Final Technical Report

Integrated Wellbore Integrity Analysis Program for CO_2 Storage Applications

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Project results reflect contributions from many people on the project team. The project lead was Battelle, and J.R. Sminchak was the project manager. Mark Moody and Dr. Neeraj Gupta were technical advisors. Task leads were Dr. Andrew Duguid, Matt Place, and Jared Hawkins. Other contributions were made by Autumn Haagsma, Desiree Padgett, Kelly Quigley, Leo Chiques, Jen O'Brian, Jacob Markiewicz, and others. Carol Brantley, Colin Kegel, Theresa Schaff, and Jackie Gerst assisted with project administration and management.

Abstract/Plain Language Summary

Exposure to CO_2 in the subsurface is a concern for wellbore integrity at CO_2 storage sites. This project completed a review of 1,500 wells, field survey of 83 wells, and detailed wellhead testing on 23 wells at three CO_2 field sites. The field testing results did not show significant well defects. Well construction and/or cement carbonation sealing may have contributed to well integrity. Geochemical analysis suggests subsurface conditions at the field sites were suitable for cement sealing of gas migration pathways via calcium carbonate precipitation. Results support effective management of CO_2 storage applications in areas with many legacy oil and gas wells.

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List of Acronyms and Abbreviations

Bcf	billion standard cubic feet
$CaCl_2$	calcium chloride
$CaCO_3$	calcium carbonate
$Ca(OH)_2$	Portlandite
CBL	cement bond log
CCS	carbon capture and storage
CCUS	carbon capture, utilization, and storage
CO_2	carbon dioxide
cm^3	cubic centimeter
CH	calcium hydroxide
C-S-H	calcium-silicate-hydrate
DEP	Department of Environmental Protection (State of West Virginia)
DEQ	Department of Environmental Quality (State of Michigan)
DOE	U.S. Department of Energy
EDX	Energy Data Exchange
EOR	enhanced oil recovery
FEP	Features, Events, and Processes
ft	foot
ft^3	cubic foot
kg	kilogram
kg/L	kilograms per liter
km	kilometer
LCM	lost circulation material
LLNL	Lawrence Livermore National Laboratory
LTSI	long term shut in
µm	micrometer
m	meter
MD	measured depth
mg/kg	milligrams per kilogram
mg/L	milligrams per liter

List of Acronyms and Abbreviations (cont)

MICP	mercury injection capillary pressure
mm	millimeter
MPa	megapascal
MRCSP	Midwest Regional Carbon Sequestration Partnership
MSCFD	thousand standard cubic feet per day
NETL	National Energy Technology Laboratory
nm	nanometer
NRAP	National Risk Assessment Partnership
psi	pounds per square inch
PTRC	Petroleum Technology Research Centre
SCP	sustained casing pressure
SI	saturation index
SiO_xOH_x	silicate-hydrate
TD	total depth
TOC	top of cement
TVD	true vertical depth
WAG	water alternating gas
WVGES	West Virginia Geologic and Economic Survey

Executive Summary

Carbon dioxide (CO_2) injection for geologic carbon storage and enhanced oil recovery (EOR) may result in mixtures of CO_2 and water contacting new and legacy wells in the deep subsurface. Exposure to CO_2 is a concern for wellbore integrity, because CO_2 can corrode well materials and migrate along defects around the borehole potentially reaching near surface groundwater resources or the atmosphere. This project evaluated well integrity in CO_2 wells with a combination of direct field testing and well records analysis. Key accomplishments and results of this project are summarized as follows:

- Approximately 1,500 wells at three field sites were reviewed in terms of well construction, history of exposure to CO_2, geochemistry, mineralogy, and well materials:
    - **Appalachian Basin.** The Appalachian Basin Indian Creek site is a methane and natural CO_2 field located in Kanawha County, West Virginia. The field contains 58 wells at total depths between 6,200 feet (ft) and 6,700 ft in the Tuscarora sandstone. The field has natural pockets of CO_2 at levels up to 60%.
    - **Michigan Basin.** The Michigan Basin field site is located in Otsego County, Michigan. Carbonate reef fields were developed since the 1960s in the region, and selected reefs have been subject to CO_2 EOR since the 1990s. CO_2 is present in the Antrim gas wells between 5% and 30% at depths between 1,000 ft and 1,500 ft and in the Niagaran Reef EOR wells at depths ranging from 5,000 ft to 7,000 ft.
    - **Williston Basin.** The Williston Basin field is in Saskatchewan Canada with operations dating back to 1954. More than 3,000 wells are present at the Williston Basin testing site, completed at depth of approximately 6,000 ft to 7,000 ft. CO_2 EOR was started in 2000 at the site, expanding to additional areas over time.

- A total of 83 CO_2 wells were surveyed at the Michigan Basin site (23 wells) and the Williston Basin site (60 wells) for wellhead casing pressures that may indicate well defects. The Appalachian Basin site was not available for testing, because the asset was sold to a new operator.

- Detailed sustained casing pressure (SCP) testing was completed on 23 wells that had indications of significant SCP.

- The testing results did not show significant well defects, with casing pressures less than 1 megapascals (MPa) and minor pressure buildup patterns. There was no evidence of significant defects or CO_2 migration in the wells that were tested.

- Additional geochemical modeling and meta-modeling for the three field sites and four test study areas indicated that mineralogy, hydrologic conditions, cement blends, and brine geochemistry were not critical factors to the cement carbonation process.

- Well construction and/or cement carbonation sealing appears to have contributed to well integrity. Results support effective management of CO_2 storage applications in areas with many legacy oil and gas wells.

The three field sites have wells which have been exposed to CO_2, either naturally or through EOR operations, for 5 to 50+ years under different geologic settings and subsurface conditions. These datasets provide unique opportunities to study the influence of CO_2 on wellbore integrity. The field testing was completed on a subsample of wells and does not mean all CO_2 wells would be free of defects. In addition, the SCP testing methodology requires defects that would lead to gas migration to the wellhead. Therefore, there may be existing downhole defects not revealed by the testing. Project results demonstrate that well construction procedures, well design, and well logging/testing for defects are important considerations for wellbore integrity in CO_2 environments in the subsurface. Additional work on the life-cycle effects of CO_2 would help highlight changes over time due to subsurface exposure to CO_2 in wells.

Chapter 1.0 Introduction

This Final Technical Report presents the findings for the project *Integrated Wellbore Integrity Analysis Program for CO_2 Storage Applications (FE0026585)*. The project is part of a U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) program to develop and advance technologies that will significantly improve the effectiveness and reduce the cost of implementing carbon storage. The project is designed to assess well integrity for wells exposed to carbon dioxide (CO_2) environments in the subsurface through a combination of field testing and record analysis.

1.1 Project Background

Legacy oil and gas wells are considered a key risk factor for carbon capture, utilization, and storage (CCUS) projects because they represent the most likely migration pathway out of a reservoir into overlying formations. Each well at a CCUS project, whether a legacy well or a well used for injection, production, or monitoring of the CO_2 plume, must effectively ensure that 99% of the CO_2 is accounted for within the subsurface. The goal of ensuring that CO_2 is effectively captured and stored on longer, more geologic time scales must overcome leakage risk through proper engineering and construction of wellbores.

The overall objective of this research project was to develop and validate a program for identifying and characterizing wellbore integrity issues for potential CO_2 storage applications based on analysis of well records validated with SCP field testing. The project involved analyzing existing well data for several fields where wells have been exposed to CO_2 and analyzing new data collected from SCP testing. Together, these data and analyses were used with geochemical analysis to identify trends that lead to better understanding and prediction of well integrity issues. The project was designed to result in predictive methods to survey, identify, characterize, and remediate wellbore integrity issues for CO_2 storage applications. The project was divided into the eight tasks shown in Figure 1-1. Full reports were prepared for each major task and the field testing. As such, this report focuses on presenting results of the project tasks. The task reports are available in case more details are required.

1.2 Objectives

The project goal was to develop an integrated program to identify, survey, measure, and analyze CO_2 migration in wellbores. After a well has been constructed and/or plugged, the only indication of migration through the outer well materials may be pressure buildup on the well, referred to as sustained casing pressure (SCP). The impact of CO_2 on wellbore integrity was determined by integrating field casing pressure test results with analysis of cement sealing potential, well construction details, well logs, cement bond logs (CBLs), and well history. In addition, the types of well defects (micro-annulus, cracks, porous cement, and incomplete cement coverage) were explored by analyzing casing pressure buildup curves measured in the field on CO_2 wells. Meta-modeling methods were used on CO_2 storage test fields to investigate the impact of pressure, gas saturation, and chemistry on well integrity.

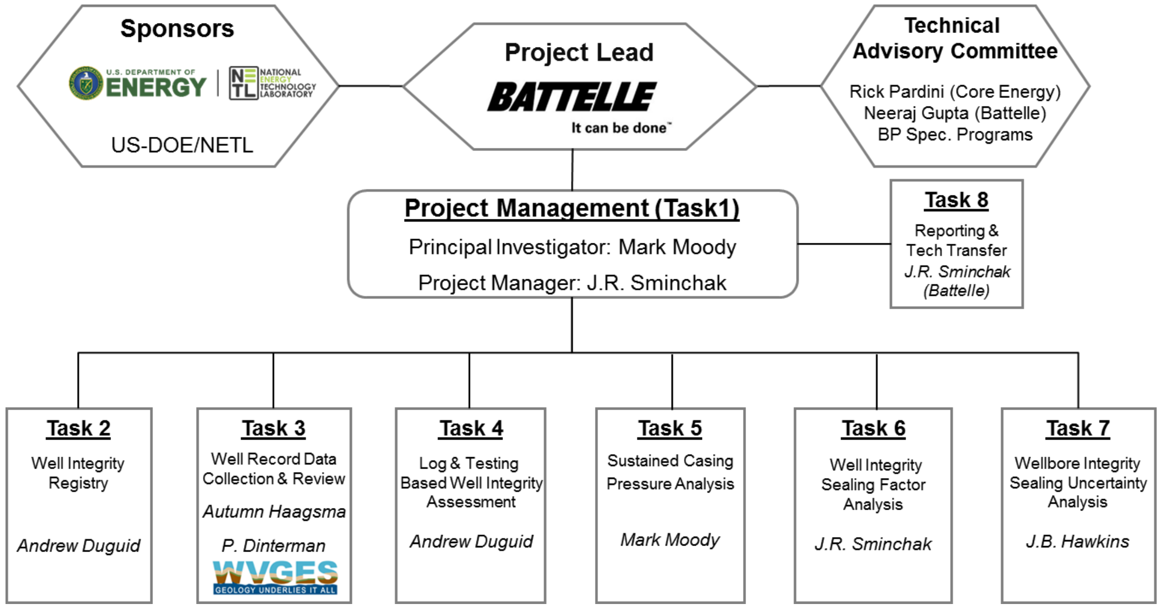


Figure 1-1. Project task organization chart.

The project was organized into eight main tasks with more detailed subtasks. Table 1-1 lists the task objectives, technical approach, and corresponding deliverables. A key objective of the project was to complete field measurements of casing pressure at several locations with existing boreholes that have wells exposed to CO_2 in the Michigan Basin, Appalachian Basin, and Williston Basin. The casing pressure testing results were integrated with analysis of cement sealing to predict well integrity problems in wells exposed to CO_2 in terms of leak location, nature, and severity. Based on SCP test results at the field sites, Tasks 6 and 7 were modified to evaluate cement sealing conditions.

1.3 Research on CO_2 Storage and Wellbore Integrity

Many research studies have evaluated the effects of CO_2 on wellbores in the subsurface (Table 1-2). In general, the studies have focused on laboratory testing of cement samples, surveys of existing well data, modeling of CO_2 exposure and/or migration, and field studies on wells (Zhang & Bachu, 2011). Given all this research, there are relatively few direct field studies with field testing of multiple CO_2 wells, because it is difficult to access wells in the subsurface and to collect samples from these wells. In addition, operators are hesitant to participate in research on wellbore integrity.

Therefore, many researchers have completed laboratory tests on prepared cement samples. Laboratory tests have generally confirmed the potential for geochemical reactions with Portland cements resulting in dissolution of cement and precipitation of calcium carbonate ($CaCO_3$). Laboratory tests have included diffusion-based tests in pressure vessels and flow-through tests with CO_2 and brine mixtures. Field studies have taken sidewall cores through casing and cement that have shown a dissolution front and mineralization front. Modeling studies have had more varied results simulating CO_2 migration within well boreholes, since it is difficult to determine cement permeability and pathways in boreholes. Studies have also examined cement sealing potential for different fracture aperture widths, concluding that $CaCO_3$ mineralization may reduce permeability in fractures less than approximately 50 to 200 nanometers (nm) wide.

Table 1-1. Project task objectives and deliverables.

Task	Milestone Description	Objective	Deliverable
1	Project Management & Planning	Coordinate project schedule, budget, progress reporting, and planning.	Project Management Plan (Oct 2015), Quarterly Research Performance Progress Reports
2	Wellbore Integrity Registry	Develop a registry of potential well defects for CO_2 storage applications based on well construction methods, well casing integrity issues, well cement issues, geologic processes, and CO_2 subsurface environments.	Well Integrity Registry Summary Report (June 2016)
3	Well Record Data Collection & Review	Describe field sites based on cementing, drilling, operational, and well workover records.	Well Record Data Summary Report (June 2017)
4	Log & Testing Based Well Integrity Assessment	Complete analysis of field sites based on well logs, well historical records, and quantitative well integrity indicator analysis.	Log & Testing Based Well Integrity Assessment Summary Report (November 2017)
5	SCP Analysis	Complete field testing of SCP in 20+ existing wells at field sites in Michigan Basin, Appalachian Basin, and Williston Basin. Analyze results for quantitative indicators of wellbore integrity defects.	Michigan Basin Field Testing Summary Report (March 2017), Williston Basin Field Testing Summary report (February 2018)
6	Field-Based Analysis of CO_2 Cement Sealing Conditions	Analyze field data on mineralogy, fluids, cement, hydrologic conditions & CO_2 exposure for the three field sites to determine cement sealing & well integrity relationship	Field-Based Analysis of CO_2 Cement Sealing Summary Report (June 2018)
7	Wellbore Integrity Sealing Conditions Uncertainty Analysis	Examine sealing conditions uncertainty for CCS projects in areas where there are a large number of existing wells with meta modeling.	Field-Based Analysis of CO_2 Cement Sealing Summary Report (June 2018), Final Technical Report
8	Reporting & Technology Transfer	Document project results and distribute project data for other CO_2 storage research and applications	Technical Reports, Presentations, Final Technical Report (September 2018)

Table 1-2. Summary of research on wellbore integrity for CO_2 storage.

Author	Date	Topic	Category
Bruckdorfer	1984	Carbon dioxide corrosion in oilfield cements	Lab testing
Burke	1984	Synopsis: Recent Progress in the Understanding of CO_2 corrosion	Data survey
Onan	1984	Effects of supercritical carbon dioxide on well cements	Data survey, field study
Shen and Pye	1989	Effects of CO_2 attack on cement in high-temperature applications	Data survey
Bonett & Pafitis	1996	Getting to the root of gas migration	Data survey
Chen et al.	2002	CO_2 corrosion for oil tube steel	Lab testing

Author	Date	Topic	Category
Rochelle et al.	2002	Geochemical interactions between supercritical CO_2 and the Midale Formation. II: Initial results	Lab testing
Rochelle et al.	2002	Geochemical interactions between supercritical CO_2 and the Midale Formation. I: Intro to fluid-rock experiments	Lab testing
Kermani & Morshed	2003	Carbon dioxide corrosion in oil and gas production—a compendium	Data survey
Rochelle et al.	2003	Geochemical interactions between supercritical CO_2 and the Midale Formation. III: Midale Fmt	Lab testing
Bateman et al.	2004	Geochemical interactions between supercritical CO_2 and the Midale Formation. VI: Midale Marly	Lab testing
Boukhelifa	2004	Evaluation of Cement Systems for Oil and Gas Well Zonal Isolation in a Full-Scale Annular Geometry	Data survey
Duguid et al.	2004	The effect of CO_2 sequestration on oil well cements.	Lab testing
Gasda et al.	2004	Spatial characterization of the location of potentially leaky wells penetrating a deep saline aquifer in a mature sed. basin	Data survey
Rocelle et al.	2004	Interactions between supercritical CO_2 and borehole cements used at the Weyburn oilfield	Lab testing
Ladva et al.	2005	The Cement-to-Formation Interface in Zonal Isolation	Modeling, lab tests
Cui et al.	2006	Study on corrosion properties of pipelines in simulated produced water saturated with supercritical CO_2	Lab testing
Czernichowski-Lauriol	2006	Geochemical Interactions between CO_2, Pore-Waters and Reservoir Rocks	Lab testing
Duguid et al.	2006	The effect of carbonated brine on the interface between well cement and geo. formations under diffusion-controlled conditions.	Lab testing
U.S. DOE	2006	Degradation of wellbore cement due to CO_2 injection	Modeling, lab tests
Vignes et al.	2006	PSA Well Integrity Survey, Phase 1 summary Report	Data survey
Carey et al.	2007	Analysis and performance of oil well cement with 30 years of CO_2 exposure from the SACROC unit, West Texas, USA	Field study
Kutchko et al.	2007	Degradation of well cement by CO_2 under geological sequestration conditions	Lab testing
Randhol et al.	2007	Ensuring well integrity in connection with CO_2 injection	Data survey
Bachu & Watson	2008	Review of failures for wells used for CO_2 and acid gas injection in Alberta, Canada	Data survey
Carey et al.	2008	Wellbore integrity and CO_2-brine flow along the casing-cement microannulus	Field study
Duguid	2008	An estimate of the time to degrade the cement sheath in a well exposed to carbonated brine	Modeling, lab tests
Kutchko et al.	2008	Rate of CO_2 attack on hydrated Class H well cement under geological sequestration conditions	Lab testing
Lecolier et al.	2008	Behavior of permeable steel/cement interface in contact with CO_2-saturated brine	Lab testing
Liteanu et al.	2008	Failure behaviour of wellbore cement in the presence of water and supercritical CO_2	Lab testing

Author	Date	Topic	Category
Rimmele et al.	2008	Heterogeneous porosity distribution in Portland cement exposed to CO_2-rich fluids	Lab testing
Strazisar et al.	2008	Chemical reactions of wellbore cement under CO_2 storage conditions: effects of cement additives	Lab testing
Barlet-Gouédard et al.	2009	A solution against well cement degradation under CO_2 geological storage environment	Lab testing
Watson & Bachu	2009	Evaluation of the Potential for Gas and CO_2 Leakage Along Wellbores	Modeling
Wigand et al.	2009	Geochemical effects of CO_2 sequestration on fractured wellbore cement at the cement/caprock interface	Lab testing
Huerta et al.	2009	Utilizing SCP Analog to Provide Parameters to Study CO_2 Leakage Rates Along a Wellbore	Modeling study
Crow et al.	2010	Wellbore integrity analysis of a natural CO_2 producer	Field study
Krupka et al.	2010	Thermodynamic Data for Geochemical Modeling of Carbonate Reactions Associated with CO_2 Sequestration - Lit Rev	Data survey
Carey and Lichtner	2011	Computational studies of two-phase cement–CO_2–brine interaction in wellbore environment	Modeling study
Han et al.	2011	A coupled electrochemical–geochemical model of corrosion for mild steel in high-pressure CO_2–saline environments	Modeling study
Han et al.	2011	Effect of debonded interfaces on corrosion of mild steel composites in supercritical CO_2-saturated brines	Lab testing
Liteanu & Spears	2011	Fracture healing and transport properties of wellbore cement in the presence of supercritical CO_2	Lab testing
Schaef et al.	2011	Brucite [$Mg(OH)_2$] carbonation in wet supercritical CO_2: An in situ high pressure X-ray diffraction study	Lab testing
Scherer et al.	2011	Characterization of cement from a well at Teapot Dome Oil Field: implications for geological sequestration	Field study
Yalcinkaya et al.	2011	Experimental study on a single cement-fracture using CO_2-rich brine	Lab testing
Zhang & Bachu	2011	Review of integrity of existing wells in relation to CO_2 geological storage: What do we know?	Data survey
Pan et al.	2011	Transient CO_2 leakage and injection in wellbore-reservoir systems for geologic carbon sequestration	Modeling study
Agbasimalo & Radonjic	2012	Experimental Study of Portland Cement/Rock Interface in Relation to Wellbore Stability for Carbon Capture and Storage	Lab testing
Han et al.	2012	Degradation of cement–steel composite at bonded steel-cement interfaces in supercritical CO_2 saturated brines	Lab testing
Jacquemet et al.	2012	Armouring of well cement in H_2S–CO_2 saturated brine by calcite coating – experiments and numerical modelling	Modeling, lab tests
Cao et al.	2013	Dynamic alterations in wellbore cement integrity due to geochemical reaction in CO_2-rich environments	Lab testing
Carey	2013	Geochemistry of wellbore integrity in CO_2 sequestration: Portland cement–steel–brine–CO_2 interactions	Lab testing
Choi et al.	2013	Wellbore integrity and corrosion of carbon steel in CO_2 geologic storage environments: A literature review	Data survey
Hawkes & Gardner	2013	Pressure transient testing for assessment of wellbore integrity in the IEAGHG Weyburn-Midale CO_2 Project	Field study

Author	Date	Topic	Category
Huerta et al.	2013	Exp. evidence for self-limiting reactive flow thru a fractured cement core: Implications for time-dep wellbore leakage	Lab testing
Jung et al.	2013	Imaging wellbore cement degradation by CO_2 under geo. sequestration conditions using X-ray computed microtomography	Lab testing
Jung et al.	2013	Experimental study of potential wellbore cement carbonation by various phases of carbon dioxide during geologic seq	Lab testing
Luguot et al.	2013	Hydro-dynamically controlled alteration of fractured Portland cements flowed by CO_2-rich brine	Modeling study
Mason et al.	2013	Chemical and mechanical properties of wellbore cement altered by CO_2-rich brine using a multi-analytical approach	Modeling study
Newell & Carey	2013	Experimental evaluation of wellbore integrity along the cement-rock boundary	Lab testing
Walsh et al.	2013	Permeability of wellbore-cement fractures following degradation by carbonated brine	Lab testing
Wenning et al.	2013	Reactive flow channelization in fractured cement-implications for wellbore integrity	Modeling study
Duguid et al.	2014	Well integrity assessment of a 68 year old well at a CO_2 injection project.	Field study
Nygaard et al.	2014	Effect of dynamic loading on wellbore leakage for the Wabamun Area CO_2 Sequestration Project	Modeling study
Sminchak et al.	2014	Investigation of wellbore integrity factors in historical oil and gas wells for CO_2 geosequestration in the Midwestern U.S.	Data survey
Glazewski et al.	2015	Wellbore Evaluation of the basal Cambrian System	Data survey
Haagsma et al.	2015	Utilizing Cement Bond Logs to Evaluate Wellbore Integrity for CO_2 Storage	Data survey
Jordan et al.	2015	A response surface model to predict CO_2 and brine leakage along cemented wellbores	Modeling study
Moody & Dotson	2015	SCP Diagnosis Using the Wellhead Model	Field study
Zhang et al.	2015	Wellbore cement integrity under geologic carbon storage conditions	Lab testing
Brunet et al.	2016	Fracture opening or self-sealing: Critical residence time as a unifying parameter for cement-CO_2-brine interactions	Modeling study
Brunet et al.	2016	Cement fracture opening or self-sealing: critical residence time unifies observations under different conditions	Modeling study
Huerta et al.	2016	Reactive transport of CO_2-saturated water in a cement fracture: Application to wellbore leakage during geo. CO_2 storage	Modeling, lab tests
Wolterbeek et al.	2016	Reactive transport of CO_2-rich fluids in simulated wellbore interfaces: Flowthrough experiments on the 1− to 6-meter (m) length scale	Lab testing
Wolterbeek et al.	2016	Effect of CO_2- induced reactions on the mechanical behavior of fractured wellbore cement	Lab testing
Carroll et al.	2017	Influence of Chemical, Mechanical, and Transport Processes on Wellbore Leakage from Geologic CO_2 Reservoirs	Data survey
Iyer et al.	2017	Incorporating reaction-rate dependence in reaction-front models of wellbore-cement/carbonated-brine systems	Modeling study

The research for this project integrates direct SCP testing of wells along with examination of defects and geochemical reactions along the length of the borehole, providing a more holistic examination of the effects of CO_2 on wellbore integrity. Many studies have verified that CO_2 brine mixtures may dissolve oilfield cements and precipitate $CaCO_3$. However, it is difficult to examine this process in situ along the borehole length, since the wells are cemented in place 3,000 to 15,000 feet (ft) deep in the subsurface. For example, CO_2 may mix with brine in the reservoir zone and dissolve cement, but then precipitate $CaCO_3$ in overlying caprock zones. Or, certain minerals in carbonate rock layers may buffer CO_2 brine mixtures, reducing potential for CO_2 to corrode well materials. Consequently, it is useful to evaluate the interaction of CO_2 with fluids, pressure conditions, geological layers, cement blends, and well construction materials.

1.4 Summary of Appalachian Basin, Michigan Basin, and Williston Basin Field Sites

A key part of the project was testing and analysis at three field test sites. The three field test sites identified for wellhead SCP testing were located in the Appalachian, Michigan, and Williston sedimentary basins. These sites have wells exposed to CO_2 at depths of 1,000 to 7,000 ft and 5 to 50+ years of age (Table 1-3). Therefore, they provided an excellent opportunity to examine CO_2 storage wellbore integrity at field sites. The wells were surveyed for indications of SCP, and a subsample of wells were tested for wellhead casing pressure buildup. The field test sites were characterized for geologic setting, field history, well construction specifications, and hydrologic conditions. Field site characteristics are summarized in Table 1-3 and are discussed in the following subsections.

Table 1-3. Summary of field sites.

Parameter	Appalachian Basin	Michigan Basin	Williston Basin
Field area (acres)	30,000	3,000	45,000
Reservoir depth (ft)	6,200-7,000	1,000 & 6,000	5,000
Reservoir type	Sandstone	Carbonate reefs	Carbonate
Caprock	Shale/carbonate	Evaporite	Evaporite
CO_2 type	Natural gas & CO_2	CO_2 EOR	CO_2 WAG EOR
Temperature (°F)	140	105	145
Discovery pressure (psi)	2,900	3,000	2,000
Discovery year	1973	1960	1954
# Wells	58	~45	~3,000

Note: WAG = water alternating gas; EOR = enhanced oil recovery; psi = pounds per square inch.

Appalachian Basin Site

The Appalachian Basin Indian Creek site is a natural CO_2 and methane field located in Kanawha County, West Virginia (Figure 1-2). The field contains approximately 58 wells at total depths between 6,200 ft and 6,700 ft. The Indian Creek field produces in the Tuscarora sandstone, where the percent of CO_2 in some wells ranged from 44% to 83% and nitrogen ranged from 13.9% to 35% (Avary, 1996). A completion report for the discovery well, API number 4703901684, listed CO_2 at 65%. Two scout cards, for wells 4703902718 and 4703902719, both listed CO_2 at 60%. Hamak & Sigler (1991) and Hamak & Gage (1992) reported produced gas with an average CO_2 at 65.8%, 305 British thermal units per cubic foot, and 1.214 grams per centimeter average gas gravity. One gas sample in the field taken by Jenden et al. (1993) reported a CO_2 content of over 61%. At depth, pressure conditions in the Indian Creek field were likely >2,800 pounds per square inch (psi) and temperatures were >110 °F. Thus, the CO_2 would be in supercritical state.

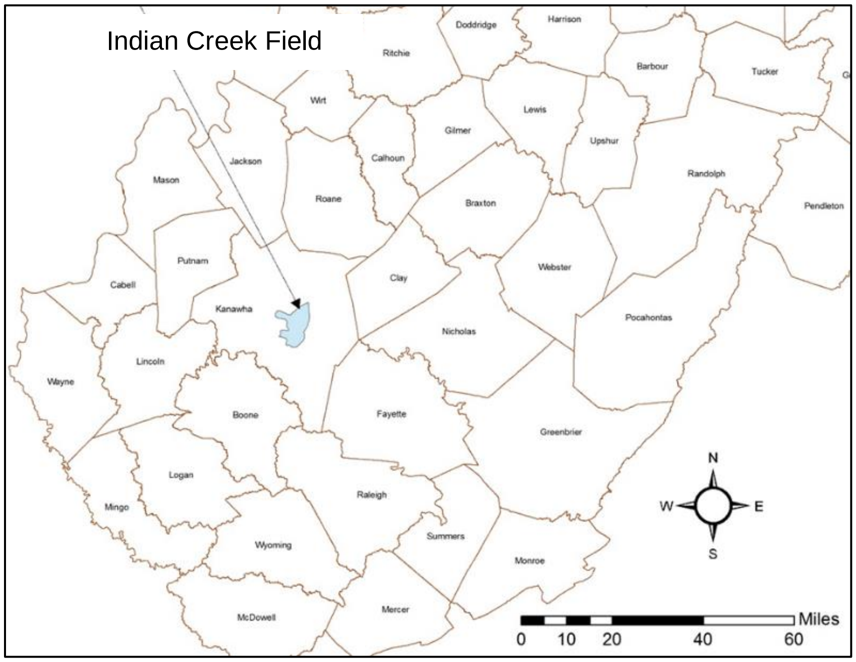


Figure 1-2. Location of the Indian Creek field in Kanawha County, West Virginia.

Michigan Basin Site

The Michigan Basin study site is located in the northern portion of the Niagaran reef trend in Otsego County, Michigan (Figure 1-3). The fields have been developed since the 1960s in the region, and selected reefs have been subject to CO_2 enhanced oil recovery (EOR) since the 1990s. There are several hundred Antrim gas wells at depths between 1,000 ft and 1,500 ft, and there are dozens of Niagaran reef wells at depths ranging from 5,000 ft to 7,000 ft in Otsego County. The Antrim shale wells produce methane and CO_2. The CO_2 volume in the produced gas is between 5% and 30%. Some of the Niagaran reefs in the area have been subject to CO_2 EOR over the past 10 to 20 years. Overall, the Antrim shale wells and Niagaran reef CO_2 EOR wells are attractive candidates for well integrity analysis.

Williston Basin Site

The Williston Basin is a large sedimentary basin which spans the southern portion of Saskatchewan, Canada, and the north-central United States. The Weyburn field is located on the northwestern edge of the Williston Basin geologic feature and was a major oil play which is now used for CO_2 EOR (Figure 1-4). The main reservoir for the Weyburn oil field consists of the Marly Midale and Vuggy Midale beds, which are part of the Mississippian-aged Madison group (Wilson & Monea, 2004). Approximately 3,000 wells are located in the Williston Basin testing site. The testing site is a mature oil field that began production in 1954. Prior to the start of CO_2 EOR, the Williston Basin testing site produced roughly 340 million barrels of oil, or an estimated 25% of the field's total reserve. As such, conventional methods for oil production are no longer viable for profit. To keep the oil field active, CO_2 EOR was started at the Weyburn field in 2000 using CO_2 transported via pipeline from a gasification synfuels plant in North Dakota.

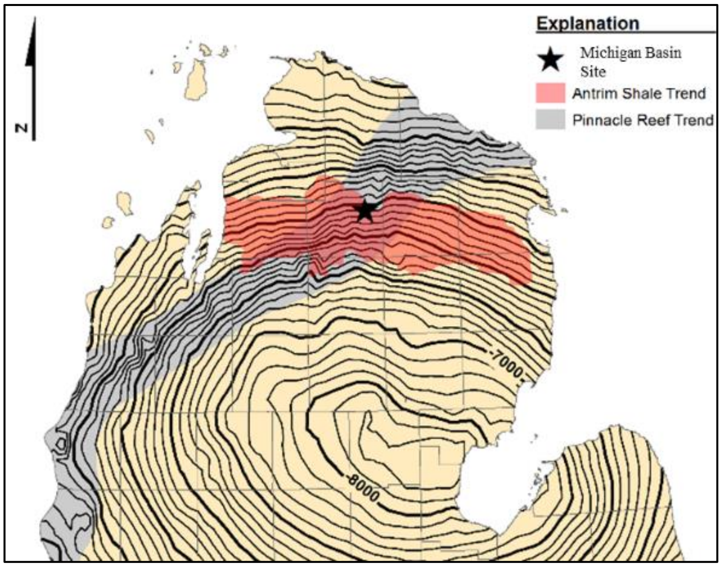


Figure 1-3. Structure map of the Brown Niagaran showing the pinnacle reef trend (gray), Antrim shale trend (red), and the Michigan Basin site (star).

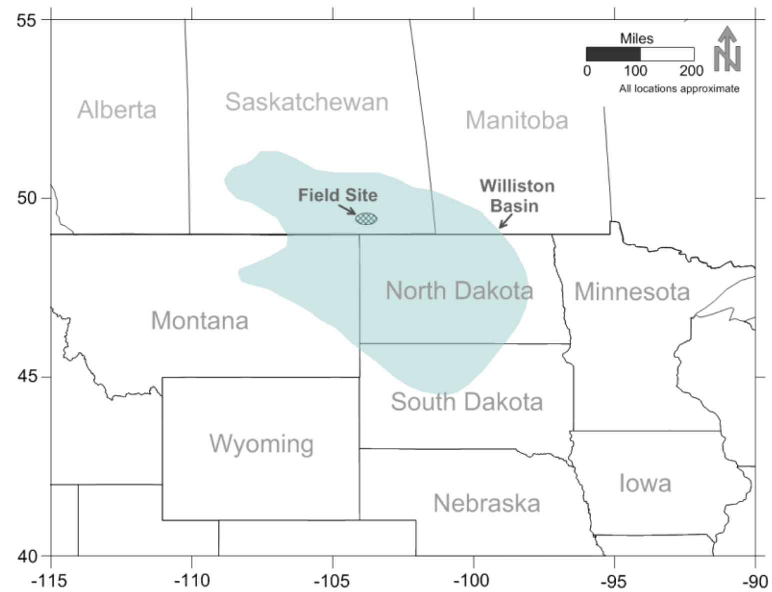


Figure 1-4. Location of the Williston Basin field site.

Chapter 2.0 Well Integrity Registry

Well integrity issues may arise from the materials, construction, operations, and subsurface conditions specific to a well. The objective of this task was to develop a wellbore integrity registry that describes actual or potential well integrity issues that may affect carbon storage projects. The registry was based on existing research and on experience related to well construction methods, well casing integrity issues, well cement issues, and geologic processes for CO_2 environments.

2.1 Well Construction Methods

Historical and current well construction methods for deep wells are important components to understanding well integrity. Important factors can include hole conditions, tubular design, cement slurry properties, hydrated cement properties, geologic conditions, and operational conditions. The cemented annulus, the cement space between the casing and formation, represents most of the leakage risk associated with the well. Leakage pathways through the cement matrix and many leakage pathways around the cement are described in this section.

Production wells, injection wells, and other deep wells generally consist of a conductor casing, a surface casing, a production casing, and intermediate casing strings in unstable hole conditions. A liner, a string of casing that does not extend to the surface, may also be used to case the bottom section of the well. Most casing used in wells is metal, but fiberglass, coatings, and alloys are sometimes used. The size and strength of casing in a well are determined by the production rate and loads on the casing in the well. Most wells are constructed using mild carbon steel, but corrosion-resistant alloys are used in corrosive environments. Primary cement is placed in the annulus between the casing and formation or the annulus between the inner and outer casing while the well is being constructed.

Well repair failures and defects within the well architecture may lead to well integrity issues that can cause gas and/or fluid migration along the borehole. Remedial cement may be emplaced with a squeeze job to address well defects. Cement plugs are used to close off portions of a well or to abandon the well. Plugs are generally set across the perforated zone, across resource zones, at casing seats, and at the top of the well. Multiple methods may be used to set cement plugs in a well, including a balanced plug method, a dump bailer method, and a two-plug method.

Multiple researchers, including Gasda et al. (2004), Duguid et al. (2012), and Carroll et al. (2016), have characterized migration pathways. In general, this research concludes that the main migration pathway occurs through or around the cement matrix that makes up the primary and plug cement in a well (Figure 2-1). Leakage through the cement matrix may include flow through the cement matrix, degraded cement, cement-casing interface, formation-cement interface, mud channels, and fractures/cracks in the cement sheath, and as well as through casing defects in the open wellbore. The results of the Duguid et al. (2012) study indicate that higher-permeability flow pathways around the cement matrix are the major pathway for gas migration.

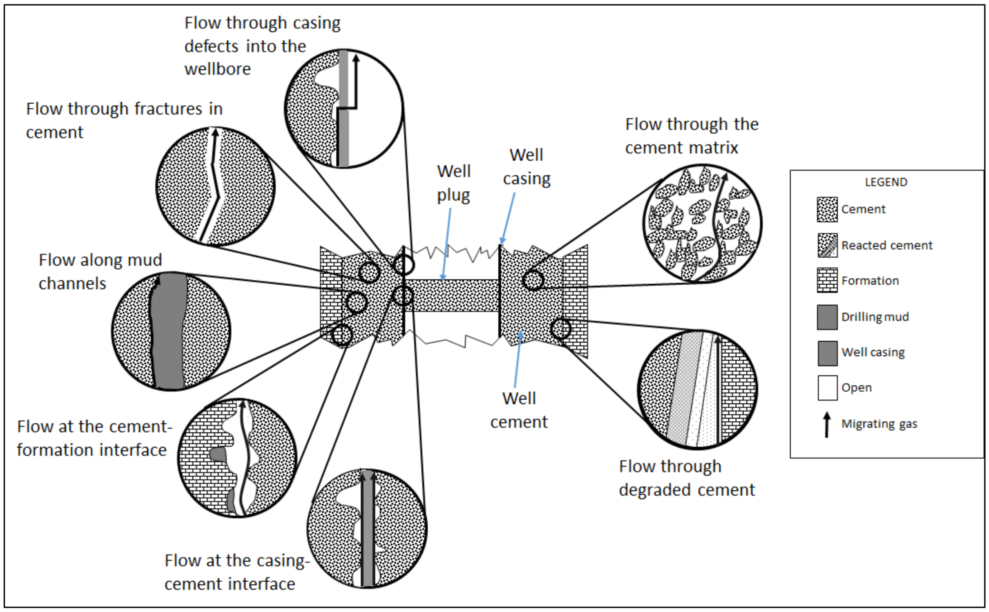


Figure 2-1. Diagram illustrating possible leakage pathways within a well.

2.2 Well Casing Integrity

Casing is employed to keep the wellbore from closing after it is drilled and allow a pathway for access to the reservoir. Casing represents a barrier between the cemented annulus and the open inside of the wellbore. At carbon storage projects, the casing may be exposed to CO_2 and formation fluids in injection wells and legacy oil and gas wells that penetrate the storage zone. Exposure to operational and geologic factors, including temperature and pressure cycles, carbonated brines, chlorides, and hydrogen sulfide, can lead to corrosion, wear, leaky collars, and other casing issues. Holes and cracks in the casing can allow fluids to enter the well and use the wellbore as a leakage pathway. Debonding of the casing from the primary cement can lead to microannuli, allowing leakage between the cement and casing. Well casing failure mechanisms may include the following processes:

Thermomechanical cycling. Thermomechanical cycling due to production or injection can cause well casing to debond from the cement surrounding it. Differences in thermal expansion and engineering properties cause the cement and steel to expand and contract to different degrees when exposed to the same conditions, causing the bond between the cement and steel to break and leading to a microannulus.

Wear. Physical wear to the casing can occur when the casing is run into the well after drilling, when tools are run in the casing during workover operations, or when the production tubing and the production casing rub together. Wear can weaken the casing, making the casing more likely to burst or collapse, and leading to either a casing breach or separation of the casing from the cement.

Corrosion. Corrosion needs to be considered when designing new wells or when repurposing existing wells for CCUS. Corrosion of the casing can create holes, allowing CO_2 being injected into the formation to enter the wellbore and migrate from the reservoir to the wellhead or into overlying formations. This process could then lead to SCP. CO_2-saturated fluids are corrosive to mild steel and can cause a failure in the wellbore integrity. Casing steel in contact with supercritical CO_2 was found to corrode at a rate of 20 millimeters (mm) per year (Carey, 2013). A Plains CO_2 Reduction Partnership study (PCOR, 2014) also found corrosion of steel casing, but lower corrosion in J55 and N80 grade steels.

Corrosion, cracks, and leaking connections can be inferred from the existence of SCP or leaks near or at the surface. Dead vegetation around a well can indicate a leak. Gas bubbles leaking from an abandoned well head are a strong indication of a casing integrity problem (Carey, 2013). Corrosion can be detected using corrosion logging tools to monitor the condition of the inside and outside of the casing. Several different types of tools exist, including multi-finger caliper tools that measure pitting and defects on the inside of the casing, ultrasonic tools that measure the location of the inside and outside of the casing, electromagnetic tools that measure the amount of metal in the casing, and magnetic flux leakage tools that measure inner and outer corrosion.

2.3 Well Cement Integrity

Well cements are typically Portland cements similar to those used in the construction industry. Well cements are made by combining calcareous materials (such as limestone) and argillaceous materials (such as shale) and heating them to create clinker, then grinding the cooled clinker with calcium sulfate. Many research projects have focused on using historical well data, changes in economy, and regulatory changes to predict or assess the risk of leakage in CO_2 storage fields; however, these studies have not integrated field testing with data analysis.

The addition of water causes a hydration reaction that creates calcium-silicate-hydrate (C-S-H), calcium hydroxide (CH), and other phases that make up set cement. Neat Portland is stable at high pH values owing to the hydroxide phases that are byproducts of hydration. Portland cement is susceptible to carbonation and acid attack at lower pHs, including those common to CO_2 storage conditions (pH 2 to 5).

Exposure to CO_2 and carbonated brine will lead to carbonation and, under the right conditions, further reaction and degradation of the carbonate and cement minerals. In brine or water, the first reaction is CO_2 dissociation (Equation 1):

$$CO_2 + H_2O \leftrightarrow H_2CO_3^* \leftrightarrow H^+ + HCO_3^- \leftrightarrow 2H^+ + CO_3^{2-} \quad \text{[Equation 1]}$$

The carbonate species from Equation 1 interact with the cement, C-S-H, and CH to create $CaCO_3$ (Equations 2 through 5):

$$Ca(OH)_2(s) + 2H^+ + CO_3^{2-} \rightarrow CaCO_3(s) + 2H_2O \quad \text{[Equation 2]}$$

$$Ca_3Si_2O_7H \bullet 4H_2O(s) + 2H^+ + CO_3^{2-} \rightarrow CaCO_3(s) + SiO_xOH_x(s) \quad \text{[Equation 3]}$$

$$Ca(OH)_2(s) + H^+ + HCO_3^- \rightarrow CaCO_3(s) + 2H_2O \quad \text{[Equation 4]}$$

$$Ca_3Si_2O_7H \bullet 4H_2O(s) + H^+ + HCO_3^- \rightarrow CaCO_3(s) + SiO_xOH_x(s) \quad \text{[Equation 5]}$$

For cement exposed to wet supercritical CO_2 and carbonated brine that is not refreshed often (diffusion conditions with a small volume of brine as compared to the volume of cement), the reaction with CO_2 stops with $CaCO_3$ being created within the cement pores. However, if cement is exposed to flowing carbonated brine or the carbonated brine is refreshed often, the carbonate that formed in the pores can be reacted away (Equations 6 and 7), leaving a soft silicate-hydrate gel (SiO_xOH_x in Equations 3 and 5).

$$CO_2 + H_2O + CaCO_3(s) \leftrightarrow Ca^{2+} + 2HCO_3^- \quad \text{[Equation 6]}$$

$$2H^+ + CaCO_3(s) \leftrightarrow CO_2 + Ca^{2+} + H_2O \quad \text{[Equation 7]}$$

Cement carbonation has been identified in both the laboratory and field setting. Kutchko et al. (2007), Duguid and Scherer (2010), and others have conducted experiments on cements under batch and flowing conditions. Carbonic acid can weaken wellbore integrity when it comes in contact with Portland cement. Portland cement is an alkaline substance (pH greater than 12.5) which is incompatible with CO_2 fluids (pH less than 6) (Carey, 2013). An experimental study conducted by Kutchko et al. (2007) showed three distinct zones around the cement following a contact with CO_2 saturated fluids. Zone 1 showed an increase in porosity and a depletion of the Portlandite ($Ca(OH)_2$) in the cement. Zone 2 exhibited decreased porosity and was dominated by $CaCO_3$ polymorphs. Zone 3 was completely leached of $CaCO_3$, leaving an amorphous silica layer. Barring mechanical failure of the cement or casing, the decreased porosity of zone 2 acts as a protective barrier slowing further degradation of the cement (Duguid et al., 2011). The primary geochemical threat to cement exists along the interfaces (Carey, 2013).

The reactions represented in Equations 2 through 7 were visible in multiple fronts moving from the exposed edge of the cement toward the center of the samples. In samples exposed to flowing carbonated brine, moving from the outside to the inside of the samples, Duguid et al. saw two zones totally depleted of calcium, indicating that the reaction had progressed to the point of leaving the soft silicate-hydrate gel mentioned above (Figure 2-2). Inside the $CaCO_3$-enriched zone is a zone depleted of CH and then an unreacted zone in the center of the sample. Cement degradation can lead to large increases in permeability.

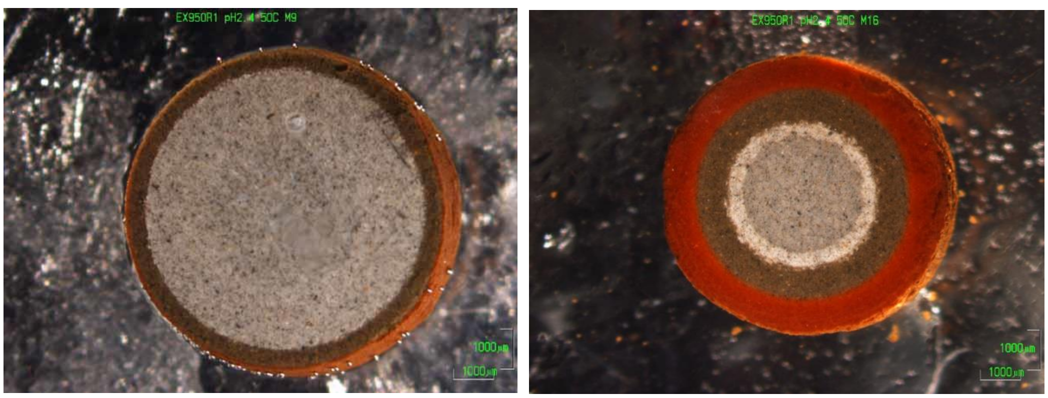


Figure 2-2. Photos showing the results of well cement exposed to flowing carbonated brine at 50°C and pH 3. Left photo shows the outer orange and brown silicate-hydrate zone outside of a CH-depleted cement zone, with an unreacted cement in the center. Right photo shows the outer orange and brown silicate-hydrate zones, the white $CaCO_3$-rich zone, and a CH-depleted cement zone in the center.

Multiple field investigations have been conducted on wells exposed to CO_2 or generally on well construction as it relates to carbon capture and storage (CCS) leakage risk. Carey et al. (2007), Crow et al. (2010), and Duguid et al. (2014) have all studied wells to identify well integrity defects and identify changes brought on by exposure to CO_2. Carey et al., Crow et al., and Duguid et al. all found evidence of carbonation in cements in and above the CO_2 reservoir.

- Carey et al. (2007) looked at a 50-year-old well that was exposed to CO_2 for 30 years in the SACROC oil field in Scurry County, Texas. The cement was collected at the surface during a sidetracking operation. The cement in the well was a neat Portland Type 1. The authors saw carbonation and discoloration of the samples and measured a permeability of an air-dried sample of 0.1 millidarcy.

- Crow et al. (2010) studied a 30-year-old natural CO_2 producer in southern Colorado. The authors analyzed seven sidewall core samples collected from the well. The well cement was a Portland cement with fly ash and bentonite additives. The permeability ranged between 0.3 and 32 microdarcys, with the highest values of 5, 27, and 32 microdarcys measured in samples collected in or adjacent to the CO_2 zone.
- Duguid et al. (2014) studied a 68-year-old well that was a producer, was plugged and abandoned, and then was converted to a CO_2 storage test monitoring well and exposed to CO_2 for 5 years. Two whole sidewall core samples were collected about 400 ft above the CO_2 zone. Both samples showed incomplete carbonation with both $CaCO_3$ and CH being present in the samples. The upper sample was likely squeeze cement and still contained unhydrated cement phases. The sample collected 4.5 ft lower was likely primary cement with heavy alteration.

The integrity of the cement in wells with CCUS applications can be damaged by exposure to CO_2 and carbonated brines or as the result of physical processes during construction, operation, and abandonment. Defects in the wells may be brought about by physical processes such as microannuli, gas contamination, mud contamination, and cracking. Many of these defects can result in SCP, defined as the persistent buildup of pressure over time by an intake of fluid into a well's annulus. Early-stage SCP is related to well completion methods; for example, poor casing centralization may cause mud displacement, leaving it on the borehole wall. Long-term SCP is typically attributed to temperature cycling causing the casing to expand and contract; this process subsequently leads to a detachment between the elastic steel and brittle cement interface (Huerta et al., 2009). A variety of processes may affect cement integrity during initial well construction and further well life cycle events. These processes may lead to the following leakage pathways:

Microannulus. A microannulus is a small gap between the casing and primary cement. It occurs when the cement and casing debond or the bond is never established. A microannulus can extend part or all of the way around the casing (circumference) and can act as a leakage path. A microannulus can be created at the time of well construction or after construction, during operations or workover.

Cracking. Cracking of the cement sheath can be caused by thermomechanical cycling of the casing, shrinking of the primary cement, or geomechanical forces on the well. The removal of overburden in or near river valleys can change geomechanical forces on the well by reducing the lithostatic pressure that controls flow to the surface.

Eccentering. Eccentering of casing occurs when the casing is not centered in the borehole. In severe cases, the casing may be in contact with the borehole wall. Centralizers can be employed in the casing as it is run into the borehole to reduce eccentering. Eccentered casing can lead to poor mud cleanout and/or poor cement placement on the narrow side of the hole.

Mud contamination and mud channels. During the drilling process, thick muds such as oil-based muds can build up on the borehole wall, creating a mudcake. If the well is not thoroughly cleaned out, mud can keep the cement from contacting the borehole wall, keeping a cement-to-formation bond from forming. The interface between the cement and mud and between the mud and formation can act as a leakage path. Mud channels can also form when cement slurry fingers through the mud annulus or eccentered casing.

Fluid/gas invasion. Invasion of fluids or gas during hydration can damage cement's isolation capacity. When cement is pumped, it acts as a liquid with a hydrostatic head. As cement hydrates, its ability to provide overbalanced pressure against the surrounding formation can be lost, allowing fluid to enter the cement and creating connected pathways, sometimes referred to as "gas-cut" cement.

Well integrity problems in cement can be detected through testing, monitoring, logging, or a combination. Successful detection and mitigation procedures are important to test and prepare a wellbore for CO_2 storage. Common detection methods include casing inspection logs, temperature logs, mechanical integrity tests, radioactive tracer surveys, and SCP measurements. Recorded successful mitigation processes include using pressure-activated sealant, cement squeezing techniques, swelling technologies, and self-healing cements; controlling pH levels; and using plug replacements and chemical enhancements.

2.4 Geologic Processes

Geologic processes can greatly influence the condition of a wellbore and create potential fluid migration pathways. These processes include formation lithology, influence of CO_2 on wellbore cement and surrounding formations, ambient conditions, lost circulation zones, geomechanical stresses, and geochemical environments. Monitoring and mitigation processes can detect and fix problems caused by geologic processes.

Lithology can influence the integrity of a wellbore based on the condition of the wellbore and the bond between the wellbore and cement. Borehole breakout and drilling-induced fractures are common during drilling. Borehole breakout is the enlargement of a borehole due to the removal of more material from an interval than from the overlying and underlying intervals. This can cause an increase in the stress in adjacent rocks (Bell and Gough, 1979). Drilling-induced fractures are fractures created around a borehole which are parallel to the direction of drilling (Aadnoy, 1990). These fractures are created when the induced stress of the drilling exceeds the maximum stress of the formation. Borehole breakout and induced fractures could both lead to potential fluid migration pathways along the borehole and caprocks. These occur most frequently in brittle and soft rocks.

The introduction of CO_2 into a reservoir changes the local stress field. This geomechanical shift in pressure affects both the caprock and the wells penetrating the target formation. The changing pressures within the reservoir could lead to cement or casing failure, resulting in fractures or microannuli (Zhang and Bachu, 2011). Radial, axial, and shear deformations can cause the cement and casing to debond or crack. Radial deformation is caused by an increase in temperature and pressure, as well as external pressures from viscous movement of the surrounding rock. Axial deformation is caused by compaction during production and subsequent expansion during injection. Due to the brittle nature of cement, this deformation may cause the cement-casing bond to fail. Shear deformation is caused by the presence of local faults and fractures; these can cause the casing to shear and the cement to fracture (Orlic, 2009). This stress is particularly damaging in deformable lithologies such as salt and shale because stress is more readily transmitted to the well.

2.5 Key Findings of Well Integrity Registry

Many research projects have focused on using historical well data, changes in economy, and regulatory changes to predict or assess the risk of leakage in CO_2 storage fields; however, those studies have not always identified the well integrity issues that can lead to a leak. The wellbore integrity registry presented in Table 2-1 identifies the well component, integrity issues, causes, timing, and leakage pathways that may occur in wells. Most wellbore integrity problems are located in the casing, cement, or interface between the two components (Figure 2-3). Other problems arise due to geological processes such as formation lithology and geomechanical stresses.

Table 2-1. Wellbore integrity registry of identified integrity issues.

Well Component	Integrity Issue	Description	Causes	When	Leakage Pathway
Casing	Thermo-mechanical cycling	Contraction and expansion of well casing	Differences between properties of materials	Construction, operation, workover, abandonment	Debonding along cement interface (microannulus)
	Wear	Wear to the casing	Casing interactions with wellbore and tools	After drilling, during workovers	Burst, collapse, holes in casing
	Corrosion	Corrosion of casing	Contact with corrosive fluids saturated with CO_2	Construction, operation, workover, abandonment	Holes in casing, cracking
Cement	Degradation	Dissolution or alteration of cement	Contact with corrosive fluids saturated with CO_2	Construction, operation, workover, abandonment	Pores in cement or along degraded cement at interfaces
	Microannulus and cracking	A small gap between casing and cement and cracks in the cement	Casing and cement debond, or bond was never established or was broken	Construction, operation, workover, abandonment	Along casing-cement interface
	Mud contamination	Poor mud removal before cementing	Poor cement job design, poor hole cleanout	During construction	Along interfaces or through bulk cement
	Eccentering	Casing is not centered in the borehole	Poor centralization	During construction	Along casing, cement, or mud interfaces
	Mud channels	Cement slurry fingers through the mud in the annulus	Poor cement job design	During construction	Along mud channel interface or through flowing mud
	Fluid invasion	Invasion of fluids into cement	Poor cement slurry design and loss of hydrostatic pressure	During construction	Poor zonal isolation
Borehole wall (Geologic Processes)	Formation lithology	Borehole breakout and drilling induced fractures	Induced stress greater than maximum of the formation stress	During drilling	Poor cement bond to borehole wall
	Geomechanical stresses	Changes in stress field	Pressure gradient changes and creep	Construction, operation, workover, abandonment	Cement and casing damage or failure

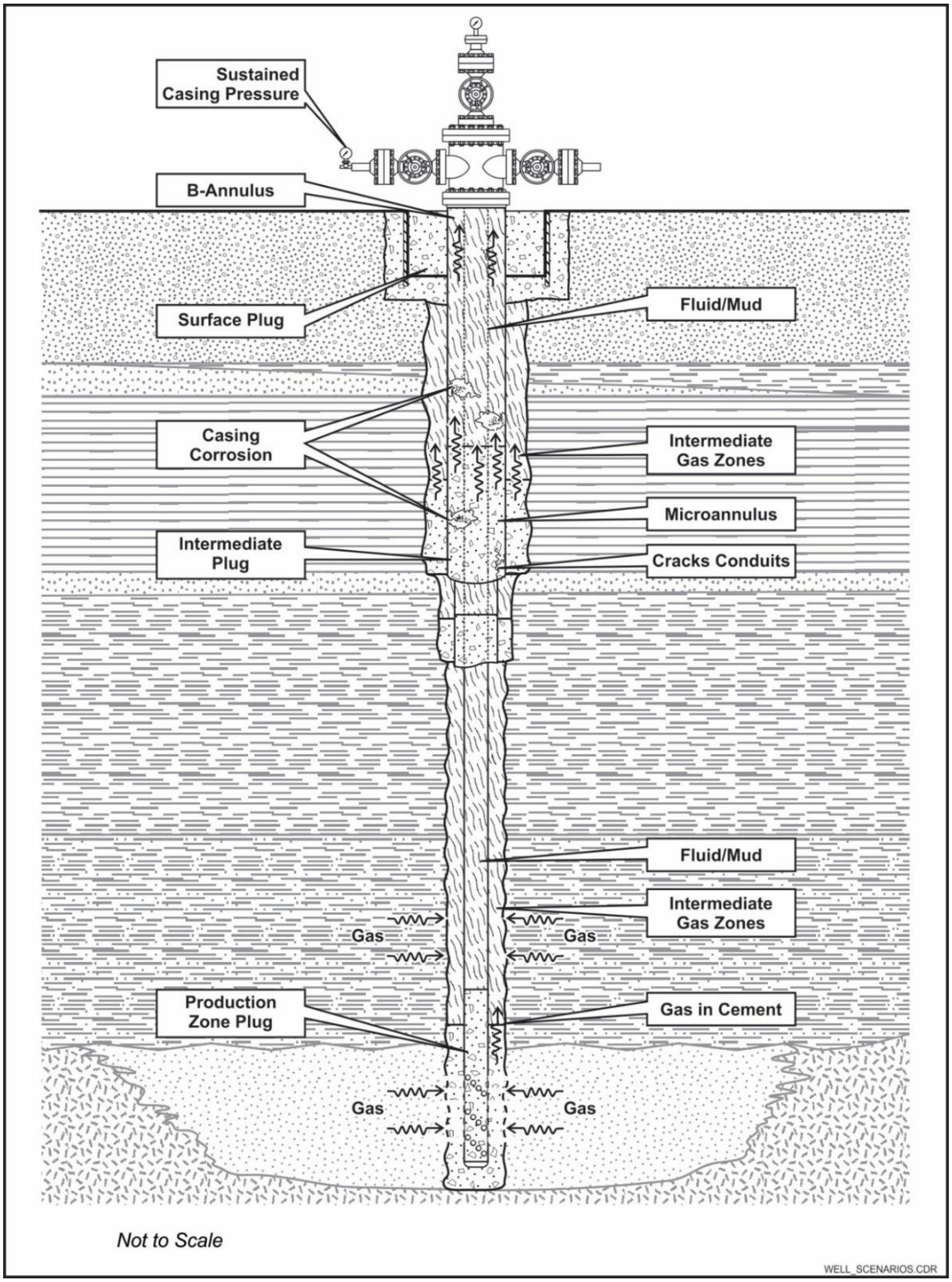


Figure 2-3. Wellbore schematic showing types of wellbore integrity issues and where they occur (Sminchak et al., 2016).

Chapter 3.0 Well Record Data Collection and Review

Task 3 was divided into three subtasks to compile available information on existing wells at the field test sites in Otsego County, Michigan (Michigan Basin site), Kanawha County, West Virginia (Appalachian Basin site), and Saskatchewan, Canada (Williston Basin site). The well data collection task was completed in June 2017. Information was compiled and evaluated for well cementing/drilling, operation, and well workover records. This dataset included over 1,000 items related to wellbore construction in the three study sites. The information from the well collection task will be used to evaluate the overall condition of boreholes in the study areas and as input for future tasks (Figure 3-1).

Oil and gas records were acquired from publicly available resources such as the Michigan Department of Environmental Quality (DEQ), the West Virginia Geologic Survey (WVGES), and the Government of Saskatchewan. The primary focus was collecting data on active and producing wells. Operational and workover records were also acquired from the same sources. Additional, proprietary information was shared by select operators.

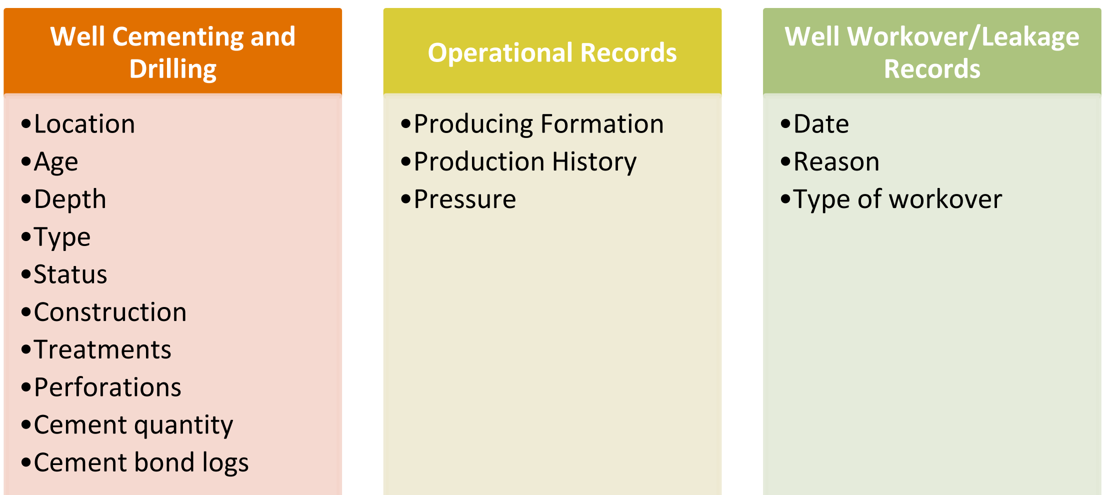


Figure 3-1. Summary of well record collection parameters.

3.1 Field Site Descriptions

The field sites were selected, because they have wells exposed to CO_2 at depths of 1,000 to 7,000 ft and 5 to 50+ years of age (Table 3-1). Therefore, they provided an excellent opportunity to examine CO_2 storage wellbore integrity at field sites. The wells were surveyed for indications of SCP, and a subsample of wells were tested for wellhead casing pressure buildup. The field test sites were characterized for geologic setting, field history, well construction specifications, and hydrologic conditions.

Table 3-1. Summary of field sites.

Parameter	Appalachian Basin	Michigan Basin	Williston Basin
Field area (acres)	30,000	3,000 (across multiple reefs)	45,000
Reservoir depth (ft)	6,000-7,000	1,000 & 6,000	5,000
Reservoir type	Sandstone	Carbonate reefs	Carbonate
Caprock	Shale/carbonate	Evaporite	Evaporite
CO_2 type	Natural gas & CO_2	CO_2 EOR	CO_2 WAG EOR
Temperature (°F)	140	105	145
Discovery pressure (psi)	2,900	3,000	2,000
Discovery year	1973	1960	1954
# Wells	58	~45	~3,000

Note: WAG = water alternating gas; EOR = enhanced oil recovery; psi = pounds per square inch.

3.2 Michigan Basin Site

A significant number of oil and gas wells were drilled at the Michigan Basin site in Otsego County, Michigan. Records for 1,204 Antrim formation wells and for 418 Niagaran wells were reviewed for well construction and cementing details. The earliest Antrim well in the study area was drilled and completed in the 1950s; however, very few Antrim wells were drilled until the 1980s, when the Antrim play became more economic. Since the 1980s, the number of Antrim wells drilled per year has been reduced by approximately two-thirds. Within the study area, the Antrim play is relatively shallow, with the deepest well reaching a depth of 2,250 ft. The Niagaran play experienced a boom in the 1970s; nearly half of the Niagaran wells were installed in that decade. The number of Niagaran wells installed has dropped significantly since the 1980s; currently, only a small fraction of Niagaran wells are installed annually compared with the numbers completed in the 1970s and 1980s. The Niagaran wells vary more in depth due to the influence of the basin, with a range of 5,050 ft to 6,700 ft.

The majority of Antrim wells (94%) were drilled as gas wells, while 5% were drilled for brine disposal. The remaining 1% were dry holes. Michigan well records through 2016 show that 90% of the wells are still producing methane and 4% have been plugged and abandoned. Records also show that 324 wells listed with a terminated permit were never drilled.

Niagaran wells were drilled for a wide range of purposes. Nearly 60% of Niagaran wells were dry holes because of the isolated, compartmentalized reef structures and the variable lithology within the reefs. However, the percentage of dry holes drilled has decreased over time as a result of improved characterization techniques and a better understanding of the reef structure and composition. Wells that produced were mostly oil, with some recorded as gas wells. A small percentage of Niagaran wells were used for brine disposal and injection. As of 2016, 79% of the Niagaran wells were plugged and abandoned; only 18% are currently active and/or producing. The remaining 3% were temporarily abandoned or shut in.

Due to the large number of Antrim wells in the general area, a subset of wells was randomly selected for more detailed analysis. Antrim wells were consistently constructed with three casing strings: conductor, surface, and production. The conductor casing was 13.375 inches in diameter in nearly half of the wells, while 30% of wells used larger-diameter casing and 24% used smaller-diameter casing. The surface casing was set at the base of the glacial drift (550 to 1,150 ft) and generally used a casing diameter of 8.625 or 7 inches. Approximately 3% had an intermediate casing diameter of 11.75 inches. The production casing was often 5.5 inches or 4.5 inches in diameter.

The Niagaran wells were consistently constructed with four casing strings in the general area. The conductor casing was typically 16 inches in diameter, with 15% of wells having smaller or larger diameters. The total depth of the conductor casing was set between 38 and 147 ft deep within the glacial drift. The surface casing string was predominantly 13.375 inches in diameter and was set at the base of the glacial drift (474 to 1,142 ft). Next, the intermediate casing was mostly 8.625 inches in diameter, with a few wells having larger or smaller diameters. The casing was typically run to the Bass Islands or within the Salina group (~3,400 ft deep). Finally, the deep casing string was typically 5.5 inches in diameter and was set in the Niagaran with some wells set higher in an open hole or barefoot completion. Figure 3-2 illustrates common well construction used for the Antrim and Niagaran wells.

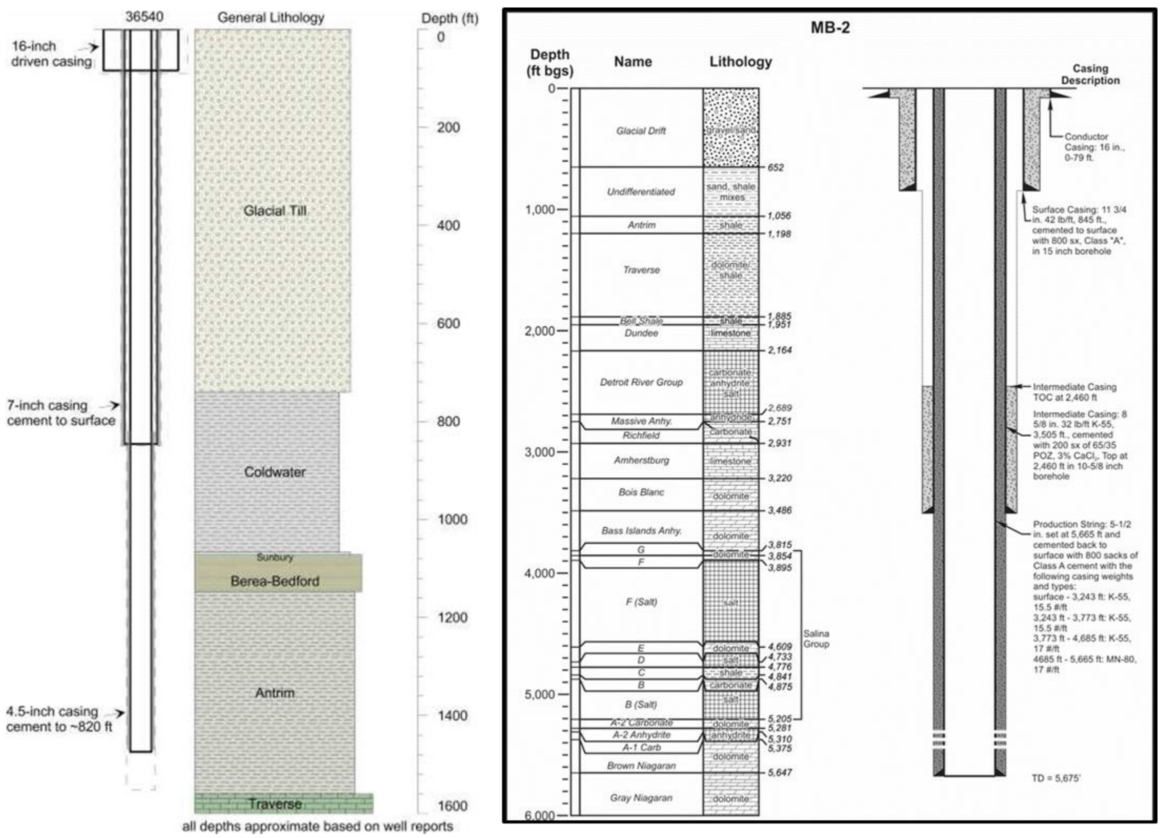


Figure 3-2. Typical Antrim (left) and Niagaran (right) well construction.

CBLs were available for 87 wells in the Michigan Basin field site area. The types of cement were not typically entered in well records. The surface casing in Antrim wells was mostly driven (95%) with only 5% having recorded using cement. The amount of cement used ranged from 350 to 460 sacks. The cement used in the intermediate casing ranged from 160 to 700 sacks of cement, with an average of 360 sacks. Some wells did not have cement data available but were recorded to have had cement circulate to the surface. The deep casing had recorded cement ranging from 55 to 660 sacks with an average of 243 sacks. Occasionally, wells were recorded to have had cement circulate to the surface.

The conductor casing in Niagaran wells was mostly driven (70%) with 18% having recorded using cement. The amount of cement ranged from 100 to 200 sacks. The remaining 12% of wells did not have recorded cement. The cement used in the second surface casing string ranged from 200 to 1,130 sacks, with an average of around 600 sacks. A subset of wells (9%) did not have a second casing string. The cement used in the intermediate casing ranged from 200 to 950 sacks with an average of 406 sacks. The cement used in the deep casing string ranged from 75 to 950 sacks with an average of 484 sacks. A deep casing string was not recorded for 9% of wells.

Production data were available for 2,541 Antrim wells and 414 Niagaran wells at the Michigan Basin site, which included monthly production of oil, gas, and water since 1982. Cumulative gas production by well ranged from 2,355 thousand cubic feet (MCF) to 31 million MCF for Antrim wells. On average, a well had a cumulative gas production of 5.1 million MCF. Wells experienced different ranges of production time and many starts and stops. Gas production records showed that wells produced from 1 month up to 28 years, with an average lifespan of 15 years. Production was greatest in the southeastern corner of the general study area and lowest toward the west. Water cut and CO_2 content increased throughout the lifespan of the average well; the more gas produced, the more water and CO_2 were produced. Water production ranged from 0 to 2 million barrels with an average of 370,000 barrels. CO_2 content ranged from 2%-30%.

Over 110 million barrels of oil have been produced from Niagaran wells at the Michigan Basin site since 1982. The cumulative oil production by well ranged from 0 barrels to 5.2 million barrels with an average of 270,000 barrels. There are several individual production fields which are composed of single to multiple reefs. The producing interval and length varied greatly by well and by field. The wells had recorded production from 0 months to 26 years with an average of 10 years. Many wells also experienced periods of stopped production after primary production, and then periods of production during secondary and tertiary recovery periods. Production of oil was greatest along the northern trend of reefs and during the early 1980s. Monthly production steadily declined into 2016 (Figure 3-3).

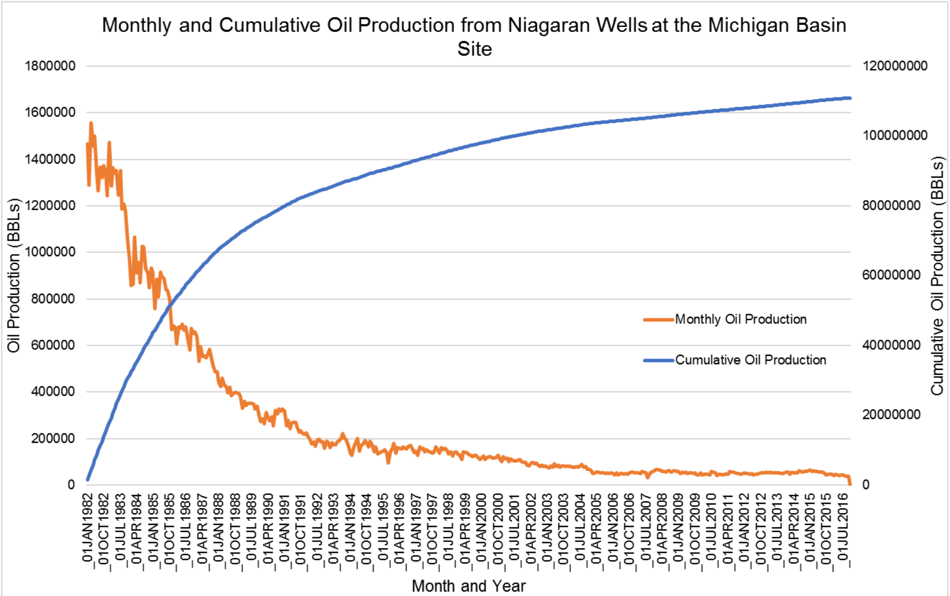


Figure 3-3. Monthly and cumulative oil production from Niagaran wells showing greatest monthly production in the early 1980s and a steady monthly decline through 2016.

Over 380 million MCF of gas have been produced from Niagaran wells at the Michigan Basin site since 1982. The cumulative gas production by well ranged from 0 MCF to 10 million MCF with an average of 930,000 MCF. Niagaran wells had incremental periods of gas production since 1982 with varying production lengths. The recorded production ranged from 0 to 26 years with an average of 10 years, following the oil production trend. Gas production remained high through the 1980s and began tapering off in the 1990s, with lowest production from 2005 to 2016. The greatest gas production occurred in the largest fields without a strong trend of direction. Water production was also recorded for the Niagaran wells. The produced water ranged from 0 to 2.5 million barrels with an average of 150,000 barrels per well. The greatest water production was recorded in the late 1990s through early 2000s, which tapered off toward 2016. No production was recorded prior to 1992. The greatest water production occurred in the center of the reef trend, where some wells penetrated the oil-water contact.

As part of this study, records for 57 Antrim wells and 54 Niagaran wells were reviewed for post-completion workovers (casing replacement, tie-back strings, etc.).

Antrim Wells. In general, very few "true" workovers were performed on the Antrim wells following initial completion; however, perforations were frequently added to access more productive zones in the Antrim and improve well productivity. Of the 57 wells investigated, perforations were commonly added to the wells. Seven wells were deepened, typically by underboring the well beneath the existing casing; the bottom of the well was left as open hole. Cast-iron bridge plugs were added to two of the wells to seal off deeper (likely unproductive) portions of the well. Any time the wells were reperforated, the wells were also refractured with a frac fluid/foam and a proppant, and acidized after the perforations were complete.

Niagaran Wells. Similar to the Antrim wells, relatively few workovers have been performed on the wells completed in the Niagaran reefs. Of the 54 wells investigated, only three were part of a workover, which involved running additional casing/line (Well 21137299580000), running a tie-back string (Well 21137578160000), or performing a cement squeeze job for a casing leak (Well 21137290910000). Eight wells were extended through a kickoff or had a portion of the well temporarily abandoned with a bridge plug. However, slightly more than 60% of the wells had additional perforations to access more productive zones. Typically, acid was pumped into the wells when new perforations were added.

3.3 Appalachian Basin Site

The earliest Indian Creek well was drilled in the 1940s. Drilling activity remained low until the 1970s and 1980s, when drilling increased substantially. Activity tapered off after the 1980s, when only an additional eight wells were drilled. Indian Creek wells primary targeted the Tuscarora sandstone, with a few wells producing from nearby sandstones (Clinton, Oriskany). The resulting depth of the wells was mostly between 6,300 and 7,300 ft; however, one well was drilled to 8,075 feet. Indian Creek wells produced natural gas; 85% were recorded as gas wells while the remaining 15% were dry holes. As of 2016, 20% of the wells were recorded as plugged and abandoned with 80% still operational.

The wells in the Indian Creek field were commonly constructed with four to five casing strings. The conductor casing diameter was mostly 13.375 or 20 inches in diameter, with 30% of wells having recorded smaller or larger sizes. The depth of the conductor casing ranged from 18 to 930 feet. The conductor casing depths averaged 183 feet, placing the casing in the undifferentiated Pennsylvanian/Mississippian strata. The second surface casing string was typically 9.625 or 13.375 inches in diameter. The depth of the surface casing ranged from 77 to 2,670 feet, placing it across several shale formations that could produce gas. The intermediate casing was either 7 or 9.625 inches in diameter and was run through the Devonian shale or Helderberg formations. When a fourth, or second intermediate, casing string was used, it was 7 inches in diameter and set in the Helderberg through the Tuscarora. The deepest casing string, or production string, was 4.5 inches in diameter and set in the Tuscarora. A typical wellbore diagram is illustrated in Figure 3-4.

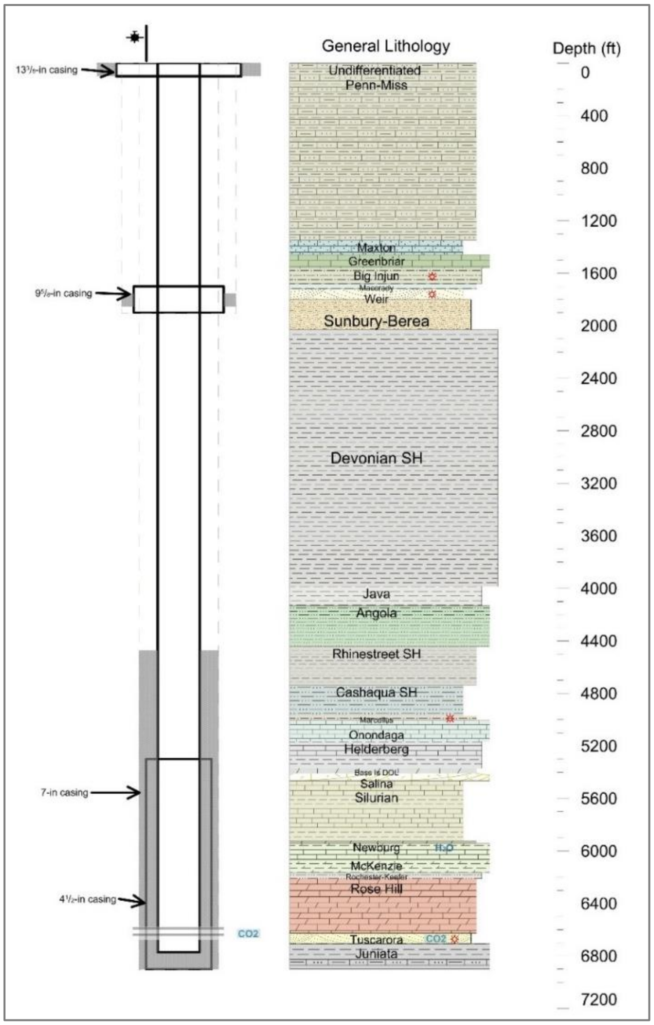


Figure 3-4. Wellbore diagram of an Indian Creek well showing common well construction.

In addition to construction data, information on perforations, treatments, and treatment volumes were recorded. These data provide information on well stimulations and additional stresses applied to the wellbores. Only 22% of the wells were recorded to have perforations, while many wells were completed open hole. Nearly 60% of the wells were treated with acid and fractured. The volumes and types of materials used for treatments varied greatly by well.

CBLs were available for 15 wells in the Indian Creek field. The CBL analyses were conducted, and are summarized, under Task 4. Results showed moderate thickness of good quality cement with frequent intervals of poor cement (Figure 3-5). Additionally, caliper logs were collected to be used in Task 4 with CBLs and cement sacks to determine the volume and thickness of a cement column. The number of sacks of cement was recorded for each casing string; cement type was not readily available. Eight wells did not have cement data available. The conductor casing was set with 10 to 826 sacks of cement with an average of 183 sacks of cement. Wells were frequently recorded to have had cement circulate to the surface. The surface casing string used 150 to 1,121 sacks of cement with an average of 548 sacks. It was also commonly recorded to have been cemented to the surface. The intermediate casing used 148 to 1,226 sacks of cement with an average of 544 sacks. The fourth casing and deep casing strings used similar amounts of cement, ranging from 75 to 280 sacks.

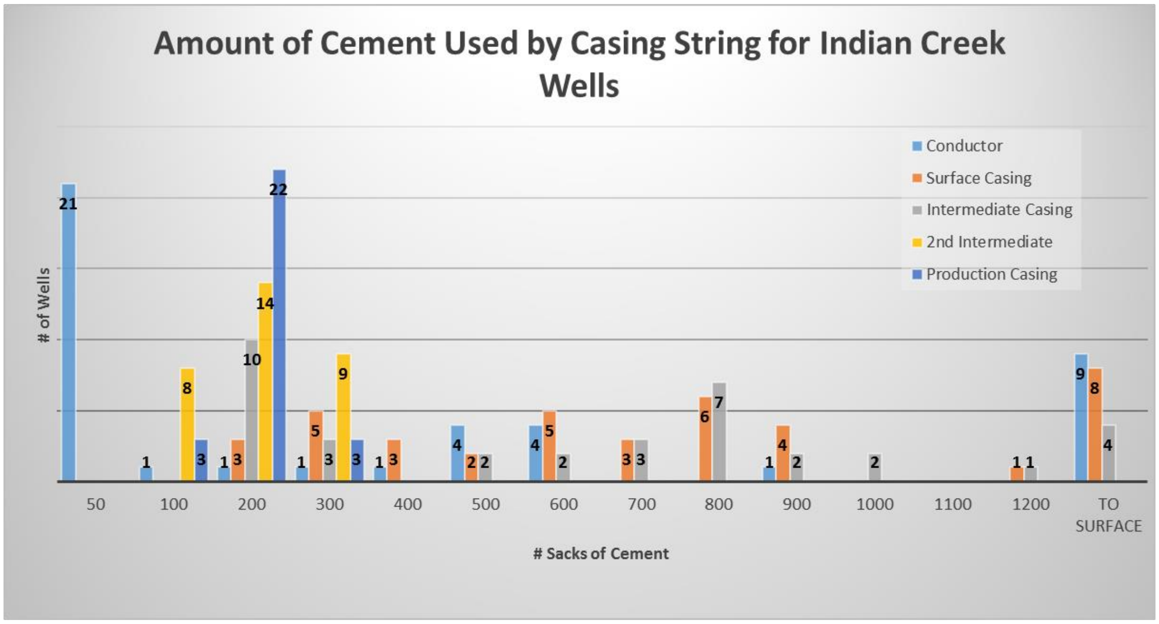


Figure 3-5. Histogram of sacks of cement used for each casing string in the Indian Creek wells.

Production data were available for 52 wells in the Indian Creek field on a monthly basis since 1985. Over 40 billion standard cubic feet (Bcf) of gas were produced since 1985 between the 52 production wells. The cumulative production by well ranged from 0 MCF to over 4.3 million MCF. On average, a well had a cumulative gas production of 780,000 MCF. The Indian Creek field experienced two major periods without production: from January 1987 to October 1987 and again from January 2012 to October 2013. Production ended in January 2015, and the field has recently been sold to new ownership.

Figure 3-6 shows the annual and cumulative production of gas for each well in the Indian Creek field; in the figure, the periods of no production are visible. The production of gas was not consistent across the field. The greatest amount of gas was produced in the southernmost wells, while the least amount was produced in the northern wells.

No well workover or leakages were recorded for wells in the Indian Creek field. A search on the West Virginia DEP oil and gas database showed no violations listed for Indian Creek wells. Detailed operator records were unavailable for the field. Informal discussions with the field technician suggest that the wells had few problems with no significant cause for frequent repairs or other corrective actions.

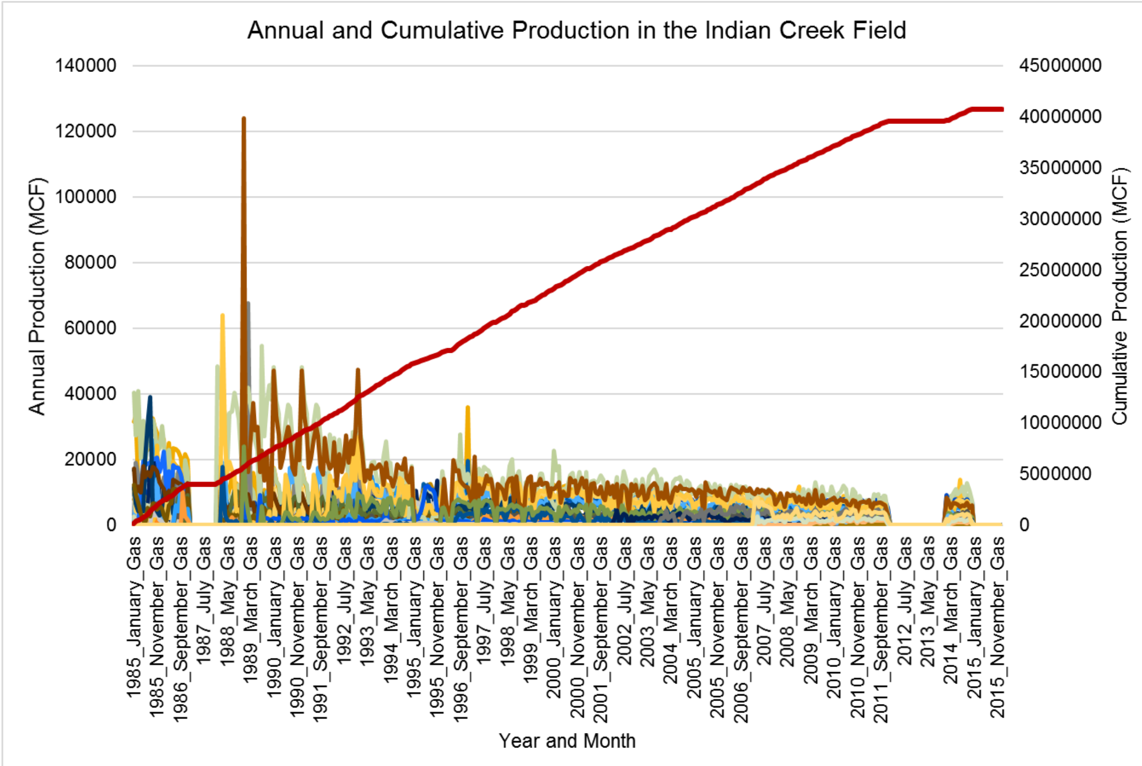


Figure 3-6. Annual and cumulative production in the Indian Creek field since 1985.

3.4 Williston Basin Site

Due to different reporting regulations and publicly available data, the dataset collected for the Williston Basin site contained different information than those collected for the Michigan Basin and Appalachian Basin sites. Information pertaining to well type, status, construction, and cementing was available. There were over 3,000 identified wells in the Williston Basin site, and data were compiled for 1,432 wells.

Well drilling in the Williston Basin surged in the 1950s. Drilling tapered off through the 1990s, followed by another increase in drilling in the 2000s. Approximately 60% of the wells were vertical, with 39% recorded as horizontal. The remaining 1% of wells were not indicated or were listed as deviated. The primary target formation was the Midale, which resulted in 97% of the wells reaching a true vertical depth between 4,000 and 5,000 ft. The wells were mostly oil wells (68%); however, some were used for CO_2, H_2O, or WAG injection. Nearly 22% of the wells have been abandoned, 42% are producing, and 22% are operating (Figure 3-7). The remaining wells have been listed as observation, suspended, or long term shut in (LTSI). Most wells were recorded as being exposed to oil (68%), and some wells were exposed to CO_2, gas, water, or a combination thereof.

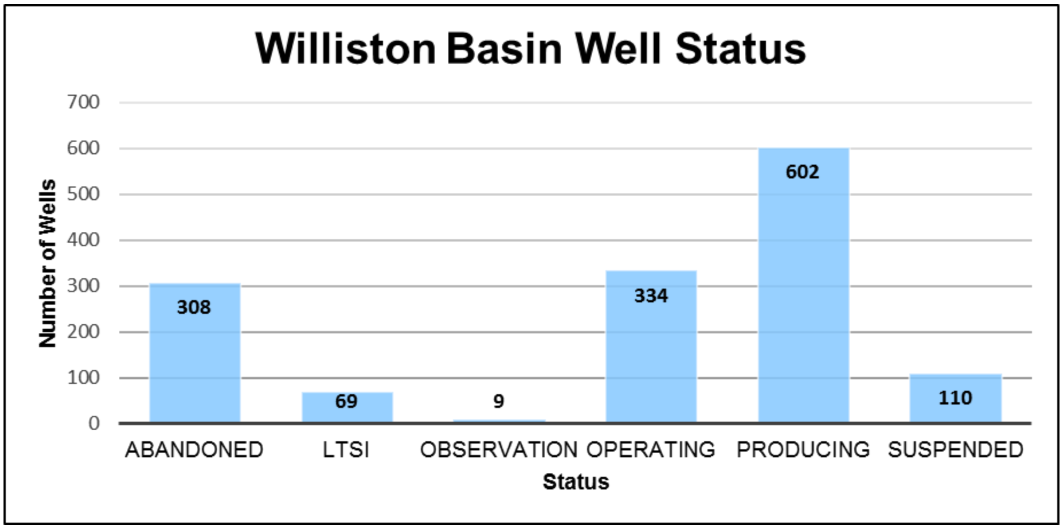


Figure 3-7. Status of wells at the Williston Basin site.

Casing details were available for 1,328 wells at the Williston Basin site. The wellbores were consistently constructed using two casing strings: a surface casing and a production casing. The diameter of the surface casing ranged from 7.0 to 13.375 inches. The most common surface casing diameter was 8.625 or 9.625 inches, with 96% of the wells drilled no deeper than 1,000 feet. The production casing ranged in diameter from 2.875 to 10.75 inches. Approximately 50% of the wells had 7-inch-diameter production casing, with 30% of wells having production casing of 5.5 inches in diameter and 18% with 4.5-inch casing. The production casing was set at depths up to 5,600 ft, with most wells set between 4,000 and 5,000 ft deep to target the Midale.

Cementing data were recorded as cement volumes rather than the amount of materials used. Cement volumes were only available for 135 wells. The volumes ranged from 170 cubic feet (ft^3) to 1,560 ft^3, with an average of 545 ft^3. Most wells had less than 400 ft^3 of cement. Figure 3-8 shows a histogram of cement volumes for available wells at the Williston Basin site.

Full operational data and workover histories were not publicly available for Williston Basin wells. However, numerous wells (80%) were tested for SCP as part of a monitoring program. The level of SCP was categorized by leakage severity. Most of the wells tested did not show any SCP or leakage through the wellbore; a small percentage had minor SCP associated with non-serious leakage. Some wells (34%) showed significant SCP and were categorized as having serious leakage. Figure 3-9 illustrates the number of wells that fell into each leakage category.

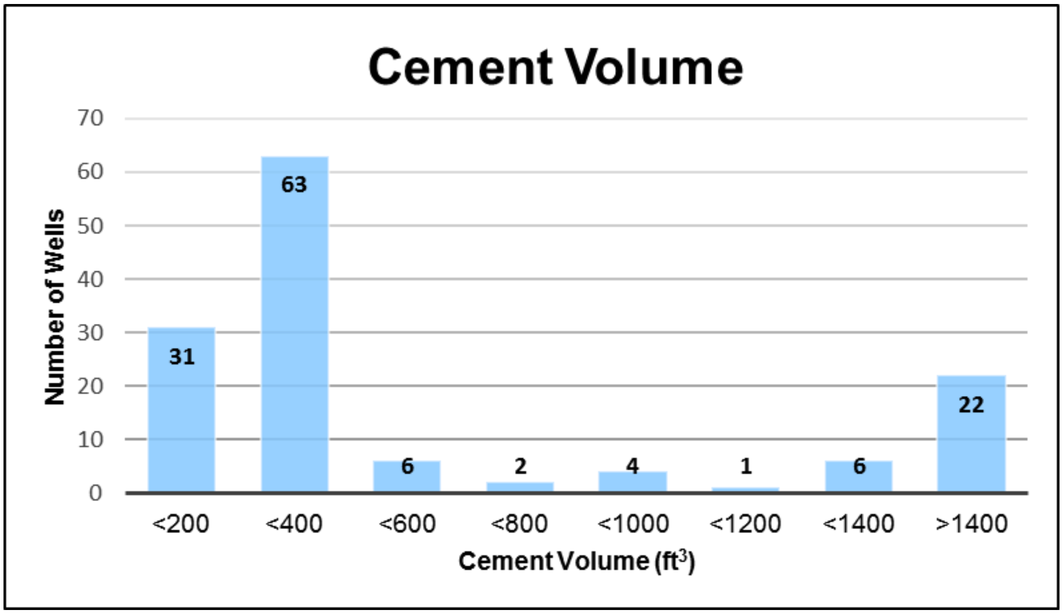


Figure 3-8. Cement volumes for wells at the Williston Basin site.

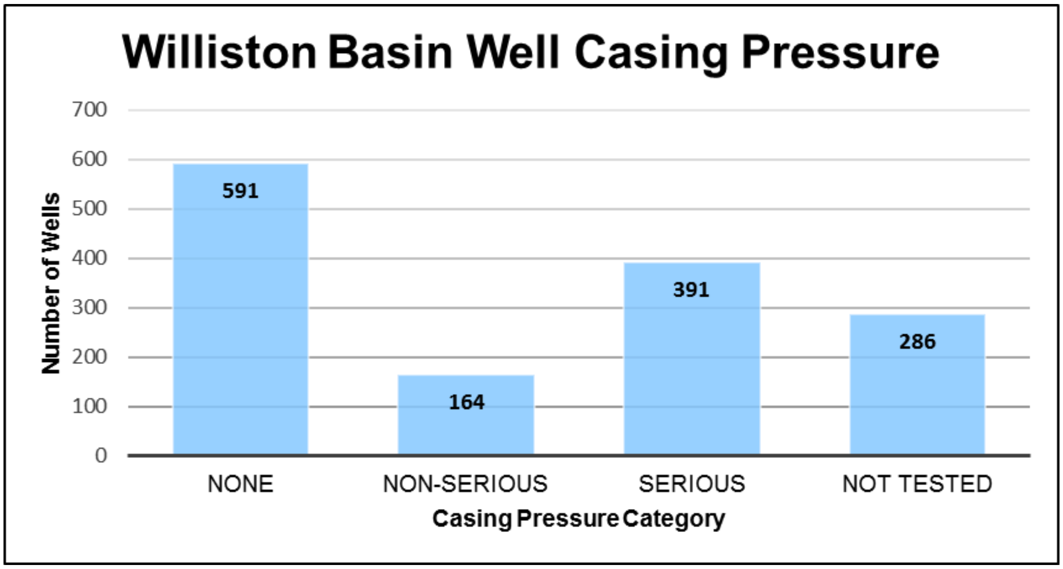


Figure 3-9. Casing pressure category for wells at the Williston Basin site.

3.5 Key Findings of Well Record Data Collection and Review

To assess wellbore integrity, publicly available data were collected for the three field test sites for wells with different levels of exposure to CO_2. The data included information on well construction, cementing, workovers/leakage, and operations. Data availability varied by site due to differences in reporting regulations on the state and country level.

Data Collection and Summary for the Michigan Basin

- Data were collected and reviewed for 1,622 wells (418 Niagaran and 1204 Antrim wells).
- Antrim wells occurred at shallow depths and were exposed to naturally occurring CO_2. The Antrim derived CO_2 is removed in gas processing and partially utilized for CO_2 EOR operations.
- Niagaran wells produced oil and gas from reef structures. Additionally, some were used for CO_2 EOR as either injection or producing wells.
- Drilling, construction, and cementing data were available for all wells.
- Well workovers were often recorded for wells but were typically maintenance or adding perforations. No major workovers or leakages were reported.
- Operational data were available for all production wells on a monthly basis since 1982.

Data Collection and Summary for the Appalachian Basin

- Data were collected and reviewed for 55 wells.
- The primary target was the Tuscarora sandstone in the Indian Creek field.
- CO_2 was naturally occurring in the Indian Creek field, exposing wells to varying amounts of CO_2 over the well life cycle.
- Drilling, construction, and cementing data were available for all wells.
- No well workovers or leakages were reported in public files.
- Operational data were available for all wells on a monthly basis since 1985. The data showed periods of production and non-production.

Data Collection and Summary for the Williston Basin

- Data were collected and reviewed for 1,432 wells.
- The primary target was the Midale carbonate in the Weyburn field.
- Wells were primarily used for oil and gas production, but many were later utilized for CO_2 EOR operations.
- Drilling and construction data were available for all wells. Cementing data were sparse and recorded as cement volumes.
- No well workovers were recorded; however, many wells were tested for SCP as part of monitoring regulations. The level of leakage associated with SCP was indicated for the wells.

Overall, the data collected for the three field test sites represent wells which have been exposed to CO_2 either naturally or through EOR operations. These datasets provide unique opportunities to study the influence of CO_2 on wellbore integrity. The available data varied greatly by site, but the datasets were valuable for developing wellbore integrity predictors for Tasks 4 through 7.

Chapter 4.0 Log- and Testing-Based Well Integrity Assessment

The objective of Task 4 was to analyze well integrity for the three field sites based on logs and well records. Task 4 was divided into three subtasks: Log Analysis, Well Record Analysis, and Well Integrity Evaluation. The well risk analysis was focused on field test sites in Otsego County, Michigan (the Michigan Basin site), Kanawha County, West Virginia (the Appalachian Basin site), and Saskatchewan, Canada (the Williston Basin site). Task 4 was completed in October 2017. Well log data for the Michigan Basin and Appalachian Basin field sites were collected in Task 3. Log data for Weyburn Field were collected as part of the SaskCO_2USER project (Duguid et al., 2011) and were provided to Battelle already interpreted for risk assessment. The available log data are summarized in Table 4-1.

Table 4-1. Number of logs used for Otsego, Michigan, and Indian Creek, West Virginia, fields.

Log Type	Otsego, MI	Indian Creek, WV
Cement Bond Log (CBL)	1	12
Gamma Ray (GR)	54	11
Formation Bond (FBL)	--	7
Neutron Log (NEU)	43	1
Density (DEN)	38	3
Acoustic (XMAC)	26	--
Resistivity (RT)	49	--
Pulsed Neutron Capture (PNC)	3	--
Caliper Log (CAL)	53	36
Bit Size Log (BIT)	6	--

4.1 Log Analysis

Log analysis included caliper log analysis for borehole irregularities and CBL analysis for cement emplacement. Analysis was performed on subset of available logs for the Michigan Basin and Appalachian Basin sites.

Caliper Analysis

Caliper logs from the deep section of 53 wells within the Michigan Basin field test site and 36 wells within the West Virginia field test site were reviewed to determine the variations over the depth. Where possible, the reasons for variation were identified, including washouts due to formation properties. The deep section of the wells was divided into different zones (over depth) based on variations in the diameter of the wellbore shown in the caliper logs. For example, if sections of the well displayed different borehole diameters, these sections would be split into different zones. For each zone, the average borehole diameter was then estimated based on visual inspection of the caliper logs, and the annular volume was calculated using the borehole diameters. Ultimately, the volumes for each zone were added together to determine the annular volume over the entire well.

In the Michigan Basin site, the boreholes were close to gauge (bit diameter) over most of the deep section of the well, often showing a borehole diameter of between 8 (gauge) and 10 inches. However, in the F-Salt zone, which is dominated by halite deposits, the borehole shows significant washouts that increase the borehole diameter to greater than 16 inches (or tool limit) in some cases. Like the Michigan Basin wells, the wells in the Appalachian Basin site typically run close to gauge of the bit (often 6 to 7 inches in these wells). However, washouts occur in the Rose Hill formation, where the borehole diameter may increase to greater than 13 inches.

CBL Analysis

Twelve CBLs were available for the Appalachian Basin site. CBL analysis was completed with a standardized CBL interpretation tool that was developed by Battelle to evaluate well cement quality (Haagsma et al., 2015). The CBL interpretation tool uses a bond index method to provide a more objective rating of cement quality in a well. The results of the tool may be used to determine cement-to-casing bond in vertical zones within a well. Considering multiple wells in a field, spatial trends in cement-to-casing bond may be apparent. CBLs for the Appalachian Basin field test site were imported into the CBL interpretation tool, and the cement bond was rated for discrete intervals.

A total of 87 CBLs were available for the Michigan Basin field test site. The CBLs were also analyzed with the Battelle CBL interpretation tool. Many of the Antrim well CBLs were not suitable for analysis due to illegible log quality in the available raster images. The majority of the wells were in the 80% to 100% rating, but 20% of the wells had an index rating of less than 60%. The percentage of total casing that was cemented for the Michigan Basin wells showed a similar distribution. Overall, the CBL analysis suggests that there is a bit of a bimodal distribution of cement quality in the Michigan Basin field test site. The deeper Niagaran reef wells had high-quality cement ratings, but the shallow Antrim shale wells had lower cement ratings.

4.2 Well Record Analysis

Well records were collected from public databases and project partners. Data were collected from the Michigan DEQ, the WVGES, and the Alberta Energy Utilities Board. Core Energy provided additional details on their wells used in the study, and the Petroleum Technology Research Centre (PTRC) provided the database used for the risk assessment performed in the SaskCO_2USER project (Zaluski et al., 2016; Duguid et al., 2017). The data included drilling records, cementing records, workover records, plugging records, logs, and permits. The records provided a consistent set of data that could be used to develop a proxy for likelihood of leakage and severity of impact for each well in each field. Records were collected for 54 wells in Michigan, 47 wells in West Virginia, and 1,391 wells in Alberta. From these records, the dataset was developed to include five categories common across each field. Table 4-2 lists the categories and the number of wells in each category for each field.

Table 4-2. Number of wells in each field with known data for each category ranked in the well integrity evaluation.

Risk Type	Field	Michigan Basin	Appalachian Basin	Williston Basin
Likelihood of leakage	Total number of wells (records collected)	54	47	1,391
	Cemented through caprock	51	41	176
	Well deviation	54	47	1,391
	Well age	54	47	1,390
	Well status	54	47	1,391
	Well type	54	47	1,391
Severity of impact	Distance from developed populated areas	54	47	1,391
	Distance to domestic groundwater well	54	47	1,391
	Distance to environmentally sensitive areas (including surface water sources)	54	47	1,391

4.3 Well Integrity Analysis

Wellbores with integrity issues in CO_2 storage fields can lead to leakage out of the storage zone. Using the data collected in Subtasks 4-1 and 4.2, a well integrity evaluation was conducted in order to determine the overall risks for each well in the three field test sites. The well log data analyses, well record analyses, and risk factors were integrated to calculate a Risk Score for each well. These Risk Scores were then used to determine the wells that posed the greatest risk to wellbore integrity issues. A method to calculate the risk from the individual wells in the field was adopted generally following that of Duguid et al. (2017). The method used here calculates a Total Likelihood Score as the summation of the individual scores judged to be proxies for the likelihood of leakage category (Equation 8) and calculates a Total Severity Score as the summation of the severity of impact category each ranked between one and five (Equation 9). Total Risk was calculated as the product of Total Likelihood and Total Severity (Equation 10).

$$Total\ Likelihood = \sum_{i=1}^{n} Likelihood \qquad \text{(Equation 8)}$$

$$Total\ Severity = \sum_{j=1}^{m} Severity \qquad \text{(Equation 9)}$$

$$Total\ Risk = Total\ Likelihood * Total\ Severity \qquad \text{(Equation 10)}$$

The wells were divided into categories common to wells at each field test site. Equation 10 was used to calculate a semiquantitative risk based on ranking each category between 1 and 5 for each well. Five categories affecting the likelihood of leakage along a wellbore were identified: primary cement through the caprock, deviation of the well, age of the well, status of the well (i.e., producing/injecting or abandoned), and type of the well. These likelihood criteria were ranked from 1, the lowest likelihood of contributing to a leak, to 5, the highest likelihood of contributing to a leak. To provide the most conservative estimate of wellbore risk, any likelihood criteria that was unknown was automatically assigned the highest value (5).

The depth of the top of cement (TOC) in a borehole was determined one of two ways: (1) through volumetric calculation, using borehole and casing diameter from wells and the number of sacks of cement based on construction records, or (2) picking the TOC based on CBLs. If a primary cement job placed at least 40 ft of cement into the caprock, it was assumed that an effective seal was established. The orientation of the well or the degree of deviation (vertical, horizontal, etc.) can affect the construction of the well and the ability to isolate the well from different zones. Well orientation was classified as vertical, horizontal, deviated, slant, and unknown, and each category was qualitatively ranked with respect to leakage likelihood.

Well materials are subject to degradation over time through corrosion or other chemical processes. Thus, older wells are considered to have a higher likelihood of leakage than more recently drilled wells. Older well casing or cement is more likely to have degraded through exposure to ambient and produced fluids, and older wells are more likely to be damaged by well operations such as workovers. In addition, changes in regulations for oil and gas well construction have led to more effective environmental controls over time, which also reduces the likelihood of leakage. Well age was binned in 13- to 15-year intervals, beginning in 2017.

The status of the well (active, temporarily abandoned, plugged and abandoned, etc.) could also affect the likelihood of leakage. The status of the well, whether producing or not producing, affects the pressure gradient around the wellbore and also the amount of monitoring the well receives. Wells were categorized in four groups for this assessment: active, shut-in, temporarily abandoned, and plugged and abandoned. Well type likelihood scores were determined based the types of fluids near the well and the operations being conducted. Monitoring wells do not have active injection or production but are exposed to formation fluids. The monitoring wells included in this project were completed in a reservoir with CO_2 brine and hydrocarbons.

Three potential receptor categories were assessed for severity of impact due to leakage: population centers (i.e., people); groundwater; and surface water and environmentally sensitive areas (treated as a single category). Although an entire aquifer formation would be considered an underground source of drinking water, the actual groundwater receptors were wells used for potable water and, where applicable, wellhead protection areas were used as receptor locations. Surface water receptor locations consisted of intermittent and perennial streams, lakes and ponds, and surface water infrastructure (i.e., canals), where applicable. Two designations in the dataset referred to inferred surface water pathways: artificial paths and connectors. These were also treated as surface water features since they represent the most likely path of surface water flow in areas with missing data.

Once the individual parameters were tallied, Likelihood Scores, Severity Scores, and Total Risk Scores were calculated using Equations 8, 9, and 10, respectively. Likelihood and Severity Scores are the sum the scores of all individual likelihood criteria and severity criteria, respectively. Total Risk Scores are calculated by multiplying the sum of the Likelihood Scores by the sum of the Severity Scores.

This section presents the score results by field test site. Total Risk Scores for the Michigan Basin wells ranged from 77 to 255. The histogram of Risk Scores for the wells included in this study is a bell curve that centers around bins 151-175 and 176-200, each of which contains 16 wells (Figure 4-1). Differences in Risk Score do not follow an obvious geographical pattern (Figure 4-2).

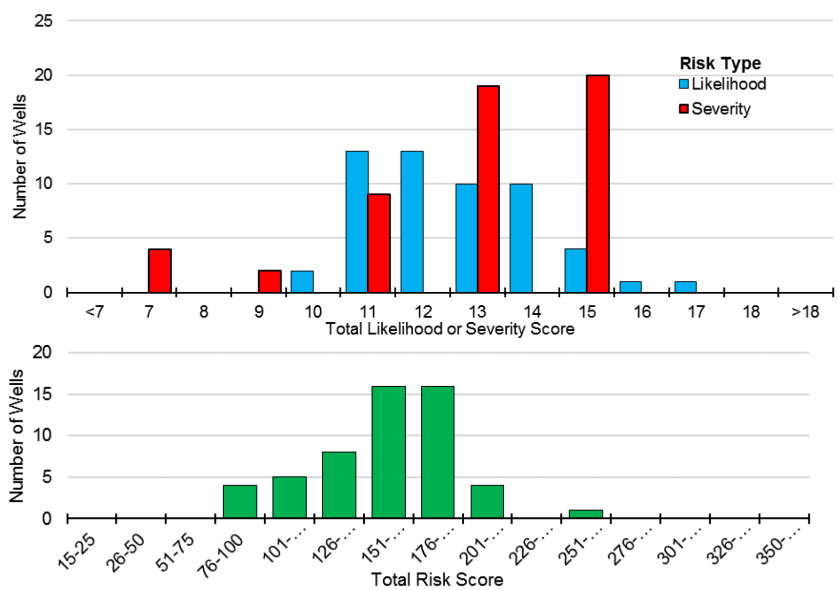


Figure 4-1. Histograms of Total Likelihood and Total Severity Scores (top) and Total Risk Scores (bottom), Northern reef trend, Otsego County, Michigan.

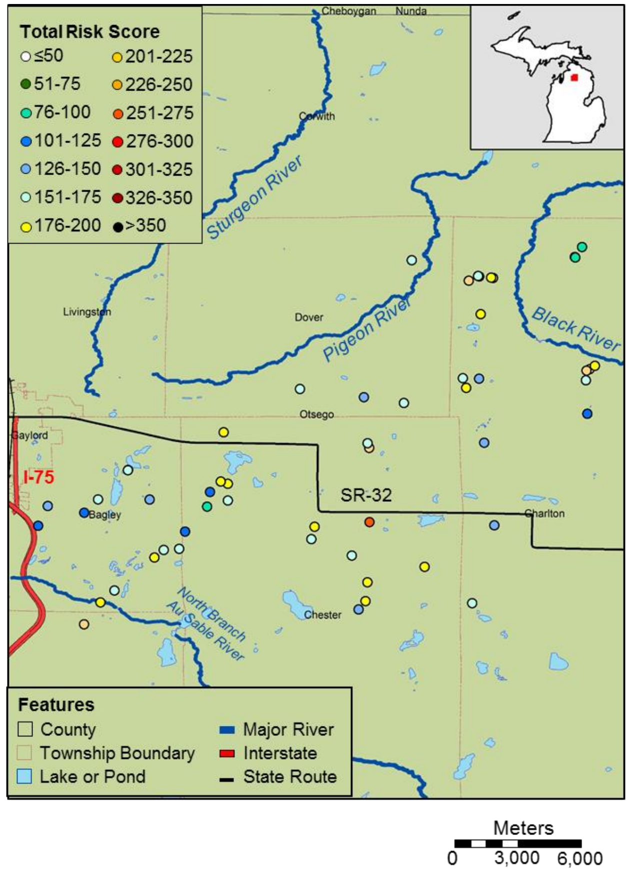


Figure 4-2. Total Risk Scores, Northern reef trend, Otsego County, Michigan.

Total Risk Scores for the Appalachian Basin wells ranged from 55 to 165 (the minimum possible Total Risk Score was 15, while the maximum possible Total Risk Score was 375). The average Total Risk Score was 98.2 with a standard deviation of 45.3. The histogram for risk scores was a bell-shaped curve centered between the bins 76-100 and 101-125 that skewed toward lower values (Figure 4-3). More than half of the wells had a Total Risk Score of 100 or less (25 locations). The wells with lower Total Risk Scores are located in the eastern and central portions of the field, away from population centers (Figure 4-4), suggesting that distance to population was a determining factor for total risk.

Histograms for the Total Likelihood Scores, Total Severity Scores, and Total Risk Scores for Williston Basin wells included in this study are presented in Figure 4-5. Maps are not presented for the Weyburn Field at the request of the operator that provided the data. Total Risk Scores for the Williston Basin wells included in this study range from 27 to 300 (the minimum possible Risk Score is 15, while the maximum possible Risk Score is 375). The average Total Risk Score was 101.7 with a standard deviation of 25.6. The histogram of Total Risk Scores for the wells included in this study is skewed toward lower values. The largest number of wells has a Total Risk Score between 101 and 125. More than half of the wells included in this study (756 locations) had Total Risk Scores of 100 or less.

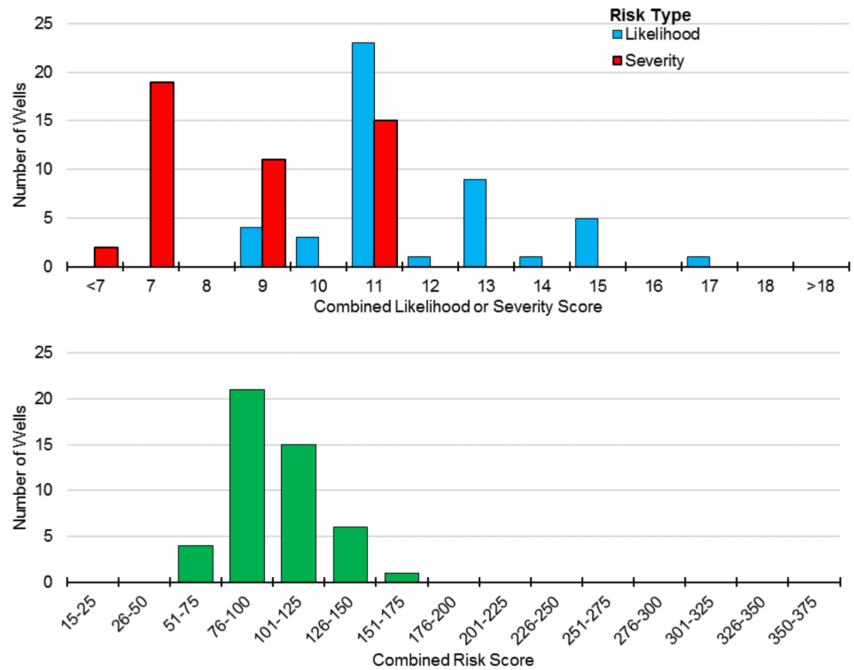


Figure 4-3. Histograms of Total Likelihood and Total Severity Scores (top) and Total Risk Scores (bottom), Indian Creek Field, Kanawha County, West Virginia.

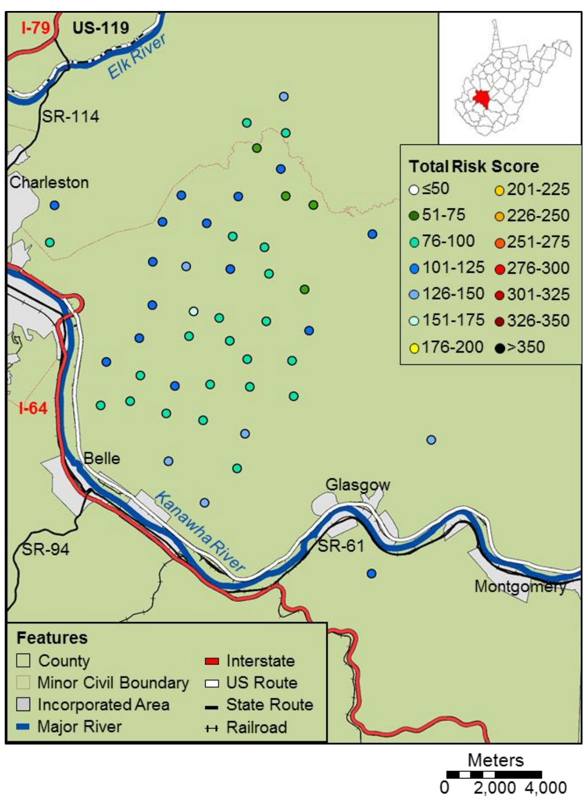


Figure 4-4. Total Risk Scores, Indian Creek Field, Kanawha County, West Virginia.

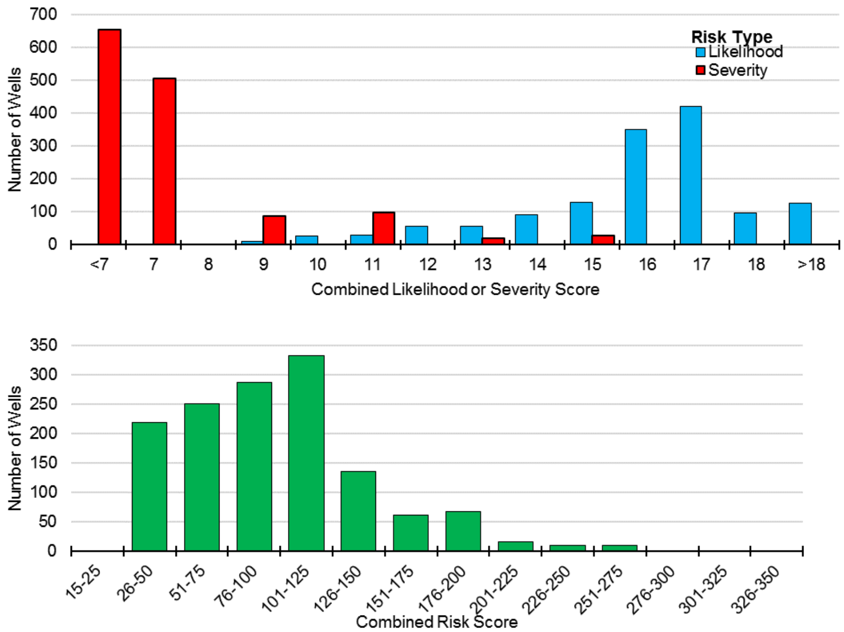


Figure 4-5. Histograms of Total Likelihood and Total Severity Scores (top) and Total Risk Scores (bottom), Weyburn Field, Saskatchewan, Canada.

The three field test sites were assessed using a Features, Events, and Processes (FEP)-based risk ranking methodology. The fields varied in size, geography, and geology. The assessment showed that Total Severity was probably more important in determining Total Risk. Correlation analyses of the Total Likelihood data showed that cement through caprock, well age, and well status had the largest effect on the Total Severity rank, with cement through caprock being the most important for each field. The CBL analysis conducted for the Indian Creek and Otsego wells shows that some wells may have primary cement that may pose a risk with values of less than 80% bond index.

The effect of unknown data was also most pronounced in the Alberta dataset, with only 176 of 1,391 wells with data for the cement through caprock category. However, for each of the other fields, the most missing data were in the cement through caprock category as well. The strong correlation may be due to giving the worst-case score to categories with missing data, but it also highlights the need to collect additional data to ensure that these categories can be fairly and fully evaluated. Correlation analyses of the data show that Total Risk follows more closely the Severity categories than the Likelihood categories. This finding has implications for risk mitigation. Mitigation of severity is most likely to come from early warnings from monitoring tools, implying that the receptors of concern (the local population, groundwater, and surface water and environmentally sensitive areas) may need to be monitored.

4.4 Key Findings of Log- and Testing-Based Well Integrity Assessment

The three field test sites in Otsego, Michigan, Indian Creek, West Virginia, and Alberta, Saskatchewan, were assessed using a risk ranking methodology. The fields varied in size, geography, and geology. The assessment showed that Total Severity was more important in determining the Total Risk.

Correlation analyses of the Total Likelihood data showed that cement through caprock, well age, and well status had the largest effect on the Total Severity rank, with cement through caprock being the most important for each field. This finding may indicate that well isolation for each CCS project may need to be better understood in order to properly assess leakage risk. The CBL analysis conducted for the Indian

Creek and Otsego wells shows that some wells may have, on average, primary cement that may pose a risk with values of less than 80% bond index. However, in many cases there were portions of each well that would be expected to isolate the CO_2 zone from the surface. If a cement job is poor and no information can be found, risk could be mitigated by working over wells to establish that there is isolation or by monitoring wells to catch leaks early.

The effect of unknown data was most pronounced in the Alberta dataset, with only 176 of 1,391 wells with data for the cement through caprock category. However, for each of the other fields, the most missing data were in the cement through caprock category as well. The strong correlation may be due to giving the worst-case score to categories with missing data, but it also highlights the need to collect additional data to ensure that these categories can be fairly and fully evaluated.

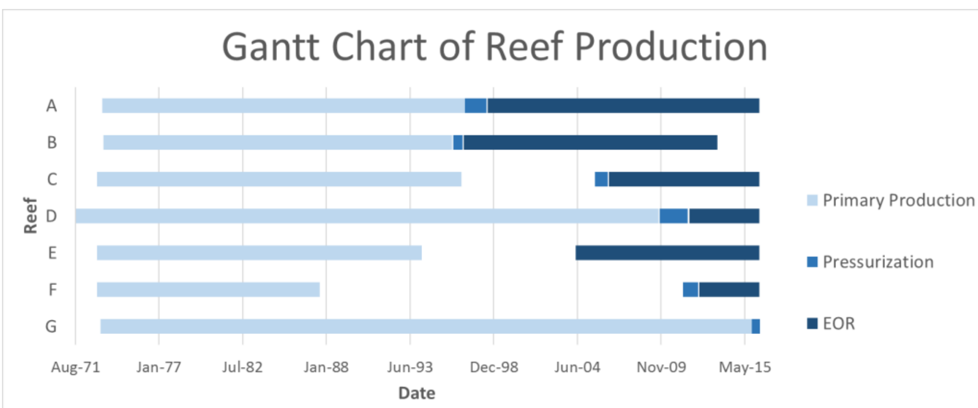
Chapter 5.0 Sustained Casing Pressure Analysis

A key part of the project was testing SCP in CO_2 wells at the field test sites. The tests provide a means to measure the nature and severity of well defects in CO_2 wells. The procedures, results, and analysis of SCP field testing are provided in Sections 5.1 (Michigan Basin) and 5.2 (Williston Basin).

5.1 Michigan Basin SCP Field Testing

Niagaran reefs at the Michigan Basin field test site have been subject to CO_2 EOR since 1996, with operations expanding to a total of 10 reefs. The Niagaran fields were developed since the 1960s in the region. The production history of the tested reefs is outlined in Figure 5-1. Overall, the Antrim shale/Niagaran reef is an attractive area for examining wells exposed to different types of CO_2 environments in the subsurface. The site also has other hydrocarbon wells and injection wells for comparison testing (Figure 5-2).

Multiple wells in the Michigan Basin were measured for casing pressure. If well conditions indicated that pressure might continue in the well, the well was selected to be part of enhanced testing. Six selected wells were tested using a pressure bleed-down/buildup test, and gas samples were collected from the wells. In addition, the gas chamber volume was measured in select wells. Table 5-1 summarizes the well construction specifications for the 23 wells surveyed for indications of SCP. The majority of the tested wells were drilled as primary production wells in the 1970s; however, a few of the wells were drilled as part of recent CO_2 EOR operations.



Reef	Primary	Pressurization	EOR
Reef A	5/73 - 4/97	2/97 - 07/98	08/98 - Present
Reef B	5/74 - 4/96	5/96 - 12/96	01/97 - 11/12
Reef C	1/73 - 11/96	08/05 - 06/06	07/06 - Present
Reef D	08/71 - 10/09	11/09 - 09/11	10/11 - Present
Reef E	1/73 - 4/94	5/04 - 5/04	5/4 - Present
Reef F	1/73 - 8/87	5/11 - 5/12	06/12 - Present
Reef G	4/73 - 11/15	12/15 - Present	N/A

Figure 5-1. Timeline of production and EOR of Michigan Basin reefs, outlining the primary production, pressurization period when CO_2 was being injected without production, and EOR period.

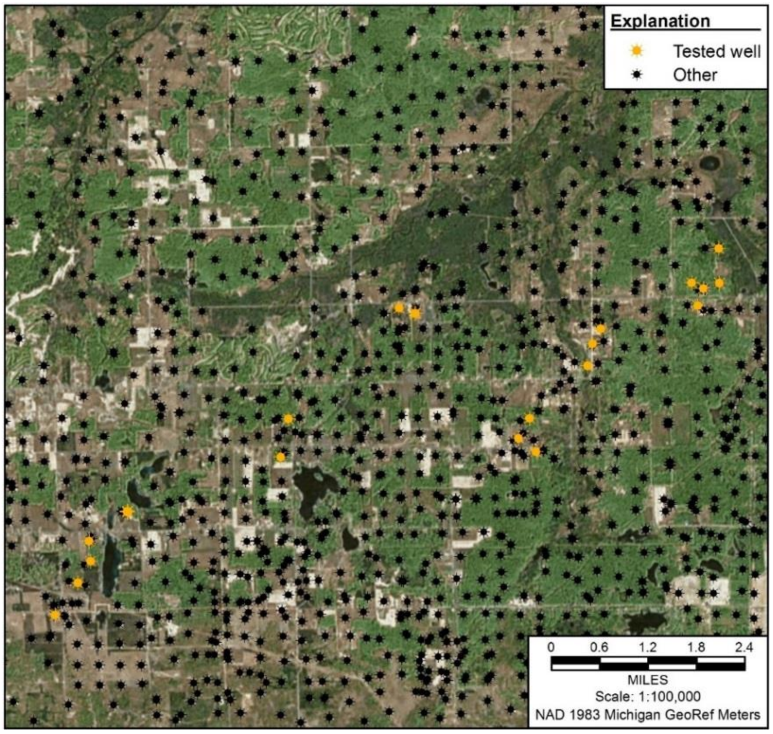


Figure 5-2. Map of tested wells in the Michigan Basin, among many other wells in the area.

Table 5-1. Construction specifications for Michigan Basin wells surveyed.

Well ID	Completion Year	Type	Total Depth (ft)	Casing Strings[a]	Comments
MB-1	1973	Vertical	5,794	4	Intermediate annulus SCP test
MB-2	1974	Vertical	5,675	4	Deep annulus SCP test, cemented to surface
MB-3	1997	Deviated	6,450	4	Deep annulus SCP test
MB-4	2008	Vertical	5,850	4	Deep annulus SCP test
MB-5	1976	Vertical	5,655	4	Deep annulus SCP test, cemented to surface
MB-6	2012	Deviated	6,970	4	Deep annulus SCP test
MB-7	1996	Kickoff	7,134	4	Vertical with kickoff TVD 5,510 ft
MB-8	1976	Vertical	5,650	4	
MB-9	1977	Vertical	6,255	4	
MB-10	2006	Vertical	5,800	4	
MB-11	1974	Kickoff	6,431	4	Vertical with kickoff TVD 5,652 ft
MB-12	1998	Vertical	5,700	4	
MB-13	1975	Kickoff	6,570	4	Vertical with kickoff TVD 5,851 ft
MB-14	1973	Vertical	5,981	4	
MB-15	2008	Vertical	6,202	4	
MB-16	1973	Vertical	5,770	4	Deep casing cement to surface
MB-17	1984	Vertical	6,250	4	
MB-18	1984	Vertical	6,324	4	
MB-19	1984	Vertical	6,045	4	
MB-20	1986	Vertical	6,130	4	
MB-21	1986	Vertical	6,200	4	
MB-22	1986	Vertical	6,000	4	
MB-23	1975	Vertical	6,013	4	

a. Including conductor. Note: TVD = true vertical depth.

Table 5-2 provides the sampling dates and field test results for the six wells (well IDs MB-1 through MB-6) that underwent SCP testing and also describes the status of the remaining wells initially surveyed for indications of significant casing pressures (well IDs MB-7 through MB-23). All the wells have a similar casing design, with a conductor pipe to aid in the drilling operations, and surface casing cemented back to the surface to protect potable aquifers. The intermediate casing is positioned with the shoe just below the Bois Blanc formation. This standardization is in place because the formation has been known to take fluid while drilling and circulating in certain parts of Michigan. The production casing is positioned near or at total depth (TD). The completion is performed by perforating the zones of interest, and chemically treating the perforations with acid and other chemicals when needed. Wellbore diagrams with geologic stratigraphic columns of the six tested wells are shown in Figure 5-3.

Table 5-2. Field test results for Michigan Basin wells.

Name	Reef	Sampled	Description
MB-1	Reef A	3/23/2016	32 psia initial pressure
MB-2	Reef B	3/23/2016	30 psia initial pressure
MB-3	Reef B	3/23/2016	162 psia initial pressure
MB-4	Reef C	5/1/2016	16 psia initial pressure
MB-5	Reef C	5/2/2016	35 psia initial pressure
MB-6	Reef D	5/3/2016	25 psia initial pressure
MB-7	Reef B	3/23/2016	inaccessible valve
MB-8	Reef C	3/23/2016	inaccessible valve
MB-9	Reef C	3/23/2016	no pressure on annulus
MB-10	Reef C	3/23/2016	inaccessible valve
MB-11	Reef E	3/23/2016	no pressure on annulus
MB-12	Reef A	3/23/2016	inaccessible valve
MB-13	Reef D	3/23/2016	inaccessible valve
MB-14	Reef D	3/23/2016	subgrade valve
MB-15	Reef F	3/23/2016	no pressure on annulus
MB-16	Reef F	3/23/2016	inaccessible valve
MB-17	Reef G	3/23/2016	subgrade valve
MB-18	Reef G	3/23/2016	subgrade valve
MB-19	Reef G	3/23/2016	subgrade valve
MB-20	Reef G	3/23/2016	no pressure on annulus
MB-21	Reef G	3/23/2016	no pressure on annulus
MB-22	Reef G	3/23/2016	no pressure on annulus
MB-23	Reef G	3/23/2016	27 psia initial pressure, drops to 17 psia after 2 mos

Note: Highlighted rows indicate the six Michigan Basin wells selected for SCP testing.

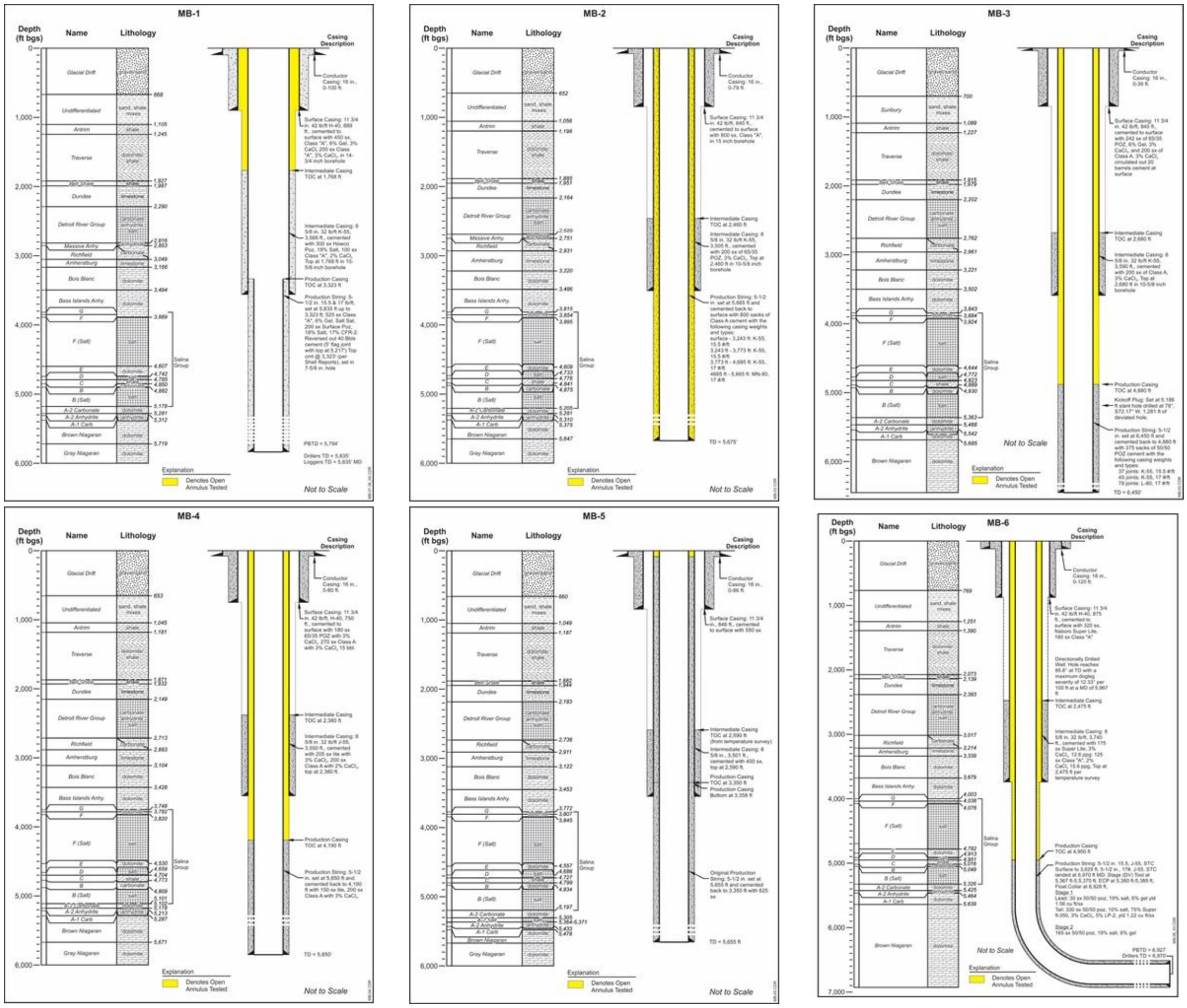


Figure 5-3. Well diagrams for Michigan Basin wells tested for SCP buildup.

Monitoring was performed by recording the temperature and pressure to have a record of pre-test conditions. The process was continued through depleting the pressure in the annulus to atmospheric conditions. In cases where gas chamber volume was needed, a flow meter was attached to the correct valve, and the volume of flow out of the annulus space was recorded. Later, these data were converted from atmospheric conditions (pressure and volume coming out of the wellhead into the atmosphere) using the annulus pressure and a form of the Ideal Gas Law formula to calculate the gas volume released.

After opening the valve, venting the gas, and properly closing the valve, a memory gauge was attached. This was done to monitor the pressure buildup in the annulus. The gauge was programmed to record a pressure/temperature measurement at a preselected interval of time, such as a minute-by-minute measurement. The well was then left alone for a minimum of 2.5 weeks to see if the pressure would build up in the annulus. After this time period had fully passed, the gauge was removed and the pressure buildup data were collected. The data revealed how long it took for the pressure to return to previous levels, as well as the influence of thermal changes on the gas in the annulus.

If there was SCP in the annulus of the well, a gas sample was taken. This sample would have been procured after the initial drawdown of the well to ensure that the sample was representative of the gas that was making its way into the annulus. It was important to ensure that the sampling cylinder was visually inspected and cleaned ahead of time, and it is often purged on site with annulus gas. Each sample was tracked with a tag that included the well name, API, date/time, and all other pertinent identifiers. These samples were then sent to a laboratory for testing to determine the individual gas compositions, such as CO_2, nitrogen, hydrogen, helium, oxygen, methane, ethane, butane, pentane, and other gases. Results of these analyses are discussed in the following section. Table 5-3 lists the wells that were tested, along with a short summary of the well. Some wells were inaccessible due to adverse conditions. Subgrade valves did not allow for annulus testing.

Test results in Table 5-2 and alternatively in Figure 5-3 illustrate that six wells had no pressure, four wells had subgrade valves, six wells were inaccessible, one well produced results inconclusive with SCP after pressure monitoring, and six wells had gas samples collected. These six wells were also monitored for pressure. One gas sample was inconclusive, which was taken from MB-6. Out of those five wells with conclusive gas samples, only one well, MB-3, had a significant percentage of CO_2 in the annulus. However, further analysis will be needed to determine if this is due to CO_2 injection, or if the CO_2 buildup is due to gas from the Antrim formation.

Table 5-3. Gas sampling results of six tested wells.

Component	MB-1	MB-2	MB-3	MB-4	MB-5	MB-6[a]
	Mol %					
Helium	0.23	NIL	NIL	NIL	NIL	N/A
Hydrogen	0.148	56.212	17.521	30.952	0.795	N/A
Carbon Monoxide	NIL	NIL	NIL	NIL	NIL	N/A
Oxygen	0.035	1.406	0.225	0.624	16.383	N/A
Nitrogen	1.198	6.506	1.153	51.035	74.058	N/A
Methane	95.456	35.378	1.976	16.39	2.81	N/A
Carbon Dioxide	1.175	0.031	75.263	0.191	0.607	N/A
Ethane	1.308	0.035	0.602	0.159	1.182	N/A
Propane	0.075	0.086	0.88	0.2	1.387	N/A
Iso-Butane	0.098	0.035	0.325	0.047	0.638	N/A
n-Butane	0.017	0.05	0.586	0.133	0.975	N/A
Iso-Butylene	NIL	NIL	NIL	0.005	0.011	N/A
Iso-Pentane	0.06	0.03	0.462	0.062	0.573	N/A
n-Pentane	0.007	0.016	0.343	0.073	0.332	N/A
Hexanes Plus	0.193	0.215	0.664	0.129	0.249	N/A

a. Samples were taken of MB-6, but the sampling process was unsuccessful.

A pressure bleed-down/build-up test was performed on each well involved in this study to evaluate the pressure-response curve related to the SCP. The casing valve associated with the annulus being tested was then opened to allow the pressure to bleed down to near-atmospheric conditions. Next, a data-recording pressure/temperature gauge was connected to the annular space to monitor the pressure recovery curve. Figure 5-4 shows the comparison of pressure and temperature versus time for the Michigan Basin wells. For MB-1, MB-4, and MB-6, it is apparent that temperature is driving the changes in pressure. MB-3 seems to be building pressure over time. MB-2 and MB-5 are inconclusive; these tests, for example, may have been affected by the formation of ice, hydrate, or another substance. The beginning and end points show where the gauge is reading standard conditions before and after being connected to the well.

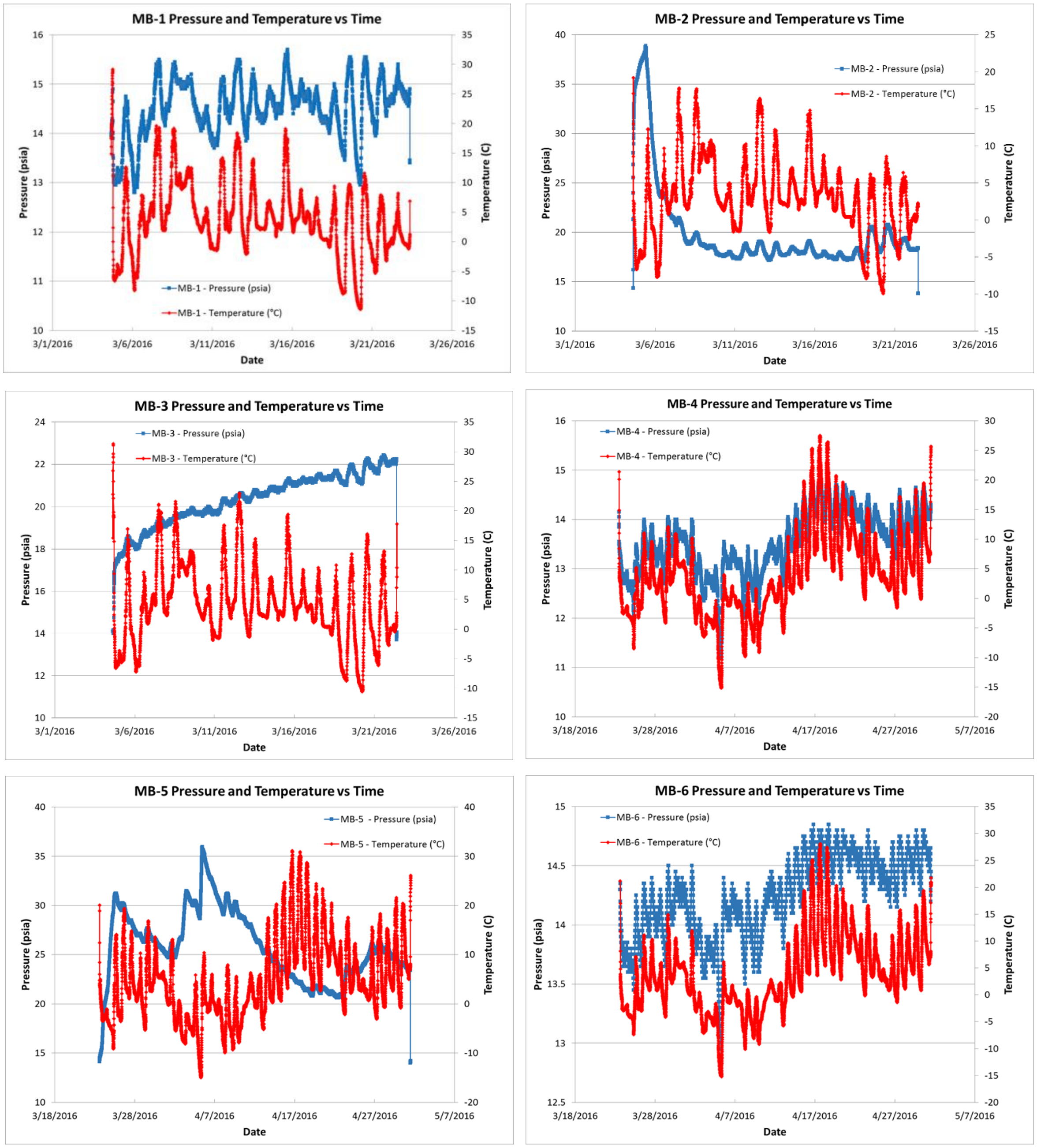


Figure 5-4. Pressure and temperature testing data from Michigan Basin wells.

In two of the wells, the annular space was bled down through a flow meter to determine the volume of the gas released; a valve at the outlet of the wellhead maintained a constant flow rate. Using the time required to blow the well down to near-atmospheric levels and the initial pressure, the gas volume released was calculated. The total volume and the initial pressure were used with the Ideal Gas Law to determine the gas volume released. The volume of gas released from the annulus of well MB-1 was calculated to be about 18 ft^3, which was calculated using a well pressure of 17 psia, and bleeding down to a pressure of 15 psia. The total open annulus volume was calculated to be about 420 ft^3, using standard casing and hole sizes. The volume of gas released from the annulus of well MB-3 was calculated to be about 66 ft^3, which was calculated using a well pressure of 32 psia, and bleeding down to a pressure of 18 psia. The total open annulus volume was calculated to be about 865 ft^3, using standard casing sizes. The open annulus volumes were calculated from the surface to the top of cement. These released volumes are much smaller than the size of the open annulus.

5.2 Williston Basin SCP Field Testing

Approximately 3,000 wells are located in the Williston Basin test site. Field operational records were reviewed to identify wells with reoccurring wellhead pressures on the deep annulus that would be candidates for SCP testing. The screening effort identified 60 wells for this testing study. In order to better pre-screen which wells to test, the operator performed bagging tests, where a bag was attached to the annulus valve of the well to physically measure the amount of gas building up in the annulus. This qualitative test helped to determine if the pressure drawdown test procedure listed above would have any pressure buildup to measure. This survey effort resulted in 17 tested wells with significant casing pressure. The wells were primarily oil producers with select wells used for H_2O or CO_2 injection. Figure 5-5 shows the locations of the tested wells.

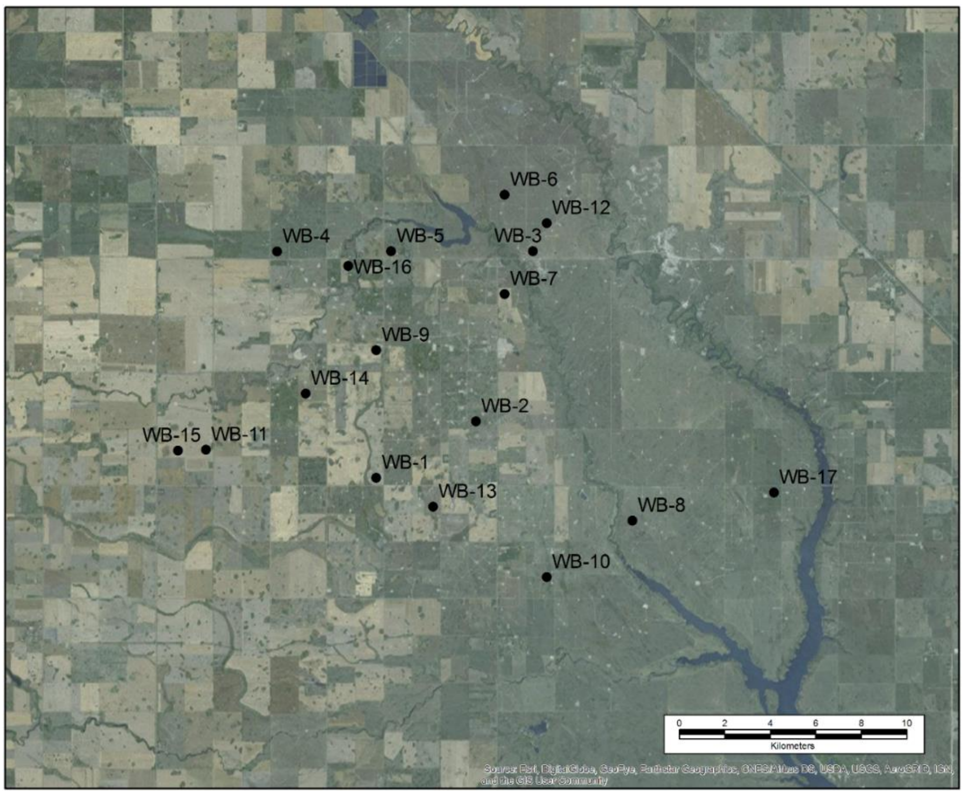


Figure 5-5. Map of studied wells in the Williston Basin field test site.

Table 5-4 summarizes the well construction specifications for the 17 Williston Basin wells tested for SCP. Figure 5-6 shows the wellbore diagrams for WB-1, WB-4, WB-5, WB-10, WB-13, and WB-15 (other well diagrams are provided in the full field testing report). Testing showed that these six wells had casing pressure buildup. The tested wells were between 1,381 and 1,582 meters deep (measured depth [MD]). The tested wells in the field are being used for production, WAG, or water injection. Eight of the wells were drilled in the 1950s, with the rest being drilled in the 1990s or 2000s. CO_2 EOR operations began in 2000, and the wells have been in CO_2 environments in the subsurface since the early 2000s, some of which have likely been exposed to CO_2 since being drilled. Detailed operational data, well histories, and certain details pertaining to well construction, such as cementing records, were not available from the operator.

Table 5-4. Williston Basin well specifications.

Well ID	Well Profile	Comp. Date	TD, TVD (m)	Csg Strings	Surface Csg Depth (m)	Surface Csg OD Nominal (in)	Prod Csg Depth (m)	Prod Csg OD Nominal (in)	Prod Csg Cement (m)
WB-1	Horizontal	2005	1,456	2	137*	9.625*	1,300*	5.5*	885*
WB-2	Vertical	1957	1,471	2	111	8.625	1,470	4.50	N/A
WB-3	Vertical	1955	1,582	2	152	10.75	1,411	7.00	N/A
WB-4	Vertical	1957	1,402	2	184	10.75	1,402	5.50	1,051*
WB-5	Vertical	1957	1,410	2	95	8.625	1,410	5.50	1,059*
WB-6	Vertical	1958	1,381	2	94	8.625	1,381	5.50	N/A
WB-7	Horizontal	2001	1,399	2	152	9.625	1,315	7.00	N/A
WB-8	Vertical	1959	1,480	2	91	8.625	1,480	5.50	N/A
WB-9	Horizontal	2005	1,424	2	137*	9.625*	1,300*	5.5*	N/A
WB-10	Horizontal	1995	1,471	2	163	9.625	1,361	7.00	N/A
WB-11	Horizontal	2000	1,443	2	150	9.625	1,358	7.00	N/A
WB-12	Vertical	1997	1,420	2	137*	9.625*	1,300*	5.5*	N/A
WB-13	Horizontal	1994	1,458	2	153	9.625	1,355	7.00	N/A
WB-14	Horizontal	2005	1,433	2	185	9.625	1,335	7.00	N/A
WB-15	Horizontal	2001	1,459	2	156	9.625	1,351	7.00	N/A
WB-16	Vertical	1957	1,439	2	92	10.75	1,442	5.50	880*
WB-17	Vertical	1957	1,515	2	142	8.625	1,484	6	N/A

*estimated Note: TD = total depth; TVD = true vertical depth.

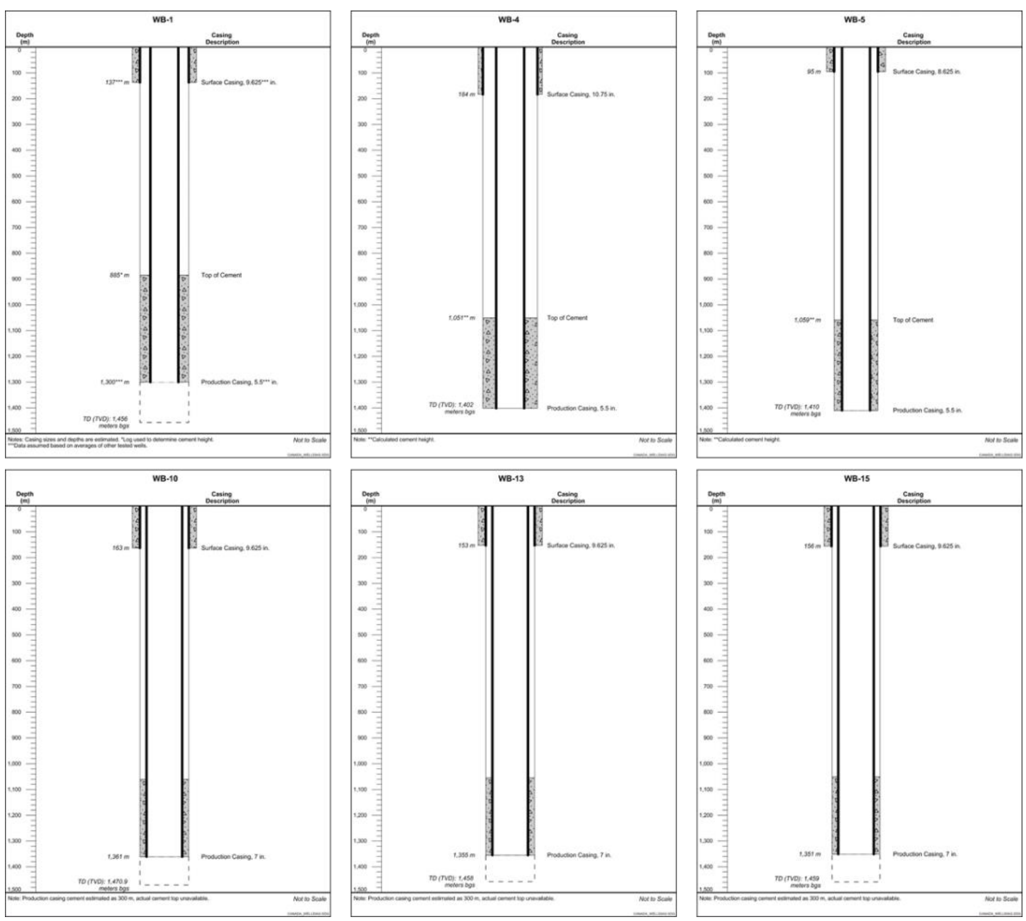


Figure 5-6. Williston Basin wellbore diagrams.

Pressure monitoring started with a job safety analysis that was performed at each well before testing for SCP. The surface temperature was noted along with the pressure observed via pre-existing gauges on the wellhead to ensure safe conditions. Then, a visual inspection of testing equipment was performed before any equipment was installed. The monitoring was performed by recording the temperature and pressure to have a record of pre-test conditions. The process was continued by attaching the apparatus (Figure 5-7) and depleting the pressure in the annulus to atmospheric conditions. In the cases where gas chamber volume was needed, the testing apparatus with an orifice was attached to the correct valve, and the flow out of the annulus space would have been held constant through the orifice. Later, these data were converted from atmospheric conditions (pressure and volume coming out of the wellhead into the atmosphere) using the time of bleed down, the annulus pressure, and a simplified form of the Ideal Gas Law formula to calculate the gas volume released.

Figure 5-7. Well testing apparatus at the Williston Basin site.

After this process, the gauge was removed, and the pressure buildup data were collected. The data revealed how long it took for the pressure to return to previous levels, as well as how much influence thermal changes throughout the course of the day had upon the gas in the annulus. Ideally, if there was SCP in the annulus of the well, then a gas sample would have been collected after the initial drawdown of the well to ensure that the sample was representative of the gas making its way into the annulus. Each sample would have been tracked with a tag that included the well name, API, date/time, and all other pertinent identifiers. These samples would then be sent to a laboratory for composition testing. However, for this site, gas samples could not be collected due to low pressure and flow at the wellhead. Consequently, historical operator records were examined to determine the gas chemistry and the source of the gas. These operator records were compared to available simple gas samples taken by the operator, which were used for a rough indication of where the gas was coming from. Low amounts of CO_2 indicate that CO_2 is not originating from the injection zone.

Seventeen (17) of the 60 wells considered were tested with the apparatus containing the pressure and temperature gauge. The 17 wells were ultimately chosen by the operator because of the operator's extensive knowledge of the field and well characteristics. Battelle was informed by the operator that a gas bagging technique was used to obtain a physical measurement of the gas that built up in the annulus. Also, simple, qualitative gas samples were taken (Table 5-5) in order to get a rough estimation of gas composition, but this is not to be interpreted as a replacement for laboratory-quality gas sampling. In many cases, there was not enough of a buildup to justify performing a full test with the pressure and temperature memory gauge. Initially, 60 wells were selected for the study, and for the first few weeks of testing, only one testing apparatus was available, with test duration lasting 7 days. Later in the testing period, two additional testing apparatuses were added, with the tests concluding in October 2017 due to inclement weather.

Table 5-5. Gas testing records for the Williston Basin wells.

Well Number	H_2 (ppm)	CH_4 (ppm)	CO_2 (ppm)	Orifice Size (in)
WB-1	N/A	N/A	N/A	1/8
WB-2	19,375	460,000	4,000	1/8
WB-3	2,660,000	710,000	0	1/32
WB-4	105,000	110,000	0	1/32
WB-5	N/A	N/A	0	1/32
WB-6	403,000	200,000	0	1/32
WB-7	41,000	4,000	14,000	1/8
WB-8	N/A	N/A	0	1/32
WB-9	85,000	190,000	0	1/32
WB-10	N/A	N/A	N/A	1/8
WB-11	N/A	N/A	18,000	1/8
WB-12	499,000	165,000	0	1/32
WB-13	N/A	N/A	N/A	1/8
WB-14	2,975	0	42,000	1/8
WB-15	N/A	N/A	2,000	1/8
WB-16	45,000	60,000	0	1/32
WB-17	N/A	N/A	0	1/32

Note: ppm = parts per million.

A pressure bleed-down/buildup test was performed on each of the 17 wells involved in this study to evaluate the pressure-response curve related to the SCP. The casing valve associated with the annulus being tested was then opened to allow the pressure to bleed down to near-atmospheric conditions. Next, a data-recording pressure/temperature gauge was connected to the annular space to monitor the pressure recovery curve.

Figures 5-8 and 5-9 show the comparison of pressure and temperature versus time. For WB-1, WB-4, WB-5, WB-10, WB-13, and WB-15, buildup can be seen. WB-1 shows a moderate dip in the pressure during the middle of the test period, which may have been a device error. For WB-1, the test administrator had noted that the testing apparatus ‘froze up’ during the test. WB-2 and WB-3 show no significant pressure increase, with the temperature in WB-3 having a slight effect on the pressure. WB-5 shows a possible mechanical defect, indicated by the sharp logarithmic increase in pressure. WB-10 shows an unexplained dip in the pressure buildup, perhaps due to a small release of pressure, or possibly another factor. The other wells without buildup have varying amounts of pressure dependence on temperature, with a handful of the wells experiencing a negligible decline in pressure.

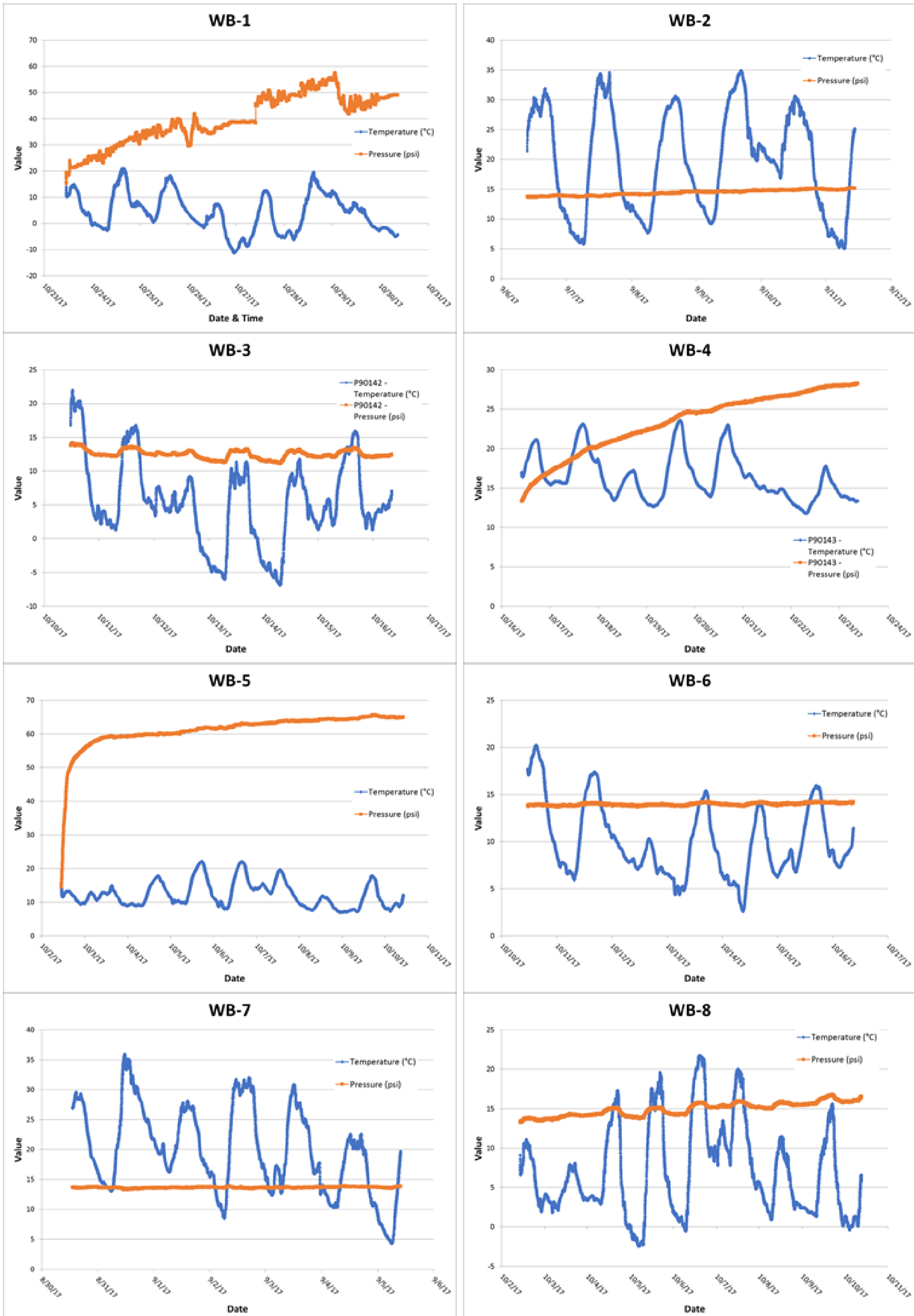


Figure 5-8. Pressure-temperature testing data from Williston Basin wells WB-1 though WB-8.

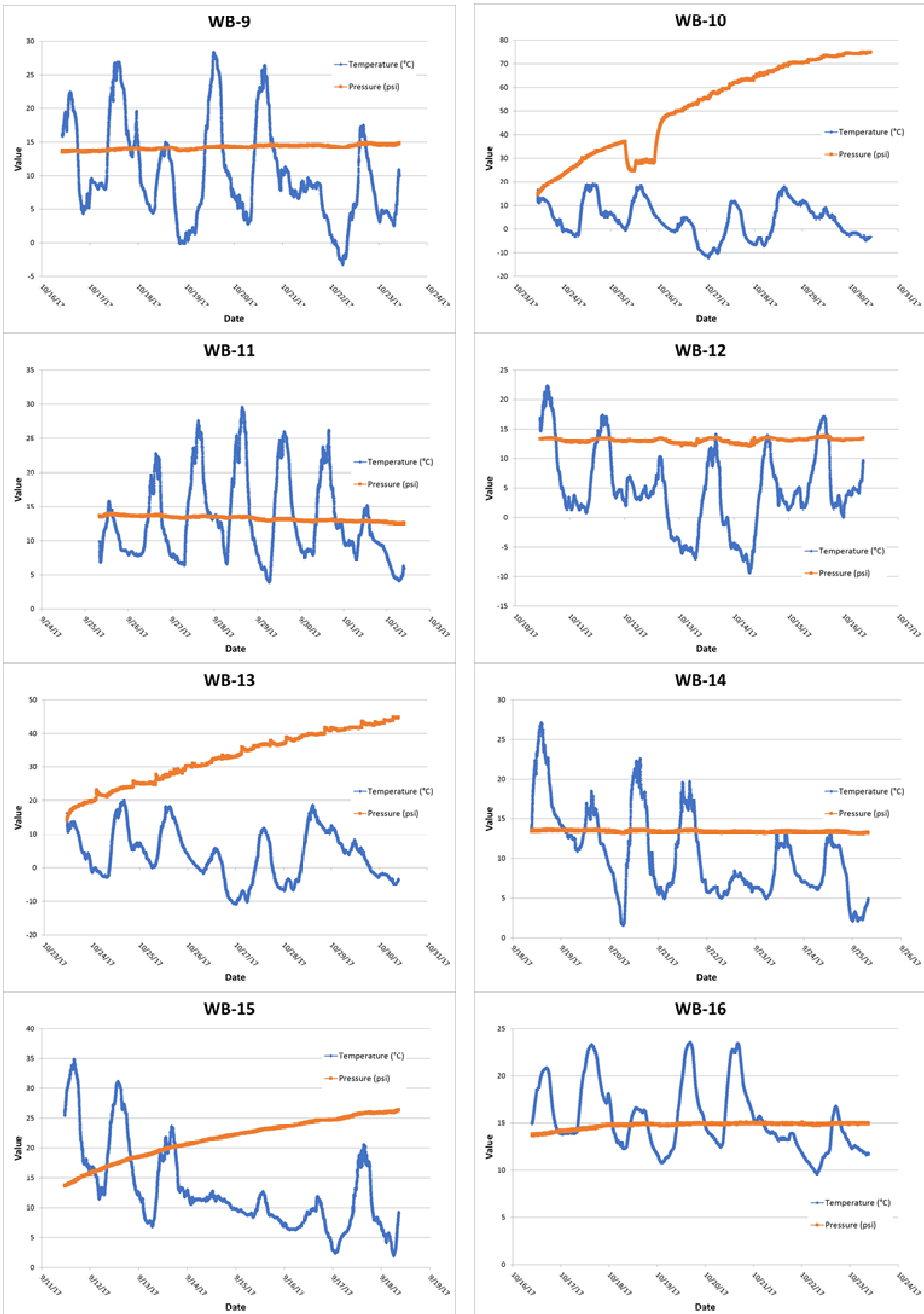


Figure 5-9. Pressure-temperature testing data from Williston Basin wells WB-9 though WB-16.

To provide more information on the nature and severity of potential well defects for the operator, the pressure buildup curves were analyzed with the methodology developed by Moody and Dotson (2015). The conventional diagnostic test for SCP is the bleed-down/buildup test, in which the gas pressure is bled off the annulus and the resulting buildup is recorded. The base SCP pattern (Figure 5-10) consists of pressure increasing at a decreasing rate to an asymptotic pressure. Several researchers have detailed SCP analysis methods, primarily originating with Xu and Wojtanowicz (2001), who described a method to calculate cemented annulus permeability from SCP pressure observations. Huerta et al. (2009) proposed the use of this method for CO_2 storage well application. The method developed by Moody and Dotson (2015) was simplified to assess the cumulative effect of all the defects in the seal represented by a hypothetical flow restriction, quantified as a flow factor located at the top of the cement. This simpler model has the advantage that it can indicate the character of the defect, providing diagnostic information not available if only a permeability flow model is assumed.

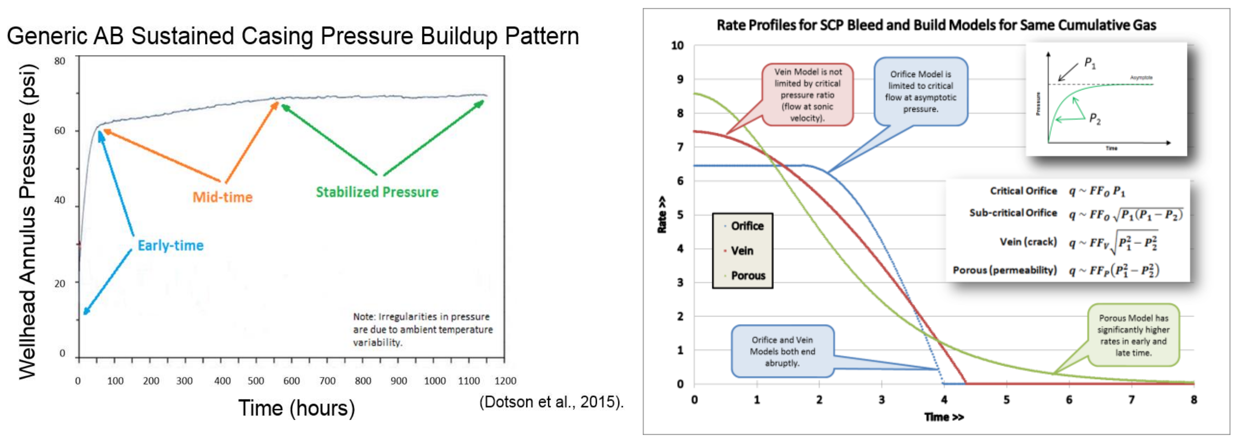


Figure 5-10. General SCP buildup curve.

Eleven (11) of the 17 wells tested at the Williston Basin site showed no significant pressure rebound pattern. However, six of the wells did exhibit a minor pressure buildup pattern that might be useful for the operator to evaluate potential well defects present in shallow zones. Well construction information, subsurface conditions, and pressure buildup data were input into the MATLAB script designed to estimate well defect factors based on the methodology by Moody and Dotson (2015). This methodology examines the gas influx rate change over time to determine the nature of a well defect based on a defect model curve, similar to pressure transient well testing methods that examine pressure derivative curves. There was some uncertainty on several input parameters related to height of liquid volume in the annulus, gas volume due to low flow conditions, and gas properties. It was assumed that the calculations used 500 ft true vertical depth (TVD) of liquid length and a gas chamber length of 30 ft.

The SCP analysis for the six wells suggests mainly a pressure-limited orifice type defect factor. None of the wells correlated to a permeable cement flow model, which would suggest cement degradation and gas migration from the reservoir zone. Figure 5-11 shows the results for the wellbore integrity analysis. For each well, the analysis provides a curve of pressure buildup over time and gas influx over time. The gas influx curve shows a wellhead model curve of the type of cement defect as detailed by Moody and Dotson (2015). For the six wells analyzed, the most suitable gas influx curve was determined to be a pressure-limited orifice (O) or non-pressure-limited vein (V) model. The wells did not show a strong match to the gas influx rate type curve for orifice type defect, so the understanding of defect type is uncertain.

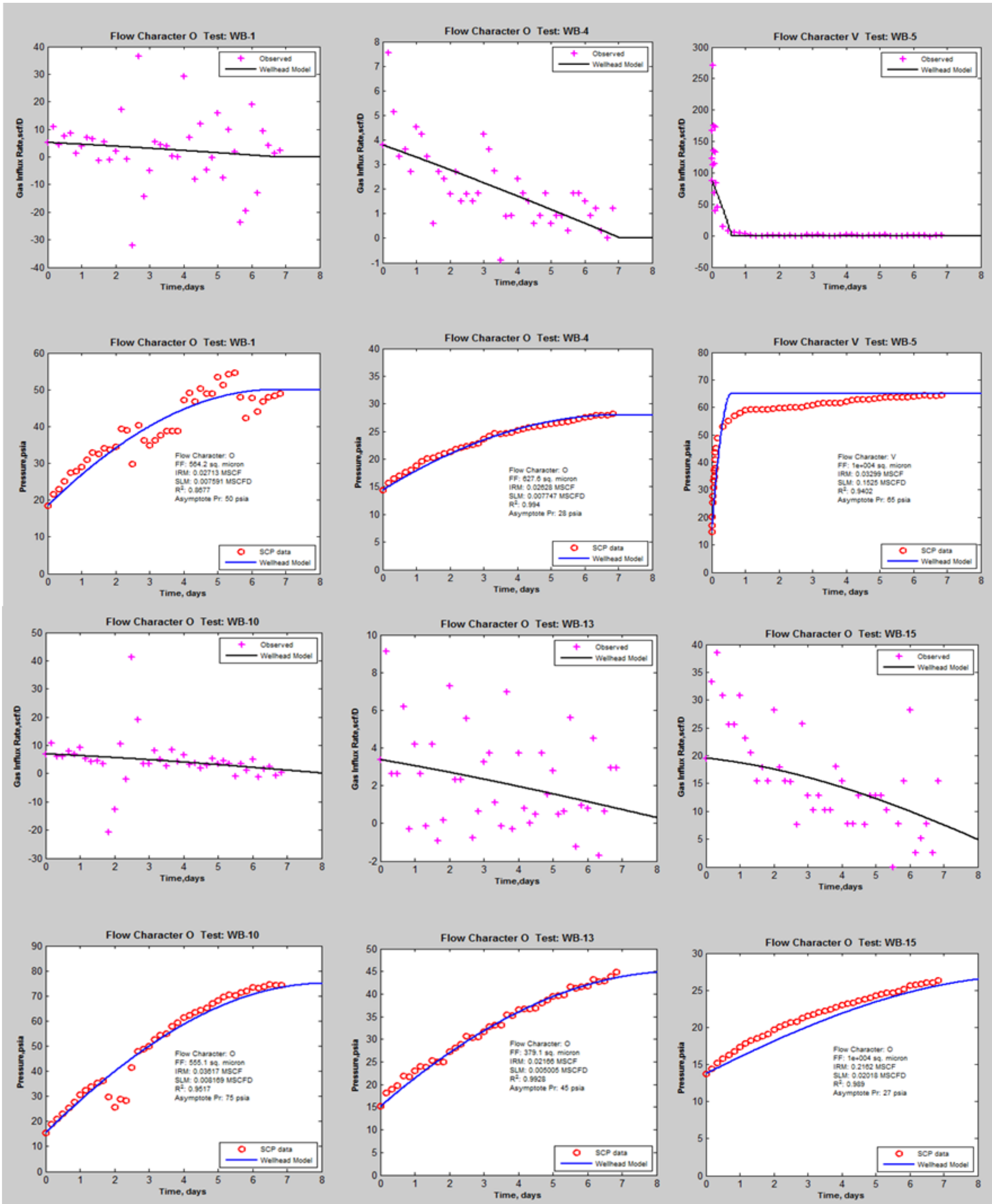


Figure 5-11. SCP plots for Williston Basin wells.

Table 5-6 summarizes SCP analysis results. WB-5 and WB-15 had higher flow factors and potential for sustained leakage. The other wells had small flow factors and less than 0.01 thousand standard cubic feet per day (MSCFD) sustained leakage metric. The defect response was unclear but seemed to show an orifice type curve. Overall, results support operator observations that there is low gas flow from a shallow source and likely water present in the casing annulus.

Table 5-6. SCP analysis results for Williston Basin field site.

Well	Well Depth (ft)	Gas Source	Asymptotic Pressure (psi)	Defect Response Type	Instantaneous Leakage Metric (MSCFD)	Sustained Leakage Metric (MSCFD)	Flow Factor (square microns)
WB-1	4,777	Shallow	50	Unclear (Orifice)	0.027	0.0076	564
WB-4	4,600	Shallow	28	Unclear (Orifice)	0.026	0.0077	627
WB-5	4,626	Shallow	65	Unclear (Orifice)	0.033	0.1500	>1,000
WB-10	4,826	Shallow	75	Unclear (Orifice)	0.036	0.0082	555
WB-13	4,784	Shallow	45	Unclear (Orifice)	0.022	0.0050	379
WB-15	4,784	Shallow	27	Unclear (Orifice)	0.220	0.0200	>1,000

5.3 Key Findings of SCP Analysis

Michigan Basin Site

A total of 23 CO_2 wells were surveyed for indications of SCP at the Michigan Basin site. These wells were present at an active CO_2 EOR field. The wells were 5,600 to 6,500 ft deep and installed in the early 1970s, with some more recent wells installed between 1997 and 2012. Many of the wells were used for primary oil production, water flooding, and CO_2 EOR. CO_2 EOR operations began in 1997, and the wells have been in CO_2 environments in the subsurface for 10 to 20 years. In general, the wells were constructed with typical oil and gas materials such as carbon steel casing and class A Portland cement.

The field survey established that six wells had no pressure, four wells had subgrade valves, six wells were inaccessible, one well produced results inconclusive with SCP after pressure monitoring, and six wells with evidence of SCP had gas samples collected and were monitored for pressure. Out of the five wells with conclusive gas samples, only one well, MB-3, had an amount of CO_2 that could be considered above background or of any statistical significance. Even with the molar percentage measured in the sample, both the volume of gas in the annulus and the measured pressure were very low.

The data from the pressure and temperature versus time graphs show various results. For MB-1, MB-4, and MB-6, it was apparent that temperature drives the changes in pressure. MB-3 seems to be building pressure over time. MB-2 and MB-5 are inconclusive. Furthermore, only one well, MB-3, had a significant initial pressure of 162 psia, but it did not build back up to that amount during the testing period.

Overall, SCP was not a common problem for the tested wells at the Michigan Basin site. Well construction practices were sufficient to isolate the injection zone and prevent any significant migration of CO_2 into the wellbore, including the following items:

- Multiple strings of casing (conductor, surface, intermediate, and deep) are present in the wells, which reduces potential for gas migration from intermediate zones.
- Most wells were cemented across or near casing string crossovers, reducing pathways for gas migration along the boreholes.
- More cement was used to cement in the casing strings than many other areas of the Midwest. Casing strings were cemented in with several hundred feet (and in many cases, over 1,000 ft) of cement.
- Cement was allowed to set and the top of cement was tagged to confirm the top of cement, which was especially pertinent to this site because there was potential to lose cement in washout zones.

Williston Basin Site

A subsample of 60 wells with exposure to CO_2 was surveyed for indications of SCP at the Williston Basin site, with 17 being tested. These wells were present at an active CO_2 EOR field. The tested wells were between 1,381 and 1,582 meters deep (MD). The tested wells in the field are being used for production, WAG, or water injection. Eight of the wells were drilled in the 1950s, with the rest being drilled in the 1990s or 2000s. CO_2 EOR operations began in 2000, and the wells have been in CO_2 environments in the subsurface since the early 2000s, some of which have likely been exposed to CO_2 since being drilled.

The field survey established that six wells had pressure buildup. The results for 11 wells showed no evidence of SCP after pressure monitoring. Further analysis would be required to draw any meaningful conclusions to the origin of the pressure buildup, as there are many meters of open annulus, being exposed to multiple formations.

The data from the pressure and temperature-versus-time graphs show various results. For WB-1, WB-4, WB-5, WB-10, WB-13, and WB-15, minor pressure buildup was observed. WB-1 and WB-10 had an inconclusive moderate dip in the pressure during the middle of the test period. WB-2 and WB-3 showed no significant pressure increase, with the temperature in WB-3 having a slight effect on the pressure. WB-5 showed a possible mechanical defect, indicated by the sharp logarithmic increase in pressure. The other wells without buildup exhibited varying amounts of pressure dependence on temperature, with a handful of the wells experiencing a negligible decline in pressure.

Overall, SCP was not a common problem for the tested wells at the Williston Basin site. Well construction practices appeared sufficient to isolate the injection zone and prevent any significant migration of CO_2 into the wellbore, based on the low annulus pressure buildup observed. For the cases where moderate pressure buildup was demonstrated, the source of pressure could not be determined. It must be taken into consideration that due to the open production casing annulus space, the slight pressure increase observed may have originated from a shallow formation. Gas samples would need to be collected and analyzed from the annulus gas, injection gas, and gas from shallow formations in order to identify the source of the casing pressure.

Chapter 6.0 Field Analysis of CO_2 Cement Sealing and Well Integrity

The objective of Task 6 was to analyze field data on mineralogy, fluids, cement, hydrologic conditions, and CO_2 exposure for the three field test sites to determine cement sealing and well integrity relationship. Data from previous tasks were analyzed for indicators of wellbore integrity factors that may predict cement sealing conditions in relation to CO_2 leakage potential in legacy oil and gas wells. These results provide a better understanding of wellbore integrity effects for CO_2 storage applications.

6.1 Analysis of Subsurface Setting for Cement Sealing

Mineralogy of the primary reservoir/CO_2 storage zone and primary caprock was determined with thin sections. The minerals present in the subsurface have the potential to interact with CO_2, cement, and brine mixtures. Table 6-1 summarizes the mineralogy for the field sites. The data on mineralogy were synthesized for inclusion in the PHREEQC modeling.

Table 6-1. Summary of mineralogy for the field test sites.

Mineral	Appalachian Basin Site		Michigan Basin Site		Williston Basin Site[e]	
	Caprock[a]	Reservoir[b]	Caprock[c]	Reservoir[d]	Caprock	Reservoir
Dolomite	---	---	39.7-99.7%	9-97.2%	1%	2-62%
Calcite	---	---	---	0.8-82.5%	39%	0-90%
Quartz	29.8-45.8%	>90%	0.3-2.1%	0-1.5%	1%	0-11%
Anhydrite	---	---	0.0-56.0%	1.3-4%	59%	1-14%
K-Feldspar	0-0.5%[f]	<1%	0.0-0.6%	0.5%	0%	0-11%
Plagioclase	---	<1%	---	---	0%	0-5%
Illite	36-60.8%	---	0.0-2.6%[g]	0-2%	0%	0-7%
Fluorite	---	---	---	---	0%	0-2%
Chlorite	5.9-12.2%	---	---	---	---	---
Pyrite	---	---	---	0-0.5%	---	---
Halite	---	---	---	0-0.8%	---	---
Iron Oxide	0-2.1%	---	---	---	---	---
Carbonate	0-7.8%	---	---	---	---	---
Chert RF	---	<1-1%	---	---	---	---
Heavy Min.	---	<1-3%	---	---	---	---

a. From Jin et al. (2010).
b. Based on Kanawha County, West Virginia, data provided by WVGES Pipeline-Plus Oil and Gas Database.
c. From core XRD analysis of three samples of the A2 carbonate from the Dover 33 Reef.
d. Includes State Chester (limestone) and Dover 33 (dolomite) reefs.
e. Based on data from Durocher et al. (2005), Braunberger et al. (2012), and Hutcheon et al. (2008).
f. Listed as feldspar in the original database.
g. Total clay.

Appalachian Basin. Mineralogy of reservoir and caprocks for the Appalachian Basin Indian Creek field was characterized by the WVGES based on analysis of available core samples from the Tuscarora sandstone. Cores were inspected, and 45 thin sections were prepared for core samples from Clay County well 4701500513 and Kanawha County well 4703903914. Rock core from the well was in poor condition, and exact sample depths were not available. The Tuscarora sandstone samples were >90% quartz with a small fraction of accessory minerals. Rose Hill shale caprock samples were not readily available, so mineralogy was based on research by Jin et al. (2010). The Rose Hill is mostly siltstone and shale consisting of clay minerals, quartz, and a minor amount of iron oxide minerals and feldspars.

Michigan Basin. Thin-section mineralogical data are available for reservoir rock in the State Chester reef and the Dover 33 reef from the Midwest Regional Carbon Sequestration Partnership (MRCSP). Thin sections were also collected from the caprock (A2 carbonate) from the Lawnichak-Myszker #9-33 well. Data from the State Chester well and the Dover 33 reef indicate that the Brown Niagaran formation (the CO_2 storage/EOR zone) is a marine carbonate dominated by calcite and/or dolomite, depending on the degree of dolomitization that the reef has undergone. Typically, calcite and dolomite make up more than 90% of the mineral phases present in the Brown Niagaran. Minor amounts of pyrite, clay minerals, feldspars, and quartz are present in the storage reservoir. The caprock (A2 carbonate) is a marine evaporite deposit that also has been dolomitized. Primary minerals in the A2 carbonate are dolomite and anhydrite. Small amounts of illite, feldspars, and quartz are also present in the A2 carbonate.

Williston Basin. General mineralogy of the storage zone and caprock for the Williston Basin field site was compiled from several previous projects to examine CO_2 storage processes in the basin. Table 6-1 summarizes general mineralogy as listed by Durocher et al. (2005), Braunberger et al. (2012), and Hutcheon et al. (2012). The storage interval at the Williston Basin site consists mainly of carbonate with minor amounts of anhydrite, quartz, and potassium feldspar. The caprock at the field site is anhydrite and carbonate. Since the field site covers 45,000 acres, variations in lithology and mineralogy are likely to occur, and the summary mineralogy should be considered general in nature.

Brine geochemistry is an important component of the subsurface system, because the brine will contact the cement and other well materials. Table 6-2 summarizes the brine chemistry for the three field sites.

Table 6-2. Summary of brine geochemistry for reservoir samples from the field test sites.

Constituent (mg/L)	Appalachian Basin[a]		Michigan Basin Site[b]				Williston Basin[c]	
	Low	High	Baseline		Post-CO_2 Injection		Low	High
			Low	High	Low	High		
Ca	10,000	40,000	67,500	110,000	84,900	99,400	1,100	2,000
Mg	800	8,000	7,985	12,100	8,060	11,200	320	490
Na	40,000	110,000	15,300	22,500	14,400	21,300	12,000	26,000
K	400	1,700	11,000	16,600	16,200	18,400	120	600
SO_4	300	1,300	81	97.1	44	150	3,180	3,620
Cl	73,000	183,000	251,000	274,000	188,000	270,000	18,000	43,000
HCO_3^-	10	160	361	468	ND[d]	956	NA	NA
Br	879	4,650	2,280	3,030	ND[e]	3,250	NA	NA
Al	0.54	3.51	ND	1.0	ND[f]	1.0	NA	NA
Fe	186	---	10	129	52.4	654	NA	NA
SiO_2	0.005	0.006	$6.90x10^{-4}$	$1.46x10^{-2}$	$2.04x10^{-3}$	$2.35x10^{-2}$		
pH	5.1	6.4	4.83	5.88	4.10	4.87	6.3	--
Alkalinity (as HCO_3^-)	7	104	296	384	ND[g]	785	NA	NA
TOC	NA	NA	ND[f]	79	27	343	NA	NA
DOC	NA	NA	ND[f]	66	16	295	NA	NA
Salinity	120,000	300,000	348,000	450,000	380,000	450,000	35,000	110,000
Water Sat.	40%	50%					30%	40%

a: Based on produced water for Medina-Tuscarora sandstones in WV & southeast OH from Battelle (2015) and Breen et al. (1985).
b: Baseline (pre-injection) data obtained from samples from five wells in fields (or lobes) that have not seen CO_2.
c: Based on data from Cantucci et al. (2009); Mills et al. (2011); and Hassani et al. (2014).
d: Minimum detected concentration: 316 mg/L.
e: Minimum detected concentration: 2,720 mg/L.
f: One detected sample.
g: Minimum detected concentration: 259 mg/L.

Appalachian Basin. Brine geochemistry for the Appalachian Basin was based on chemical analysis of produced water from the Tuscarora sandstone in the northwest West Virginia and southeast Ohio portions of the Appalachian Basin (Battelle, 2015). Data from Breen et al. (1985) were used as an additional source of data. These data were necessary to obtain measurements of aluminum and silica, which were not available in the Battelle (2015) database.

Michigan Basin. Brine geochemistry for the Michigan Basin field site was based on fluid chemistry sampling and analysis performed under the MRCSP Phase III field demonstration project. Under this project, fluid samples were collected prior to and after CO_2 injection for EOR operations. The geochemistry for the site reflects carbonate reservoirs and the anhydrite/salt caprock layers. The brine has very high salinity, high calcium, and moderate pH. Post-CO_2 injection samples show similar chemistry but with lower pH. These conditions show the range of in-situ chemistry in the reservoir during CO_2 injection.

Williston Basin. Brine geochemistry for the Williston Basin field site was based on research presented by Mills et al. (2011) and Hassani et al. (2014). The brines at the field have salinity of approximately 30,000 to 100,000 milligrams per liter (mg/L) with minor constituents of calcium, magnesium, and sulfate. Hydrogen sulfide (Laumb et al., 2017) is present in portions of the field. The field has been subjected to both water floods and water-alternating CO_2 gas floods, which may result in lower salinity than initial in-situ conditions.

Cement composition is also a factor for potential degradation of well materials and cement sealing. Raw materials of Portland cement include limestone and clay (shale), which are heated in a kiln to around 1,450 to 1,550 ºC (Taylor, 1997; Michaux et al., 1989; Chamberlain et al., 1995). The resulting mixture, referred to as clinker, is ground to a powder to form Portland cement. Most of the clinker (up to 80%) is calcium silicates: alite (tricalcium silicate) and belite (dicalcium silicate) (Table 6-3). Most of the rest of the clinker consists of celite (tricalcium aluminate) and brownmillerite (tetracalcium aluminoferrite). Gypsum is also added to the mixture to prevent rapid stiffening.

Table 6-3. Composition of typical Portland cement clinkers.

Name	Formula	Cement Short-hand	Weight %						
			Chamberlain et al. (1995)	Michaux et al. (1989)					Taylor (1997)
				Class A	Class B	Class C	Class D&E	Class G&H	
Alite	Ca_3SiO_5	C_3S	50	53	47	58	26	50	60
Belite	Ca_2SiO_4	C_2S	25	24	32	16	54	30	20
Celite	$Ca_3Al_2O_6$	C_3A	10	8	5	8	2	5	7.5
Brownmillerite	$Ca_4Al_2Fe_2O_{10}$	C_4AF	10	8	12	8	12	12	10
Gypsum	$CaSO_4 \bullet 2H_2O$	$C\bar{S}H_2$	5	(a)	(a)	(a)	(a)	(a)	(a)
Fineness (cm^2/g)	-	-	-	1500-1900	1500-1900	2000-2800	1200-1600	1400-1700	-
Application	-	-	-	None	Sulfate resistant	Early setting	Retarded	Stringent Specs	-

a. Weight % of gypsum not included

Appalachian Basin. Well completion records were reviewed for 53 wells in the Appalachian Basin field site to determine cement composition. The majority of records did not include details on cement composition because the well completion forms did not require the information. Records with cement information show generally a neat Portland Class A cement for the production casing. Records indicate a 50/50 Pozmix with calcium chloride ($CaCl_2$) and latex additive in the shallow and intermediate casing strings to approximately 2,300 ft and 5,000 ft. Since the same operator installed most of the wells in the field, it is likely that similar cement was used for all wells. Records suggest that carbon steel (Grade J-55) casing was used for the casing materials, which is typical for the wells in the region.

Michigan Basin. Cement materials and additives were evaluated for wells in the Michigan field site as part of research performed under a previous project (Battelle, 2016). Review of materials used for well completion and plugging suggests that mostly Portland Class A cement was used for nearly all wells. Cement additives were mainly $CaCl_2$ accelerant, gel, salt, lost circulation material, 'Baroco' clay, sulf-x, latex, gasblock, and Pozmix. Records suggest that standard Grade J-55 carbon steel was used for casing in the CO_2 storage-EOR zones in these wells.

Williston Basin. Rochelle et al. (2004) list well cements for the Williston Basin site as Portland Class A 50-50 Pozmix with 0.5% friction reducer additive. A tail mix was listed as Portland Type G thixotropic mix with 2% $CaCl_2$ accelerator and 0.4% flocculant. The cement mixes were prepared and set under reservoir conditions. The set cement showed Ca-MgAl-silicate hydrate± S and Fe matrix. Casing used for Williston Basin wells was typical Grade H-40 for the surface casing and Grade J-55 for production casing (Laumb et al., 2017).

General hydrologic conditions were compiled from regional datasets, well records, and previous site description tasks under this project. Table 6-4 lists general hydrologic conditions for the three field sites. All reservoirs are deep enough to sustain supercritical CO_2 temperature and pressure conditions. The Michigan Basin field site has an additional zone at 800 to 1,200 ft that has natural CO_2 mixed with natural gas. Otherwise, the sites have similar hydrologic conditions.

Table 6-4. General hydrologic conditions for three field sites.

Parameter	Appalachian Basin		Michigan Basin		Williston Basin	
	Reservoir	Caprock	Reservoir	Caprock	Reservoir	Caprock
Depth (ft bgs)	6,732	6,350	6,000	5,675	4,750	4,700
Thickness (ft)	50-75	350-400	18-280	75-160	30-100	6-30
Temperature (°F)	140	137	102	97[a]	145	144
Pressure (psi)	2,900	2,800	3,000	2,455[b]	2,100	2,020
Water Saturation (%)	50	50	20-30	0	30-40	0-5
Fluid Density	1.18	1.18	1.12-1.29	1.12-1.29	1.02-1.10	1.10+
Porosity (%)	8-16	1-5	3-11	0-1	10-40	1-3

a. Thermal gradient (depth/100 + 40°F)
b. Pressure gradient (depth*0.43 + 14.7 psi)

6.2 Geochemical Analysis to Predict Cement Sealing Conditions

Geochemical modeling was performed to evaluate interactions of well cements, reservoir/caprock minerals, brine mixtures, and CO_2 in relation to cement sealing conditions and well defects for the three field sites. Previous work by DOE-NETL was reviewed to provide guidance on geochemical processes for well cements and CO_2 environments in the subsurface. The objective of this review was to provide perspective on the conditions present at the Appalachian Basin, Michigan Basin, and Williston Basin sites. The review found that a large amount of research on wellbore integrity for CO_2 environments has been completed, including laboratory tests on cement cores and synthetic brines, analysis of sidewall cores, and modeling studies. Many of the tests were based on Williston Basin field sites, and these studies were used as the basis for this project. Consequently, the Williston Basin site was based on previous research. The Appalachian Basin and Michigan Basin sites were analyzed with geochemical models.

Williston Basin. Core flooding experiments and numerical modeling using PHREEQC code were completed by Azaroual et al. (2004) and Riding and Rochelle (2005) for the Weyburn rock formation to evaluate potential for geochemical reactions. PHREEQC geochemical equilibrium code was run for

Midale mineralogy under CO_2 injection conditions at 150 bar and 54°C. Results suggest calcite and feldspar dissolution with anhydrite, gypsum, and dawsonite precipitation. Clays dissolved near the injection zone and precipitated farther away from the injection area. Overall, the simulations showed a decrease in porosity in the storage formation. Cement interactions for Weyburn were studied by Rochelle et al. (2004) for fill cement and tail cement samples. The laboratory batch tests on fill cement showed development of calcite crystals 5 to 10 micrometers (μm) long, forming a crust approximately 40 μm thick. The researchers concluded that "The carbonation reaction produced a probable calcite-rich front with significantly reduced porosity that varied up to 50-100 μm in thickness. In contrast to the fill cement, the tail cement reacted extensively with the CO_2-rich synthetic marly porewater to produce a series of precipitates from a probable calcite and CSH gel, to ettringite and Ca-sulphate, chloride."

Appalachian Basin and Michigan Basin. PHREEQC Interactive, v. 3.4.0.12927, was used for geochemical speciation modeling of the Appalachian Basin and Michigan Basin sites. A series of model simulations were constructed to answer the questions listed in Table 6-5: (1) equilibrium model, (2) equilibrium phases model, (3) CO_2 batch model, (4) solid equilibrium phases model, and (5) batch model. For all models, the Lawrence Livermore National Laboratory (LLNL) Geochemical database was used (Johnson, 2010), supplemented with five cement mineral phases from the ThermoChimie v.8.0 (September 2011) database (sit.db): $CSH_{0.8}$, $CSH_{1.2}$, $CSH_{1.6}$, Friedel's salt, and vaterite.

Table 6-5. Questions to answer with model.

No.	Question	Method
1	What minerals are supersaturated, saturated, and undersaturated?	Equilibrium Model
2	What minerals are precipitating from initial brine solution?	Equilibrium Phases
3	What minerals dissolve or precipitate with the addition of CO_2 to the initial brine solutions?	Equilibrium Model/CO_2 batch
4	Are the formations (reservoir and caprocks of interest or cement) affected by brine/CO_2 interactions? Do they provide a buffering capacity?	Solid Equilibrium Phases
5	What roles do pressure, temp, pH, and pe play in results[a]?	Equilibrium Model w. pH, pe, P, and T

a. Appalachian Basin is reported due to redundancy. Modeling results for Michigan Basin also available.

The geochemical model is an equilibrium speciation model. Kinetic reactions for cement are not well-defined, so the model cannot demonstrate the timing of reactions. The LLNL geochemical model is calculated based on extended Debye-Hückel, which is not typically used for waters with high ion activity (e.g., brine). Pitzer calculations are used for slightly higher activity brines; however, the activities of the brines of interest in this study are beyond the conditions that dictate when Pitzer calculations are usually used. The specific model setup is based on brine chemistry across each field test site combined with solid mineral complexes from different locations. Site-specific cement mineral phases were not available, so a cement value from another site was used.

The midpoint brine sample was used in the model to determine the SIs, mineral precipitation, and matrix/brine/CO_2 interactions (Tables 6-6 and 6-7 for the Appalachian and Michigan Basins, respectively). Batch reaction modeling was done using a range of parameters guided by the minimum and maximum values for each parameter for the Michigan Basin and Appalachian Basin brines. Furthermore, each parameter was extended beyond the maximum value to determine the range of possibilities for other potential brines. The batch reaction parameters are defined in Table 6-8.

Table 6-6. Appalachian Basin chemistry summary data. Midpoint values were used for geochemical modeling.

Sample	Depth (ft)	pH (S.U.)	Density (kg/L)	TDS (mg/kg)	Ca (mol/kgw)	Mg	Na	K
Average	4,473	5.59	1.161	212,979	0.59	0.11	2.3	0.03
Minimum	2,545	4.30	1.085	118,000	0.23	0.03	1.3	0.01
Midpoint	**4,123**	**5.40**	**1.157**	**198,500**	**0.67**	**0.17**	**2.3**	**0.03**
Maximum	5,700	6.50	1.229	279,000	1.10	0.30	3.2	0.06

Sample	HCO_3^- (mol/kgw)	Alkalinity (mg/L as HCO_3^-)	SO_4^{-2} (mol/kgw)	Cl^-	Br^-	SiO_2
Average	7.3E-04	49.4	0.006	3.7	0.02	9.0E-05
Minimum	1.0E-04	7.4	0.002	1.9	0.01	8.0E-05
Midpoint	**1.4E-03**	**55.8**	**0.008**	**3.9**	**0.03**	**9.5E-05**
Maximum	2.7E-03	104.2	0.014	5.8	0.06	1.1E-04

Table 6-7. Michigan Basin chemistry summary data. Midpoint values were used for geochemical modeling.

Sample	pH (S.U.)	Density (kg/L)	Ca (mol/kgw)	Mg	Na	K	HCO_3^-	Alkalinity (mg/L as HCO_3^-)
Average	4.89	1.253	1.73	0.34	0.6	0.31		354.0
Minimum	4.10	1.118	1.05	0.26	0.1	0.15	0.0047	3.5
Midpoint	**5.10**	**1.204**	**1.60**	**0.32**	**0.5**	**0.26**	**0.011**	**427.1**
Maximum	6.09	1.289	2.15	0.39	0.9	0.37	0.173	850.6

Sample	SO_4^{-2} (mol/kgw)	Cl^-	Br^-	SiO_2	Al	Fe
Average	0.001	3.7	0.03	$9.0E^{-5}$	1.3E-05	4.1E-03
Minimum	0.0004	5.8	0.02	$1.1E^{-5}$	2.9E-06	1.4E-04
Midpoint	**0.002**	**3.9**	**0.03**	**$9.5E^{-5}$**	**1.8E-05**	**1.2E-02**
Maximum	0.004	1.9	0.03	$8.0E^{-5}$	3.3E-05	2.4E-02

Table 6-8. Batch reaction parameters.

Parameter	Basin	Batch
CO_2 (moles)	***Both Basins***	0.01 0.034[a] 0.064 0.094 0.194 0.4 0.7 1.1[b] 1.5 2 2.5 3 4 5 … 49
Pe	***Both Basins***	-6.0 -4.0 -2.0 0.0 2.0 4.0 6.0 8.0 10.0
Pressure (atm)	***Appalachian Basin***	1.0 2.0 10 50 100 150 197.3[c] 200 250
	Michigan Basin	1.0 2.0 10 50 100 150 180.3[c] 200 250
Temperature (°C)	***Appalachian Basin***	25 30 35 40 45 50 55 60[c] 70 80 90
	Michigan Basin	25 30 35 40 43.9[c] 50 55 60 70 80 90
pH (S.U.)	***Appalachian Basin***	5.1[c] 5.5 6.0 6.4[c] 7.0 9.0 11.0 13.0
	Michigan Basin	4.1[c] 4.5 5.0 5.5 5.88[c] 6.0 6.5 7.0 8.0 9.0

a. Saturation at standard temperature and pressure;
b. Approximate saturation at reservoir conditions;
c. From site data.

The mineralogy inputs for the solids in the Appalachian Basin and Michigan Basins are shown in Table 6-9 and 6-10, respectively. The reservoir rock, caprock, and cement were used as inputs for the *solid equilibrium phase* model and the *batch reactions* model. In addition, the mineral phases were used as inputs in the *equilibrium phases* model, although the molar mass for the phases was not indicated in these simulations. As shown above, site-specific data were available for the Appalachian Basin reservoir (Tuscarora sandstone) and caprock (Rose Hill) and for the Michigan Basin reservoirs (State Chester [limestone] and Dover 33 [dolomite] Brown Niagaran) and caprock (A2 carbonate). However, because cement mineralogical data were not available for the specific sites, cement equilibrium phases input is based on cement mineralogy reported by Koukouzas et al. (2017). The percent composition for the mineral phases was used to adjust the number of moles of each phase so the molar volume of the solid was 9,000 cubic centimeters (cm^3). This was reacted with 1.0 liter of water in the *solid equilibrium phases* and *batch reactions* modeling efforts.

Table 6-9. Appalachian Basin solid equilibrium phases.

Mineral	V_{min}	Tuscarora		Rose Hill		Cement	
	cm^3/mol	% Comp.	Moles	% Comp.	Moles	% Comp.[a]	Moles
Quartz	23.1	0.951	296.0	0.336	18.1	-	-
K-Feldspar	108.7	0.005	1.5	0.008	0.4	-	-
Albite	99.9	0.005	1.5	-	-	-	-
Illite	256.2	0.014	4.5	0.540	29.1	-	-
Pyrite	24.5	0.010	3.1	-	-	-	-
Siderite	29.3	0.004	1.3	0.005	0,2	-	-
Hematite	159.7	0.012	3.6	0.005	0.2	-	-
Chamosite 7A	207.6	-	-	0.088	4.7	-	-
Calcite	36.9	-	-	0.019	1.0	0.0777	4.2
Aragonite	34.2	-	-	-	-	0.118	6.4
Vaterite	39.4	-	-	-	-	0.043	2.3
Wollastonite	40.9	-	-	-	-	0.035	1.9
Portlandite	33.2	-	-	-	-	0.080	4.4
Ca_2SiO_4	52.5	-	-	-	-	0.0.138	7.5
Hatrurite	89.2	-	-	-	-	0.028	1.5
$Ca_4Al_2Fe_2O_{10}$	52.8	-	-	-	-	0.085	4.6
Ettringite	130.3	-	-	-	-	0.005	0.3
$CSH_{0.8}$	356.2	-	-	-	-	0.129	7.0
$CSH_{1.2}$	356.2	-	-	-	-	0.129	7.0
$CSH_{1.6}$	356.2	-	-	-	-	0.129	7.0
Friedel's salt	123.1	-	-	-	-	0.000	0.0

b. From Koukouzas et al. (2017), reference hydrated cement.

Table 6-10. Michigan Basin solid equilibrium phases.

Mineral	V_{min}	Limestone		Dolomite		A2 Carbonate		Cement	
	cm^3/mol	% Comp.[a]	Moles	% Comp.	Moles	% Comp.	Moles	% Comp.[a]	Moles
Calcite	36.9	0.825	153.3	0.008	1.1	-	-	0.0777	4.2
Dolomite	64.7	0.090	16.7	0.972	136.7	0.598	1.9	-	-
Pyrite	24.5	0.005	0.9	-	-	-	-	-	-
Illite	256.2	0.040	7.4	-	-	0.015	0.5	-	-
K-Feldspar	108.7	0.010	1.9	-	-	0.003	89.6	-	-
Anhydrite	45.8	-	-	0.013	1.8	0.371	55.5	-	-
Quartz	23.1	0.030	5.6	-	-	0.013	5.5	-	-
Halite	27.0	-	-	0.008	1.1	-	-	-	-
Aragonite	34.2	-	-	-	-	-	-	0.118	6.4
Vaterite	39.4	-	-	-	-	-	-	0.043	2.3
Wollastonite	40.9	-	-	-	-	-	-	0.035	1.9
Portlandite	33.2	-	-	-	-	-	-	0.080	4.4
Ca_2SiO_4	52.5	-	-	-	-	-	-	0.0.138	7.5
Hatrurite	89.2	-	-	-	-	-	-	0.028	1.5
$Ca_4Al_2Fe_2O_{10}$	52.8	-	-	-	-	-	-	0.085	4.6
Ettringite	130.3	-	-	-	-	-	-	0.005	0.3
$CSH_{0.8}$	356.2	-	-	-	-	-	-	0.129	7.0
$CSH_{1.2}$	356.2	-	-	-	-	-	-	0.129	7.0
$CSH_{1.6}$	356.2	-	-	-	-	-	-	0.129	7.0
Friedel's Salt	123.1	-	-	-	-	-	-	0.000	0.0

a. From Koukouzas et al. (2017), reference hydrated cement.

Equilibrium Model

The results of the Appalachian Basin equilibrium model are shown in Figure 6-1. The stability of most cement minerals, as measured by log SIs, increases from the minimum brine value to the midpoint brine value. The increase in the log SI value from the midpoint to the maximum value is not as large, even though the change in parameters was the same between the minimum and midpoint values as the midpoint and maximum values. This indicates that the change begins to level off as the parameters increase in value. The most stable cement mineral phases are calcite, aragonite, and vaterite, which are at or near saturation in the midpoint and maximum values and have log SI values less than -3 in the minimum sample. The cement mineral SIs calculated using the summary data for the Michigan Basin are presented in Figure 6-2. Calcite, aragonite, and vaterite are all saturated in the minimum, midpoint, and maximum values. This is likely due to the buffering capacity provided by the defined alkalinity.

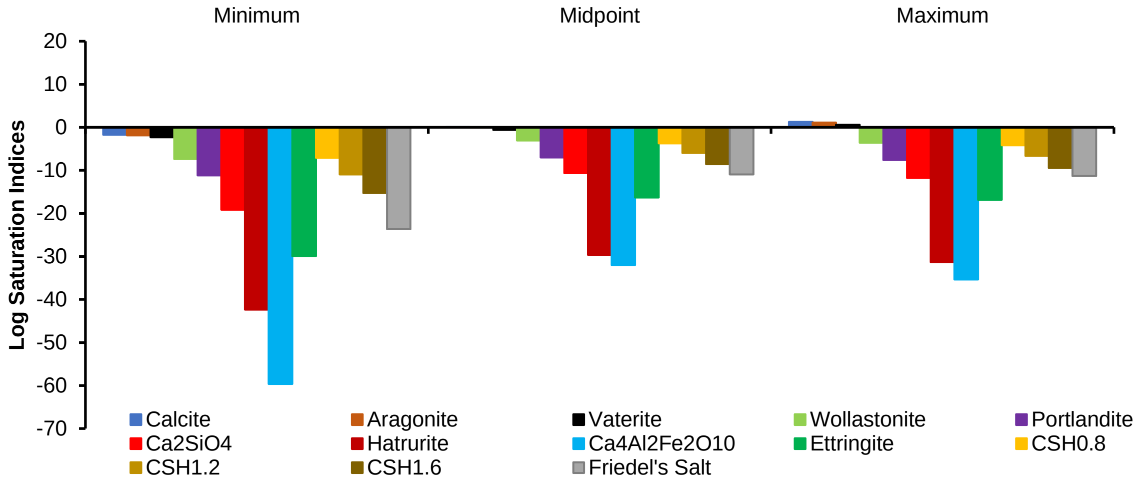


Figure 6-1. Log SI values for cement mineral phases in initial Appalachian Basin summary solutions.

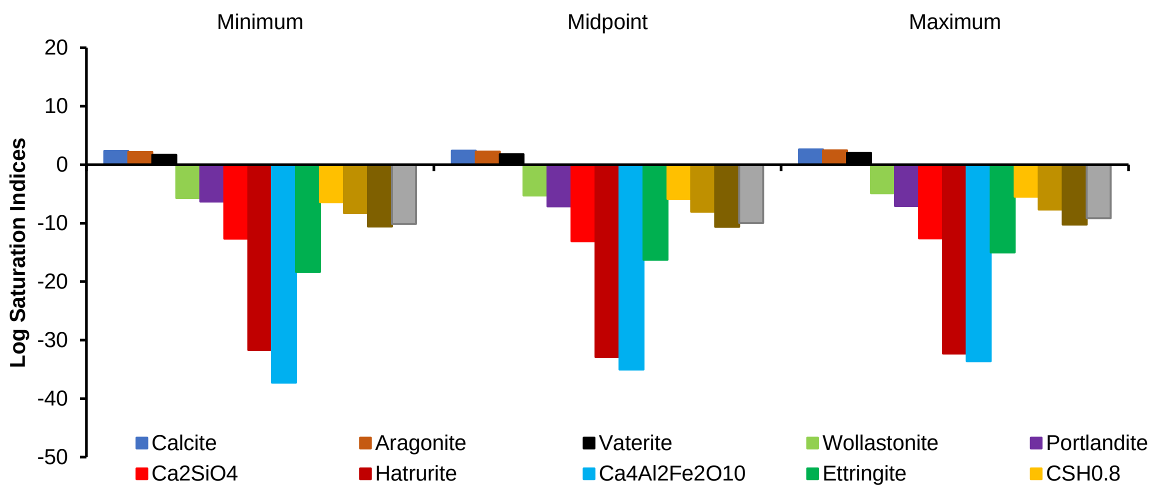


Figure 6-2. Log SI values for cement mineral phases in initial Michigan Basin summary solutions.

Equilibrium Phases Model

SIs provide a measure of whether a mineral is saturated with respect to the activity of its components and the overall ionic strength of the solution. It does not, however, provide the amount of the mineral that will precipitate from a solution. In some cases, an SI that indicates that a mineral is saturated does not equate to mineral precipitation because other minerals may precipitate first. For instance, aragonite and calcite have the same chemical formula ($CaCO_3$) and often have similar SIs in a given solution; however, calcite may precipitate preferentially and pull Ca^{2+} and CO_3^{2-} out of solution. After calcite precipitates to achieve equilibrium, aragonite may be undersaturated. The *equilibrium phases model* was designed to determine the amount of the specific mineral species that would precipitate in each sample solution.

The mineral phases that precipitated in the Appalachian Basin summary solutions are listed in Table 6-11. Four mineral phases precipitate from the maximum sample solution: anhydrite ($CaSO_4$), diaspore (α-AlO(OH)), dolomite ($CaMg(CO_3)_2$), and hematite (Fe_2O_3). Diaspore and hematite also precipitate from the minimum and midpoint solutions. When 1.1 mol of CO_2 is added to the solutions, the amount of each of these minerals that precipitates from each solution decreases, except for hematite in the midpoint solution, which remains constant. Dolomite in the maximum solution and diaspore in each summary solution do not precipitate when CO_2 is added. In contrast, hematite and anhydrite are not greatly affected by the addition of CO_2.

Table 6-11. Amount of each mineral phase that precipitates from Appalachian Basin summary solutions, with and without 1.1 mol of CO_2. Precipitates are reported in mol/kg water. Columns labeled "Δ with CO_2" show the change in precipitation when the solution is reacted with CO_2.

Solution	Anhydrite	Anhydrite Δ with CO_2	Diaspore	Diaspore Δ with CO_2	Dolomite-ordered	Dol-ord Δ with CO_2	Hematite	Hematite Δ with CO_2
Minimum	---		2.00E^{-5}		---		3.34E^{-8}	
Midpoint	---		7.83E^{-5}		---		8.51E^{-4}	
Maximum	3.64E^{-3}		1.30E^{-4}		3.91E^{-4}		8.15E^{-5}	
Min. w. CO_2	---	---	---	-2.00E^{-5}	---	---	1.19E^{-8}	-2.15E^{-8}
Mid. w. CO_2	---	---	---	-7.83E^{-5}	---	---	8.51E^{-4}	-0-
Max. w. CO_2	3.57E^{-3}	-6.5E^{-5}	---	-1.30E^{-4}	---	-3.91E^{-4}	8.14E^{-5}	-1.00E^{-7}

The mineral phases that precipitated in the Michigan Basin summary solutions are listed in Table 6-12. Three mineral phases precipitate from all three summary solutions: diaspore (α-AlO(OH)), dolomite ($CaMg(CO_3)_2$), and hematite (Fe_2O_3). When 1.1 mol of CO_2 is added to the solutions, the amount of each of diaspore and dolomite that precipitates from each solution decreases. The amount of hematite that precipitates did not change when CO_2 was added. The amount of diaspore that precipitated after the addition of CO_2 decreased by about a third in the minimum solution and by less than 3% in the midpoint and maximum samples. Dolomite did not precipitate in the minimum solution after the addition of CO_2 and decreased by around an order of magnitude in the midpoint and maximum samples.

Table 6-12. Amount of each mineral phase that precipitates from Michigan Basin summary solutions, with and without 1.1 mol of CO_2. Precipitates are reported in mol/kg water. Columns labeled "Δ with CO_2" show the change in precipitation when the solution is reacted with CO_2.

Solution	Diaspore	Diaspore Δ with CO_2	Dolomite-ordered	Dol-ord Δ with CO_2	Hematite	Hematite Δ with CO_2
Minimum	2.92E^{-6}		1.22E^{-3}		6.79E^{-5}	
Midpoint	1.80E^{-5}		2.24E^{-3}		2.33E^{-3}	
Maximum	3.31E^{-5}		3.79E^{-3}		3.90E^{-3}	
Min. w. CO_2	---	-2.92E^{-6}	---	-1.22E^{-3}	6.77E^{-5}	-2.00E^{-7}
Mid. w. CO_2	---	-1.80E^{-5}	---	-2.24E^{-3}	2.33E^{-3}	-0-
Max. w. CO_2	---	-3.31E^{-5}	---	-3.79E^{-3}	3.90E^{-3}	-0-

6.3 Review of Well Defects and Pore Network Dimensions for Field Sites

Field data from the Michigan Basin site were evaluated to determine the range of well defects and pore network dimensions in relation to potential for CO_2 migration. Several researchers have analyzed the relationship of fracture aperture diameter and cement sealing potential (Carroll et al., 2016). Pore throat radius of rock core samples, fracture width of reservoir/caprock, and cement features were evaluated to determine potential for gas migration.

MICP Pore Throat Radius. Mercury injection capillary pressure (MICP) analysis data were evaluated to estimate pore throat radius for the reservoir and caprock zones. These features may be pathways for upward CO_2 migration around the borehole. MICP is a method of characterizing the capillary-pressure behavior of subject rock formations for determining caprock sealing potential, fluid saturations, permeability, wettability, and capillarity properties. This analysis is based on capillary law in which liquid penetration into small pore systems is a function of surface and interfacial liquid tensions, pore throat size and shape, and the wetting properties of the rock, which may be described for a nonwetting liquid by the Washburn (1921) equation below:

$$rc = -2\gamma cos\theta / P_c$$

Where Pc is capillary pressure (dynes/cm^2), ϒ is surface tension of Hg, θ is the contact angle of mercury in air, and rc is the radius of the pore throat aperture (μm) for a cylindrical pore.

The Dover 9-33 well at the Michigan Basin site was evaluated based on 16 MICP experiments conducted at various depths within the well. Comprehensive elements of pore architecture vary according to the depositional environment and facies-specific diagenetic modifications; however, these elements generally remain consistent within lithologies for most of the cored intervals observed, rendering lithology-based MICP results generally consistent. Samples described were tight mudstone, vuggy mudstone, skeletal wackestone, skeletal packstone, stromatoporoid framestone, and stromatoporoid-tabulate coral framestone. Table 6-13 summarizes descriptive statistics performed on pore throat radii distributions for each lithology. Pore throat distributions between major representative lithologies vary between three orders of magnitude but statistically are not much different.

Table 6-13. Descriptive statistics of MICP-derived pore throat radius distribution for lithologies at the Dover 33 reef field.

Pore Throat Radius Statistic	Mudstone		Skeletal Wackestone	Skeletal Packstone	Stromatoporoid Framestone	Stromatoporoid Coral Framestone
	Vuggy	Tight				
Mean Radius (μm)	8.83	8.81	8.87	8.84	8.84	8.74
Standard Dev. (μm)	21.90	21.80	22.01	21.89	21.89	21.47
Range (μm)	133.00	133.00	135.00	135.00	134.998	131.00
Minimum (μm)	0.00196	0.00196	0.00196	0.00196	0.00196	0.00196
Maximum (μm)	133	133	135	135	135	131
Kurtosis	15.64	15.67	15.96	16.07	16.07	15.50
Skewness	3.74	3.74	3.76	3.77	3.77	3.71
n	85	85	85	85	85	85

Image Log Fracture Characterization. Image logs were evaluated to estimate the dimensions of induced and natural fractures around the borehole at the Michigan Basin site. These fractures may be pathways for CO_2 migration and carbonation. Electrical and acoustic image logs are geophysical wireline tools for describing features around the borehole. Fracture width was measured by hand from a physical copy of the resistivity formation image log (Baker Hughes, Star tool) from the Lawnichak 9-33 well of the Dover 33 reef field. When fractures with well-defined dimensions were identified, the apparent width of the fractures was measured by hand in centimeters and converted into degrees to calculate the scaled apparent aperture. With track width spanning the full 360 degrees of the borehole, features may be measured by hand or electronically and converted into degrees. Degrees may then be converted into apparent aperture using the following equation:

$$A' = \frac{A^0(2\pi r)}{360}$$

Where A' is the apparent fracture aperture, A^0 is the measured feature width in degrees, and r is the borehole radius (obtained from caliper).

Fractures were identified within both caprock and reservoir intervals. Ten fractures were determined to be suitable for aperture analysis; seven were identified within the caprock interval, and the remaining three were within the reservoir interval. Fracture aperture data from these features are summarized in Tables 6-14. The geometric mean of caprock fracture aperture was 46.1 mm and the arithmetic mean was 51 mm, with 95% confidence lower and upper bounds of 31 mm and 71 mm, respectively. The geometric mean of reservoir fracture aperture was found to 110.9 mm and the arithmetic mean was 119 mm, with 95% confidence lower and upper bounds of 16.5 and 254.5 mm, respectively.

Table 6-14. Summary of aperture data derived from fractures located within the caprock interval of the Dover 33 FMI log.

Caprock fracture ID		Width		
		Measured (cm)	Circumferential (deg)	Calculated (mm)
1		0.1	9.5	35.7
2		0.2	19.0	71.4
3		0.1	9.5	35.7
4		0.15	14.2	53.6
5		0.05	4.7	17.9
6		0.2	18.5	71.4
7		0.2	18.5	71.4
Geometric mean		-	-	46.1
Arithmetic mean		-	-	51.0
Confidence level (95%)	Lower bound	-	-	31.0
	Upper bound	-	-	71.0
Reservoir fracture ID		Width		
		Measured (cm)	Circumferential (deg)	Calculated (mm)
8		0.2	18.9	71.4
9		0.3	28.4	107.1
10		0.5	47.4	178.5
Geometric mean		-	-	110.9
Arithmetic mean		-	-	119.0
Confidence level (95%)	Lower bound	-	-	16.5
	Upper bound	-	-	254.5

CBL Features. Defects in cement were also evaluated as pathways for CO_2 migration. In 2009, a CBL mapping tool (the Schlumberger Isolation Scanner) was run through the intermediate casing section of the State Charlton 4-30 well of the Charlton 30/31 fields in Otsego County, Michigan. The isolation scanner utilizes ultrasonic imaging technologies in combination with flexural wave imaging to yield a full azimuthal profile of the borehole. This profile can be used to identify cement bond integrity, possible channels or fractures within cement, casing integrity, and degree of zonal isolation between the formation and a wellbore. This study utilized the Isolation Scanner to measure and calculate the apparent aperture of several cement channels observed within the State Charlton 4-30 well.

Cement features like channels or fractures were identified within the Charlton 4-30 well by noting sharp changes in flexural attenuation where a low value of attenuation appeared. The presence of channels or fractures was verified using the Solid Liquid Gas Map, where interpreted cement features would be saturated with either gas or water. The apparent width of the features was measured by hand using a ruler and a physical copy of the log. With track width spanning the full 360 degrees of the borehole, features may be measured by hand or electronically and converted into degrees. Degrees may then be converted into apparent width using the following equation:

$$A' = \frac{A^0(2\pi r)}{360}$$

Where A' is the apparent width, A^0 is the measured feature width in degrees, and r is the production casing radius.

Four channels/fractures were interpreted to be present within the Charlton 4-30 well, located at 2,552 ft MD, 2,802 ft MD, 3,014 ft MD, and 3,052 ft MD. A cement channel was identified by its low attenuation and borehole-parallel shape from 2,552 ft to 2,562 ft. This feature has a measured maximum width of 61 degrees and a calculated maximum width of 106 mm. A large irregular feature interpreted to be a cement channel was identified from 2,802 ft to 2,828 ft based on its irregular shape, low attenuation, and gas saturation. The feature's maximum width was measured as 247 degrees, and its maximum width was calculated to be 425 mm. A small cement channel/feature was identified from 3,014 ft to 3,017 ft based on its low attenuation, partial gas-water saturation, and distinct ellipsoid shape elongated perpendicular to the borehole. The feature's measured maximum width was 154 degrees, and its calculated maximum aperture was 270 mm. The fourth and final cement fracture/channel was identified from 3,052 ft to 3,080 ft; it was identified by its low flexural attenuation, distinct shape, and gas saturation (Figure 6-3). The feature's measured maximum width was 123 degrees, and its calculated maximum aperture was 210 mm. Over the entire intermediate casing interval, the mean aperture size of cement features was calculated to be 252 mm, with a standard deviation of 6.65 mm and 95% confidence upper and lower bounds of 464 mm and 41 mm, respectively (Figure 6-4).

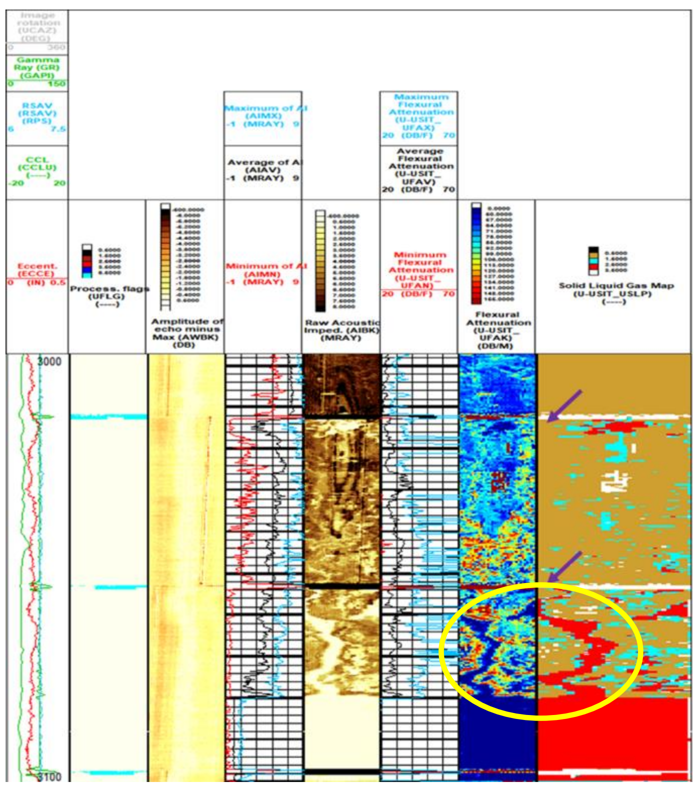


Figure 6-3. Cement channel/fracture identified within the Charlton 4-30 well from 3,052 to 3,080 ft, highlighted by the yellow circle. Note the low attenuation (blue color) and its gas saturation (red) illustrated on the Solid Liquid Gas Map (right-most track).

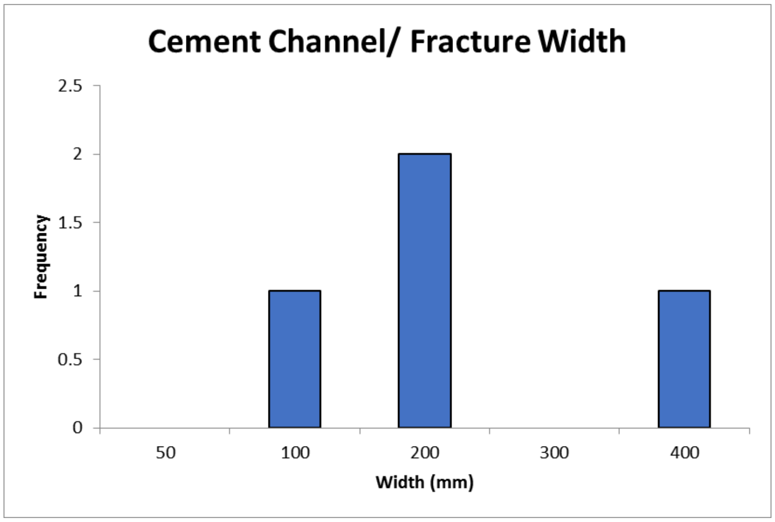


Figure 6-4. Distribution of measured calculated defects (mm) within the intermediate casing interval of the Charlton 4-30 well.

6.4 Key Findings of Field Analysis of CO_2 Cement Sealing and Well Integrity

Appalachian Basin, Michigan Basin, and Williston Basin field test sites were evaluated for cement sealing conditions based on mineralogy, brine geochemistry, cement chemistry, hydrologic conditions, and CO_2 exposure. The analysis was completed because SCP testing and well history review on CO_2 wells suggested that well defects were not a common problem at these field sites. Therefore, the sites were investigated to determine if cement carbonation would potentially seal well defects, limiting gas migration and casing pressure buildup in the CO_2 wells. The results provide a better understanding of wellbore integrity effects for CO_2 storage applications as listed below:

Analysis of Subsurface Setting for Cement Sealing. Thin sections, well materials, cement properties, and hydrologic, temperature, pressure, brine chemistry, and saturation conditions were summarized for the pertinent CO_2 reservoir zones and caprocks to provide a basis for further analysis of CO_2 sealing conditions in the Appalachian Basin, Michigan Basin, and Williston Basin field sites. Key findings of the subsurface parameters are as follows:

- The field sites have wells exposed to CO_2 at depths of 1,000 to 7,000 ft, pressures of 2,000 to 3,000 psi, temperatures of 105 °F to 145 °F, and CO_2 exposure durations of 5 to 50 years.
- Reservoirs were sandstone and carbonates with shale and evaporite caprocks. The reservoir zones contain a fairly large portion of quartz in the sandstone and dolomite in the carbonate reservoirs, with a small amount of trace minerals.
- Brine geochemistry includes high salinity at the Appalachian Basin and Michigan Basin sites.
- Standard Portland Class A cement and carbon steel well casing were used for well materials at all three field sites.

Together, these findings help define the subsurface system for the field sites in terms of interactions between cement, brine, minerals, and CO_2 in the subsurface.

Geochemical Analysis to Predict Cement Sealing Conditions. Information compiled on the field sites was utilized to analyze geochemical interactions in relation to cement sealing conditions and well defects for the three field sites with geochemical model PHREEQ-C. Key conclusions of the geochemical analysis are as follows:

- Geochemical modeling of the subsurface systems was completed using a combination of equilibrium, equilibrium phase, and batch reaction models.
- Overall, it appears that the cement would be the most reactive component of the system, similar to results observed in other research on cement-CO_2 interactions in the subsurface.
- Model results suggest that carbonation reactions occur between the cement and brine that potentially seal defects.

Analysis of MICP and Wireline Data to Evaluate Potential Gas Migration. Potential gas migration features in the Michigan Basin field site were analyzed to estimate potential for gas migration through pore network, natural fractures, and cement around the borehole.

- MICP tests on rock core had mean pore throat radius of 8.8 μm and maximum of 135 μm.
- Natural features observed in image logs from reef wells had mean aperture of 46 mm in the reservoir and 110 mm in the caprock.
- Features observed in cement logs from the Michigan Basin site were irregular voids, partial channels, and gaps. These features appeared to be 200 to 500 mm in size, but they were isolated features that were not connected along the borehole.
- Overall, it appears that the features observed at the Michigan Basin field site would not be pathways for CO_2 migration. Pore throat network dimensions would fall into the category that would be sealed based on research by Carroll et al. (2016), which suggests that fractures less than ~200 μm would be sealed by cement mineralization. The natural fractures and cement channels observed in the Michigan Basin field site were in the range of 46 to 500 mm, but they appeared to be isolated features that would not be gas migration pathways.

Chapter 7.0 Wellbore Integrity Sealing Factor Uncertainty Analysis

Ranges of formation geothermal gradients, water chemistry, subsurface pressure, and mineralogy were evaluated with geochemical models to determine if there are suitable indicators for cement sealing conditions in the subsurface. Potential indicators were analyzed using a CO_2 batch reaction model and the solid equilibrium phase model. Geochemical sealing conditions in the subsurface were also evaluated for four test study areas with meta-modeling techniques.

7.1 CO_2 Batch Model Indicator Geochemical Analysis

CO_2 batch model scenarios were run with different CO_2 levels to evaluate the effect of the addition of CO_2 in relation to various parameters. The changes in pH and pe when CO_2 is added to the Appalachian Basin midpoint summary solution are shown in Figure 7-1. The reduction in pH due to the addition of CO_2 is initially large (i.e., a 32% decrease with the addition of 0.01 mol of CO_2) and continues to decrease at slower rates with the addition of more CO_2 until it reaches a minimum of 2.27 after 27 moles of CO_2 are added. At this point, the pH begins to increase, slowly at first (0.02% per mole added) until the model ends when the pH has reached a pH of 2.62 after 49 moles of CO_2 is added.

The SIs of cement minerals when CO_2 is added to the Appalachian Basin midpoint summary solution are shown in Figure 7-2. The addition of CO_2 decreases the SIs of all cement mineral phases, although at different scales. For instance, the most stable mineral phases found in the equilibrium model, calcite, aragonite, and vaterite, decreases from near saturation to around -2.5 to around -3.1 in brine that is 48.5 molal CO_2. Other mineral phases, on the other hand decrease more dramatically, similar to the pH batch reactions.

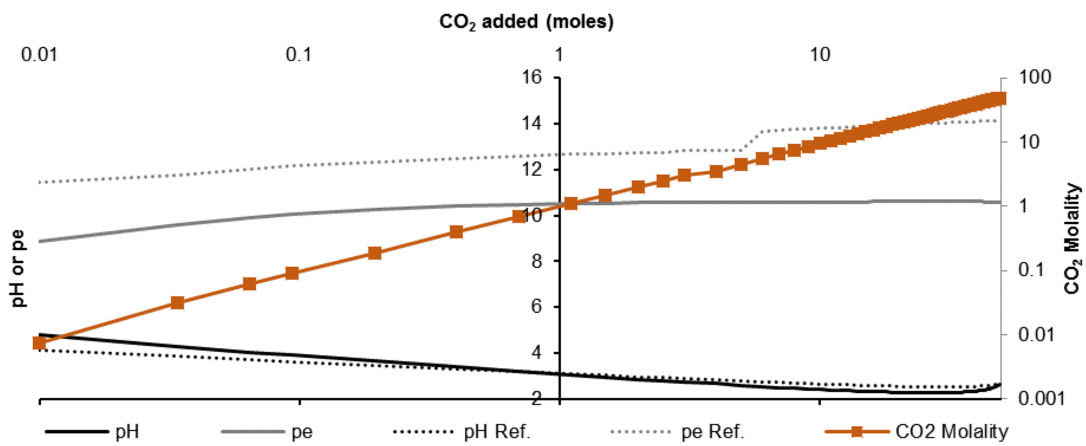


Figure 7-1. pH and pe of the Appalachian Basin summary solutions, CO_2 batch reactions. Reference pH and pe are simulated for CO_2 added to pure water for comparison.

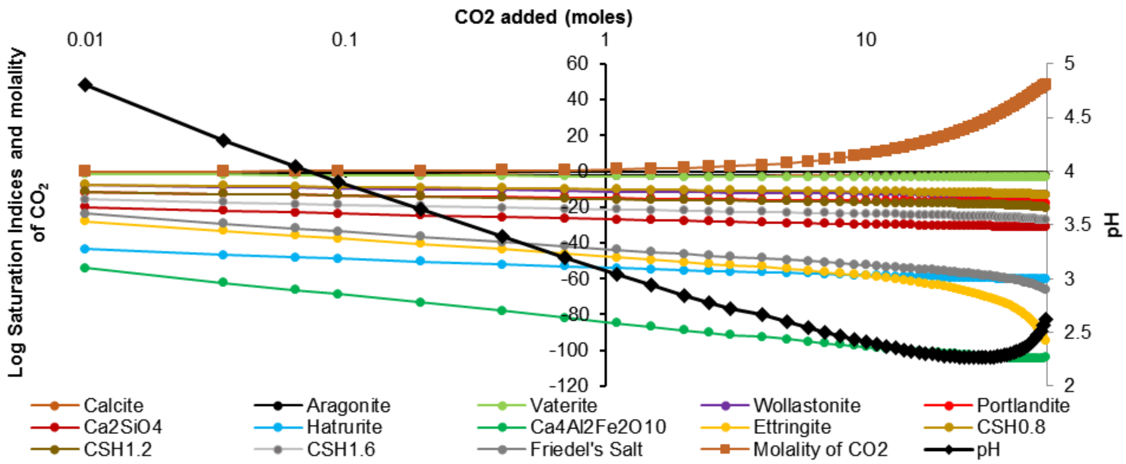


Figure 7-2. Log SI values for cement mineral phases in Appalachian Basin summary solutions, CO_2 batch reactions.

Solid Equilibrium Phases Model

The change in precipitation of mineral phases with the addition of CO_2 to the Appalachian Basin midpoint brine summary and solid equilibrium phases is shown in Figure 7-3. With the addition of 0.01 moles of CO_2, quartz, illite, and hematite precipitate and albite and siderite dissolve. Pyrite and K-feldspar are at equilibrium. The amount of these minerals that precipitate with the addition of more CO_2 continue to increase the amount of these minerals that precipitate and dilute until four moles of CO_2 are added, at which point quartz, illite, and albite do not change with the addition of CO_2. Prior to the addition of 4 moles of CO_2, the pH and pe were buffered from the effects of the CO_2. Like the Tuscarora, the Rose Hill also provides a buffer for changes in pH and pe. In the cement model, Calcite, wollastonite, Friedel's salt, and portlandite with the addition of 0.01 moles CO_2 while vaterite, dicalcium silicate, and aragonite, hatrurite, $CSH_{0.8}$, $CSH_{1.2}$, $CSH_{1.6}$ all dissolve completely. With the addition of CO_2, portlandite begins to dissolve at a relatively constant rate (around 1 mole per mole of CO_2 added) until it is depleted after 20 moles of CO_2 are added, after portlandite is consumed, $Ca_4Al_2Fe_2O_{10}$ begins to dissolve at a rate of around 0.3 moles per mole of CO_2 added until it is consumed after 29 moles of CO_2 are added. Only two solid phases remaining after the batch reactions: calcite 61.4 moles, a net increase of 48.5 moles) and wollastonite (23.2 moles, a net increase of 21.3 moles).

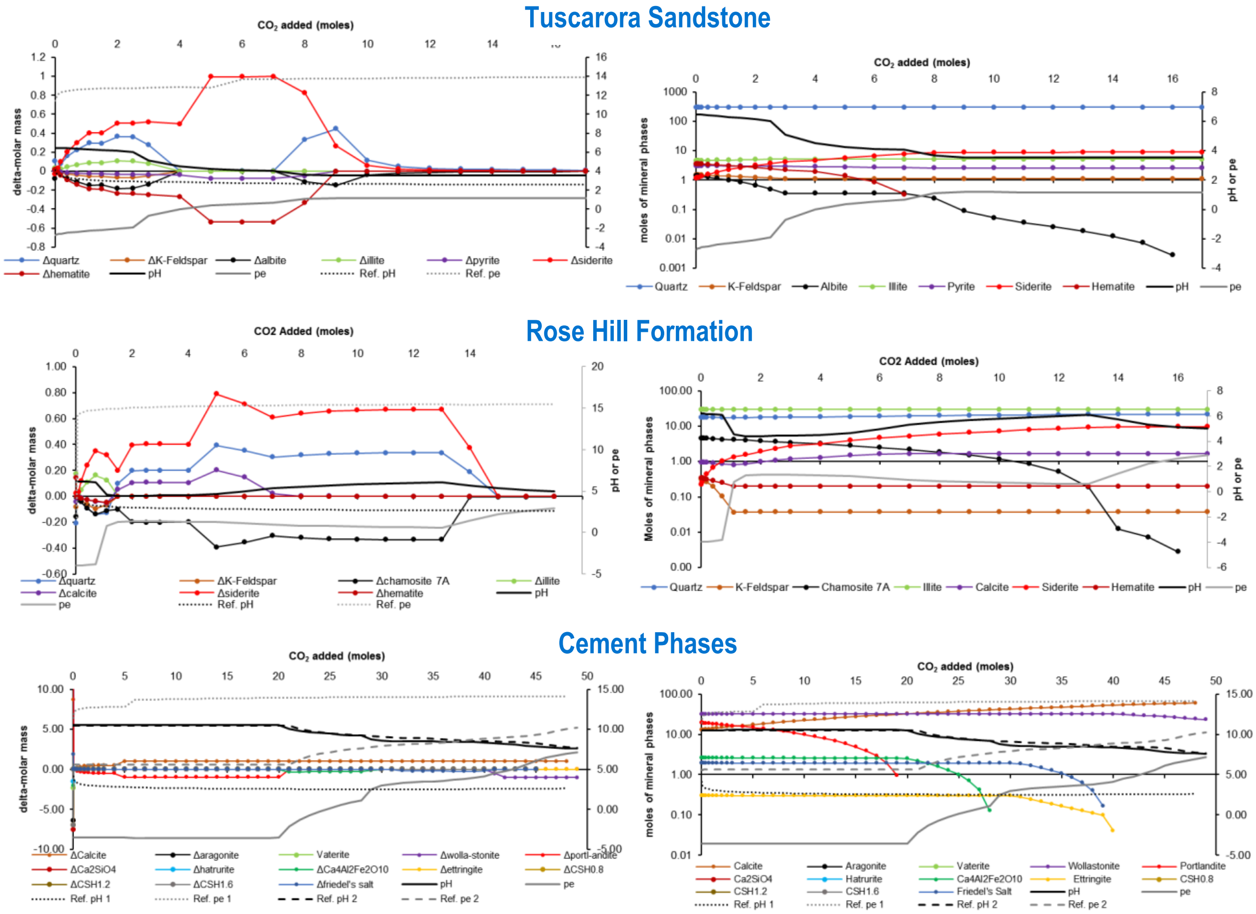


Figure 7-3. CO_2 batch delta molar mass (moles of mineral phases that precipitated or dissolved from previous CO_2 batch step) and moles of mineral phases with midpoint summary solution for Tuscarora sandstone, Rose Hill formation, and cement phases.

Michigan Basin

The change in precipitation of mineral phases with the addition of CO_2 to the Michigan Basin midpoint brine summary for the State Chester limestone, Dover 33 dolomite, Dover 33 A2 Carbonate, and cement mineral solid equilibrium phases is shown in Figure 7-4. K-feldspar dissolves and quartz precipitates as CO_2 is added. The remaining minerals are at or near equilibrium, although, at a lower rate, dolomite dissolves and calcite precipitates. In the Dover 33 dolomite, the dolomite precipitates and calcite and halite dissolve with the addition of CO_2. The minerals are then at or near equilibrium as CO_2 nears saturation. The remaining calcite then begins to dissolve (around 0.2 mol calcite dissolve in the final step of the batch reaction). The Michigan Basin midpoint brine summary and Dover 33 A2 Carbonate solid equilibrium phases shows that illite and quartz precipitate and K-feldspar dissolves. All minerals then reach a state of equilibrium when 6.0 moles of CO_2 added. The changes in the Michigan Basin cement with the addition of CO_2 are similar to the cement solid equilibrium cement phases analysis for the Appalachian Basin, indicating that the initial brine solution is not an important factor when comparing the midpoint values of the Michigan and Appalachian Basins.

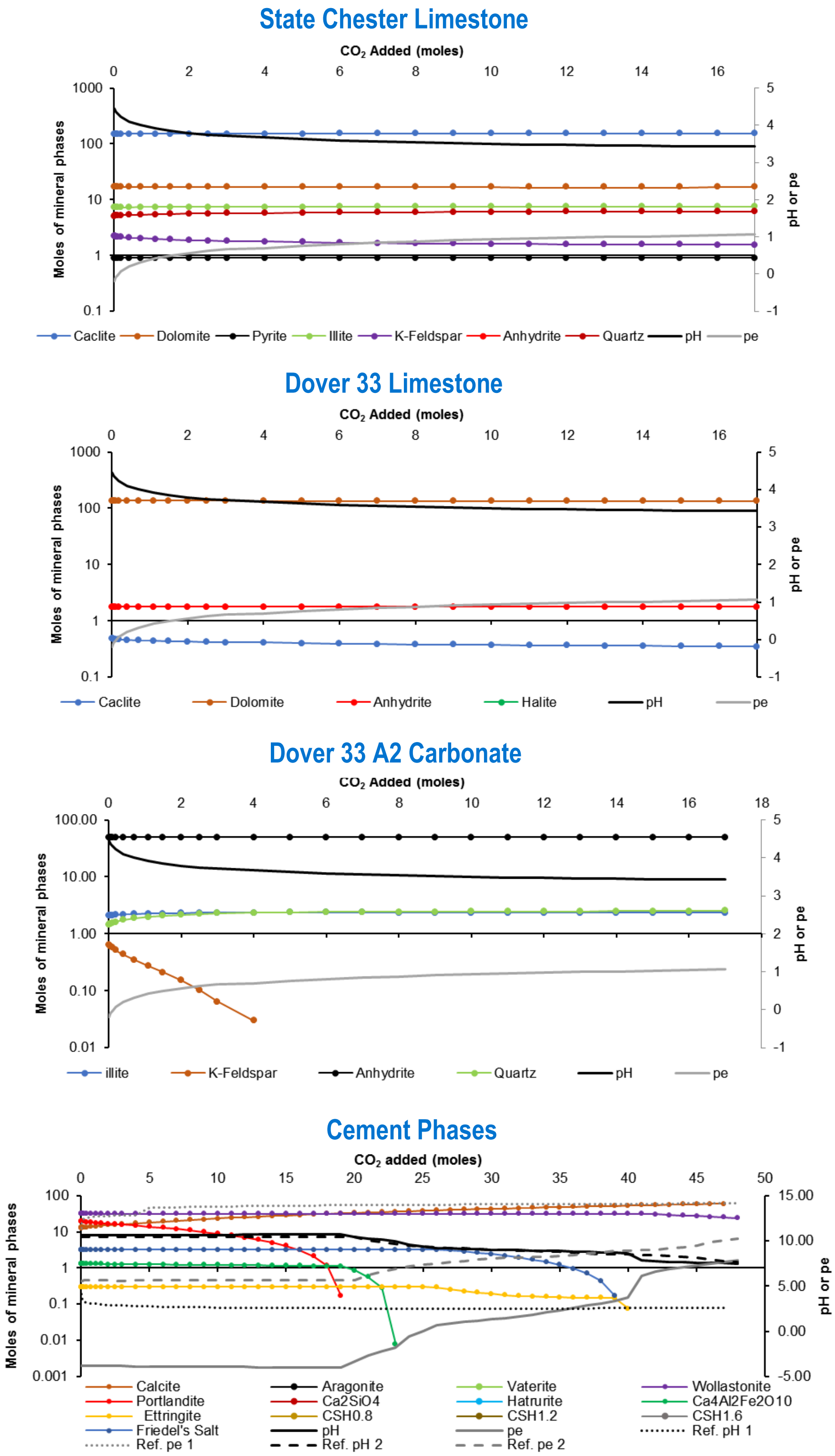


Figure 7-4. CO_2 batch delta molar mass (moles of mineral phases that precipitated or dissolved from previous CO_2 batch step) (top) and moles of mineral phases (bottom), State Chester limestone, Dover 33 limestone, Dover 33 A2 carbonate, and cement mineral phases with midpoint summary solution. The reference pH and pe (Ref. pH and Ref. pe) were found by reacting the CO_2 batch with pure water alone.

7.2 CO_2 Reaction Batch Model Indicator Geochemical Analysis

The Appalachian Basin was used as the example for the batch reactions model. Results from model scenarios were used to evaluate variation in pH, pe, pressure, and temperature on geochemical reactions. Figure 7-5 shows the SIs for cement minerals in the Appalachian Basin when the minerals are exposed to varied pH, temperature, and pressure conditions. For pH, the SIs for cement minerals in the midpoint summary solution show that the most stable cement mineral is calcite, which is above saturation until under pH 9. For temperature, the SIs for cement minerals in the midpoint summary solution show that all cement minerals become more stable (move closer to saturation) as the temperature increases, with one exception: ettringite, which has a log SI value of -13.9 at 35ºC and decreases to -16.5 at 90ºC. The most stable minerals are calcite and aragonite; their log SI values increase from -0.4 at 25ºC and become supersaturated at 80ºC. Finally, the SIs for cement minerals exposed to the pressure batch reaction show that pressure does not affect the log SI values or precipitation of cement mineral phases in any appreciable way. The addition of CO_2 does not affect these results.

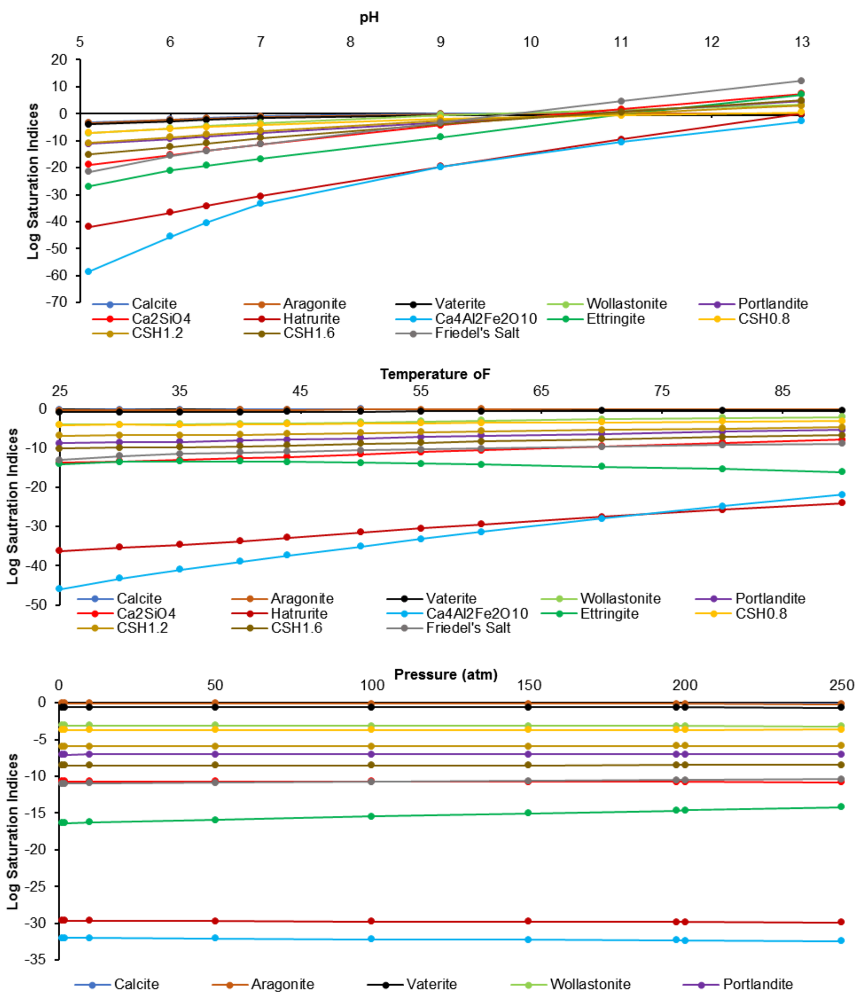


Figure 7-5. Log SI values for cement minerals batch reaction for pH, temperature, and pressure, Appalachian Basin.

7.3 Geochemical Analysis Meta-Modeling

Subsurface conditions, well construction specifications, and storage zone/caprock mineralogy were assessed for four test study areas. This information was identified to aid in the meta-modeling of cement sealing conditions across actual oil and gas fields. Four test study areas were selected for further analysis of cement sealing conditions (Figure 7-6):

- a 7- x 7-kilometer (km) area in the vicinity of Calhoun County, Michigan,
- a 6- x 6-km area in the vicinity of St. Clair County, Michigan,
- a 15- x 15-km area in the vicinity of Muskingum-Coshocton County, Ohio, and
- a 15- x 15-km area in the vicinity of Trumbull County, Ohio.

The objective of this analysis was to examine the uncertainty and variations in subsurface well integrity and cement sealing conditions based on actual well materials, hydrologic conditions, and geologic setting. The test study areas were selected because they have many legacy oil and gas wells and are located near large CO_2 sources. Therefore, they present useful and realistic test study areas to examine the ramifications of wellbore integrity for CO_2 storage applications.

Table 7-1 summarizes the test study area parameters. The size of each test study was determined by estimating the size of the CO_2 plume after injection of 70 million metric tons of CO_2 into the most suitable storage zone using a simple volumetric calculation. 70 million metric tons equates to 3.5 million metric tons of CO_2 per year emitted from a typical 500-megawatt coal-fired power plant for 20 years. Well construction specifications were described for these sites in a previous DOE-NETL project (FE0009367) examining wellbore integrity (Sminchak et al., 2016). This database was used as a starting point for the cement sealing uncertainty analysis. Test study areas are described in more detail below.

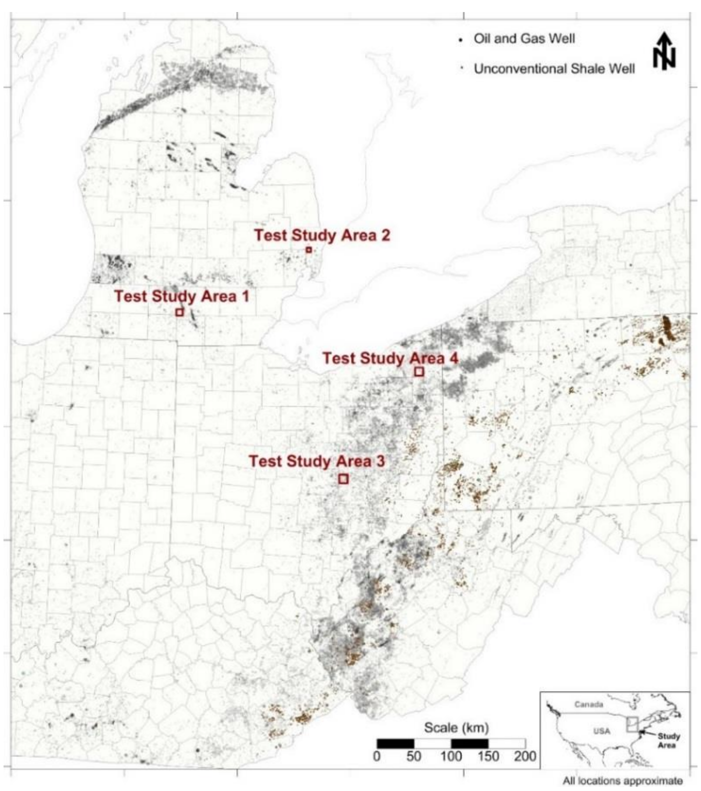


Figure 7-6. Map showing four test study areas.

Table 7-1. Summary of four test study areas.

Parameter	Test Study Area			
	1	2	3	4
Location	Calhoun Co., MI	St. Clair Co., MI	Muskingum Co., OH	Trumbull Co., OH
Size (km)	7 x 7	6 x 6	15 x 15	15 x 15
Reservoir Depth (m)	1,707	975	2,150	2,200
Thickness (m)	100	122	35	35
Reservoir Type	Sandstone	Niagaran Reefs	Carbonates	Carbonates
Caprock	Shale	Evaporites	Shale	Shale
Porosity (%)	12	12	6.5	6.5
Temperature (°C)	44	31	53	57
Pressure (MPa)	17.2	10.1	23.3	23.8
Salinity (mg/L)	225,000	350,000	250,000	300,000
# Wells	22	155	1,221	357

Test Study Area 1. Test study area 1, located in the vicinity of Calhoun County, Michigan, is 7 x 7 km based on the parameters listed in Table 7-1, which were selected using wireline data and literature. The study area encompasses 22 oil and gas wells that primarily target the Trenton-Black River formations in the Albion-Scipio play. The potential storage zone in this study area is the Mt. Simon sandstone, with the Eau Claire shale as the primary confining layer.

Test Study Area 2. Test study area 2, located in the vicinity of Saint Clair County, Michigan, was estimated as 6 x 6 km based on the parameters listed in Table 7-1, which were selected using wireline data and literature. The test study area encompasses 155 oil and gas wells that primarily target the Niagara reef system. These Niagaran Reefs are the primary target for CO_2, and this site would be a CO_2 EOR scenario where the depleted reefs would be filled with CO_2. The reefs are fairly shallow at approximately 975 m depth.

Test Study Area 3. Test study area 3, located in the vicinity of Muskingum County, Ohio, was estimated as 15 x 15 km based on the parameters listed in Table 7-1, which were selected using wireline data and literature. The test study area has 1,221 oil and gas wells that primarily target the Clinton-Cataract group. There are 12 large CO_2-emitting facilities nearby. The targeted storage formations are the Copper Ridge dolomite down to the basal sandstone, with the Queenston shale to the Black River group as the confining layers.

Test Study Area 4. Test study area four, located in the vicinity of Trumbull County, Ohio, was estimated as 15 x 15 km based on the parameters listed in Table 7-1, which were selected using wireline data and literature. The study area encompasses 357 oil and gas wells that primarily target the Cataract-"Clinton" sandstone group. The potential storage zone in this study area is the Copper Ridge dolomite down to the basal sandstone, with the Queenston shale to Black River group as the confining layers.

Well materials were reviewed for each test study area to determine the general well cement, casing, and additives used to complete wells in each study area. Table 7-2 summarizes well materials for the four study areas. As shown, there are 22 wells in test study area 1, 155 wells in test study area 2, 1,221 wells test study area 3, and 357 wells in test study area 4. Some of the wells date back to the 1920s, but most of the wells are 1970-1980s vintage. Standard casing programs and class A Portland cement were used for well construction, as is the typical practice in the Midwest United States. Additives include Pozmix, $CaCl_2$, and lost circulation material (LCM).

Table 7-2. Summary of test study area well construction specifications.

Parameter	Test Study Area			
	1	2	3	4
Location	Calhoun Co., MI	St. Clair Co., MI	Muskingum Co., OH	Trumbull Co., OH
# Wells	22	155	1,221	357
Storage reservoir depth (m)	1,707	975	2,150	2,200
Oil and gas reservoirs	Albion-Scipio (Trenton)	Niagaran Reefs	Berea, Clinton-Medina, Rose Run	Clinton-Medina
General casing program	Shallow 8 5/8” Deep 5 1/2”	Shallow 8 5/8” Deep 5 ½”	Shallow 8 5/8” Deep 4 ½”	Shallow 8 5/8” Deep 4 ½”
Cement	Class A Portland (shallow) Class A Portland 50/50 Pozmix (deep)	Class A	Class A	Class A
Cement additives	2% $CaCl_2$, LCM	Pozmix, 2-4% $CaCl_2$	Pozmix	Pozmix, $CaCl_2$, gilsonite

Well construction specifications were also tabulated for wells at the four test study areas. Well locations, completion date, total depth, casing schedule, cementing information, plugging details, and well status details were compiled. The thickness of the cement in the production casing was also mapped out for test study areas, because this directly relates to potential CO_2 migration from the storage zone along the boring. In addition, the thickness of the plugs was mapped out for plugged and abandoned wells. Figure 7-7 shows maps of cement thickness outside of the production casing string. As shown, all sites generally have 100 to 200 ft production casing cement, and many wells were cemented more than 500 ft into overlying casing string. Production zone plugs are less thick and have a greater variation.

Subsurface Conditions. Subsurface conditions for the test study areas were determined for caprock/reservoir mineralogy, pressure, temperature, salinity, and pH. This provides a range of conditions to be examined with the uncertainty analysis and meta-modeling. Mineralogy was based on regional trends in oil and gas reservoirs (Roan et al. 1996), oil and gas drilling records, and research on CO_2 storage. Table 7-3 summarizes the general mineralogy for the caprock and reservoir zones for each study area. Overall, the mineralogy would be expected to be fairly consistent across these local test study areas. Brine geochemistry was based on regional studies on brine samples from the reservoir zones for each site (Table 7-4). As shown, the sites have high salinity and moderate pH, which is typical for Paleozoic-age rocks in the Midwest United States.

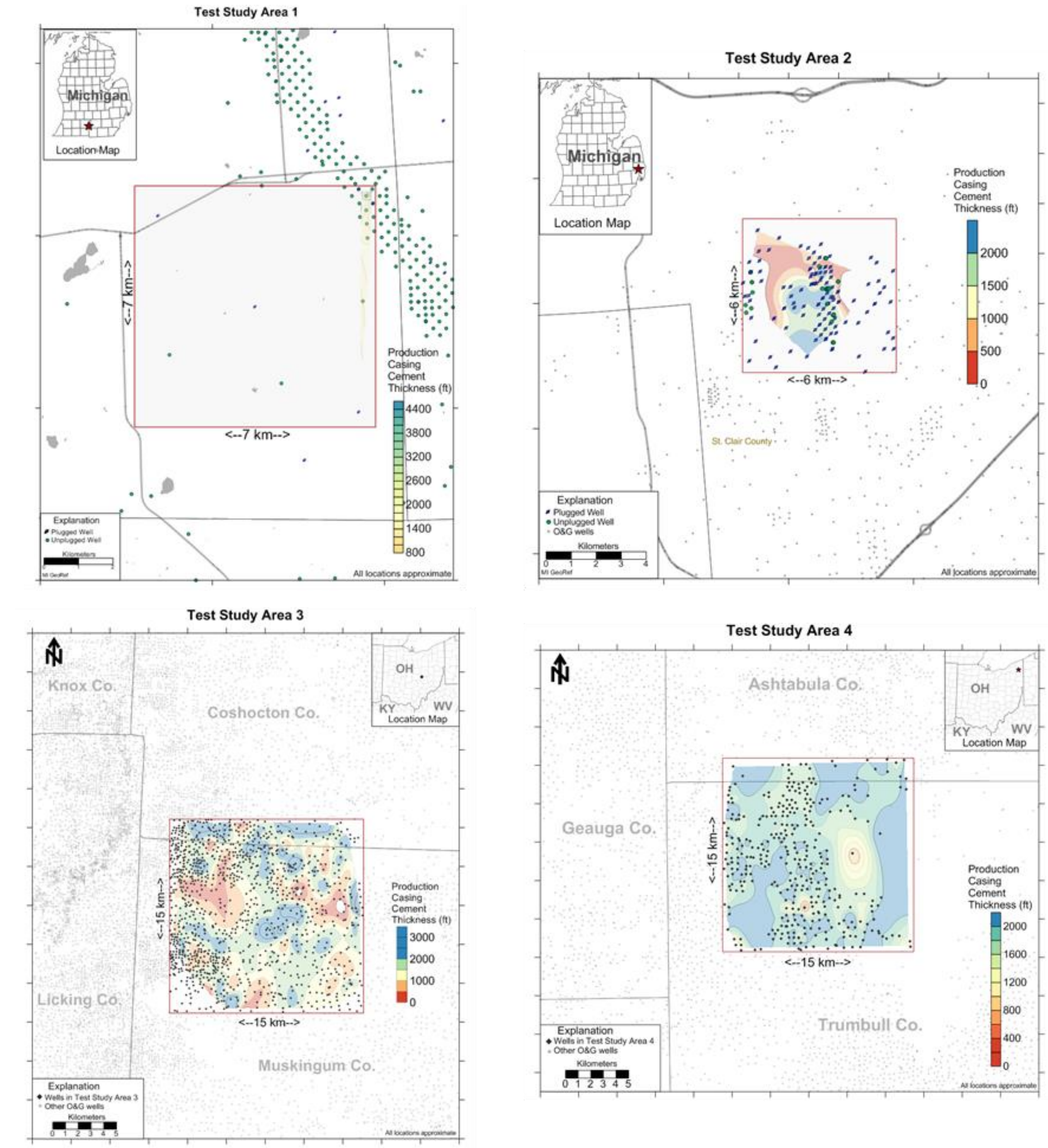


Figure 7-7. Map of production casing cement thickness across test study areas.

Table 7-3. Summary of general mineralogy for test study areas.

Mineral	Test Study Area 1		Test Study Area 2		Test Study Area 3		Test Study Area 4	
	Caprock	Reservoir	Caprock	Reservoir	Caprock	Reservoir	Caprock	Reservoir
	Shale	Sandstone	Evaporites	Carbonates	Shales	Dolomites	Shales	Dolomites
Dolomite	12%	<0.1%	40-99%	9-97%	3%	50%	3%	50%
Calcite	8%	<0.1%	<0.1%	0.8-82%	95%	0.3%	95%	0.3%
Quartz	32%	72%	0.3-2%	0-1.5%	1%	43%	1%	43%
Anhydrite	<1%	1%	0-56%	1.3-4%	<0.1%	<1%	<0.1%	<1%
K-Feldspar	36%	22%	0-0.6%	0.5%	<0.1%	0.5%	<0.1%	0.5%
Plagioclase	<1%	<0.1%	<0.1%	<0.1%	0.6%	0.6	0.6%	0.6
Clays	9%	4%	<0.1%	0-2.6%	0.7%	2.5%	0.7%	2.5%
Other			<0.1%	<0.1%		0.3%pyrite		0.3%pyrite
Source	Gupta et al., 2004		MRCSP, 2004		Wickstrom et al., 2011		Wickstrom et al., 2011	

Table 7-4. Summary of brine geochemistry for test study areas.

Constituent (mg/L)	Test Study Area 1		Test Study Area 2		Test Study Area 3		Test Study Area 4	
	Low	High	Low	High	Low	High	Low	High
Na	28,000	65,000	15,300	22,500	45,000	82,000	45,000	82,000
Cl	57,000	83,000	251,000	274,000	150,000	200,000	150,000	200,000
Ca	7,200	14,000	67,500	110,000	22,000	45,000	22,000	45,000
K	975	975	11,000	16,600	3,500	7,000	3,500	7,000
Fe	92	92	10	129	30	600	30	600
Mg	1,400	4,500	7,985	12,100	2,400	9,100	2,400	9,100
SO_4	277	1,450	81	97	90	800	90	800
pH	5.6	7.9	4.8	5.9	5.6	7.5	5.6	7.5
HCO_3^-	23	23	361	468	25	260	25	260
Salinity	40,000	110,000	348,000	450,000	200,000	300,000	200,000	300,000
Source	Sass et al., 1998		MRCSP sampling		Gupta et al., 2004; Sass et al., 1998			

To help visualize the variations in subsurface conditions for wells at the test study areas, maps were prepared for temperature and pressure. Temperature and pressure were based on well depths in each study area. Subsurface temperatures were estimated with mean ambient temperature and 1° F per 100-ft gradient. Pressures were based on a 0.444 psi/ft pressure gradient. Figure 7-8 shows the estimated subsurface pressure distribution in wells. Since the pressure and temperatures were based on well depth, the maps mainly reflect depths of the wells.

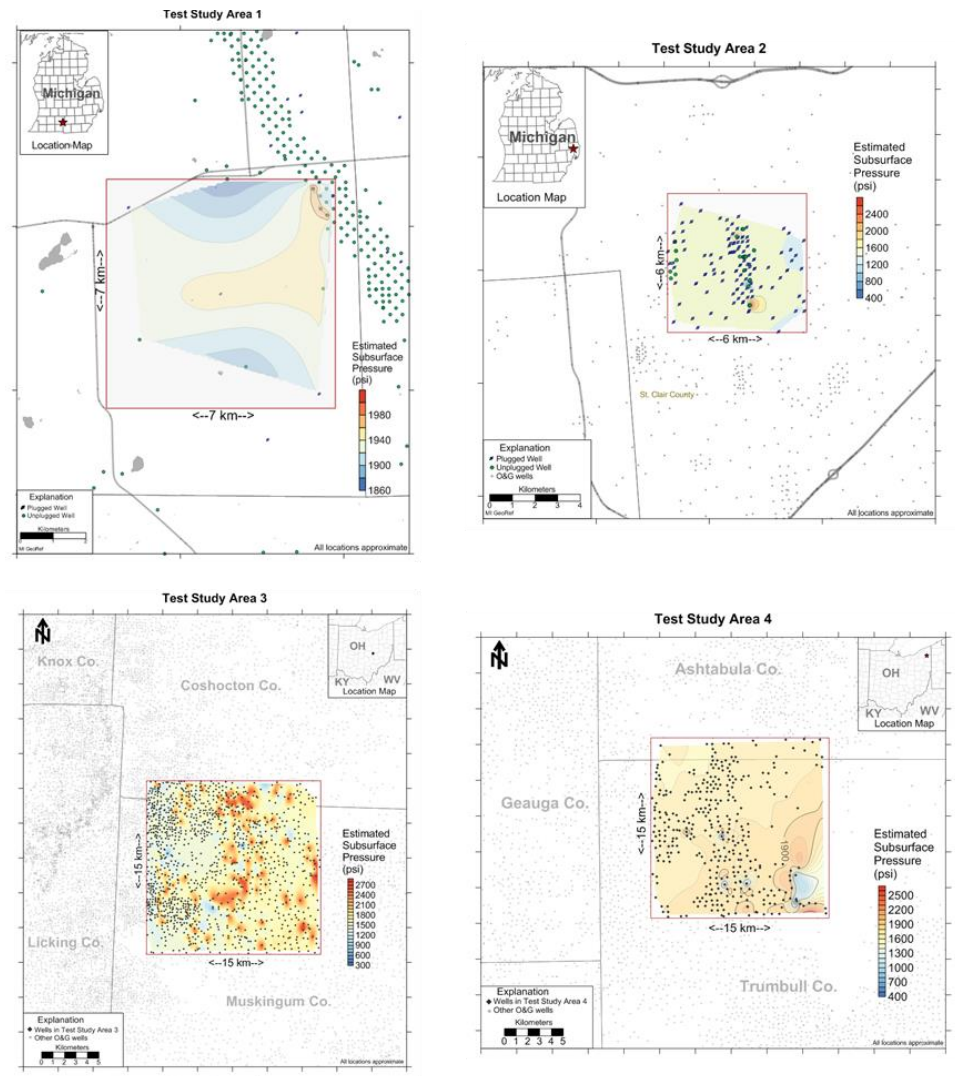


Figure 7-8. Baseline pressure conditions at test study areas.

Meta-Model Development

To evaluate the cement sealing potential in wells at the four test study areas, meta-models were applied to the sites based on subsurface pressure, temperature, and pH conditions present at the sites. The meta-models portray how cement sealing conditions in the subsurface may vary across CO_2 storage areas with legacy wells. A meta-model is a model of a model, or a systematic method to portray a problem based on metadata or input parameters. In this case, the metadata are the pressure, temperature, pH, fluid chemistry, mineralogy, and cement makeup for the legacy wells. The meta-model approach assumes that CO_2 would be injected, contact the legacy wells near the well total depth, and introduce changes in pressure, temperature, and pH (Figure 7-9). The meta-modeling predictions were constrained to parameters in the space of interest. For example, the pressure ranges were constrained to initial pressure and maximum injection pressure anticipated in the subsurface for each test study area. In this case, the PHREEQ-C model output was represented by a proxy-model estimating $CaCO_3$ saturation indices (SIs) at various pressure, depth, and pH conditions. These scenarios represent conditions likely to be present in the subsurface due to the injection of CO_2.

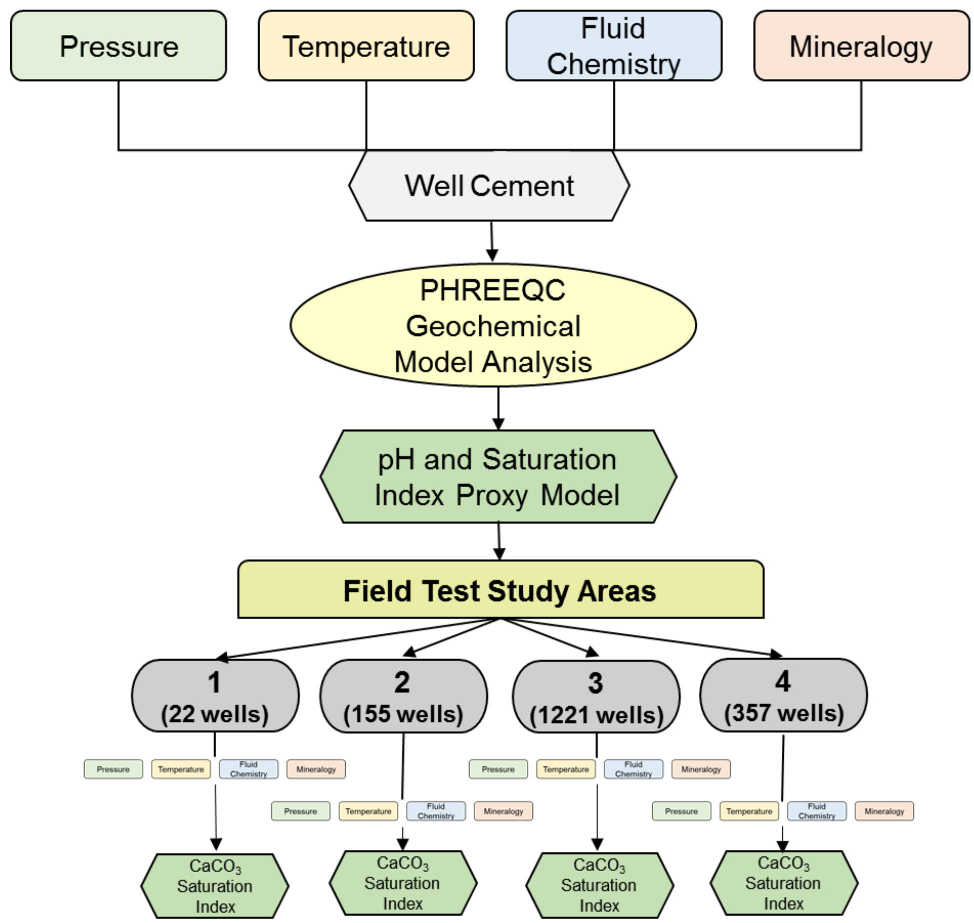


Figure 7-9. Flow chart illustrating the meta-modeling process for evaluating geochemical cement sealing conditions across the four test study areas.

The PHREEQC geochemical simulations results were processed to develop a proxy model to estimate geochemical changes as a function of the depth, temperature, pressure, and introduced pH. The results focused on the calcite SIs as an indicator of cement sealing potential. The proxy model was used to develop a database of $CaCO_3$ SIs for the wells at the four test study areas for different combinations of pressure, temperature, and pH. For example, Figure 7-10 shows the meta-model output for the 357 wells at test study area 4 at temperature +10 °C, pressure + 0%, and pH -2 from baseline conditions. The user may adjust the 'sliders' for pressure, temperature, and pH to see how they affect the SI for the wells. Thus, the meta-model is a way to visualize how differences in subsurface conditions may affect cement sealing potential. In general, the meta-models showed only minor amount of variation in SI across the test study areas. For example, the scenario shown in Figure 7-10 ranged from -4.9 to -5.2, a fairly small range. Meta-models for the other test study areas show small changes for a combination of metadata. This suggests that CO_2-related cement sealing processes would not be sensitive to subsurface conditions.

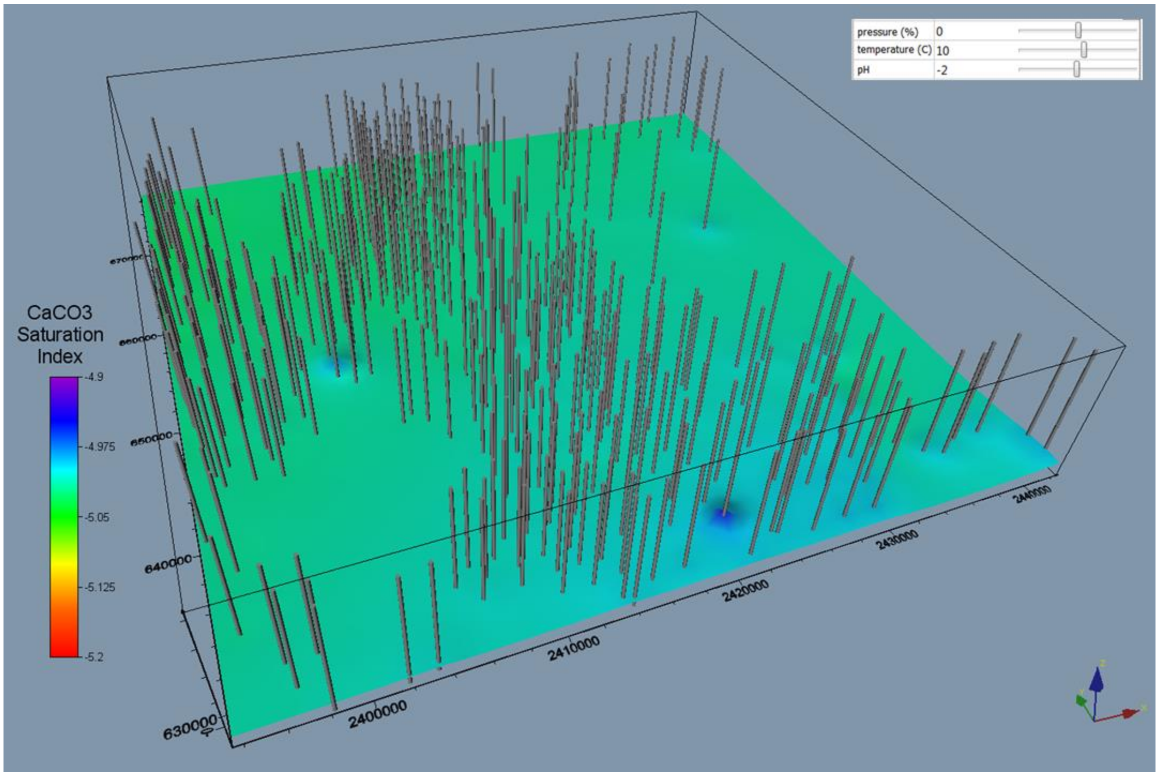


Figure 7-10. Meta-modeling output for test study area 4 at pressure +0, temperature +10 °C, and pH -2.

7.4 Key Findings of Wellbore Integrity Sealing Factor Uncertainty Analysis

The sensitivity of the subsurface system was examined with geochemical models run over a range of conditions (temperature, CO_2 saturations, pressure, mineralogy, brine chemistry). Results of the modeling were processed to identify key indicator parameters related to well-sealing conditions in the regional basins (Appalachian, Michigan, and Williston). Key conclusions of the indicator analysis are as follows:

- Model results were not especially sensitive to the range of subsurface conditions. Temperature affected the SIs of most cement mineral phases, but the pH and, to a lesser extent, pe were the main factors investigated that influenced cement mineral phase reactions.
- The model showed that the largest effect of the addition of CO_2 is a decrease in pH. This, in turn, drives dissolution reactions of cement mineral phases.
- The addition of CO_2 also increased the pe, which the batch reactions suggest makes cement mineral phases more unstable (more undersaturated). The change in pe could also cause redox-sensitive metals, particularly iron, to precipitate and potentially affect the porosity and permeability of the cement or surrounding formation.
- The solid equilibrium phases model showed a logical progression of cement mineral dissolution, beginning with portlandite and continuing with (in order) $Ca_4Al_2Fe_2O_{10}$, ettringite, and wollastonite. Calcite precipitated in conjunction with these reactions (i.e., cement carbonation was occurring). In addition, portlandite provided a pH buffer with the release of hydroxide ions until it was fully dissolved, an effect suggested by Kutchko et al. (2007).

Meta-models were applied to the four test study areas in Michigan and Ohio to assess the relationship between cement carbonation and subsurface conditions in typical wells in the region. These test study areas had 22-1,221 legacy oil and gas wells. Thus, they provide a real-world example of conditions at potential carbon storage applications. PHREEQC geochemical simulation results were processed to develop a proxy model to estimate geochemical changes as a function of the depth, temperature, pressure, and introduced CO_2. Results used calcite SIs as an indicator of cement-sealing potential. The proxy model was used to develop a database of $CaCO_3$ SIs for the wells at the four test study areas for different combinations of pressure, temperature, and pH. Results suggest that subsurface conditions would not have a large effect on the carbonation of well cements and potential cement sealing.

Like many other studies, the results suggested that carbonation of well cements would occur in these subsurface environments. It appears that mineralogy, hydrologic conditions, cement blends, and brine geochemistry were not especially critical factors to the cement carbonation process, as they had minor effect on the modeled saturation index. The largest effect on the subsurface was pH change triggered by the dissolution of the injected CO_2 into the subsurface and subsequent production of carbonic acid. Results indicate that life-cycle effects of CO_2 on well integrity are challenging to evaluate. It appears that well construction procedures, well design, and well logging/testing for defects are important considerations for wellbore integrity in CO_2 environments in the subsurface.

Chapter 8.0 Reporting and Technology Transfer

The objective of the reporting and technology transfer task was to document project results and provide project data to other CO_2 research projects. Reporting and technology transfer activities included preparation of task reports, technical meetings, project review meetings, and synergistic activities with other carbon storage research projects.

8.1 Reporting

Summary reports were prepared for the major technical tasks and field work. Table 8-1 summarizes reports generated and submitted to DOE-NETL. In addition, routine quarterly research performance progress reports and financial reports were submitted to document technical and financial progress.

Table 8-1. Summary of deliverables.

Task	Milestone Description	Deliverable	Planned Due Date	Submission Date
1	Update Project Management Plan	Project Management Plan	30 days after initial award	**October 6, 2015**
2	Complete Wellbore Integrity Registry	Well Integrity Registry Summary Report	June 2016	**June 30, 2016**
3	Collect Well Record Data	Well Record Data Summary Report	June 2017	**June 29, 2017**
4	Complete Log & Testing Based Well Integrity Assessment	Log & Testing Based Well Integrity Assessment Summary Report	September 2017	**November 1, 2017**
5	Collect All SCP Analysis Data	Compiled database of SCP Analysis Data (uploaded to EDX September 2018) Appalachian Basin Field Testing Summary Report (March 2017) Williston Basin Field Testing Summary Report (February 2018)	March 2018	**December 2017**
6-7	Wellbore Integrity Sealing Factor Analysis	Wellbore Integrity Sealing Factor Summary Report	June 2018	**June 29, 2018**
8	Final Technical Report	Final report with all project methods, results, and conclusions	September 2018	**September 27, 2018**

8.2 Technology Transfer

Several technical presentations, posters, and papers were prepared under the project to communicate project results to scientific community, stakeholders, and industry. A project overview presentation was given by J.R. Sminchak at the DOE-NETL Carbon Storage Program Review Meeting in Pittsburgh, Pennsylvania, August 16-18, 2016, August 12-15, 2017, and August 13-17, 2018. Summary Excel data sheets were prepared for the well SCP tests. The data sheets contain the pressure-temperature time series, well description, and well diagrams. The data sheets were uploaded to the DOE-NETL Energy Data Exchange (EDX) website on September 5, 2018 (Figure 8-1). The project team also engaged with researchers on the DOE-NETL National Risk Assessment Partnership (NRAP) program to provide information on field data for NRAP tool validation for CarbonSAFE projects. Technology transfer items are summarized as follows:

- *Sustained Casing Pressure Testing of CO_2 Wells for Wellbore Integrity Defects: Environmental Risk Implications for Carbon Storage Projects,* J.R. Sminchak and Matt Place, IEAGHG Modelling and Risk Network Meeting, 19-22 June 2018, Grand Forks, North Dakota, USA.
- *Battelle Progress on CO_2 injection projects and legacy oil and gas wells*, provided to IEAGHG working group to prepare a Report on Well Engineering and Injection Regularity in CO_2 Storage Wells, January 2018.
- *DOE-NETL Web Meeting- Project Update: Integrated Wellbore Integrity Analysis Program for CO_2 Storage Applications*, J.R. Sminchak, A. Duguid, A. Haagsma, and M. Place, 2 March 2018.
- *Case Study on Wellbore Integrity for Two Fields with Wells Exposed to CO_2 in the Subsurface in the Midwest U.S.* Jacob Markiewicz, J.R. Sminchak, and Mark Moody. SPE Eastern Section Regional Meeting, 4-6 October 2017, Lexington, Kentucky.
- *Is your well flat or carbonated? What sustained casing pressure testing and beer have in common*. J.R. Sminchak. 11th IEAGHG Monitoring Network Meeting. June 13-15, 2017, Traverse City, Michigan.
- *Field Testing and Well History Analysis on Wells Exposed to CO_2 in the Subsurface in the Midwest U.S.*, J.R. Sminchak, Mark Moody, Autumn Haagsma, Andrew Duguid, Matt Place, and Neeraj Gupta. Carbon Capture, Utilization, and Storage Conference, June 14-16, 2016, Tysons, Virginia, USA.
- *Sustained Casing Pressure Diagnosis with Extended Data Collection*, Matt Place, Glenn Larsen, Bryan Dotson, Nigel Jenvey, and Mark Moody, SPE Eastern Regional Meeting, 13-15 October 2015, Morgantown, West Virginia.

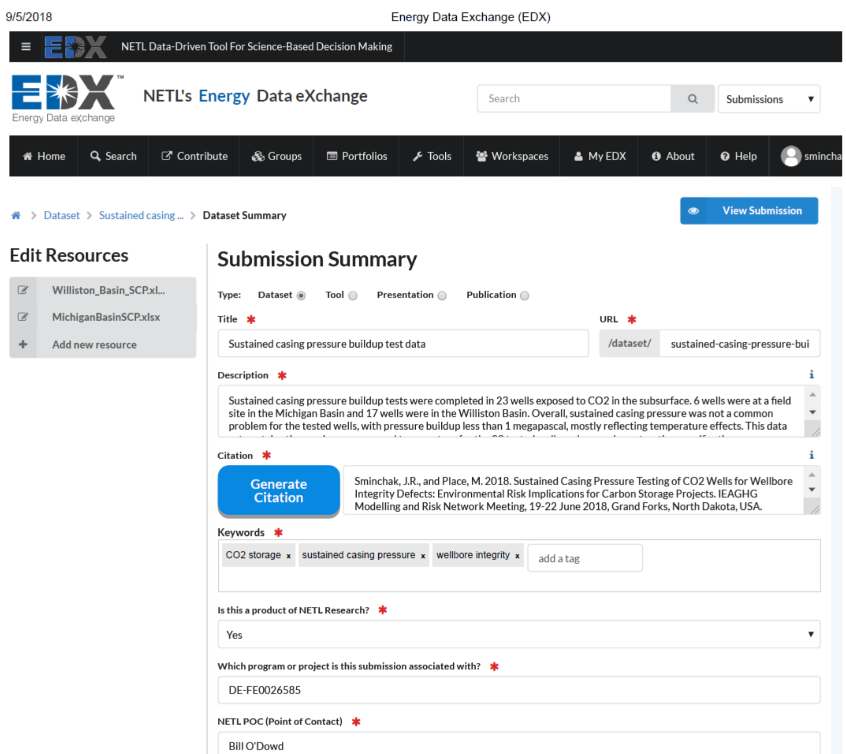


Figure 8-1. EDX data upload submission summary.

Chapter 9.0 Conclusions

Subsurface exposure to CO_2 is a concern for wellbore integrity at CO_2 storage sites, because CO_2 can corrode well materials and migrate along defects around the borehole. These processes may affect new wells and legacy oil and gas wells. Consequently, this project completed a program to evaluate well integrity in CO_2 wells with a combination of direct field testing and analysis of well records. Project results were used with geochemical analysis to identify trends that lead to better understanding and prediction of well integrity issues for CO_2 storage applications.

In this project, approximately 1,500 wells at three sites were reviewed in terms of well construction, history of exposure to CO_2, geochemistry, mineralogy, and well materials. The field sites included the following locations:

- **Appalachian Basin**. The Appalachian Basin Indian Creek site is a natural CO_2 and methane field located in Kanawha County, West Virginia. The field contains approximately 58 wells at total depths between 6,200 ft and 6,700 ft. The Indian Creek field produces in the Tuscarora sandstone. The field has CO_2 levels up to 60% in some areas.
- **Michigan Basin.** The Michigan Basin study site is located in the northern portion of the Niagaran reef trend in Otsego County, Michigan. The fields were developed since the 1960s in the region, and selected reefs have been subject to CO_2 EOR since the 1990s. CO_2 is also present in the Antrim gas wells between 5% and 30% at depths between 1,000 ft and 1,500 ft. The Niagaran reef EOR wells are completed at depths ranging from 5,000 ft to 7,000 ft.
- **Williston Basin.** The Williston Basin field is located on the northwestern edge of the Williston Basin geologic feature and was a major oil play which is used for CO_2 EOR. Approximately 3,000 wells are located in the Williston Basin testing site, completed at depth of 6,000 to 7,000 ft. The Williston Basin testing site is a mature oil field that began production in 1954. CO_2 EOR was started in 2000 at the site, expanding to additional areas over time.

A total of 83 CO_2 wells were surveyed at the Michigan Basin (23 wells) and Williston Basin (60 wells) sites for wellhead casing pressures that may indicate well defects. The Appalachian Basin site was not available for field testing, because the asset was sold to a new operator. Detailed SCP testing was completed on 23 wells that had some indication of significant SCP.

The test results did not show significant well defects, with casing pressures less than 1 MPa and minor pressure buildup patterns. The wells demonstrated zonal isolation, with no CO_2 gas migrating to the wellhead b-annulus. Analysis of wells with minor pressure buildup was inconclusive in terms of nature and severity of the defects. These results were surprising, given that 15-20% of typical oil and gas wells develop casing pressure. It was expected that more defects would be present in CO_2 wells, because of carbonic acid evolution and corrosive conditions in the subsurface.

Additional geochemical modeling and meta-modeling for the three field sites and four test study areas were completed to determine if subsurface conditions at the field sites were suitable for cement sealing of gas migration pathways via $CaCO_3$ precipitation. Well construction and/or geochemical conditions for cement carbonation appear to have contributed to well integrity. Results support management of CO_2 storage applications in areas with many legacy oil and gas wells.

Some key conclusions of the integrated wellbore integrity analysis program include the following:

- The wellbore integrity registry developed in this project provides a catalog of the well component, integrity issues, causes, timing, and leakage pathways that may occur in wells. Most wellbore integrity problems are in the casing, cement, or interface between the two components or arise due to geological processes such as formation lithology and geomechanical stresses.

- The three field sites have wells which have been exposed to CO_2 either naturally or through EOR operations for 5 to 50 years. The sites have different geologic settings and subsurface conditions. These datasets provide unique opportunities to study the influence of CO_2 on wellbore integrity.
- Three different fields were assessed using a risk ranking methodology. The fields, in Otsego, Michigan, Indian Creek, West Virginia, and Alberta, Saskatchewan, varied in size, geography, and geology. The assessment showed that Total Severity was more important in determining the Total Risk.
- The field testing was completed on a subsample of wells and does not mean all CO_2 wells would be free of defects. In addition, the SCP testing methodology requires defects that would lead to gas migration to the wellhead. Therefore, there may be existing downhole defects not revealed by the testing.
- SCP testing is an effective, quick, direct, and low-cost method to test and monitor wellbore integrity. It is a useful option for CO_2 storage areas with many legacy oil and gas wells in lieu of more expensive down-hole logging or well plugging.
- Geochemical analysis and modeling results suggested that carbonation of well cements would occur in these subsurface environments. It appears that mineralogy, hydrologic conditions, cement blends, and brine geochemistry were not especially critical factors to the cement carbonation process.
- Results indicate that life-cycle effects of CO_2 on well integrity are challenging to evaluate. It appears that well construction procedures, well design, and well logging/testing for defects are important considerations for wellbore integrity in CO_2 environments in the subsurface.

Additional work on the life-cycle effects of CO_2 would highlight changes over time due to subsurface exposure to CO_2 in wells. This life-cycle analysis may include periodic CBLs, sidewall cores, and SCP testing. The analysis would help determine the rate, nature, and severity of well integrity effects over time for CO_2 wells.

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