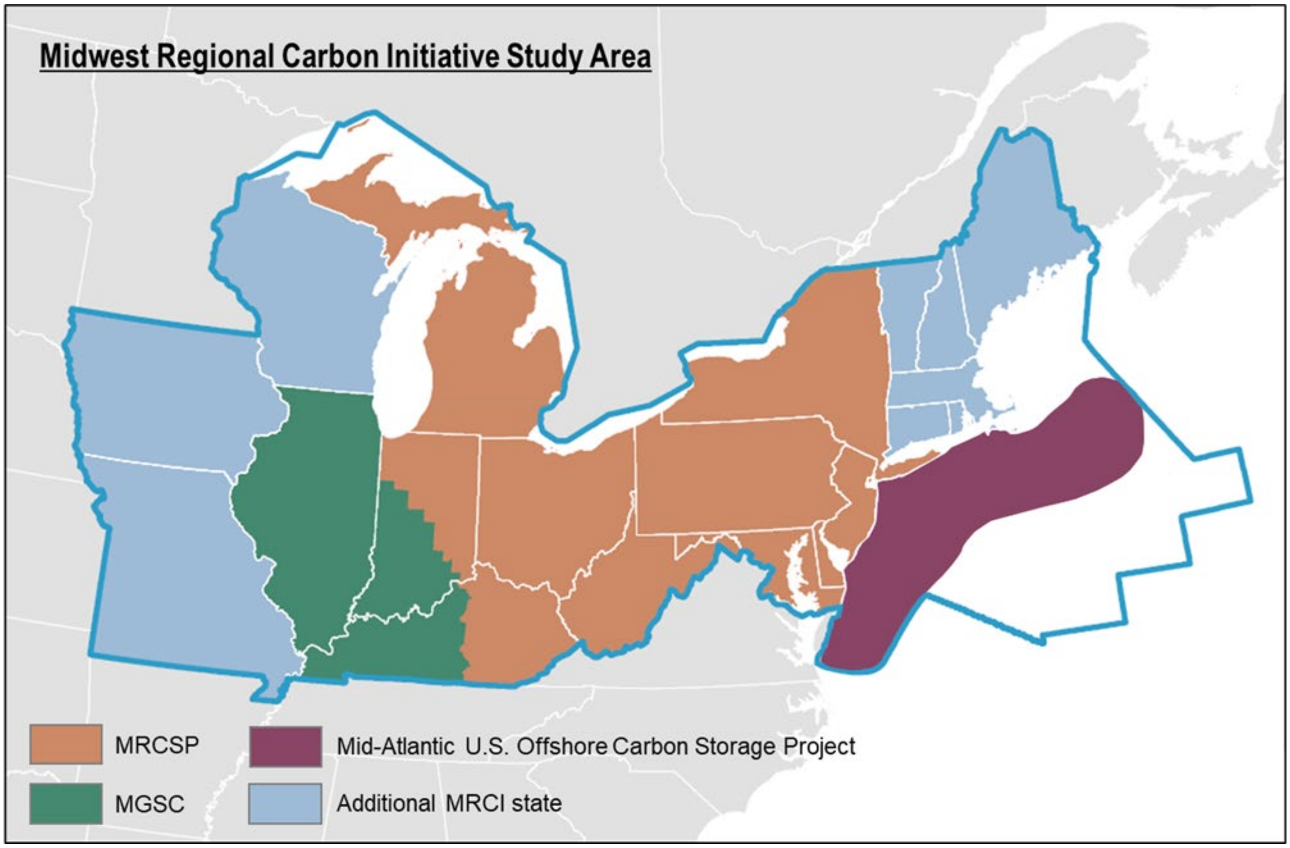

Figure 5-1. Study Region Covered under the Midwest Regional Carbon Initiative (MRCI)

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