# An Evaluation of the Carbon Sequestration Potential of the Cambro-Ordovician Strata of the Illinois and Michigan Basins

Final Report

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## Executive Summary

The studies summarized herein were conducted during 2009–2014 to investigate the utility of the Knox Group and St. Peter Sandstone deeply buried geologic strata for underground storage of carbon dioxide ($CO_2$), a practice called $CO_2$ sequestration (CCS). In the subsurface of the midwestern United States, the Knox and associated strata extend continuously over an area approaching 500,000 sq. km, about three times as large as the State of Illinois. Although parts of this region are underlain by the deeper Mt. Simon Sandstone, which has been proven by other Department of Energy-funded research as a resource for CCS, the Knox strata may be an additional CCS resource for some parts of the Midwest and may be the sole geologic storage (GS) resource for other parts.

One group of studies assembles, analyzes, and presents regional-scale and point-scale geologic information that bears on the suitability of the geologic formations of the Knox for a CCS project. New geologic and geo-engineering information was developed through a small-scale test of $CO_2$ injection into a part of the Knox, conducted in western Kentucky. These studies and tests establish the expectation that, at least in some locations, geologic formations within the Knox will (a) accept a commercial-scale flow rate of $CO_2$ injected through a drilled well; (b) hold a commercial-scale mass of $CO_2$ (at least 30 million tons) that is injected over decades; and (c) seal the injected $CO_2$ within the injection formations for hundreds to thousands of years. In CCS literature, these three key CCS-related attributes are called injectivity, capacity, and containment. The regional-scale studies show that reservoir and seal properties adequate for commercial-scale CCS in a Knox reservoir are likely to extend generally throughout the Illinois and Michigan Basins. Information distinguishing less prospective subregions from more prospective fairways is included in this report.

Another group of studies report the results of reservoir flow simulations that estimate the progress and outcomes of hypothetical CCS projects carried out within the Knox (particularly within the Potosi Dolomite subunit, which, in places, is highly permeable) and within the overlying St. Peter Sandstone. In these studies, the regional-scale information and a limited amount of detailed data from specific boreholes is used as the basis for modeling the $CO_2$ injection process (dynamic modeling). The simulation studies were conducted progressively, with each successive study designed to refine the conclusions of the preceding one or to answer additional questions. The simulation studies conclude that at Decatur, Illinois or a geologically similar site, the Potosi Dolomite reservoir may provide adequate injectivity and capacity for commercial-scale injection through a single injection well. This conclusion depends on inferences from seismic-data attributes that certain highly permeable horizons observed in the wells represent laterally persistent, porous vuggy zones that are vertically more common than initially evident from wellbore data. Lateral persistence of vuggy zones is supported by isotopic evidence that the conditions that caused vug development (near-surface processes) were of regional rather than local scale.

Other studies address aspects of executing and managing a CCS project that targets a Knox reservoir. These studies cover well drilling, public interactions, representation of datasets and conclusions using geographic information system (GIS) platforms, and risk management.

Overall, the studies validate the identification of the Knox Group and overlying St. Peter Sandstone as CCS targets in the Midwest, and confirm the expectation that local well data will be consistently needed to investigate injectivity at any specific proposed injection site. At any proposed injection site, caprock, along with reservoir attributes, would be confirmed through an exploratory well that could become an injector. Compared to a massive sandstone injection reservoir like the Mt. Simon Sandstone, the lesser lateral and vertical homogeneity of a porous Knox reservoir is more likely to require a second exploratory well—so that injection can be effectively tested—before further investment decisions are made. If a CCS project location allows good access for data acquisition, a $CO_2$ plume migrating within the Knox is reasonably likely to be observable using the seismic profiling technique. Within Knox reservoirs, the likely existence of unanticipated highly permeable migration pathways will increase the uncertainty of plume prediction and could increase the radius of regulatory Areas of Review.

# Project Summary

## Objectives

This project (DE-FE0002068) evaluates the carbon sequestration (CCS) potential of the Cambro-Ordovician St. Peter Sandstone and the Knox Group in the Illinois and Michigan Basins covering the states of Illinois, Indiana, Kentucky, and Michigan. There was very little reservoir and seal data for these two intervals even though it may have the most significant CCS potential in areas where the Mt. Simon Sandstone is absent or too deep to be a viable target. This project helps determine if 1) the Knox has potential as a seal, 2) the Maquoketa Shale would be a good seal for carbon dioxide ($CO_2$), 3) the reservoir quality of the Knox and St. Peter Sandstone in specific areas of the Illinois and Michigan Basins is adequate, 4) $CO_2$ will interact with the waters and mineralogy of the seal and reservoir, and 5) the risk of fracturing the seals or the reservoir and allowing $CO_2$ to move in unanticipated directions. The Knox is equivalent to the Arbuckle in Oklahoma and Ellenburger in Texas and this project would help support potential sequestration projects in those regions.

In summary, the project objectives are to evaluate the three fundamental geological criteria for a CCS project—injectivity, capacity, and containment—whose target reservoir is within the Cambro-Ordovician units of the Illinois and Michigan Basins and adjacent Midwestern areas at the regional scale. Although nearly all geologic data (and all data cited by the 19 topical reports) is site specific, the report authors have typically extrapolated their conclusions cautiously toward the regional scale. No actual CCS project would proceed far without site-specific data, but the regional-scale inferences about both reservoir and caprock quality will help project operators identify Midwestern subregions that may provide suitable sequestration targets for specific $CO_2$ sources. Besides criteria strictly related to the reservoir and caprock, other broad requirements for a successful CCS project include ability to monitor the $CO_2$ plume (using data from seismic reflection and other methods), ability to satisfy local residents that the project is safe, and the ability to identify, evaluate, and address risks associated with project execution. The DE-FE0002068 studies described in this final report also address some, but not all aspects of these requirements.

## Accomplishments and Benefits of this Project

The results of this project show how to reduce storage risk by documenting the uncertainties related to any commercial CCS project that involves the St. Peter Sandstone and the Knox Group. The project delineated potential new geologic intervals for carbon storage in Illinois, Indiana, Michigan, and Western Kentucky and will enhance the North American carbon storage resource potential. This final project report includes best practice recommendations for each task, including site selection, characterization, site operations, and closure practices.

The major accomplishments and benefits of this project to carbon storage are listed below:

- Developed a Best Practices Manual that illustrates the methodology for reducing storage risks for the Knox and St. Peter Sandstone.
- Highlighted areas of high risk and low risk for carbon storage in the St. Peter Sandstone and Knox strata in the Illinois and Michigan Basins.

- Showed how seismic reflection data can be used to delineate high- and low-risk areas.
- Evaluated seals and reservoirs for faulting and fracture risk (geomechanical studies), as well as their interactivity and reactions with $CO_2$ in the presence of brine (geochemical studies).
- Illustrated injectivity and storage potential of commercial injection into St. Peter Sandstone and Knox with reservoir simulation.
- Performed $CO_2$ injection test in an existing well in Hancock County, Kentucky, to evaluate injectivity of the Knox.
- Developed regional $CO_2$ storage resource estimates for the Knox and St. Peter Sandstone for use in future version of the US Department of Energy's (DOE's) North American $CO_2$ Storage Resource Atlas.
- Showed that reservoir characterization and reservoir flow simulation are both important tools in understanding plume migration but there is a limit on their effectiveness. Adding more information to the model did not necessarily change the results enough to justify the costs and time involved.

## Results and Discussion

This final report is primarily composed of 19 different topical reports submitted as deliverables to the US Department of Energy. Please refer to the individual topical reports for further details and references to the detailed work completed by this project.

A number of the topical reports and research directions were the result of an American Society of Mechanical Engineers (ASME) Peer Review (October 22–26, 2012) for the National Energy Technology Laboratory (NETL). The ASME recommended further reservoir simulations, geochemical studies, and evaluations of the geologic model used in the reservoir flow simulations. These recommendations have all been completed.

The project included a geologic and geophysical appraisal of the Cambro-Ordovician interval from the Maquoketa (Utica) Shale (significant secondary seal in the region) to the top of the Eau Claire Shale (the primary seal for the Mt. Simon Sandstone; Figure 1). We investigated both the reservoir and seal capacity of the intervening layers, with emphasis on the St. Peter Sandstone and the Knox Group. This stratigraphic interval is regionally present in multiple states and, when the Mt. Simon Sandstone is not a potential reservoir, may be the most important sequestration target in the United States Midwest. We acquired whole and sidewall cores from the Maquoketa Shale and Knox Super Group. The upper Knox and the Maquoketa was evaluated for seal potential and the lower Knox for reservoir potential.

| SYSTEM | GROUP | FORMATION |
|---|---|---|
| Ordovician | Maquoketa | Brainard |
| | | Ft. Atkinson |
| | | Scales |
| | Galena | Kimmswick |
| | | Decorah |
| | Plateville | |
| | Ancell | Joachim |
| | | St. Peter |
| | Knox | Shakoppee |
| | | New Richmond |
| | | Oneota |
| | | Gunter |
| Cambrian | | Eminence |
| | | Potosi |
| | | Franconia |
| | | Ironton-Galesville |
| | | Eau Claire |
| | | Mt. Simon |
| Precambrian | | |

**Figure 1. Stratigraphic column of Precambrian through Ordovician rocks in the Illinois Basin.**

The key stratigraphic intervals were mapped in the four-state area (Figure 2) using well data. More detailed work was completed around the Illinois Basin–Decatur Project (IBDP) using the newly acquired three-dimensional (3D) seismic dataset and well logs to evaluate the Knox Group and St. Peter Sandstone intervals. The IBDP is evaluating the sequestration potential of the Mt. Simon Sandstone and, because of its adequacy, is not doing any detailed evaluation of the overlying Knox Group and St. Peter Sandstone. Our additional work at the IBDP was extremely important because the high-quality 3D seismic data set was correlated to the rock physics data acquired from wireline logging and whole core analysis. The project funded additional core and wireline logs from the Maquoketa Shale and the Knox Group. Geomechanical testing of the core was critical in understanding the rock properties for reservoir flow modeling of a hypothetical $CO_2$ sequestration project.

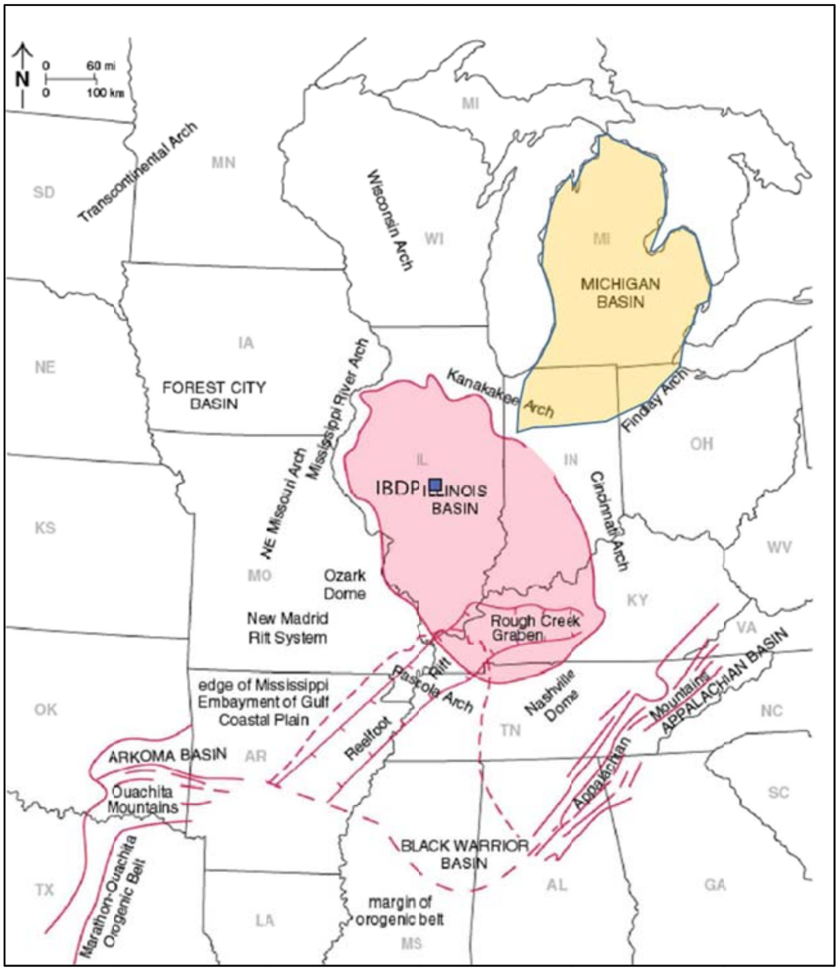



Figure 2. Regional map showing the location of Illinois and Michigan Basins, IBDP, and important regional tectonic features.

Both the reservoir and caprock were characterized on local and regional scales in order to understand $CO_2$ migration patterns and the overall storage potential of an individual site. This characterization included the delineation of reservoir properties, structural geology, and stratigraphy of both the sinks and seals within the Cambro-Ordovician. We were able to save millions of dollars by acquiring core from the already planned IBDP and Illinois Industrial Carbon Capture and Storage Project (NETL, 2009) monitoring wells (VW1 and VW2) at Decatur, Illinois. The monitoring wells were drilled to monitor injection into the Mt. Simon Sandstone. We acquired new core during the drilling that was not originally planned for this well because, at Decatur, the shallower intervals were not the injection target. The injection wells had a full set of wireline logs that was used to plan the best places to take core.

Our second characterization site was at Hancock County, Kentucky, where the Kentucky Consortium for Carbon Storage (KYCCS) at the Kentucky Geological Survey had drilled a $CO_2$ test injection well. This project was funded by the Commonwealth of Kentucky and several industry partners. At the Hancock site, we conducted a second phase of injection in the Knox Group to characterize a second reservoir zone and further test the capacity and lateral extent of reservoir zones in the well. After injection, we acquired a state-of-the-art vertical seismic profile (VSP) to monitor the injected $CO_2$ and image its distribution in the area around the well bore.

Carbon dioxide injection inherently alters the pressure of the brine, its chemical content, and possibly the temperature around the injection wells and also across the reservoir. These perturbations trigger complex coupled processes (multiphase fluid flow, heat transfer, rock-fluid interactions and mechanical processes) whereby the reservoir and the surrounding rock masses, and any fractures and faults within them, undergo a change in stress; hence, deformations and, possibly, failure can occur. The Knox Group contains no thick shale intervals and is composed of mostly dolomite rocks. Geomechanical testing allowed us to evaluate the importance of this unit as a possible seal for the lower Knox and as a secondary seal for the Mt. Simon Sandstone. In the Illinois Basin, there are only limited core from the Maquoketa Shale and Knox in areas that have sequestration potential. The Maquoketa core was collected to enable us to evaluate the seal potential for not only the Knox but also for the St. Peter Sandstone, but also as a secondary seal for the Mt. Simon Sandstone.

Within the sealing components—the primary and secondary caprocks and, if any, the sealing faults—rock failure, the re-activation of fractures and faults, or the creation or propagation of hydraulic fractures may drastically enhance permeability and result in the leakage of fluids ($CO_2$ or brines) outside the intended storage complex. Geomechanics helped determine whether these features, if present, could potentially become conduits for movement of $CO_2$ or brine to shallower layers.

We conducted a second phase of injection in the KGS #1 Blan well. A second phase of injection allowed KYCCS to test different reservoir facies in the Knox and test the lateral continuity and capacity of the initial $CO_2$ test zone with additional fluid volume.

The Cambro-Ordovician Knox Group and the St. Peter Sandstone of the Illinois and Michigan Basins meet the storage criteria of being able to store 30 million tonnes of $CO_2$. The Knox is a regionally extensive and thick (over 609.5 m [2,000 feet]) dolomite with well-developed porosity common in both basins. The Knox was also shown to have the capacity to store 50 million tonnes of $CO_2$ at a site in Henderson County, Kentucky, as part of Kentucky's FutureGen proposal in 2006. A number of waste disposal wells in Illinois and Kentucky use the Knox as the target interval. In both the Illinois and Michigan Basins, porosity in the Knox can range from 4% to 17% in some zones. Both the injection well at the IBDP and the well at the Hancock site encountered lost circulation and porous intervals in the Knox. Natural gas storage fields have used the Knox and St. Peter as a reservoir. Early estimates of the storage capacity in the St. Peter Sandstone in the Illinois Basin suggest that there are 1.6 to 6.4 billion tonnes, with additional capacity in the Michigan Basin (DOE, 2008). However, these early St. Peter Sandstone calculations were based on very imprecise data. Regional variations in St. Peter Sandstone were not taken into account and no regional assessment was done highlighting areas of high potential with those of higher risk. In our assessment of the St. Peter Sandstone, we will include new data from our IDBP well and new wells in the Michigan Basin.

The primary goal of this project was to analyze the sequestration potential of the Cambro-Ordovician interval in the Illinois and Michigan Basins. We did not use any untested technology. The best practices manual that is the final product in this research is specific to these formations. We will be able to significantly lower the cost of sequestration site assessment because all basins and formations have unique issues that must be assessed to adequately understand the uncertainties and risks to the sequestration project.

## Knox and St. Peter Sandstone Geology and Reservoir Properties

The Knox carbonates are considered part of the Great American Carbonate Bank (GACB) that was deposited during the Cambrian and Ordovician and is found throughout North America (Fritz et al., 2012). The Knox is the stratigraphic equivalent of the Arbuckle in Kansas and Oklahoma and the Ellenberger Group in Texas. In the Illinois Basin, the Knox carbonates range in thickness from 300 to 500 ft (90 to 152 m) in northern Illinois to as much as 6,000 ft (1,828 m) in southern Illinois.

In this report, we concentrated on the geologic and geophysical interpretation of the Potosi Dolomite, which is part of the lower Knox succession. The Potosi Dolomite is characterized by thick vuggy intervals (up to 7 ft thick [2.1 m]) and brecciated zones that suggest a paleokarst environment (James and Choquette, 1988).

The Potosi Dolomite was chosen for this study because of its high permeability values and large capacity for $CO_2$ storage. The Potosi's excellent reservoir properties have been documented by a chemical waste deposal project at Tuscola, Illinois. This disposal project has already injected over 50 million tonnes of $CO_2$ equivalent in liquid chemical waste into the Potosi Dolomite. We were able to acquire new core and wireline data from the Potosi Dolomite and use existing 3D seismic reflection data from the Decatur, Illinois, area to model the movement of $CO_2$ through the reservoir.

### *Stratigraphy*

The objective of this topical study (Lasemi and Khorasgani, 2014 ) was to determine lateral and vertical lithologic variations of the rocks within the Upper Cambrian through Lower Ordovician succession (Sauk II–III sequences) deposits in Illinois that could serve as a reservoir or seal for $CO_2$ storage. More than 1,000 deep wells penetrating the Mt. Simon Sandstone were studied for detailed subsurface stratigraphic evaluation of the Knox succession. The Cambro-Ordovician rocks in the Illinois Basin consist of mixed carbonate-siliciclastic deposits. The Knox succession thickens in a southeast direction; its thickness ranges from nearly 800 ft in the extreme northwest to nearly 8,000 ft in the Reelfoot Rift in the extreme southeastern part of Illinois. The succession overlies, with a gradational contact, the Middle Cambrian Mt. Simon Sandstone and underlies, with the major sub-Tippecanoe unconformity, the Upper Ordovician St. Peter Sandstone.

In northern and central Illinois, the Cambro-Ordovician rocks are classified as the Cambrian Knox and the Ordovician Prairie du Chien Groups, which consist of alternating dolomite and siliciclastic units. The Upper Cambrian Knox Group includes, from base to top, the Eau Claire Formation, Galesville and Ironton Sandstones, Franconia Formation, Potosi Dolomite, and the Eminence Formation that grades laterally into the Jordan Sandstone in the extreme northwest part of the state. The Lower Ordovician Prairie du Chien Group comprises the Gunter Sandstone at the base followed by Oneota Dolomite, New Richmond Sandstone, and the Shakopee Dolomite. The siliciclastic intervals thin southward and, in the southern and deeper part of the Illinois Basin, the contacts of the dominantly carbonate units cannot be determined with confidence. Long regarded as the undifferentiated Knox Group, the Cambro-Ordovician succession in southern Illinois consists chiefly of fine to coarsely crystalline dolomite capped by the Middle Ordovician Everton Formation.

Detailed facies analysis indicates that the carbonate units consist mainly of mudstone to grainstone facies (fossiliferous/oolitic limestone and dolomite) with relics of bioclasts, ooids, intraclasts and peloids recording deposition on a shallow marine ramp setting. Porous and permeable vugular or fractured/cavernous dolomite intervals that grade to dense fine to coarsely crystalline dolomite are present within the dolomite units. Several hundred barrels of fluid were lost in some of these porous intervals during drilling, indicating high permeability. The sandstone intervals are porous and permeable and are texturally and compositionally mature.

The permeable sandstone and dolomite intervals are laterally extensive and could serve as important reservoirs to store natural gas, $CO_2$ or hazardous waste material. The dominant lithology of the Knox and the overlying Prairie du Chien Group is fine to coarsely crystalline, dense dolomite. The intercrystalline pore space of the dolomite was lost as a consequence of late-stage diagenetic dolomite overgrowth or cementation. The dense dolomite intervals, therefore, could serve as an effective seal for the encompassing porous and permeable sandstone and dolomite intervals.

The results of this study show that the Cambro-Ordovician Knox Group in the Illinois Basin may be an attractive target for $CO_2$ sequestration because these rocks are (1) laterally extensive, (2) consist of some porous and permeable dolomite and sandstone intervals, and (3) contain abundant impermeable shale and carbonate seals.

The focus of this investigation is the Cambrian Potosi Dolomite in the lower portion of the Knox, which is partially equivalent to the Copper Ridge Dolomite in Eastern Kentucky and Ohio. The Potosi Dolomite is underlain by the Franconia Formation and is overlain by the Eminence Formation. The Franconia Formation consists of glauconitic and argillaceous sandstone, shale, and dolomite. The Franconia is the oldest formation exposed in Illinois and is generally less than 100 ft (30 m) thick in northern Illinois and possibly greater than 700 ft (213 m) thick in the depocenter of the Illinois Basin. The contact with the overlying Potosi Dolomite is transitional as sandstone and shale diminish upward in the Franconia, making it difficult to distinguish. The Eminence is a relatively light-colored, fine- to medium-grained dolomite that contains abundant chert, quartz grains, and green clay. Thin interbedded mudstones and sandstones are common. It is commonly bioturbated, moderately vuggy, highly fractured, and brecciated. The Eminence is generally less than 100 ft (30 m) thick in extreme northern Illinois and 150 to 200 ft (45 to 61 m) thick in the southern part of the Basin. In Indiana and Kentucky, the Eminence is not recognized as a separate formation and is considered to be part of the Potosi Dolomite. In Illinois and Missouri, the Eminence has previously been differentiated from the underlying Potosi Dolomite by the absence of drusy quartz lining vugs. The top of the Eminence is separated from the overlying Gunter Sandstone by a regional unconformity that can be traced across most of North America (Palmer et al., 2012). In the Illinois Basin there is no available core across the Eminence-Potosi contact. We hypothesize that the Potosi Dolomite was subjected to early vadose or phreatic karstification, likely a result of subaerial exposure at the top of the Eminence; however, without core, this interpretation is difficult to prove.

### Potosi Dolomite

The Potosi Dolomite is a thick to massively bedded, gray to light brown, fine- to medium-crystalline dolomite characterized by vugs lined with dolomite, chalcedony, and megaquartz. In central and northern Illinois, lost circulation zones are encountered when drilling the Potosi Dolomite. Losses of thousands of barrels of drilling fluid have been reported from these lost circulation intervals. There are also reports of the drill bits dropping multiple feet when encountering these lost circulation intervals. In the wells at the IBDP, zones have been imaged with the FMI, indicating vuggy intervals up to 7 ft (2.1 m) thick. Lost circulation and abundant drilling fluid loss suggest these caverns are well connected rather than isolated dissolution voids.

Based on 30 ft (9 m) of core cut from the Potosi Dolomite above and into the lost circulation zone at the IBDP, the Potosi Dolomite is a cyclic carbonate dominated by subtidal and intertidal facies. Suspected algal structures and bioturbated facies are common throughout. Other facies include homogeneous dolomitized mudstones, thinly laminated dolomite, edgewise or flat-pebble conglomerates, and intraclastic dolomite. The suspected algal structures and bioturbated facies are highly obscured by a strong diagenetic overprint. This diagenetic overprint includes varying degrees of dolomitization, extensive fracturing, dissolution, brecciation, and quartz and dolomite cementation. These diagenetic processes are most abundant in the algal and bioturbated facies. However, depositional facies are difficult to identify in breccia zones. Isolated vugs that are less than 2 cm (.7 in.) are commonly lined with concentrically zoned late-stage dolomite. Vugs that are greater than 2 cm (.7 in.) are lined with dolomite, chalcedony, and megaquartz. This diagenetic quartz is typical of the Potosi Dolomite throughout the Illinois Basin and into Missouri and Wisconsin in equivalent strata, suggesting a diagenetic event that extends out of or along the margins of the Illinois Basin.

It was difficult to get accurate porosity data from conventional wireline tools because of the problems encountered when drilling through the lost circulation zone. In all three wells at the IBDP site, the use of lost circulation material was not adequate for reducing fluid loss; instead, the operators had to pump cement into the solution cavities. In the CCS1 well, they had to use 1,050 sacks of cement to control the drilling fluid loss (James Kirksey, personal communication, Schlumberger Carbon Services, 2013). Therefore, all of the originally higher porosity zones are filled with cement. The FMI was the best tool for evaluating the size and amount of vugs and solution cavities present in the well. The cement has a significantly lower resistivity than the dolomite and solution cavities were easily discernible with a microresistivity tool.

## Knox Group Capacity Estimates

Topical report DOE/FE0002068-19 summarizes the stratigraphy and capacity estimates of the Knox Group (Harris et al., 2014). Permitting of $CO_2$ injection into saline formations by the Environmental Protection Agency Underground Injection Control (EPA UIC) program requires that storage is only considered for the portion of the formation in which total dissolved solids of native brines exceed 10,000 ppm. Furthermore, to ensure that $CO_2$ remains in a dense supercritical phase, the standard approach to defining the net area of a potential saline formation storage reservoir is to remove any area of the storage formation that has a reservoir-seal contact boundary lying above 800 m depth. During the technical review of our results, we found that a portion of the Knox Group reservoir in Illinois did not meet these requirements. As a result, we redefined the reservoir boundary accordingly as shown in Figure 3. The volumetric equations were recalculated for this reduced reservoir domain and the final storage resource estimate (SRE) results are given in Table 1.

The recent work of (Ellett et al., 2013) indicates that the application of efficiency factors published in the DOE methodology (Goodman et al., 2012) to a reservoir volume has been spatially constrained based on water quality (10,000 ppm requirement) and $CO_2$ phase criteria (>800 m depth for suitable pressure and temperature conditions), and thus will effectively underestimate the resource. As a result it, should be noted that the storage resource estimates given in Table 1 are considered to be conservative estimates for the Knox Group reservoir.

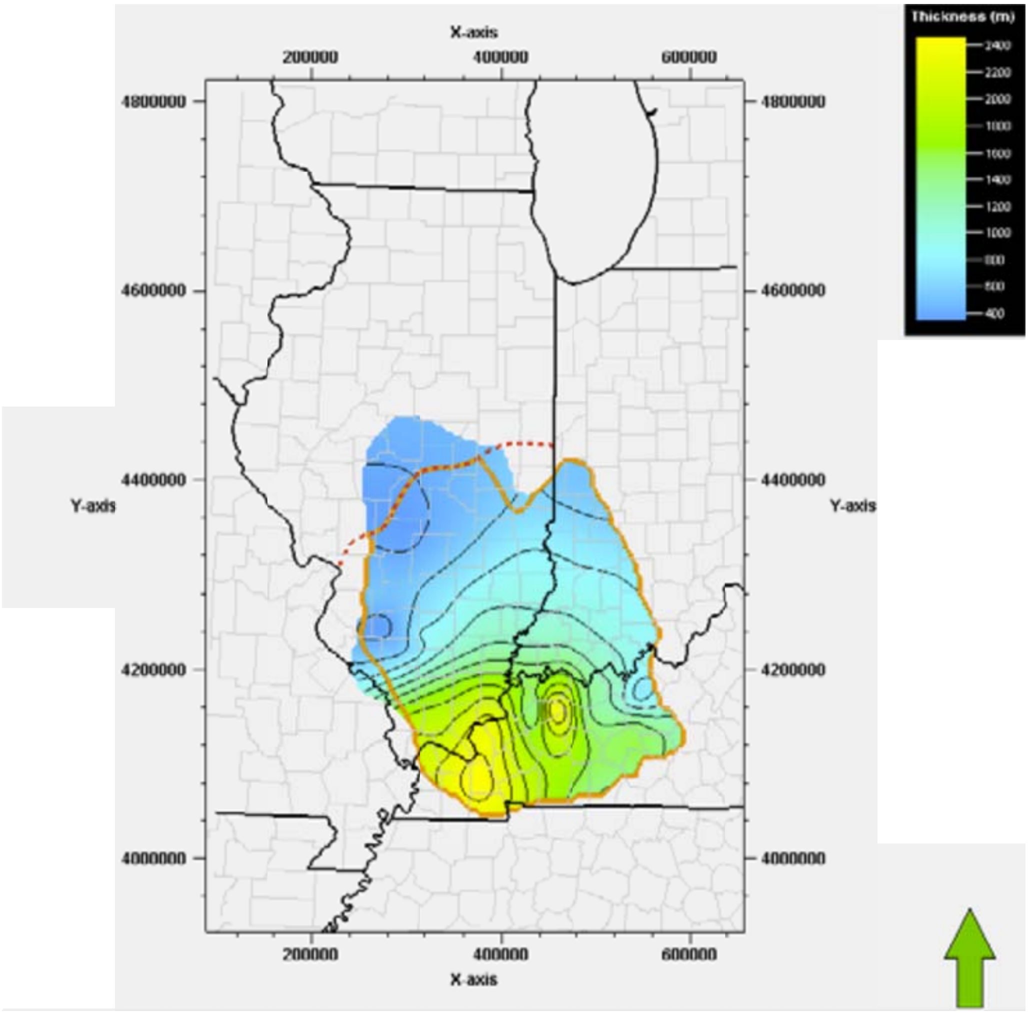



**Figure 3 Map showing the portion of the Knox Group reservoir in Illinois that was explicitly removed from the final SRE calculations based on the 10,000 ppm criteria (dashed red line) or the seal contact defined at top of the St. Peter Sandstone. Only the area inside the orange outline was used for the final volumetric calculations.**

**Table 1 Summary of final storage resource estimates for the Knox Group in the Illinois Basin.**

| | **$CO_2$ Storage Resource (billion metric tonnes)** | |
|---|---|---|
| **Details of Knox Group Storage Resource Estimates** | $P_{10}$ **Estimates** | $P_{90}$ **Estimates** |
| Single reservoir unit; assume effective porosity from core (6.4% mean); constant density (0.7 g/cc assumed); E= 0.64% ($P_{10}$) and 5.5% ($P_{90}$) for dolomite lithology. | 30 | 256 |
| Same as above but using nphi mean porosity of 5.8% to correct for sampling bias of core dataset (core mostly from Arches province vs. logs mostly from the reservoir domain). | 27 | 232 |

## Recommend Best Practices and Lessons Learned

The recommend best practices and lessons learned are given below:

- The FMI wireline tool is an absolute necessity to understand the amount of fractures and solution cavities. It must be acquired on all new wells in a CCS project that penetrate the Knox Group.
- Regional mapping of the reservoir is necessary to understand the continuity of the different carbonate formations.
- Geomechanical testing of the core was critical in understanding the rock properties for reservoir flow modeling of a hypothetical $CO_2$ sequestration project.

## St. Peter Sandstone

The topical report DOE/FE0002068-6 summarizes the stratigraphy and capacity estimates of the St. Peter Sandstone (Barnes and Ellett, 2014). The Middle Ordovician-age St. Peter Sandstone is a widespread, lithologically distinct, typically pure quartz arenite lithostratigraphic unit found throughout the upper Midwest, USA. The geological occurrence of the St. Peter Sandstone ranges from surface outcrop to deep burial settings in the cratonic interior Michigan and Illinois Basins at depths in excess of 3.5 km. The St. Peter Sandstone was initially defined as “ortho” quartzite sandstone exposed in Minneapolis and St. Paul, Minnesota, along the "St. Peter River," which is now called the Minnesota River. The type section is in a bluff where the Minnesota River joins the Mississippi River at Fort Snelling in Minneapolis.

The St. Peter Sandstone and transitional/correlative, carbonate-dominated facies occur throughout much of the central US, including at least some portions of the states of Indiana, Ohio, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, and Nebraska (Figure 4). Similar lithostratigraphic units of the Simpson Group are also recognized as far south as Oklahoma and Arkansas. In the upper Midwest, the St. Peter ranges in thickness from a widespread stratigraphic pinch out (typically on structural arch settings, e.g., Kankakee, Findley-Algonquin, Wisconsin, and Cincinnati arches) to in excess of 330 m (1,200 ft) in the Michigan Basin. In structurally positive arch areas of the upper Midwest, the St. Peter typically overlies a deep erosion surface or is absent above the inter-regional, base Tippecanoe (Knox) unconformity, which was cut into various older strata. In some areas of Wisconsin, southern lower Michigan, Indiana, and elsewhere, closely spaced stratigraphic sections of the St. Peter Sandstone infill erosional relief on the unconformity surface in thickness of as much as 70–100 m within a few kilometers or less of stratigraphic sections where the St. Peter Sandstone is thin or absent. In contrast, the contact with Lower-Middle Ordovician strata of the Knox and equivalent strata, including the Prairie du Chien Group, is considered conformable in the central portions of the Michigan and Illinois Basins. On the basis of biostratigraphic studies, the St. Peter Sandstone is older (Whiterockian) within the central Illinois and Michigan Basins, whereas it appears to be younger (Mohawkian) in the Upper Mississippi Valley type section area and other arch areas of the upper Midwest. These age relations suggest that deposition of the St. Peter Sandstone was time transgressive from the central Michigan and Illinois Basins outwards to arch areas, such as southeastern Minnesota.

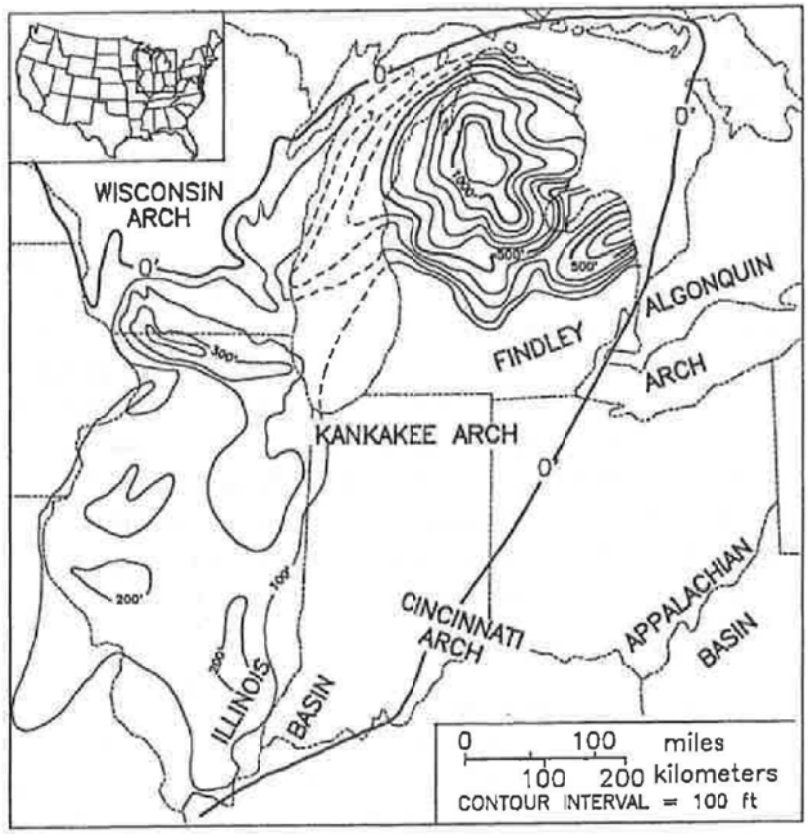



**Figure 4 Generalized, regional St. Peter Sandstone isopach map in the Midwest Basins and Arches geologic province (Barnes et al., 1996). Lithofacies transitions in the St. Peter to carbonate-prone strata towards the east and south result in the placement of the zero isopach line. In other positive, cratonic arch areas where the St. Peter Sandstone isopach thins, sandstone lithofacies are irregularly distributed with depositional outliers present in isolated areas above the base Tippecanoe unconformity surface.**

The reservoir potential of the St. Peter Sandstone is well established on the basis of historic potable water production in the upper Midwest and successful natural gas storage operations in Illinois. More recently, active deep exploration well drilling has resulted in commercial natural gas, natural gas liquids and minor petroleum being produced from the St. Peter Sandstone (also known as the “PDC” sands) in 75 fields from over 250 wells (about 110 currently producing) in the Michigan Basin. This production is noteworthy because producing intervals occur at depths in excess of between 2,000 to 3,000 m in generally strongly indurated and cemented sandstone lithofacies. These lithologic properties are in marked contrast to shallow aquifers in the upper Midwest, which typically produce from friable, fine- to medium-grained, well-sorted and rounded quartz-arenite at depths typically less than a few hundred meters. The St. Peter Sandstone has been studied and developed for natural gas storage in Illinois (Buschbach and Bond, 1974) at depths of less than 1 km but at depths below the occurrence of ground water of less than 10,000 ppm total dissolved solids (TDS). The St. Peter Sandstone in these fields possesses excellent reservoir quality with average porosity of 14%–16% and average permeability of $1.48 \times 10^{-9}$–$3.94 \times 10^{-9}$ $cm^2$ (150–400 mD). Petrologic study of the St Peter Sandstone in the Hillsboro storage field of Montgomery Co., Illinois, at burial depths of about 1,000 m suggests incipient to significant lithification through compaction and diagenetic cementation of primary intergranular porosity, although reservoir quality is very good in these relatively shallowly buried sandstones with porosity of 5% to over 25% and permeability from $9.86 \times 10^{-11}$ to over $9.86 \times 10^{-9}$ (10 mD to over 1,000 mD).

### *St. Peter Capacity Estimates*

Multiple deterministic-based approaches were used in conjunction with the probabilistic-based storage efficiency factors published in the DOE methodology to estimate the carbon storage resource of the formation. Extensive data sets of core analyses and wireline logs were compiled to develop the necessary inputs for volumetric calculations. Results demonstrate how the range in uncertainty of storage resource estimates varies as a function of data availability and quality, and the underlying assumptions used in the different approaches. In the first and simplest approach, storage resource estimates were calculated from mapping the gross thickness of the formation and applying a single estimate of the effective mean porosity of the formation (Figure 5 and Figure 6). Results from this approach led to storage resource estimates ranging from 3.3 to 35.1 Gt in the Michigan Basin, and 1.0 to 11.0 Gt in the Illinois Basin at the $P_{10}$ and $P_{90}$ probability level, respectively. The second approach involved consideration of the diagenetic history of the formation throughout the two basins and used depth-dependent functions of porosity to derive a more realistic spatially variable model of porosity, rather than applying a single estimate of porosity throughout the entire potential reservoir domains. The second approach resulted in storage resource estimates of 3.0 to 31.6 Gt in the Michigan Basin, and 0.6 to 6.1 Gt in the Illinois Basin. The third approach attempted to account for the local-scale variability in reservoir quality as a function of both porosity and permeability by using core and log analyses to calculate explicitly the net effective porosity at multiple well locations, and interpolate those results throughout the two basins. This approach resulted in storage resource estimates of 10.7 to 34.7 Gt in the Michigan Basin, and 11.2 to 36.4 Gt in the Illinois Basin. A fourth and final approach used advanced reservoir characterization as the most sophisticated means to estimate storage resource by defining reservoir properties for multiple facies within the St Peter Sandstone. This approach was limited to the Michigan Basin because the Illinois Basin data set did not have the requisite level of data quality and sampling density to support such an analysis. Results from this approach led to a storage resource estimate of 15.4 Gt to 50.1 Gt for the Michigan Basin. The observed variability in results from the four different approaches is evaluated in the context of data and methodological constraints, leading to the conclusion that the storage resource estimates from the first two approaches may be conservative, whereas the net porosity based approaches may overestimate the resource.

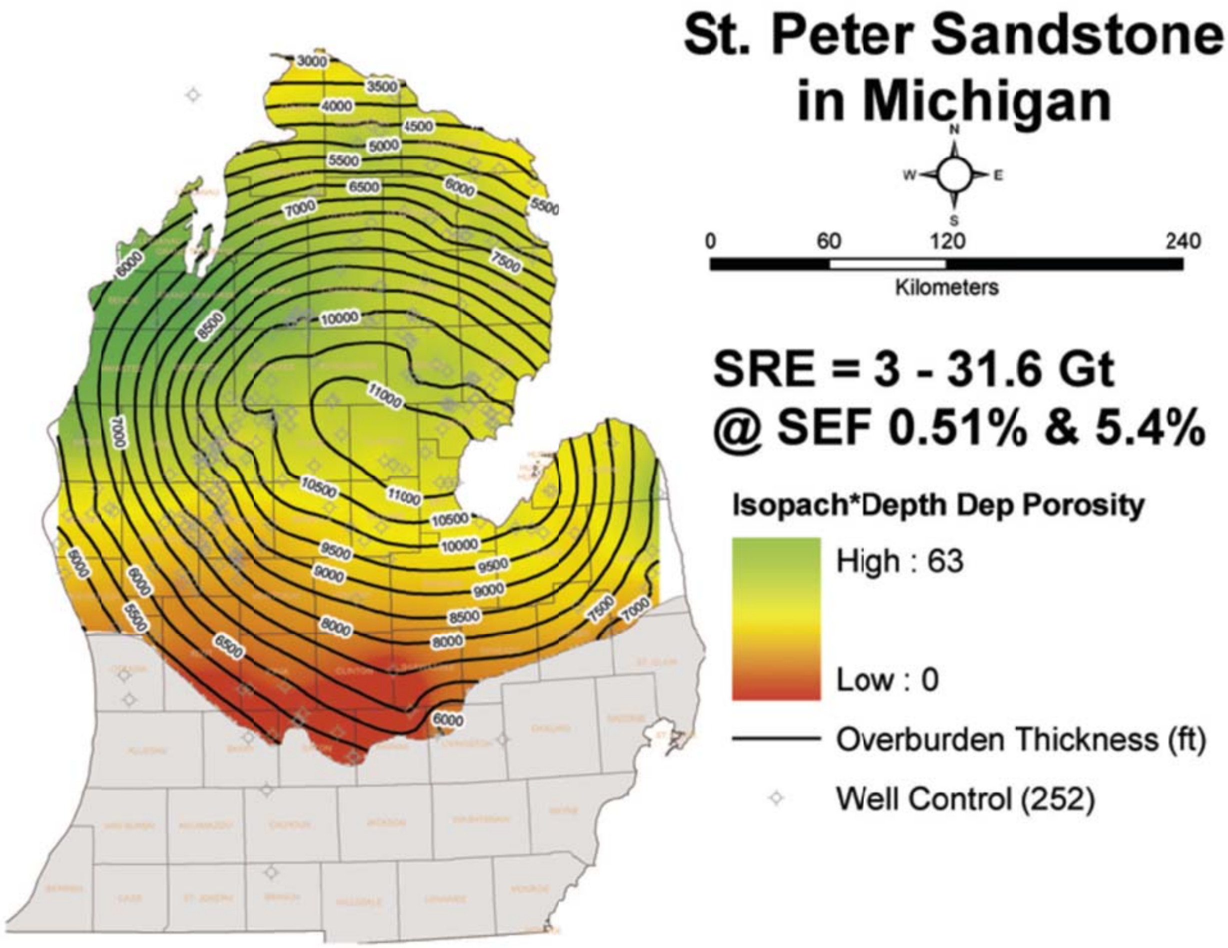



**Figure 5. Total pore volume grid for Michigan using St. Peter Sandstone Isolith (hg), area (At, in square kilometers), and depth-dependent porosity (see text for discussion). This product was incorporated into the SRE expression using a $CO_2$ density (ρ) of 0.7 gm/cc and $P_{10}/P_{90}$ storage efficiency factors (Esaline) of 0.51/5.4%.**

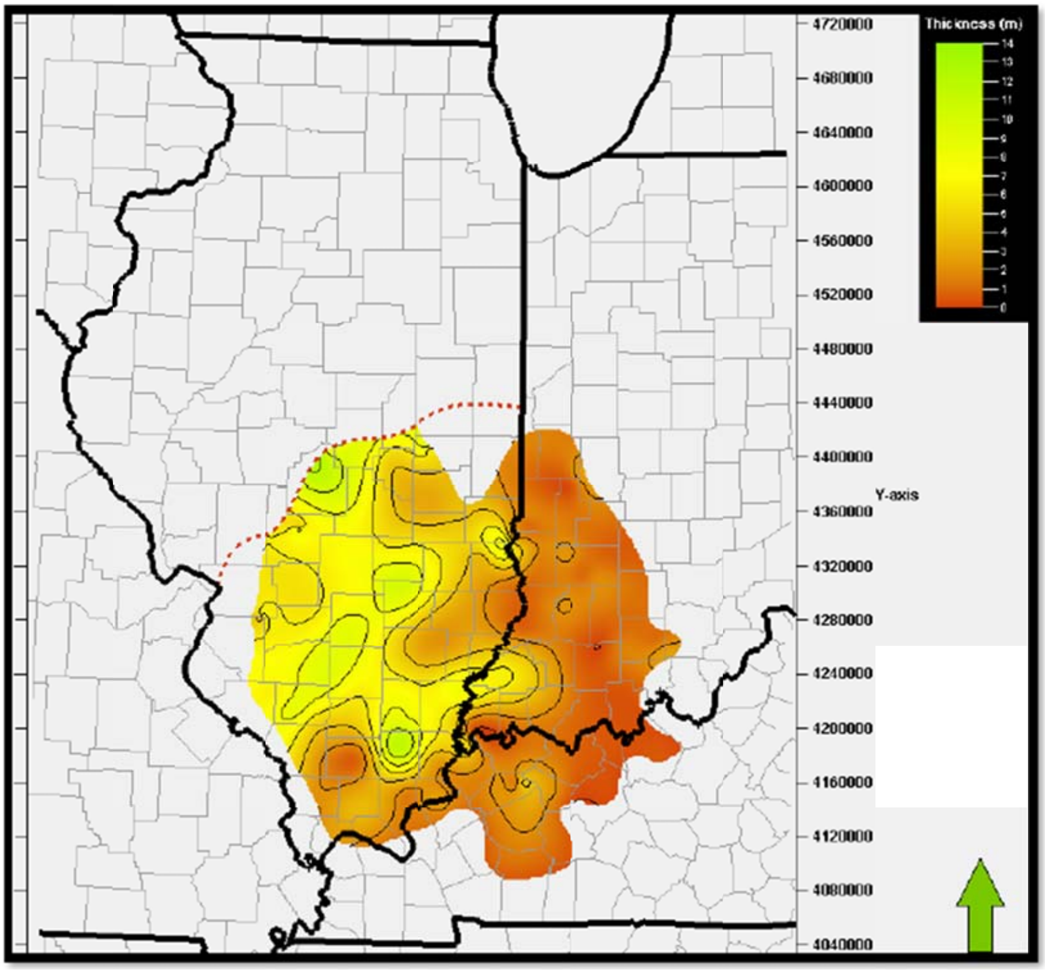



Figure 6. Total pore volume grid in the Illinois Basin using St. Peter Sandstone isopach (hg), area (At, in square kilometers), and average porosity (ϕtot; 14.1%). Unit is thickness of total porosity in meters, ranging from 0 (red) to 14 m (green). This product was incorporated into the SRE expression using a $CO_2$ density (ρ) of 0.7 gm/cc and $P_{10}/P_{90}$ storage efficiency factors (Esaline) of 0.51/5.4%.

## Recommend Best Practices and Lessons Learned

The recommend best practices and lessons learned are given below:

- Regional mapping of the St. Peter Sandstone thickness is important because the thickness of the formation can vary significantly across the Illinois Basin.
- Understanding of the reservoir quality is important in the eastern edge of the State of Illinois because of an increase in carbonates and a reduction of porosity and permeability.
- In northern Illinois, the St. Peter Sandstone has measured salinities of less than 10,000 mg/L and is considered potable water by the US Environmental Agency. Any placement of CCS sites in this formation must consider the salinities of the St. Peter Sandstone.

## Seals

The low-porosity Knox limestones may function as locally effective seals for $CO_2$ injection into a Knox sandstone unit or into the Potosi Dolomite, but the limestones are difficult to differentiate (and therefore to regionally map) and they may be too fracture prone to provide a reliable seal. In contrast, the regional Maquoketa-Utica Shale appears to be present at thicknesses exceeding 30 m (100 ft) everywhere in the Illinois and Michigan Basins. Where cored in the Blan well in Kentucky, the Maquoketa is a black, fissile shale dominated by clay minerals, and it has both sufficiently low permeability and sufficiently high compressive strength to serve as caprock for an underlying Knox $CO_2$ reservoir. In the Decatur area of the central Illinois Basin, the Maquoketa contains higher fractions of quartz and carbonate minerals relative to clays, but is thinly laminated and has low effective porosity (<3%) and permeability ($<9.86 \times 10^{-12}$ $cm^2$ [1 mD]; Zaluski, 2014). According to Young (1992), the Maquoketa "is a low permeability groundwater-confining unit throughout the Midwest."

### *Geochemistry of Seals*

In the topical report DOE/FE0002068-10 (Yoksoulian et al., 2014), portions of the Knox Group (Potosi Dolomite, Gunter Sandstone, and New Richmond Sandstone), St. Peter Sandstone, and Maquoketa Shale have been assessed for CCS potential as part of a regional study of the Illinois and Michigan Basins.

A total of 12 laboratory experiments were completed to identify the reaction mechanisms, kinetics, and solid-phase products that are likely to occur in the Knox Dolomite and the Maquoketa Shale when exposed to supercritical $CO_2$. Samples were obtained from the IBDP, outcrops and cores from within the Illinois Basin, and laboratory produced synthetic and reservoir brines. Nine high-pressure, high-temperature batch reactor experiments were conducted using Potosi Dolomite (southwest Missouri outcrop), Gunter and New Richmond Sandstone (Morgan Co, IL), and Maquoketa Shale (IBDP site). Additionally, five core flood experiments were conducted using Potosi Dolomite (IBDP site) and Gunter (Blan well, Hancock Co., KY) and St. Peter (Marion Co., IL) Sandstones, using either laboratory produced synthetic brine or deionized water (DI).

A variety of analytical techniques were used to characterize the physical, geochemical, and mineralogical changes between the pre- and post-reaction products from the batch reactor and core flood experiments. These included standard petrography, scanning electron microcopy (SEM; Figure 7), X-ray diffraction, ion chromatography, and inductively coupled plasma analyses. Results were used to compare pre- and post-reaction petrographic and geochemical conditions, as well as kinetic and equilibrium predictions from numerical geochemical modeling.

Results from the Knox Group reservoir experiments show the dissolution of dolomite, the dominant mineral present throughout the Knox Group, while in the presence of supercritical $CO_2$ and brine as expected. The SEM analysis of the Potosi Dolomite batch reactor experiments revealed pitting and degradation of dolomite crystals that appeared pristine and unaltered in pre-reaction samples. Post-reaction brines from the Potosi Dolomite, Gunter Sandstone, and New Richmond Sandstone experiments all contained elevated concentrations of calcium, magnesium, strontium, and barium greater than in the nonreacted brines. These elevated concentrations indicate that carbonate minerals such as dolomite dissolved during the experiments. There is no evidence for the formation of measureable amounts of new solid-phase products during the duration (1 to 4 months) of the batch reactor studies using the Knox Group reservoir rock; however, very small amounts of solid phase material produced during the experiments were observed, but could not be identified or quantified by the techniques used in this study.

Post-reaction brine chemistry results for all experiments were compared to United States Environmental Protection Agency (US EPA) drinking water standards for the regulated analytes As, Ba, Be, Cd, Cr, Cu, Pb, Se, and Tl (where applicable, F and $NO_3$ were compared as well) to provide context for the results of this project. However, in some cases, the results of the analytes As, Be, Cd, Pb, Se and Tl were inconclusive because analytical method detection limits (MDLs) were up to 150 times greater than the US EPA minimum contaminant levels (MCLs). The results of the Potosi Dolomite, New Richmond and Gunter Sandstones, and Maquoketa Shale batch experiments indicated that the concentrations of the analytes of concern were generally less than the US EPA minimum MCLs.

Speciation calculations based on the post-reaction brine composition during the Potosi Dolomite experiment indicate that the system reached equilibrium before the end of the 4 month experimental duration. As a result, five short-term (approximately 6 hour) core flood experiments were performed. Interpretation of post-reaction brine chemistry and equilibrium modeling of these short-term experiments indicate that the systems still reacted quickly enough to reach equilibrium with respect to carbonates. Geochemical modeling and optimization estimated reaction rate parameters for some potential reactions that could occur in the Knox Group. The observed and modeled rapid reactions suggest that larger scale models simulating $CO_2$ sequestration reactive transport for the Knox Group do not need kinetic constraints for carbonates to create an accurate understanding of reservoir processes.

The Maquoketa Shale (primary seal) batch reactor experiments indicated that feldspars, clays, carbonates and sulfide minerals dissolved as suggested by elevated concentrations of aluminum, barium, calcium, potassium, magnesium, sulfur, silicon, and strontium in the post-reaction brines. Using rate parameters derived from pre-reaction mineralogy and post-reaction fluid geochemistry, a model estimating the expected mineral reactions after 10 years indicates that alteration of k-feldspar to kaolinite and quartz dominate the changes in silicate mineralogy. These alterations contribute little to changes in porosity and therefore would not be expected to have a significant impact on seal integrity. Carbonate minerals were 48.2% of the initial volume in samples used in the experiments, and the modeled dissolution of these minerals could lead to a 2.2% decrease in mineral volume at most. However, in an actual sequestration scenario, the lower water-to-mineral ratio would limit the carbonate dissolution further.

In summary, project results indicate that the Knox Group-$CO_2$-brine system could be initially chemically reactive in a $CO_2$ sequestration scenario. The effect of this reactivity would likely reach equilibrium shortly after injection of $CO_2$ into the reservoir had stopped. According to IBDP site geophysical logs, the Maquoketa Shale is approximately 61 m (200 ft) thick in the central Illinois Basin, and a secondary (New Albany Shale) seal is 40 m (130 ft) thick. Thus, even if significant mineral dissolution occurred in the caprock, it would be highly unlikely that caprock integrity would be in jeopardy given the rapid equilibration of the Knox-$CO_2$-brine system.

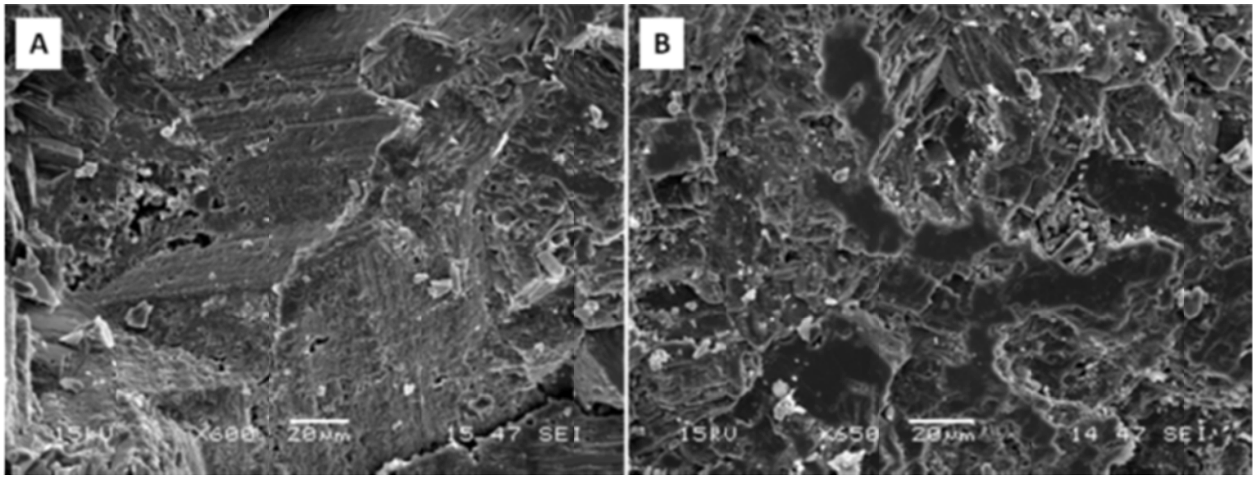



**Figure 7 SEM images of pre- (A) and post-reaction (B) Potosi Dolomite sample MO-1-9. (A) Pre-reaction sample shows dolomite crystals that are slightly pitted in areas but mostly clean of defects and (B) shows extremely etched dolomite crystals and dissolution features.**

### *Maquoketa Shale*

The Knox Project's objective is to evaluate the potential of formations within the Cambrian-Ordovician strata above the Mt. Simon Sandstone (St. Peter Sandstone and Potosi Dolomite) as potential targets for CCS in the Illinois and Michigan Basins. The suitability of the St. Peter Sandstone and Potosi Dolomite to serve as reservoirs for $CO_2$ sequestration is discussed in separate reports. In topical report DOE/FE0002068-9 (Zaluski, 2014) the data gathered from the Knox project, IBDP, and Illinois Industrial Carbon Capture and Sequestration project (IL-ICCS) are used to make some conclusions about the suitability of the Maquoketa shale as a confining layer for $CO_2$ sequestration. These conclusions are then upscaled to basin-wide inferences based on regional knowledge.

Data and interpretations (stratigraphic, petrophysical, fractures, geochemical, risk, seismic) applicable to the Maquoketa Shale from the above mentioned projects was inventoried and summarized. Based on the analysis of these data and interpretations, the Maquoketa Shale is considered to be an effective caprock for a $CO_2$ injection project in either the Potosi Dolomite or St. Peter Sandstone because it has a suitable thickness (about 200 ft [61m]), advantageous petrophysical properties (low effective porosity and low permeability), favorable geomechanical properties, an absence of observable fractures and is regionally extensive. Because it is unlikely that $CO_2$ would migrate upward through the Maquoketa Shale, $CO_2$ impact to above lying freshwater aquifers is unlikely. Furthermore, the observations indicate that $CO_2$ injected into the St. Peter Sandstone or Potosi Dolomite may never even migrate up into the Maquoketa Shale at a high enough concentrations or pressure to threaten the integrity of the caprock.

Site-specific conclusions were reached by unifying the data and conclusions from the IBDP, ICCS, and the Knox projects. In the Illinois Basin, as one looks further away from these sites, the formation characteristics are expected to vary. The degree of how well this data can be extrapolated throughout the Basins (regionalized) is difficult to quantify because of the limited amount of data collected on the Maquoketa Shale away from IBDP, IL-ICCS, and the Knox projects.

Data gathered from the IBDP, IL-ICCS, and Knox projects were used to make conclusions about the suitability of the Maquoketa shale as a confining layer for $CO_2$ sequestration. This study indicates that the Maquoketa Shale would be a suitable caprock for a $CO_2$ injection program in either the Potosi Dolomite or St. Peter Sandstone.

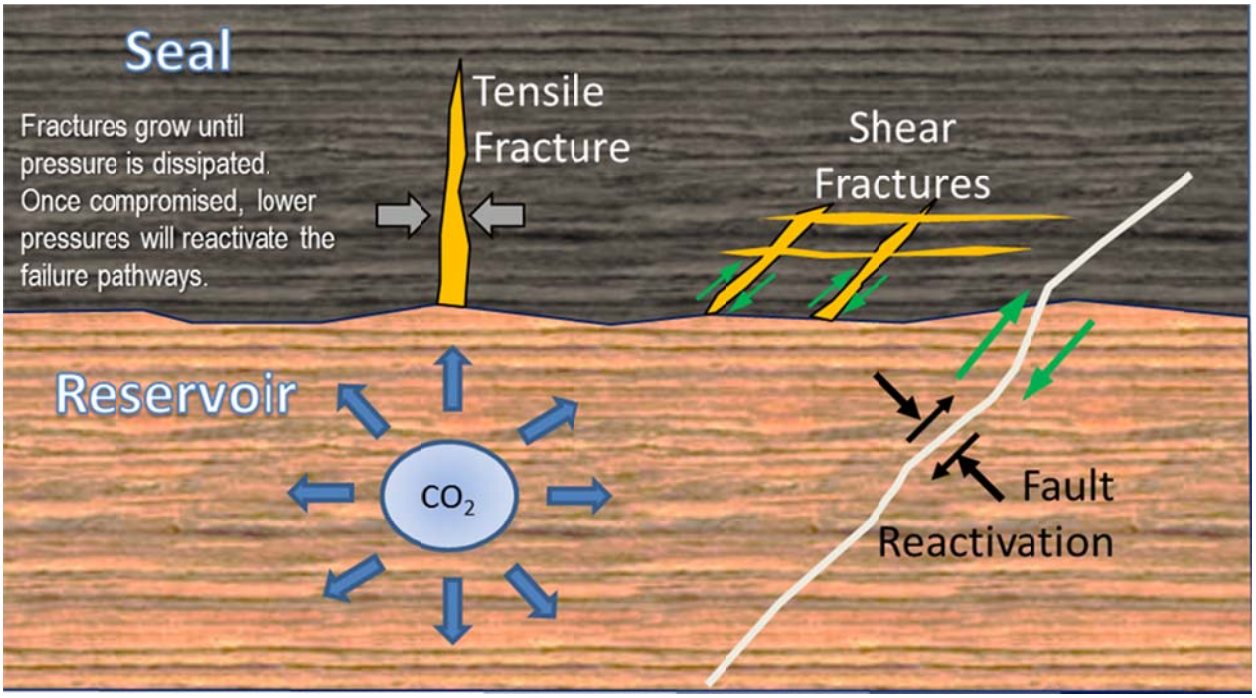



Figure 8 Geomechanical risk scenarios due to $CO_2$ injection.

## Analysis of Fault Seal Potential for Knox Reservoirs in the Southern Illinois Basin

Location-siting parameters for research- or industrial-scale geologic CCS projects often preclude areas near known faults. The topical report DOE/FE0002068-11 (Hickman, 2014) describes how finding suitable sites are problematic in areas such as the southern Illinois Basin, which have been affected by numerous tectonic episodes since at least the late Precambrian, leading to countless faults throughout the region (Figure 9).

Faults are typically avoided during CCS because of uncertainties of two factors: possible $CO_2$ leakage along or across the existing fault plane and/or the integrity of the reservoir seal with respect to future earthquake damage from fault movements (seal breaching by new fault splay). Averting earthquake damage is accomplished by avoiding areas around currently active faults. Active faults in the southern Illinois Basin can be easily identified from modern seismicity records and are generally only found in the Wabash Valley Fault System (WVFS) and the New Madrid Seismic Zone (NMSZ). For faults in seismically inactive regions, the main concern for sequestration projects is the lack of effective sealing potential within the fault damage zone.

Though detailed, site-specific studies would still be required before the construction of industrial-scale sequestration projects, initial estimates of the sealing potential of faults can be calculated using numerous methods derived from the petroleum industry. For this project, two cross sections (Figure 9) were produced through two regional fault trends in the Illinois Basin with different amounts of offset and ages of deformation, in order to estimate the potential for fault sealing above a theoretical CCS reservoir in the Knox Group. These results indicate a high probability for sealing of the Knox Group reservoirs within the Rough Creek Fault Zone, but a much lower probability for a continuous seal for reservoirs below or within the LaSalle Anticlinorium.

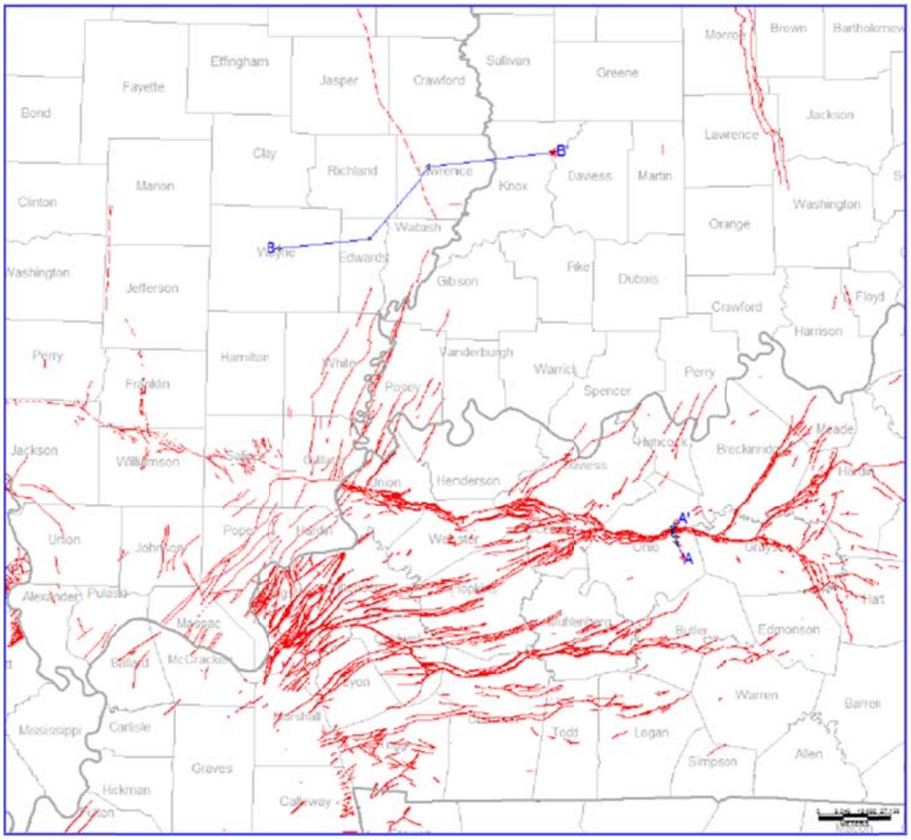



**Figure 9 Mapped faults within the southern Illinois Basin in red; locations of the two cross sections discussed in topical report are highlighted in blue.**

## Recommend Best Practices and Lessons Learned

The recommend best practices and lessons learned are given below:

- All new wells need to acquire the FMI wireline log in the evaluations of fractures in the sealing strata.
- A mechanical earth model should be completed using both wireline log data and whole core for ground truth.
- Compromised wellbore integrity is a risk that all CCS project operators must evaluate and understand.
- The geochemistry of the seals is important in understanding the long-term uncertainties for inhibiting the $CO_2$ plume from penetrating shallower horizons.

## Reservoir Injectivity

For target reservoir formations, studies of reservoir attributes aim to quantify the rate at which the formations may accept an injected flow of dense-phase $CO_2$, and to estimate the rock volume and surface-footprint area that a specified mass of injected $CO_2$ will occupy. For intended caprock formations, studies attempt to quantify (1) the added pressure (due to $CO_2$ injection) that a target caprock will withstand without fracturing, and (2) the minimum pressure required to cause $CO_2$ to enter the caprock pore space if no fracturing occurs (the pore entry pressure).

Results of this research suggest that, generally in the Illinois Basin, reservoirs in both the St. Peter Sandstone and the Potosi Dolomite (a formation of the Knox) may be capable of sustaining injection at commercial rates. We examined four different St. Peter gas storage projects in Illinois (Figure 10). These four projects illustrated the effectiveness of the reservoir and the overlying seals. The development of these S.t Peter gas storage projects date from the early 1960s to the early 1970s. All of these storage reservoirs were located on structural anticlines. These storage projects are important because they show that the rocks above the St. Peter reservoir are effective seals to the movement of gas; therefore, the St. Peter Sandstone is not only a potential reservoir, but also has the seals necessary to contain $CO_2$. The storage projects also show that the St. Peter has the necessary permeability to inject $CO_2$. Reservoir simulation results for the St. Peter indicate good injectivity and a relatively small $CO_2$ plume footprint. While a single St. Peter well is not likely to achieve the targeted injection rate of 2 million tonnes/year, results of this study indicate that development with three or four appropriately spaced wells may be sufficient. For the Potosi Dolomite, dynamic simulations discussed in in this report substantiate the possibility that in the Decatur area, the Potosi Dolomite may be capable of accepting $CO_2$ at a rate of 3.2 million tonnes per annum (MTPA) for 30 years, possibly requiring more than one injection well.

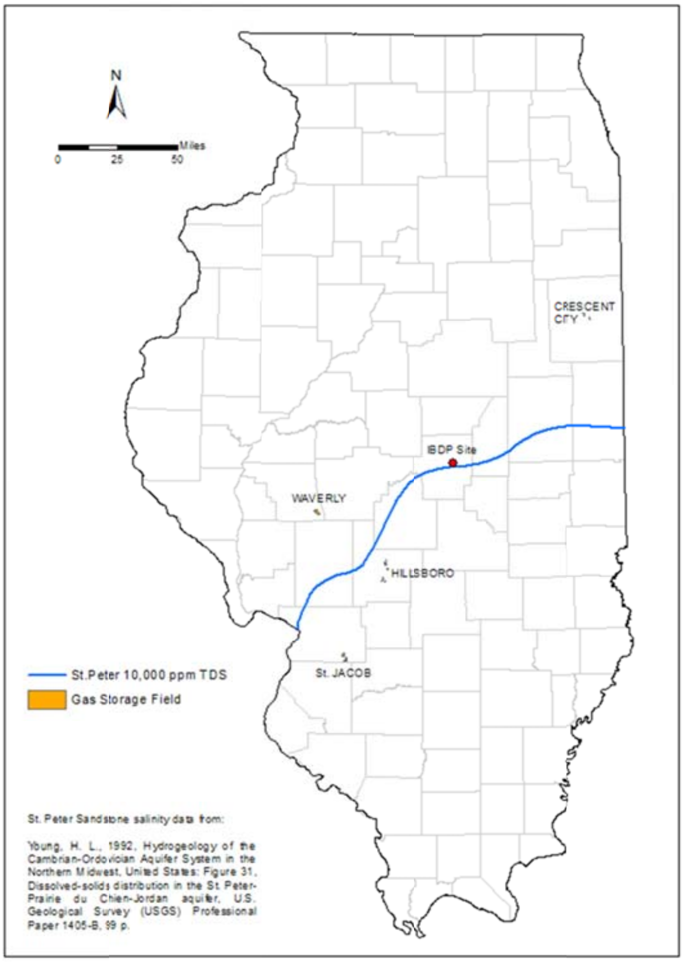



**Figure 10 Location of St. Peter natural gas storage fields. The map also shows the approximate location of the St. Peter potable water. The St. Peter is predicted be less than 10,000 mg/l north of that line.**

Data from the Marvin Blan No. 1 well in western Kentucky (Bowersox and Williams, 2014) indicate that the range of most-likely storage capacities in the Knox is from 1,000 tonnes per surface hectare for the Gunter sandstone interval alone to 8,685 tonnes per surface hectare for the entire Knox section. The Gunter has higher permeability and porosity than the bulk of the Knox carbonates, but by itself it lacks sufficient reservoir volume to be considered for $CO_2$ storage. The Gunter may provide up to 18% of the reservoir volume available in the Knox.

Reservoir simulations of the Potosi Dolomite predict that much of the injected $CO_2$ would flow into and through relatively thin, high-permeability intervals, resulting in a large plume diameter compared with the St. Peter Sandstone. The locations and depths of such high-permeability intervals within the Potosi Dolomite (and possibly at other horizons within the Knox) remain unpredictable, creating challenges in designing monitoring programs. While the present studies show that seismic inversion techniques may reduce these uncertainties, the techniques can only be successfully applied where the acquired seismic data are of high quality. Not all surface settings and noise environments allow acquiring seismic data of adequate quality, as shown by the inability at the Blan well to image the injected $CO_2$.

Highly porous and permeable intervals (as shown by lost circulation zones and high wastewater injection rates) have been penetrated within the Potosi Dolomite at multiple locations around the Illinois Basin, and Potosi Dolomite intervals displaying vuggy secondary porosity have been documented in cores. Furthermore, diagenetic history deduced from petrographic studies suggests that secondary porosity development in the Potosi Dolomite is likely to have been of a regional, rather than local nature. These observations suggest that secondary porosity adequate for a $CO_2$ injection project may occur widely in the Illinois Basin and possibly the Michigan Basin.

### Recommend Best Practices and Lessons Learned

The recommend best practices and lessons learned are given below:

- Distinguishing particular subareas that are especially favorable or unfavorable for porosity development. In a “favorable” area, estimating the chance that a favorable reservoir zone will be penetrated in an exploration well.
- Estimating the geometric, petrophysical, and hydraulic characteristics of a favorable reservoir zone.

## Injection of $SO_2$ co-injected with $CO_2$

The ASME performed a peer review (October 22–26, 2012) of selected projects within the Carbon Storage portfolio. Although not required, the panel recommended that the project perform modelling work to determine the potential impact that impurities in $CO_2$ can have on the reaction products and mineralization kinetics.

The Cambrian–Ordovician Knox Group, a thick sequence of dolostone with minor dolomitic sandstone, in western Kentucky, USA, has been evaluated as a prospective $CO_2$ sequestration target. The $CO_2$ storage potential of the Knox group was studied through a field test site, where a 2,477 m test well was drilled and 626 tonnes of $CO_2$ was injected. Rock cores, brine samples, and geophysical logs were also taken from the test well to study geology, brine chemistry, mineralogy, seal rock integrity, and long-term physical and chemical fate of injected $CO_2$. As a part of the $CO_2$ storage evaluation study, this topical report DOE/FE0002068-18 (Zhu and Harris, 2014) describes the task of evaluating potential long-term impacts of $SO_2$ when co-injected with $CO_2$ on the Knox deep saline reservoirs.

Understanding potential long-term impacts of $CO_2$ impurities, such as sulphur and nitrogen compounds, on deep carbon storage reservoirs is of considerable interest because co-injection of the impurities with $CO_2$ can bring significant economic and environmental benefits. In this topical report (Zhu and Harris, 2014), a modeling approach was used to evaluate long-term chemical and physical interactions among formation rocks, brines, and co-injected $CO_2$ and $SO_2$. The TOUGHREACT was used to build separate one-dimensional (1D) radial models for the Beekmantown Dolomite and the Gunter Sandstone, two primary reservoirs identified in the Knox. The 1D models were built on mostly field data collected from the test well. Co-injection of a mass ratio of 2.5% $SO_2$ and 97.5% $CO_2$, representative of flue gas from coal-fired plants, was simulated and the co-injection models were compared to models with $CO_2$ only injections. To accommodate co-injection of $CO_2$ and $SO_2$ in TOUGHREACT, 0.8 mol/(kg of water) of $SO_2$ was dissolved in the original formation brines and the $SO_2$-containing brines were then co-injected with $CO_2$. Each model simulated an injection period of 16 hours and subsequent reaction period of 10,000 years.

The model results suggest that added $SO_2$ created an acidic zone near the injection well in both reservoirs through a disproportionation reaction and the acidic zone enhanced dissolution of dolomite and precipitation of anhydrite, leading to noticeable increases in porosity and permeability. The added $SO_2$ changed brine chemistry, decreasing concentration of Ca+ and increasing concentrations of SO42- and Mg2+. The acidic zones appeared to be buffered rather quickly but the changes in aqueous species remained for a long time. However, the impacts on aluminosilicate minerals appeared to be insignificant in both reservoirs, slightly changing the rates of precipitation/dissolution but the overall reaction paths remained the same. The Gunter Sandstone appeared to be more active with $SO_2$ than the Beekmantown Dolomite. With the same $SO_2$ impurity, more dolomite was dissolved in the Gunter than in the Beekmantown. Consequently, porosity was raised more in the Gunter than in the Beekmantown. Additional comparison model runs with different inputs in reservoir physical properties suggested that the difference in reservoir response to $SO_2$ was likely controlled by geochemical characteristics rather than physical properties of the reservoirs.

Although a representative $SO_2$ impurity was used in this study, the degree of interactions among $SO_2$, the formation brines, and the reservoir rocks should be considered a rough approximation. The handling of $SO_2$ impurity in TOUGHREACT required the $SO_2$ to be totally dissolved in brine, which exaggerated the amount of $SO_2$ available for interacting with the reservoirs. The 2 times exaggeration would be especially high for large-scale injection scenarios where injected $SO_2$ would be expected to remain in gas phases for a long period of time.

The model results presented here should be considered as explanatory, aiming to illustrate possible major physical/geochemical alterations in the two carbon deep reservoirs because of the added $SO_2$. The 1D radial models were highly simplified, treating both reservoirs as homogeneous in physical and geochemical properties. Field conditions are certainly more complex, which may greatly change physical flow and chemical reaction path. Because of the highly simplified assumptions used in these 1D models and limitations of TOUGHREACT, the results should be considered as qualitative.

### Recommend Best Practices and Lessons Learned

The recommend best practices and lessons learned are given below:

- Injection of $SO_2$ impurities may alter the porosity and the permeability of the reservoir. More research needs to be completed on flue gas impurities that are included with the injected $CO_2$.

## Reservoir Flow Simulation (St. Peter Sandstone)

The ASME performed a peer review (October 22–26, 2012) of selected projects within the Carbon Storage portfolio. The ASME panel requested that this project conduct further reservoir simulations using reservoir properties that would be expected in deeper St. Peter reservoirs. Therefore, additional reservoir flow simulations of $CO_2$ injection in the St. Peter Sandstone were completed in this project.

The first set of flow simulations tried to inject at an injection rate of 2 million tonnes/year at a constant rate over a 20-year period DOE/FE0002068-1 (Leetaru et al., 2012). Reservoir simulation results for the St. Peter interval indicate that the plume diameter related to a single injector would be relatively small, with a radius of approximately 1 mi; however, the overall plume footprint with multiple wells may be quite large. During the 20-year simulation period, it was observed that an average injection rate of 990,000 tonnes/year was achieved at the maximum bottomhole injection pressure. During this period, the minimum injection rate was 660,000 tonnes/year ($1^{st}$ year) and the maximum injection rate was 1,164,000 tonnes/year ($20^{th}$ year). Although the well injected at maximum injection pressure throughout the injection period, injection rate increased as the saturation and mobility of $CO_2$ increased. Based on these results, a rough estimate of the number of wells needed to inject 2 million tonnes/year into the St. Peter interval can be made; however, these results ignore potential well interference effects and possible limitations due to wellbore hydraulics. Keeping these assumptions in mind, the simulation results indicate that a minimum of two wells would be required; although three or four wells are more likely in order to allow for uncertainty in reservoir performance and to provide operational reliability.

In addition to the injectivity analysis, the corresponding pressure behavior of the reservoir because of the modeled injection from a single well was delivered for geomechanical analysis. The near-wellbore region experiences the largest pressure increase; the pressure disturbance decreases at increasing radial distance from the well, with an increase in formation pressure of 100 psi observed at a radius of approximately 20,000 ft (6,096 m) from the injection wellbore at the end of the injection period.

This topical report DOE/FE0002068-7 (Will et al., 2014) addresses the question of whether or not the St. Peter Sandstone may serve as a suitable target for $CO_2$ sequestration at locations within the Illinois Basin, where it lies at greater depths (below the underground source of drinking water [USDW]) than at the IBDP site. The work performed included numerous improvements to the existing St. Peter reservoir model created in 2010. Model size and spatial resolution were increased resulting in a threefold increase in the number of model cells. Seismic data was utilized to inform spatial porosity distribution and an extensive core database was used to develop porosity-permeability relationships. The analysis involved a Base Model representative of the St. Peter at in-situ conditions, followed by the creation of two hypothetical models at in-situ plus 1,000 ft (300 m) and in-situ plus 2,000 ft (600 m) depths (Figure 11) through systematic depth-dependent adjustment of the Base Model parameters. Properties for the depth-shifted models were based on porosity versus depth relationship extracted from the core database followed by application of the porosity-permeability relationship. Each of the three resulting models (Figure 12) were used as input to dynamic simulations with the single well injection target of 3.2 MTPA for 30 years using an appropriate fracture gradient based on the bottomhole pressure limit for each injection level.

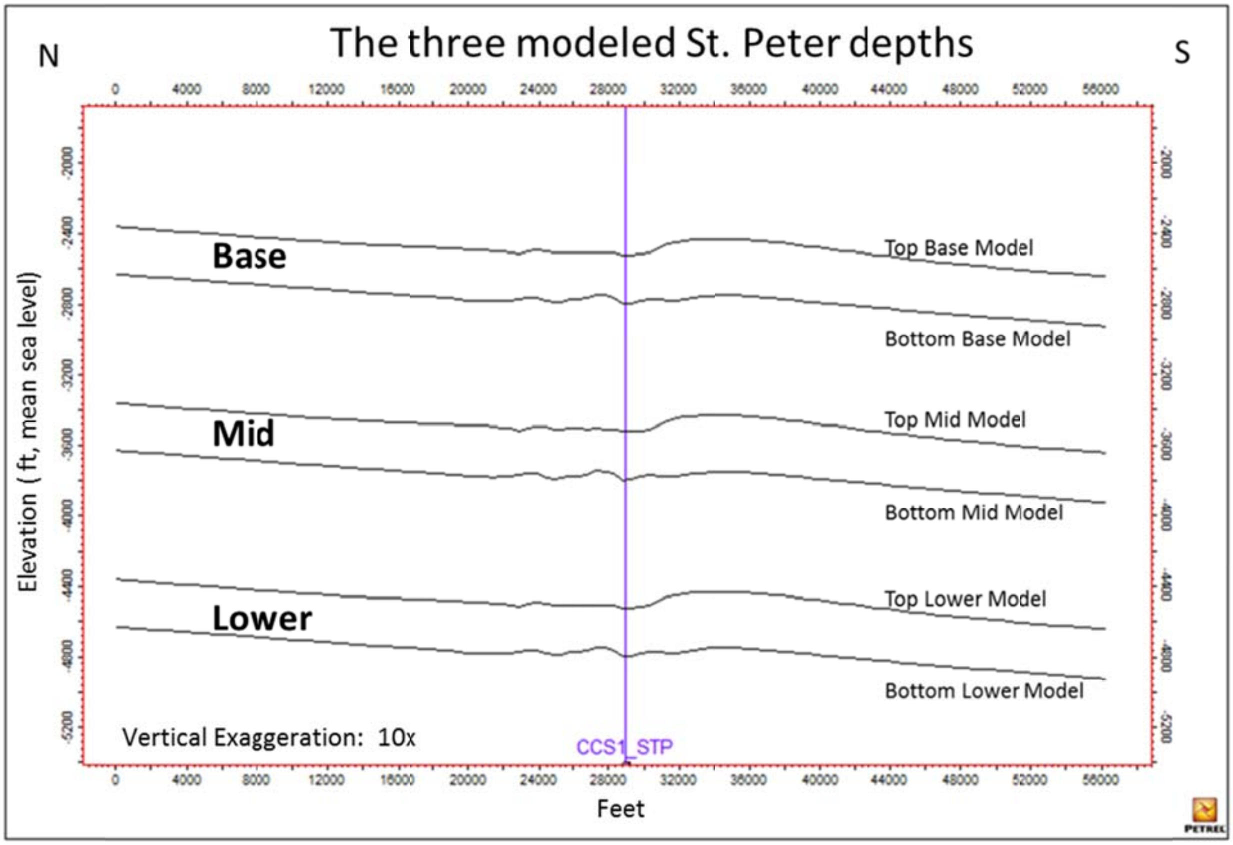



**Figure 11 N-S oriented cross section showing top and bottom of the three St. Peter static models: Base, Mid, and Lower.**

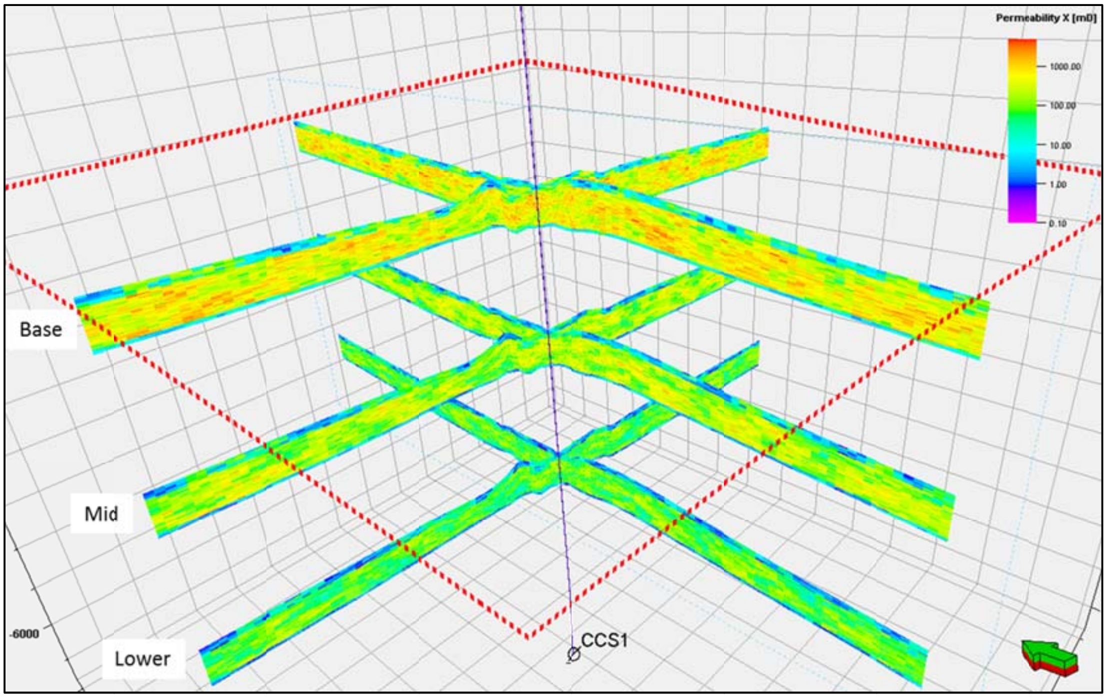



**Figure 12 N-S and E-W oriented permeability cross sections through Base, Mid, and Lower static models (24 km by 24 km [15 mi by 15 mi]).**

Modeling results are presented in terms of well bottomhole pressure (BHP), injection rate profiles, and 3D saturation and differential pressure volumes at selected simulation times. Results suggest that the target $CO_2$ injection rate of 3.2 MTPA may be achieved in the St. Peter Sandstone at in-situ conditions and at the in-situ plus 1,000 ft (300 m) depth using a single injector well. In the latter case the target injection rate is achieved after a ramp up period which is caused by multi-phase flow effects and thus subject to increased modeling uncertainty. Results confirm that the target rate may not be achieved at the in-situ plus 2,000 ft (600 m) level even with multiple wells. These new modeling results for the in-situ case are more optimistic than previous modeling results. This difference is attributed to the difference in methods and data used to develop model permeability distributions.

## Reservoir Flow Simulation (Knox)

The ASME performed a peer review (October 22–26, 2012) of selected projects within the Carbon Storage portfolio. The ASME panel requested that this project conduct further reservoir simulations using different reservoir characterization that would create a more realistic model that takes into account high-permeability pathways such as those observed in karst terrains and also include fractures. The ASME also recommended that increased volumes of $CO_2$ injection, longer injection periods, and post-injection periods be included as part of the reservoir flow simulations.

The aim of the Knox injection modeling studies is to provide guidance on reservoir and caprock properties that is meaningful towards site selection and the success of a potential specifically sited project. Though the simulation studies do investigate the adequacy for project purposes of Knox reservoir properties at or near the Decatur site, actual Knox properties at a different proposed project location cannot be known until at least one well is drilled. Project organizers must infer the relevance of these simulation results for their proposed project. Such inferences might be made by reference to better characterized analogous geologic units such as the Arbuckle.

As a second source of value, the modeling studies also demonstrate a workflow that integrates borehole and seismic data to create a model of the subsurface that is data grounded in three dimensions. While the injection-flow predictions that have been based on this static model have not been tested, the workflow itself provides a path forward for a future Knox CCS project in that it may be adapted for use at sites other than Decatur.

Dynamic simulation of $CO_2$ injection into the Knox Supergroup has been completed with different input parameters for the simulation. The first iteration of the model assumed an injection rate of 2 million tonnes/year at a constant rate over a 20-year period (Leetaru et al., 2012). In the heterogeneous simulation model in this iteration, $CO_2$ flowed preferentially into and through thin, high permeability intervals. The $CO_2$ plume shape was controlled by the modeled heterogeneity of the reservoir, resulting in a nonuniform plume shape and more mixing between reservoir layers (Figure 13). However, the overall area of the $CO_2$ plume was similar to the homogeneous case. A second difference from the homogeneous model was that the heterogeneous model had somewhat lower injectivity. For the first 5 years, injection occurred at the maximum bottomhole injection pressure and the target injection rate could not be reached. As the mobility of $CO_2$ increased and injectivity improved between year 5 and year 20, the target injection rate of 2 million tonnes/year was achieved.

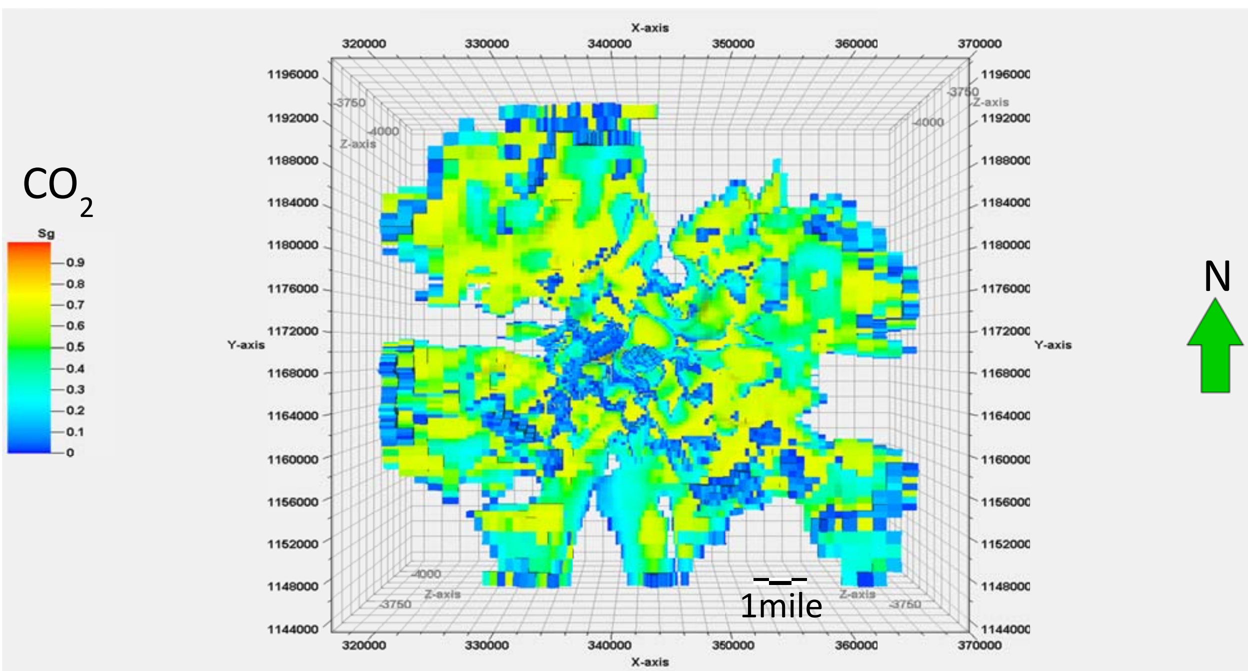



**Figure 13 Potosi Dolomite heterogeneous reservoir model simulation result showing $CO_2$ plume plan view at the end of 20 years of injection with an approximate "radius" of 5 mi (8 km).**

In topical report DOE/FE0002068-1 (Leetaru, 2012) technical performance evaluations on the Cambrian Potosi Dolomite were performed through reservoir modeling. The data included formation tops from mud logs, well logs from the VW1 and the CCS1 wells, structural and stratigraphic formation from 3D seismic data, and field data from several waste water injection wells for Potosi Dolomite. Intention was for 2 MTPA of $CO_2$ to be injected for 20 years.

The DOE requested that the simulation parameters be changed to increase the injection rate and injection period to 3.2 million tonnes/year and 30 years. In topical report DOE/FE0002068-13 (Adushita, 2014), the 2010 Potosi heterogeneous model (referred to as the "Potosi Dynamic Model 2010" in this report) was rerun using a new injection scenario: 3.2 MTPA for 30 years. The extent of the Potosi Dynamic Model 2010, however, appeared too small for the new injection target. It was not sufficiently large enough to accommodate the evolution of the plume. Also, it might have overestimated the injection capacity by over-enhancing the pressure relief due to the relatively close proximity between the injector and the infinite-acting boundaries.

The new model, Potosi Dynamic Model 2013a (Adushita, 2014), was built by extending the Potosi Dynamic Model 2010 grid to 30 mi x 30 mi (48 km × 48 km), while preserving all property modeling workflows and layering. This model was retained as the base case.

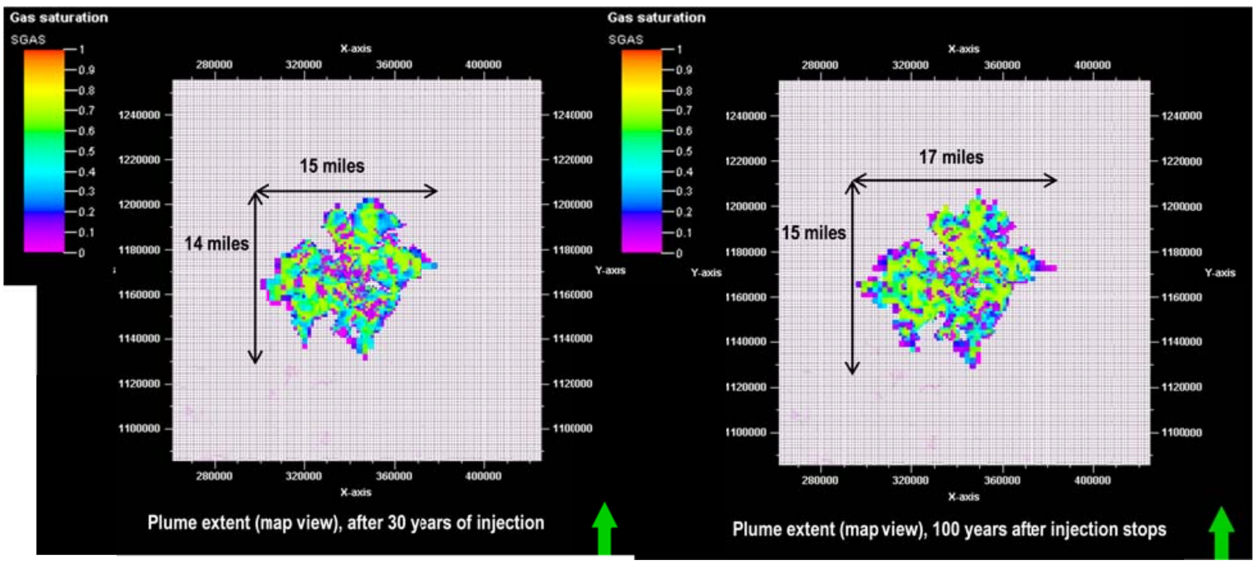



**Figure 14 Potosi Dynamic Model 2013a, plume extent, top view. Left: after 30 years of injection. Right: 100 years post-injection.**

Potosi Dynamic Model 2013a gives an average $CO_2$ injection rate of 1.4 MTPA and cumulative injection of 43 metric tonnes in 30 years, which corresponds to 45% of the injection target. This implies that, according to this preliminary model, a minimum of three (3) wells could be required to achieve the injection target. A vertical flow performance evaluation should be considered to determine the appropriate tubing size, the required injection tubing head pressure (THP) and to investigate whether the corresponding well injection rate falls within the tubing erosional velocity limit.

After 30 years, the plume extends 15 mi (24 km) in the east-west and 14 miles (22 km) in the north-south directions. After injection is completed, the plume continues to migrate laterally, mainly driven by the remaining pressure gradient. After 100 years post-injection, the plume extends 17 miles (27 km) in east-west and 15 mi (24 km) in north-south directions.

The increase of reservoir pressure at the end of injection is approximately 2,551 kPa (370 psia) around the injector and gradually decreases away from the well. The reservoir pressure increase is less than 207 kPa (30 psia) beyond 22 km (14 mi) away from injector. The initial reservoir pressure is restored after approximately 20 years post-injection. It is important to remember that the respective plume extent and areal pressure increase corresponds to an injection of 43 Mt $CO_2$. Should the targeted cumulative injection of 96 Mt be achieved, a much larger plume extent and areal pressure increase could be expected.

The 2010 Potosi heterogeneous model (referred to as the "Potosi Dynamic Model 2010" [Adushita et al., 2014]) was rerun using a new injection scenario: 3.2 MTPA for 30 years. The extent of the Potosi Dynamic Model 2010, however, appeared too small for the new injection target. It was not sufficiently large enough to accommodate the evolution of the plume. The new model topical report DOE/FE0002068-14 (Adushita and Smith, 2014), Potosi Dynamic Model 2013a, was built by extending the Potosi Dynamic Model 2010 grid to 30 mi × 30 mi (48.3 km × 48.3 km), while preserving all property modeling workflows and layering. This model was retained as the base case of Potosi Dynamic Model 2013a.

In topical report DOE/FE0002068-14 (Smith, 2014), the Potosi Dolomite reservoir model was updated to take into account the new data from the verification well VW2, which was drilled in 2012. The new porosity and permeability modeling was performed to take into account the log data from the new well. Revisions of the 2010 modeling assumptions were also done on relative permeability, capillary pressures, formation water salinity, and the maximum allowable well bottomhole pressure. Dynamic simulations were run using the injection target of 3.2 MTPA for 30 years. This new dynamic model was named Potosi Dynamic Model 2013b.

Because of the major uncertainties on the vugs permeability, two models were built: the Pessimistic and Optimistic Cases. The Optimistic Case assumes vugs permeability of $8.87 \times 10^{-8}$ $cm^2$ (9,000 mD), which is analog to the vugs permeability identified in the pressure fall off test of a waste water injector in the Tuscola site, approximately 40 mi (64.4 km) away from the IBDP area. The Pessimistic Case assumes that the vugs permeability is equal to the log data, which does not take into account the permeability from secondary porosity. The probability of such case is deemed low and could be treated as the worst case scenario, because the contribution of secondary porosity to the permeability is neglected and the loss circulation events might correspond to a much higher permeability. It is considered important, however, to identify the range of possible reservoir performance because there are no rigorous data available for the vugs permeability.

The Optimistic Case gives an average $CO_2$ injection rate of 0.8 MTPA and cumulative injection of 26 Mt in 30 years, which corresponds to 27% of the injection target. The injection rate is approximately 3.2 MTPA in the first year as the well is injecting into the surrounding vugs; it declines rapidly to 0.8 MTPA in year 4 once the surrounding vugs are full and the $CO_2$ starts to reach the matrix. This implies that, according to this preliminary model, a minimum of four (4) wells could be required to achieve the injection target. This result is lower than the injectivity estimated in the Potosi Dynamic Model 2013a (43 Mt in 30 years), because the permeability model applied in the Potosi Dynamic Model 2013b is more conservative. This revision was deemed necessary to treat the uncertainty in a more appropriate manner.

As the $CO_2$ follows the paths where vugs interconnection exists, a reasonably large and irregular plume extent was created. For the Optimistic Case, the plume extends 17 mi (27.4km) in the east-west and 14 mi (22.5 km) in the north-south directions after 30 years. After injection is completed, the plume continues to migrate laterally, mainly driven by the remaining pressure gradient. After 100 years post-injection, the plume extends 20 mi (32.2km) in the east-west and 15.5 mi (24.9 km) in the north-south directions. Should the targeted cumulative injection of 96 Mt be achieved, a much larger plume extent could be expected.

For the Optimistic Case, the increase of reservoir pressure at the end of injection is approximately 1,200 psia (8,274 kPa) around the injector and gradually decreases away from the well. The reservoir pressure increase is less than 30 psia (206.8 kPa) beyond 14 mi (22.5 km) away from injector. Should the targeted cumulative injection of 96 Mt be achieved, a much larger areal pressure increase could be expected. The initial reservoir pressure is nearly restored after approximately 100 years post-injection. The presence of matrix slows down the pressure dissipations.

The Pessimistic Case gives an average $CO_2$ injection rate of 0.2 MTPA and cumulative injection of 7 Mt in 30 years, which corresponds to 7% of the injection target. This implies that in the worst case scenario, a minimum of sixteen (16) wells could be required to achieve the injection target.

The evaluation is mainly associated with uncertainty on the vugs permeability, distribution, and interconnectivity. The different results indicated by the Optimistic and Pessimistic Cases signify the importance of vugs permeability characterization. Therefore, injection and pressure interference tests among the wells could be considered to evaluate the local vugs permeability, extent, and interconnectivity.

In topical report DOE/FE0002068-16 (Adushita and Smith, 2014) , a new property modeling workflow was applied, where seismic inversion data guided the porosity mapping and geobody extraction. The static reservoir model was fully guided by PorosityCube interpretations and derivations coupled with petrophysical logs from three wells (Figure 15). The two main assumptions are (1) porosity features in the PorosityCube that correlate with lost circulation zones represent vugular zones, and (2) that these vugular zones are laterally continuous. Extrapolation was done carefully to populate the vugular facies and their corresponding properties outside the seismic footprint up to the boundary of the 30 by 30 mi (48 by 48 km) model. Dynamic simulations were also run using the injection target of 3.5 million tons per annum (3.2 MTPA) for 30 years. This new dynamic model was named Potosi Dynamic Model 2013c.

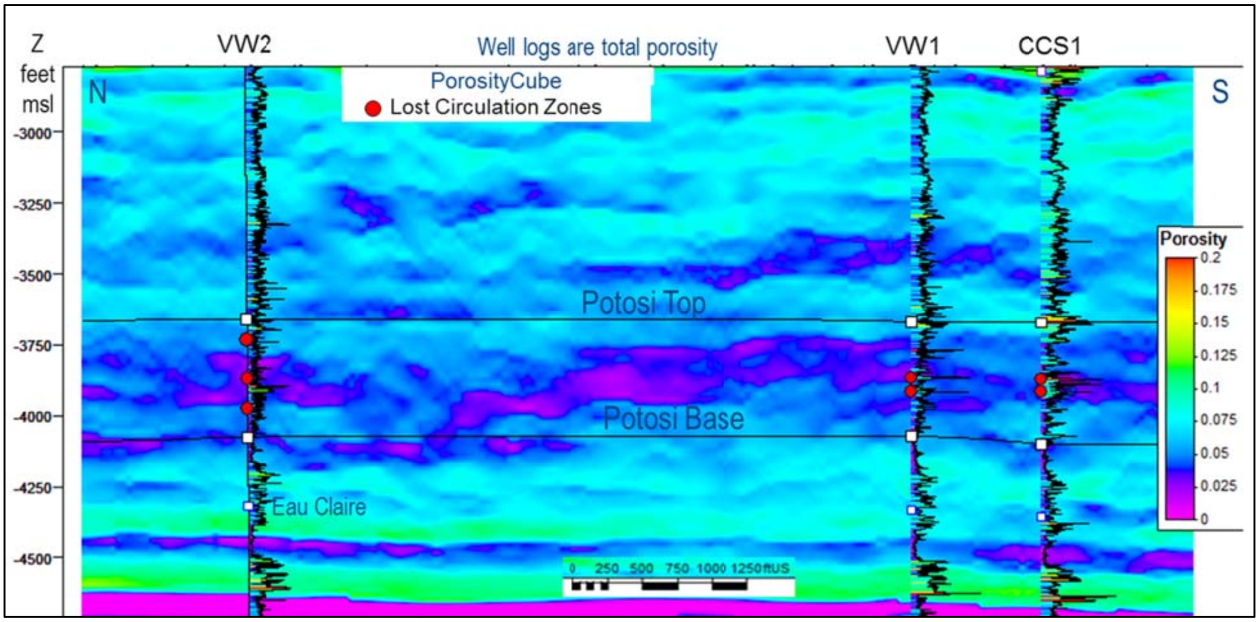



**Figure 15 PorosityCube line through the three wells. Low porosity trends within the PorosityCube correlate with lost circulation zones (portrayed by the red dots) observed in wells. These lost circulation zones correspond to vuggy intervals and represent high permeability pathways into the Potosi Dolomite. In a lateral sense, the PorosityCube is a reasonable indicator of porosity away from the well. Note, however, that there is a difference in vertical resolution between the PorosityCube and the porosity logs which may exaggerate the vertical extent of the vuggy zones. To compensate for this vertical exaggeration, geomodeling of this vuggy character was constrained to the lost circulation zones.**

Reservoir simulation with the latest model gives a cumulative injection of 43 million tons (39 Mt) in 30 years with a single well, which corresponds to 40% of the injection target. The injection rate is approximately 3.2 MTPA in the first 6 months as the well is injecting into the surrounding vugs; it declines rapidly to 1.8 million tons per annum (1.6 MTPA) in year 3 once the surrounding vugs are full and the $CO_2$ starts to reach the matrix. After, the injection rate declines gradually to 1.2 million tons per annum (1.1 MTPA) in year 18 and stays constant. This implies that a minimum of three (3) wells could be required in the Potosi Dolomite to reach the injection target. The injectivity evaluated in this task was higher compared to the preceding task, because the current facies modeling (guided by the porosity map from the seismic inversion) indicated a higher density of vugs within the vugular zones.

As the $CO_2$ follows the paths where vugs interconnection exists, a reasonably large and irregular plume extent was created (Figure 16). After 30 years of injection, the plume extends 13.7 mi (22 km) in the east-west and 9.7 mi (16 km) in the north-south directions. After injection finishes, the plume continues to migrate laterally, mainly driven by the remaining pressure gradient. After 60 years post-injection, the plume extends 14.2 mi (22.8 km) in the east-west and 10 mi (16 km) in the north-south directions and remains constant as the remaining pressure gradient has become very low. Should the targeted cumulative injection of 106 million tons (96 Mt) be achieved, a much larger plume extent could be expected.

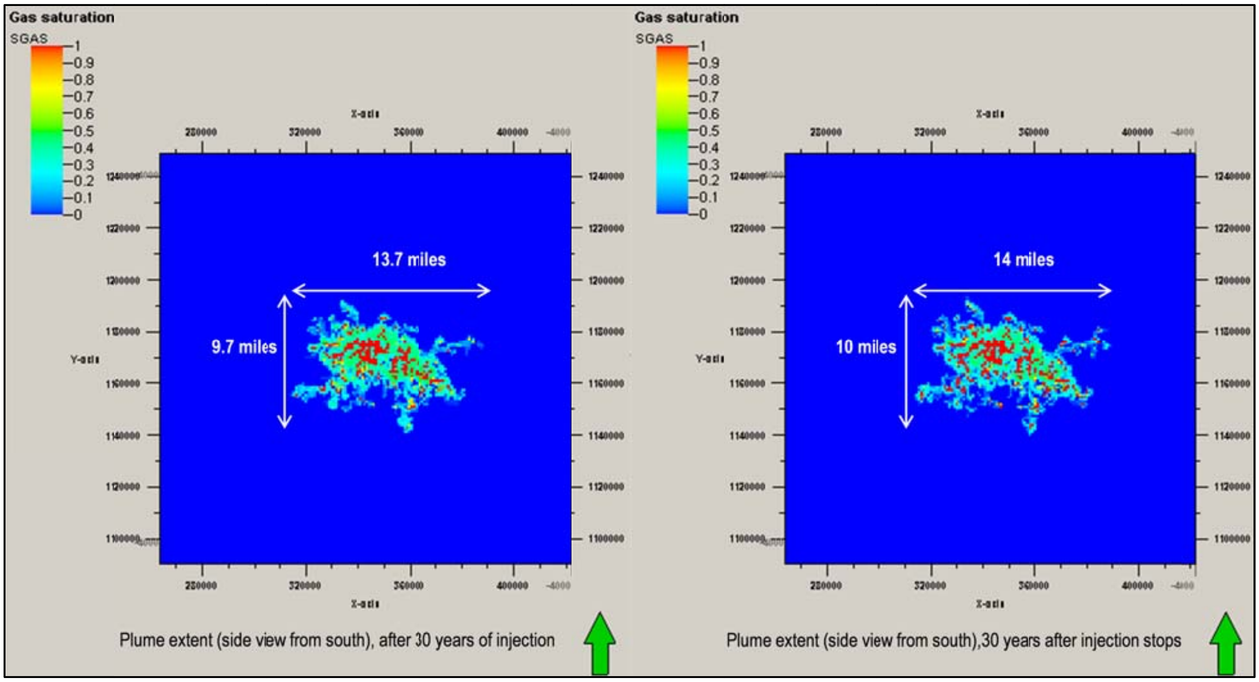



**Figure 16 Potosi Dynamic Model 2013c, plume extent, top view. Left: after 30 years of injection. Top right: 30 years post-injection.**

The increase of reservoir pressure at the end of injection is approximately 1,200 psia (8,274 kPa) around the injector and gradually decreases away from the well. The reservoir pressure increase is less than 10 psia (69 kPa) beyond 14 mi (23 km) away from injector. Should the targeted cumulative injection of 106 million tonnes be achieved, a much larger areal pressure increase could be expected. The reservoir pressure declines rapidly during the first 30 years post-injection and the initial reservoir pressure is nearly restored after 100 years post-injection.

The present evaluation is mainly associated with uncertainty on the vugs permeability and interconnectivity. The use of porosity mapping from seismic inversion might have reduced the uncertainty on the lateral vugs body distributions. However, major uncertainties on the Potosi Dolomite vugs permeability remains. Therefore, injection and pressure interference tests among the wells could be considered to evaluate the local vugs permeability, extent, and interconnectivity.

Facies modeling within the Potosi Dolomite has yet to be thoroughly addressed. The carbonates during the time of deposition are believed to be regionally extensive. However, it may be worth delineating the reservoir with other regional wells or modern day analogues to understand the extent of the Potosi Dolomite. More specifically, the model could incorporate lateral changes or trends if deemed necessary to represent facies transition.

The modeling in topical report DOE/FE0002068-17 (Smith and Adushita, 2014) was enhanced through FMI* fullbore formation microimager interpretations and porosity logs derived from FMI data through a PoroSpect* carbonate porosity solution analysis. First, the FMI logs were interpreted for open fractures within the Potosi Dolomite. Only 47 open and partially open fractures were interpreted among three wells composing 1,500 ft (457 m) of borehole. Fracture density was insufficient to recognize any consistent trends among the wells and draw any specific conclusions to support a fracture model. Fracture modeling was determined to be an insignificant contribution to the model in contrast to the vugginess present. Thus, the pursuit of a fracture network model was dropped.

Next, the PoroSpect analysis resulted in a high-resolution secondary porosity log. This log was used to better discriminate the contribution of porosity among matrix and vugs. This refinement was coupled with the porosity mapping and geobody extraction previously used in the Potosi Reservoir Model 2013c, Property Modeling Update. Thus, the static reservoir model was fully guided by PorosityCube interpretations and derivations coupled with petrophysical logs from three wells enhanced by high-resolution PoroSpect logs. The three main assumptions are (1) porosity features in the PorosityCube that correlate with lost circulation zones represent vuggy zones, (2) these vuggy zones are laterally continuous, and (3) FMI-derived porosity logs provide a finer discrimination of primary versus secondary porosity contributions. Where previous static models constrained the assignment of "vuggy-type" porosity and permeability characteristics to two lost circulation zones totaling approximately 20 ft (6.1 m) in thickness, the new PoroSpect analysis validated the presence of additional vuggy intervals outside the lost circulation zones. The new static model expanded the zones designated as "vuggy" to cover additional vertical extent above and below the lost circulation zones. This resulted in approximately 100 ft (30.5 m) of reservoir thickness assigned with elevated (that is, vuggy-type) permeability. The model described in topical report DOE/FE0002068-17 (Smith and Adushita, 2014) is more optimistic in that it considers the possibility of vuggy-type permeability outside of the two observed lost circulation zones.

Property modeling outside the seismic footprint required the extrapolation of vuggy intervals and their petrophysical properties up to the model boundary of 30 mi × 30 mi (48.3 km × 48.3 km). Dynamic simulations were again run using the injection target of 3.2 MTPA of $CO_2$ for 30 years. This new dynamic model was named Potosi Dynamic Model 2014.

Reservoir simulations resulted in a cumulative injection of 96 million tonnes obtained with a single well in 30 years, which satisfies the injection target with the injection rate of 3.2 MTPA throughout the entire injection period. Unlike the previous model, 2013b which potentially required a minimum of three (3) wells to meet the injection target, the new model can achieve the injection target with a single well within the Potosi Dolomite. As the $CO_2$ follows the paths where vug interconnection exists, a reasonably large and irregular plume extent was created. After 30 years of injection, the plume edge extends 13.5 mi (21.7 km) in the east-west and 16.8 mi (27.0 km) in the north-south directions ( Figure 17). After injection is ended, the plume does not grow laterally. Driven by buoyancy, some $CO_2$ migrates upward across layers. Vertical migration does not, however, change the lateral plume shape significantly during the 100 years after injection.

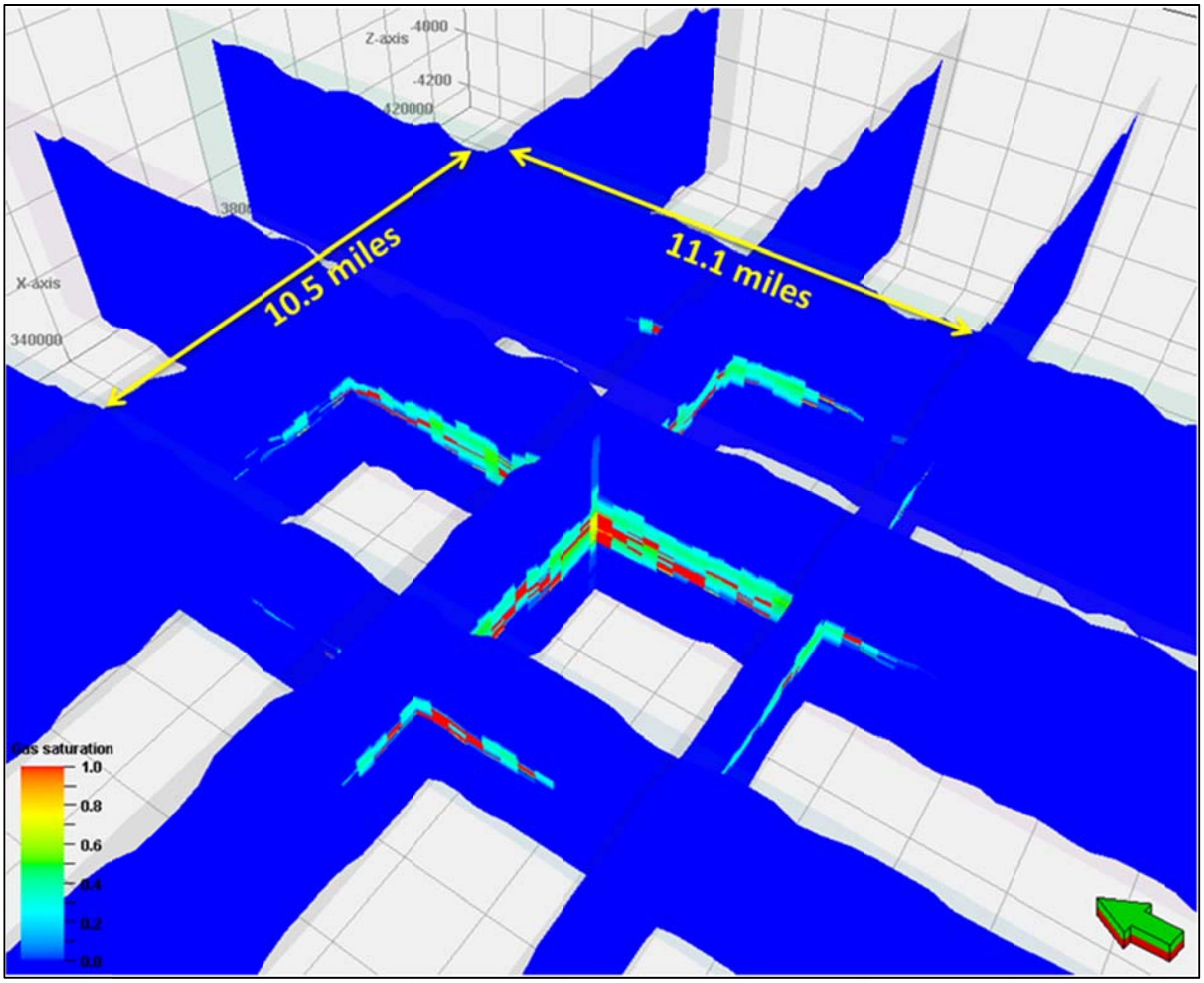



Figure 17 3D model that details $CO_2$ gas saturation after 30-year injection from Potosi Dynamic Model 2014. Vertical exaggeration is 50×.

The increase in reservoir pressure at the end of injection is approximately 80 pounds per square inch absolute (psia; 551.6 kPa) around the injector and gradually decreases away from the well. The reservoir pressure buildup is less than 10 psia (69 kPa) beyond about 12 mi (19.3 km) away from the injector. The newly incorporated thicker vertical sequences of vuggy zones resulted in the significant improvement of the $k_h$ (permeability × thickness) and injectivity and subsequently lower pressure buildup within the entire model domain.

If the Potosi Dolomite contains thicker zones of higher permeability as modeled, then it has the potential to receive and maintain the target injection rate. While the present evaluation enhances the discrimination of primary and secondary porosity, there still remains uncertainty regarding the vugs permeability and interconnectivity. The use of porosity mapping from seismic inversion might have reduced uncertainty about the locations of hypothetical discrete rock volumes (called “geobodies” here) that have porosity characteristics typical of vuggy zones. The process of “geobody extraction” from the seismic data volume results in vertical resolution that is certainly coarser than log-based observations. This probably results in greater vertical connectivity within a rock volume that is assigned the characteristics of a “vuggy geobody.” Altogether, major uncertainties on the permeability of vuggy zones in the Potosi Dolomite still remain. Therefore, injection and pressure interference tests among wells would be useful for evaluating local vuggy zone permeability, extent, and interconnectivity.

### Recommend Best Practices and Lessons Learned

The recommend best practices and lessons learned are given below:

- Developers of a planned CCS project targeting the Knox—compared to a reservoir dominated by intergranular porosity—should plan a relatively greater effort to confirm site-specific ability to track the $CO_2$ plume in the subsurface. This is important because flow in a Knox reservoir is more likely to be dominated by thin horizons of exceptionally high vuggy permeability, with these implications:
  - Thin vuggy horizons are more likely than intergranular-porosity-dominated horizons to be laterally discontinuous or intermittent.
  - Vuggy horizons that are generally stratigraphically separate may be linked through vertical high-permeability zones.
  - Through a highly porous and permeable zone of restricted dimensions, a $CO_2$ plume may migrate unexpectedly fast in an unexpected direction.
  - $CO_2$ saturation in thin horizons is difficult to image seismically.
  - $CO_2$ plume migration predictions (geometry and timing) are more uncertain, causing greater uncertainty in planning monitoring wells and monitoring programs.

## Knowledge Gaps

The Knox Group studies conducted under DOE contract DE-FE0002068 were designed primarily to generate new data in a small amount and leverage existing data in a large amount in order to develop both basin-scale and site-scale understanding of the three fundamental geoengineering attributes of a GS project: injectivity, capacity, and containment. A secondary objective was to provide a view of key management and execution aspects pertinent to a generic Knox GS project. While great strides were made, an actual Knox GS project sited elsewhere than Decatur would need more guidance than is provided by these initial studies. Prominent knowledge gaps include the following:

## Best Practices

- Best Practices for CCS development targeted at a Knox Group reservoir are generally the same as best practices for any planned CCS development.
- A main differentiating factor from a generic CCS project is this: Developers of a planned CCS project targeting the Knox—compared to a reservoir dominated by intergranular porosity—should plan a relatively greater effort to confirm site-specific ability to track the $CO_2$ plume in the subsurface. This is important because flow in a Knox reservoir is more likely to be dominated by thin horizons of exceptionally high vuggy permeability, with these implications:
  - Thin vuggy horizons are more likely than intergranular-porosity-dominated horizons to be laterally discontinuous or intermittent.
  - Vuggy horizons that are generally stratigraphically separate may be linked through vertical high-permeability zones.
  - Through a highly porous and permeable zone of restricted dimensions, a $CO_2$ plume may migrate unexpectedly fast in an unexpected direction.
  - $CO_2$ saturation in thin horizons is difficult to image seismically.

    - $CO_2$ plume migration predictions (geometry and timing) are more uncertain, causing greater uncertainty in planning monitoring wells and monitoring programs.
- Plan on dedicating two exploration wells to site characterization Multiwell interference testing is probably necessary to adequately confirm injectivity and capacity.
- However, given two wells and testing, there is less reliance on 3D seismic to substantiate reservoir characteristics.

# Operations

## Outreach

The Kentucky Geological Survey and industry partners drilled a 2,477-m (8,126-ft) deep carbon storage research well in Hancock County, Kentucky, in 2009. The public open house was summarized in a US Department of Energy Topical Report DOE/FE0002068-2 (Harris et al., 2012). Two phases of injection tests in the Knox Group carbonates and Gunter Sandstone were completed, including both brine and $CO_2$ injection. The second phase of injection was completed in September 2010 as part of US DOE Cooperative Agreement DOE-0002068, "An Evaluation of the Carbon Sequestration Potential of the Cambro-Ordovician Strata of the Illinois and Michigan Basins." One of the subtasks of this project was an open house at the conclusion of the project to present results to the public and stakeholders. The open house meeting was held on the evening of October 28, 2010, in Hawesville, Kentucky, at the Hancock County Career Center Figure 18 and Figure 19. Information presented included summaries of the project results by geologists and exhibits of rock core and log data from the well.

Although public attendance at the open house was low, key county government officials were present to hear the results and ask questions about the 2-year-long project. The low turnout was attributed to general satisfaction with how the project was conducted and the lack of problems that affected the public.

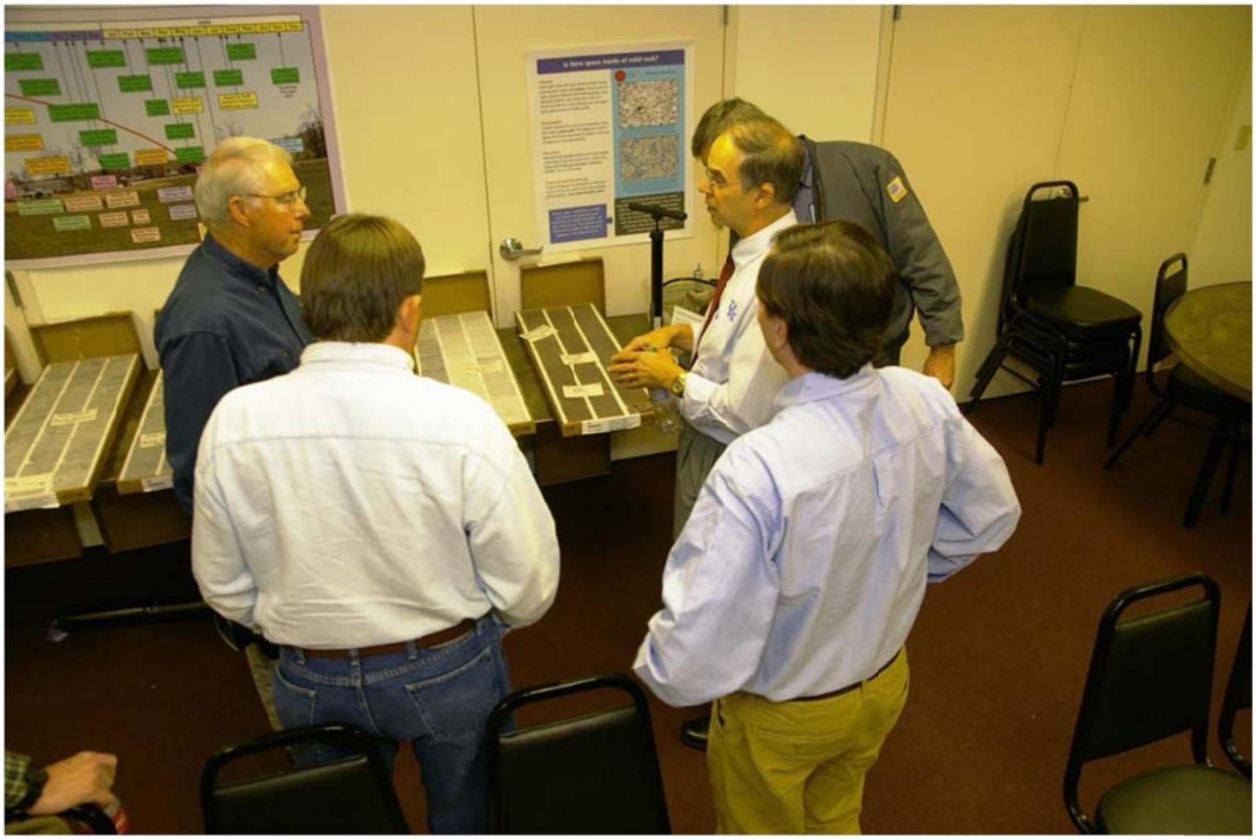
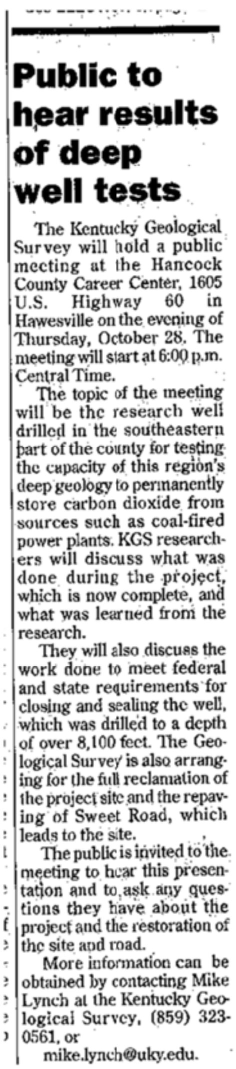


**Figure 18 Kentucky Geological Survey staff discussed cores from the KGS No. 1 Blan well that were on display at the open house.**

## Recommend Best Practices and Lessons Learned

The recommend best practices and lessons learned from the open house are given below:

- Start outreach and communications early and continue throughout the project.
- Do what you said you were going to do.
- Keep the research and outreach process open and transparent.
- Emphasize the economic impacts, which are the primary concern to local officials and residents; mitigating climate change is of secondary importance.
- Emphasize both the broader regional impact of the research and the local site-specific benefits (such as site reclamation, road repairs, and improvements to the benefit of the landowner and community).



**Public to hear results of deep well tests**

The Kentucky Geological Survey will hold a public meeting at the Hancock County Career Center, 1605 U.S. Highway 60 in Hawesville on the evening of Thursday, October 28. The meeting will start at 6:00 p.m. Central Time.

The topic of the meeting will be the research well drilled in the southeastern part of the county for testing the capacity of this region's deep geology to permanently store carbon dioxide from sources such as coal-fired power plants. KGS researchers will discuss what was done during the project, which is now complete, and what was learned from the research.

They will also discuss the work done to meet federal and state requirements for closing and sealing the well, which was drilled to a depth of over 8,100 feet. The Geological Survey is also arranging for the full reclamation of the project site and the repaving of Sweet Road, which leads to the site.

The public is invited to the meeting to hear this presentation and to ask any questions they have about the project and the restoration of the site and road.

More information can be obtained by contacting Mike Lynch at the Kentucky Geological Survey, (859) 323-0561, or mike.lynch@uky.edu.

Figure 19 Pre-meeting announcement published in the Hancock County Clarion newspaper, Oct. 21, 2010.

# Wellbore Management

## Overview

Based on regional studies, certain zones in the Knox may have adequate porosity and permeability for $CO_2$ injection, the use of the Knox for both Class I and Class II disposal wells in some areas of Illinois, and a very small amount of oil production from the upper Knox. At the IBDP in Macon County, Illinois, the three wells drilled to the deeper Mt. Simon Sandstone all had large losses of circulation fluid while drilling through the Potosi Dolomite member of the Knox Group at about –1,119 m (–3,670 ft) subsea depth: these circulation losses demonstrate the injection potential of the Knox, and also identify a main well design factor for a Knox completion. Log and core analysis suggests significant karstic porosity throughout the Potosi Dolomite interval.

In the three IBDP wells, cement plugs were set in the Knox in order to regain wellbore stability, so that intermediate casing could be set and successfully cemented to the surface. However, a well designed to inject into the Potosi Dolomite would need to be drilled such that the karstic porosity would not be damaged, while also ensuring wellbore integrity. The topical report DE-FE0002068-4 (Kirksey, 2013) develops a well plan for constructing a $CO_2$ injection well capable of injecting 3.2 million tonnes per annum (MTPA) $CO_2$ into the Knox over a period of 30 years. Though the design is specific to completing a Knox injector in the vicinity of Macon County, Illinois, the recommended design factors of long-string casing point at top of the Knox, underbalanced drilling within the Knox, and openhole completion are likely regionally valid for a planned Knox injector.

### Well Design Summary

First, the injection tubing was sized so that the rate of 3.2 MTPA could be injected below the critical erosional velocity of the tubulars (Figure 20). Then, casing strings and borehole were optimized based on tubing size. The flow simulations suggested that 14 cm (5 ½ in.) injection tubing could be used. Other well parameters such, as the long casing string would be 24.45 cm (9 ⅝ in.) inside a 31.12 cm (12 ¼ in.) borehole and the surface casing would be 33.973 cm (13 ⅜ in.) inside a 43.82 cm (17 ½ in.) borehole. The karstic porosity of the Potosi Dolomite would be protected by the long casing string top set at the top of the Potosi Dolomite. Through that casing, a 22 or 22.2 cm (8 ½ or 8 ¾ in.) borehole would be drilled to the base of the Potosi Dolomite using under-balanced drilling (UBD) methods. After the 22 cm (8 ½ in.) borehole was completed, the 14 cm (5 ½) injection tubing and packer would be installed inside the long casing string and the well would be completed using an openhole injection completion. Using this design, the long casing string will have a competent seat, and the well can be fully cemented back to surface ensuring wellbore integrity and a good seal against both the primary and secondary caprocks. The UBD techniques will protect the karstic porosity from drilling-fluid invasion and will enable obtaining a fluid sample from the very top of the karstic section.

### Potential Drilling Hazards

There are few hazards associated with drilling in the area. Previous penetrations have encountered no surface or drift gas. The well section from 304.5– 381 m (1,000–1,250 ft) can produce brackish water that, if allowed to enter the wellbore, can lead to wellbore stability problems. The upper Knox can be very hard drilling with chert and pyrite streaks that can cause premature bit wear. If drilled as planned, the well will be cased and cemented before reaching the Potosi Dolomite so that potential lost circulation would not be an issue. The UBD technique is not common the Illinois Basin so drilling crews must be coached in its use. The completion of the well as an openhole injector should be done while the drilling rig is still in place so that, after the well drilling is finished, any injection tests can be carried out without involving a rig. As in any drilling operation, good planning and attention to detail will be very important. A “Drill Well on Paper” exercise is recommended so that all parties involved with the drilling process can offer input and fully understand the scope of the planned drilling operation. A pre-spud safety and operations meeting is also recommended just before drilling begins to review the drilling plan and to outline and review all safety expectations.

### Legacy Well Integrity and Risk Mitigation

There are a number of ways well integrity can be comprised and upward migration of $CO_2$ or brine can occur (Zaluski, 2014). Figure 21 is an illustration of potential leakage pathways in an abandoned well. These failures can be the result of poor cement and historical well completion or abandonment methods that are not considered reliable compared to today's standards. In the case of legacy oil and gas wells, like many CCS projects that utilize deep saline storage, the Potosi Dolomite and St. Peter Sandstone are located well below the Mississippian-age sandstone and carbonate oil reservoirs. Because of this, oil and gas operators only drilled down to these lower formations for exploration purposes. If hydrocarbon resources were found to be absent, drilling down to these lower formations was rare; however, there are some water disposal wells in these formations. Nevertheless, the risk of one of these wells being close to the migration pathway of the $CO_2$ plume must be mitigated by the considering the following general investigations:

- This risk is already low because there are few legacy wells drilled into these deep saline formations in the Illinois Basin.
- Complete a database well search for wells that penetrate the caprock (Maquoketa Shale) and gather the below information:
    - Distance to the $CO_2$ injection well
    - Evaluate the well completion and abandonment records
    - Evaluate the cement integrity by examining the cement bond logs CBL
- Compare the results of the predictive $CO_2$ plume extent and formation pressure pulse extent from reservoir simulations with the location of the legacy well. Risk decreases substantially the further the legacy well is from the injected $CO_2$ plume.
- If a legacy well poses a potential risk, the following steps are available to mitigate this risk:
    - Locate the new $CO_2$ injection well away from the legacy well.
    - Re-enter the legacy well and quantify its well integrity or abandon the well with modern abandonment technologies.
    - A MMV program should be designed to monitor the plume development over time and there should be a way to detect the plume in the event that it migrates towards the legacy well.

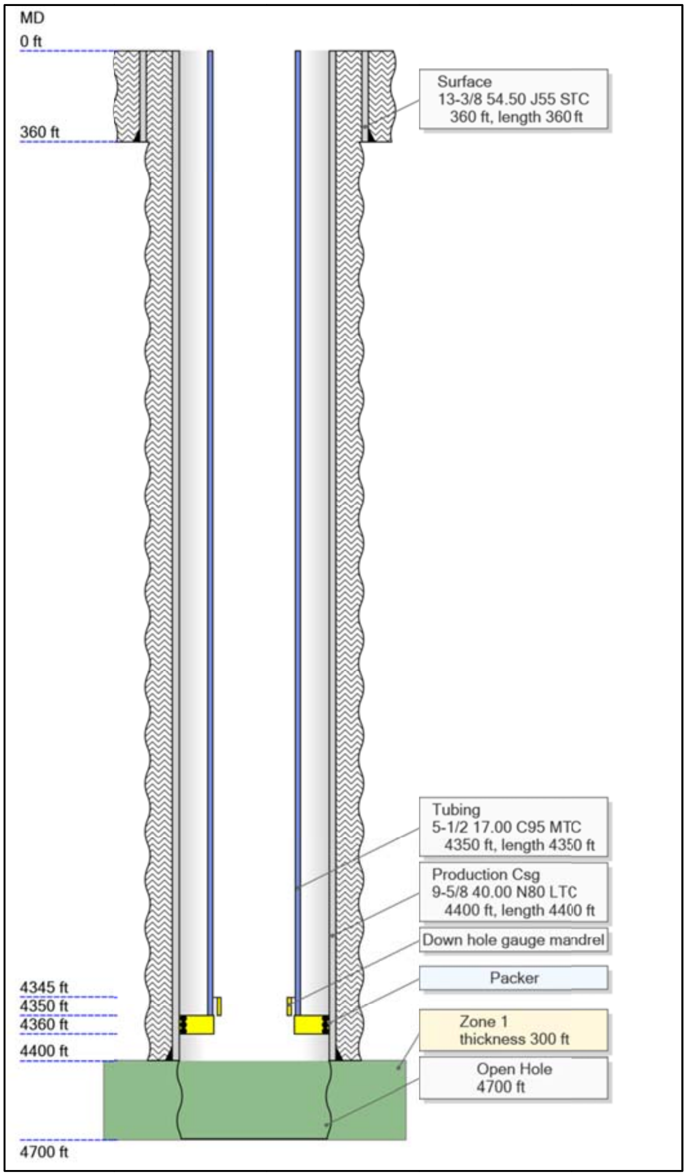



**Figure 20 Well schematic for Knox injection test.**

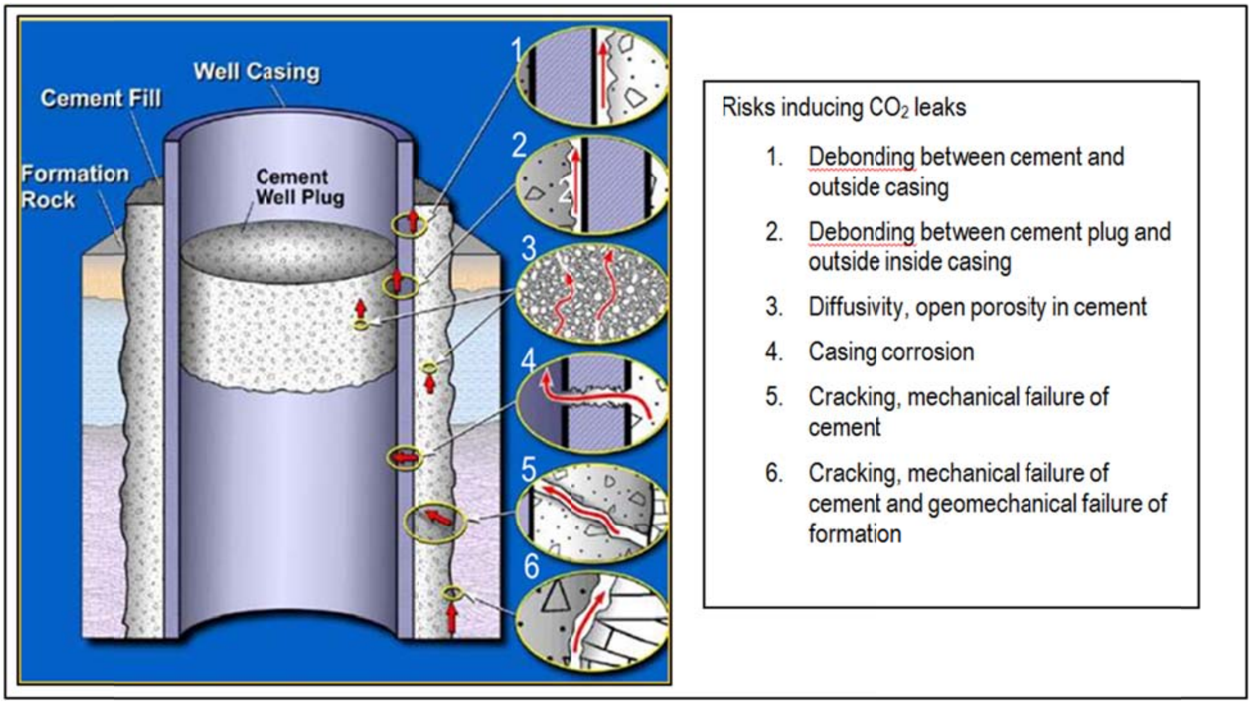



**Figure 21 Examples of compromised well integrity.**

### Recommend Best Practices and Lessons Learned

The recommend best practices and lessons learned well design are given below:

- A pre-spud safety and operations meeting is also recommended just before the commencement of drilling to review the drilling plan and outline and review all safety expectations.
- It is suggested that a third-party safety supervisor be employed to assist in the safety efforts.
- The well design involves an openhole completion through the Potosi Dolomite and the drilling of this section with air.

## Injection Testing at Blan No. 1 Well

The objective was to demonstrate the injection of supercritical $CO_2$ into the Gunter Sandstone, middle Knox Group, and provide an estimate of the supercritical $CO_2$ storage volume in the entire Knox. The topical report DOE/FE0002068-3 (Bowersox et al., 2012), summarizing results of the injection tests in the Kentucky Geological Survey Marvin Blan No. 1 well (Figure 22), provides a basis for evaluating supercritical $CO_2$ storage in Cambro-Ordovician carbonate reservoirs throughout the Midcontinent. This topical report evaluates the reservoir properties, injectivity, and storage capacity of the Gunter as well as the Knox as a whole.

The sealing capacity of the Maquoketa Shale, the primary confining interval above the Knox, was also evaluated. These evaluations were completed using laboratory core analyses, wireline geophysical electric logs, and injection pressure data acquired during MGSC Phase 1 testing conducted in the Marvin Blan No. 1 well in 2009 by the Kentucky Geological Survey and its industry partners, and MGSC Phase 2 testing conducted in 2010 by the Kentucky Geological Survey, the subject of this study. Petrophysical and graphical presentation software and spreadsheet-based physical models were employed for interpretation of these data.

Calculating reservoir volume required to store a volume of supercritical $CO_2$ required data provided by wireline electric logs, analysis of whole and sidewall cores, wireline temperature and pressure surveys, and analysis of formation waters collected before injection tests. Phase 1 injection testing focused on the entire Knox section. A total of 297 tonnes of $CO_2$ were injected into the Knox section in the open wellbore below 1,116 m. Phase 2 injection testing focused on the Gunter (Figure 23), the highest porosity and permeability section within the Knox. The Gunter section was mechanically isolated to a 70.1 m interval of the wellbore. A total of 333 tonnes of $CO_2$ were injected into the Gunter.

The wellbore was subsequently abandoned with cement plugs and the wellsite was reclaimed. Storage volume calculated for the Phase 2 test interval is 2,194 tonnes per surface hectare. Thus, 456 hectares of surface area is required to store 1 million tonnes of supercritical $CO_2$ in the Phase 2 Gunter test interval. The range of most-likely storage capacities calculated in the Knox in the Marvin Blan No. 1 is 1,000 tonnes per surface hectare in the Phase 2 Gunter interval to 8,685 tonnes per surface hectare for the entire Knox section. Thus, by itself, the Gunter lacks sufficient reservoir volume to be considered for $CO_2$ storage, but it may provide up to 18% of the reservoir volume available in the Knox as a whole.

Primary sealing strata tested in the Marvin Blan No. 1 is the Ordovician Maquoketa Shale. The Maquoketa is considered a primary reservoir seal for $CO_2$ storage in underlying reservoirs. The Maquoketa section was cored and laboratory analyses performed as part of the Phase 1 testing program. Analyses of this core included laboratory measurements of porosity, permeability, and mercury injection threshold pressure. Sealing capacity of strata was determined by two methods in this study: mercury-injection capillary pressure tests or permeability measured in core plugs. Supercritical $CO_2$ seal capacity calculated for these core plugs from the Maquoketa were 1,756–16,056 m. Rock mechanical measurements made on a representative sample from the Maquoketa yielded a compressive strength of 1.75 MPa. Therefore, the Maquoketa can act as an effective confining interval for supercritical $CO_2$ stored in the Knox.

Regional extrapolation of $CO_2$ storage potential based on the results of a single well test can be problematic unless corroborating evidence can be demonstrated. Core analysis from the Knox is not available from wells in the region surrounding the Marvin Blan No. 1 well, although indirect evidence of porosity and permeability can be demonstrated in the form of active saltwater-disposal and gas-storage wells injecting into the Knox. Pore volume is reduced in wells east of the Marvin Blan No. 1 because of erosional truncation of the Beekmantown on the western flank of the Cincinnati Arch, whereas wells west of the Marvin Blan No. 1 have sections comparable to the Marvin Blan No. 1 but lose pore volume because of compaction at their greater depths. The preliminary regional evaluation suggests that the Knox reservoir may be found throughout much of western Kentucky. The western Kentucky region suitable for $CO_2$ storage in the Knox is limited updip, to the east and south, by the depth at which the base of the Maquoketa lies above the depth required to ensure storage of $CO_2$ in its supercritical state and the deepest a commercial well might be drilled for $CO_2$ storage. The resulting prospective region has an area of approximately 15,600 $km^2$, beyond which it is unlikely that suitable Knox reservoirs may be developed. Faults in the subsurface, which serve as conduits for $CO_2$ migration and compromise sealing strata, may mitigate the area with Knox reservoirs suitable for $CO_2$ storage. The results of the injection tests in the Marvin Blan No. 1, however, provide a basis for evaluating supercritical $CO_2$ storage in Cambro-Ordovician carbonate reservoirs throughout the Midcontinent.

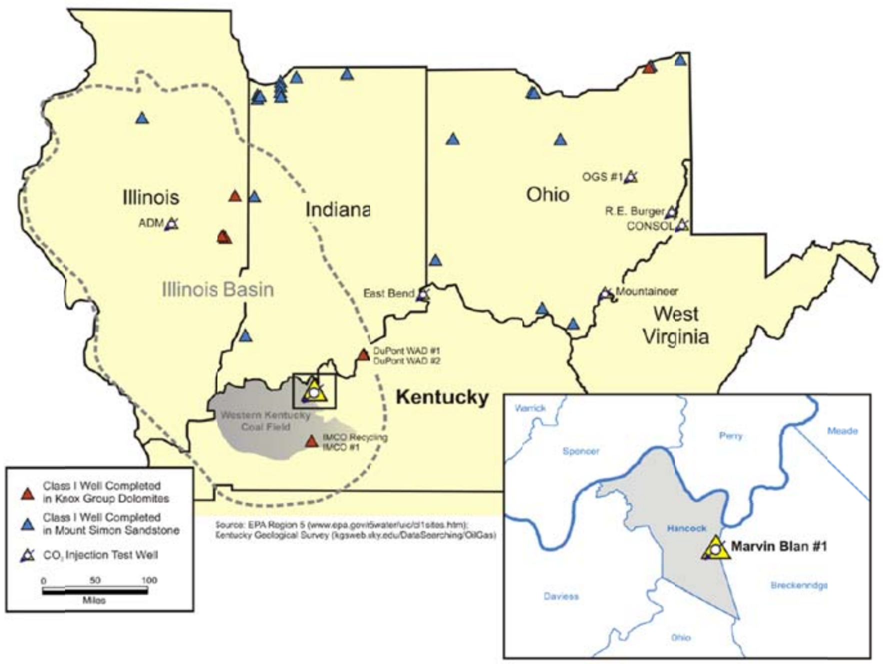



**Figure 22 Location of the Marvin Blan No. 1 well in east-central Hancock County, Kentucky.**

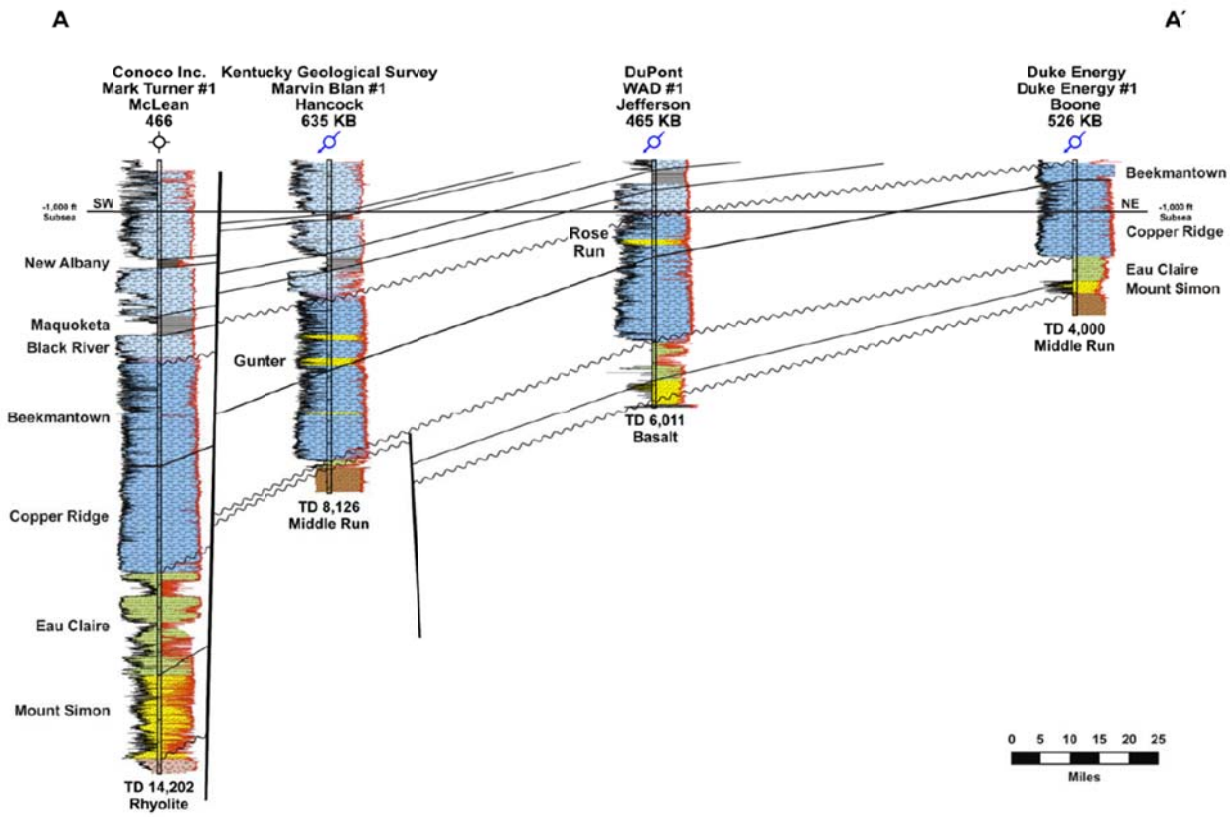



Figure 23 Generalized subsurface cross section A-A' from the Mark Turner No. 1 well from the Rough Creek Graben to the Duke Energy No. 1 on the Cincinnati Arch. The unconformity on top of the Knox truncates progressively older strata to the east, suggesting pre-Middle Ordovician initiation of the Cincinnati Arch uplift. The Marvin Blan No. 1 was drilled on a horst; thus, the Mount Simon is absent and the Eau Claire Formation is very thin compared to the other wells on the cross section.

# Seismic Reflection

## Blan Well VSP Analysis

Two three-dimensional vertical seismic profiles (3D-VSPs) were acquired at the Marvin Blan No. 1 $CO_2$ sequestration research well in Hancock County, Kentucky (Figure 24). These surveys (one just before $CO_2$ injection and one immediately following injection) were combined to produce a time-lapse 3D VSP data volume in an attempt to monitor the subsurface changes caused by the injection. While less than optimum surface access and ambient subsurface noise from a nearby active petroleum pipeline hampered quality of the results, some changes in the seismic response post-injection are interpreted to be a result of the injection process.

### Recommend Best Practices and Lessons Learned

The recommend best practices and lessons learned are given below:

- 3D VSPs for finite difference analysis appear to be a useful and valid tool for subsurface $CO_2$ storage verification and monitoring; physical limitations, such as limited surface access and ambient noise sources, can make it impractical and thus not useful for all situations.

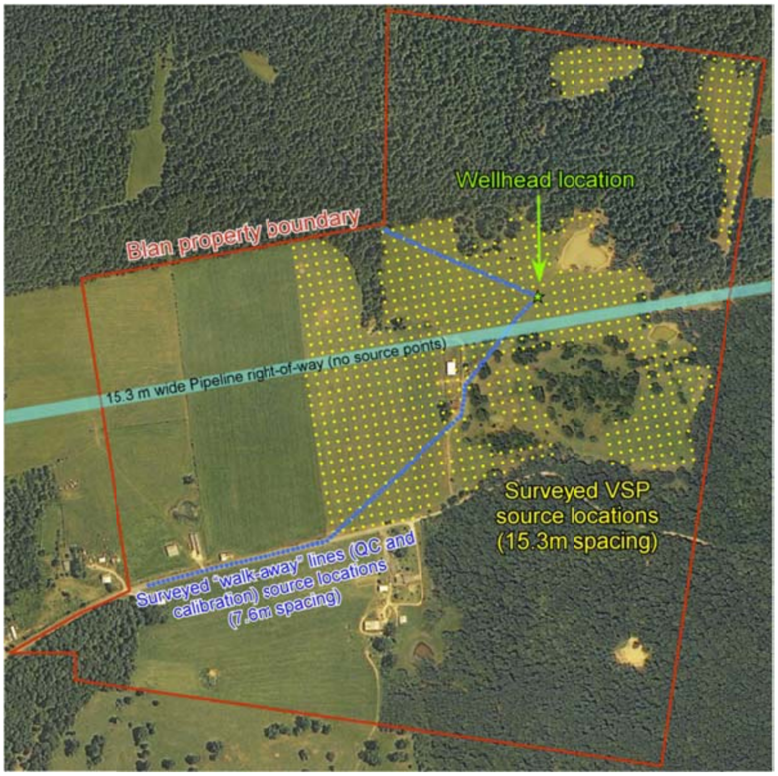



Figure 24 Blan property with locations of seismic source points.

## 2D Seismic Reflection Data across Illinois

Schlumberger Carbon Services and WesternGeco acquired two-dimensional (2D) seismic data in the Illinois Basin (Figure 25). This work, summarized in topical report DOE-FE0002068-8 (Smith and Leetaru, 2014), included the design, acquisition, and processing of approximately 201 km (125 mi) of (2D) seismic reflection surveys running west to east in the central Illinois Basin. Schlumberger Carbon Services and WesternGeco oversaw the management of the field operations (including a pre-shoot planning, mobilization, acquisition and de-mobilization of the field personnel and equipment), procurement of the necessary permits to conduct the survey, post-shoot closure, processing of the raw data, and provided expert consultation as needed in the interpretation of the delivered product.

Three 2D seismic lines were acquired across central Illinois during November and December 2010 and January 2011. Traversing the Illinois Basin, this 2D seismic survey was designed to image the stratigraphy of the Cambro-Ordovician sections and also to discern the basement topography.

Before this survey, there were no regionally extensive 2D seismic data spanning this section of the Illinois Basin. Between the northwest side of Morgan County and northwestern border of Douglas County, these seismic lines ran through very rural portions of the state. Starting in Morgan County, Line 101 was the longest at 150 km (93 mi) in length and ended northeast of Decatur, Illinois. Line 501 ran west-east from the IBDP site to northwestern Douglas County and was 40 km (25 mi) in length. Line 601 was the shortest and ran north-south past the IBDP site and connected lines 101 and 501. All three lines are correlated to well logs at the IBDP site.

Originally processed in 2011, the 2D seismic profiles exhibited a degradation of signal quality below about 400 milliseconds (ms), which made interpretation of the Mt. Simon and Knox sections difficult. The data quality also gradually decreased moving westward across the state. To meet evolving project objectives, the seismic data was re-processed in 2012 using different techniques to enhance the signal quality, thereby rendering a more coherent seismic profile for interpreters. It is believed that the seismic degradation could be caused by shallow natural gas deposits and Quaternary sediments (which include abandoned river and stream channels, former ponds, and swamps with peat deposits) that may have complicated or changed the seismic wavelet.

Where previously limited by seismic coverage, the seismic profiles have provided valuable subsurface information across central Illinois. Some of the interpretations based on this survey included, but are not limited to

- Generally, stratigraphy gently dips to the east from Morgan to Douglas County;

- The Knox Group roughly maintains its thickness. There is little evidence for faulting in the Knox. However, at least one resolvable fault penetrates the entire Knox section;

- The Eau Claire Formation, the primary seal for the Mt. Simon Sandstone, appears to be continuous across the entire seismic profile;

- The Mt. Simon Sandstone thins towards the western edge of the Basin. As a result, the highly porous lowermost Mt. Simon section is absent in the western part of the state;

- Overall basement dip is from west to east;

- Basement topography shows evidence of basement highs with on-lapping patterns by Mt. Simon sediments.

- There is evidence of faults within the lower Mt. Simon Sandstone and basement rock that are contemporaneous with Mt. Simon Sandstone deposition. These faults are not active and do not penetrate the Eau Claire Shale. It is believed that these faults are associated with a possible failed rifting event 750 to 560 million years ago during the breakup of the supercontinent Rodinia.

Figure 26 shows an example of a possible fault that penetrates through the entire Knox interval, the Maquoketa (the primary seal for the Knox) and New Albany formations. This particular fault is significant because it had not been previously observed. Faults that penetrate seals form potential leakage pathways. Carbon dioxide sequestration projects involving the Knox Group should not be located near these structural features.

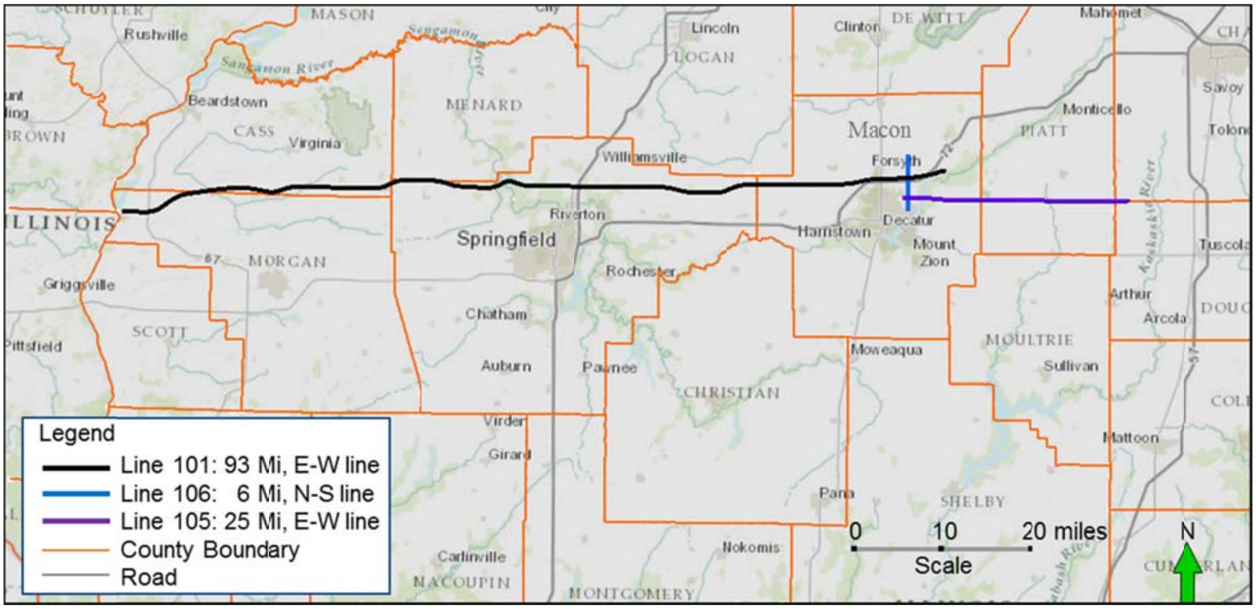



Figure 25 Location of 2D seismic line layouts across central Illinois.

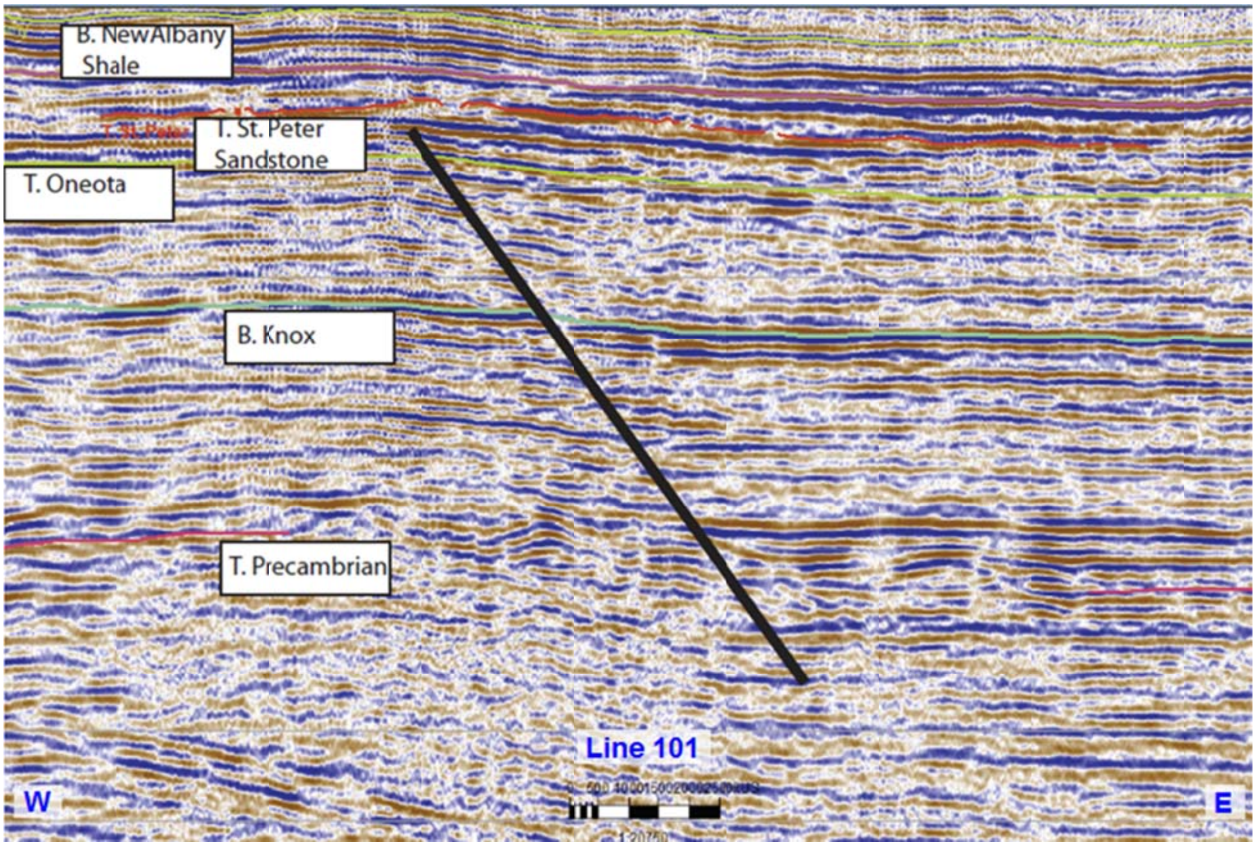



Figure 26 Central portion of Line 101. The black line is interpreted to be a fault that penetrates the entire Knox interval, the Maquoketa Shale, and probably the New Albany Formation.

## 2D Seismic Reflection Profile across Manlove Gas Storage Field

The project also acquired a 2D seismic reflection profile across Manlove Gas Storage Field in Champaign County, Illinois (Figure 27). The reflection profile was acquired to understand possible faulting on the flank of the field. At Manlove Field, natural gas is stored in the Mt. Simon Sandstone for use in extreme cold weather to fulfill the natural gas needs of the City of Chicago. This seismic was acquired at the end of our DOE-funded Knox project and seismic interpretations are still preliminary.

Initial interpretation of the seismic data confirmed that there are several faults along the western flank of Manlove Field. At least one major fault appears to penetrate all of the major seals and shallower formations (Figure 28). There are two different interpretations of this seismic profile. The first (in light blue) would be that there was extension and the strata are lower on the west side because of normal faults. The first interpretation is considered unlikely; instead, it is believed that structural inversion with a hanging wall pushed up the foot wall along a normal fault (dashed black line). The second interpretation is consistent with analysis of other similar faults in the Illinois Basin.


Figure 27 Manlove Gas Storage Field seismic line location southwest of Fisher, Illinois.

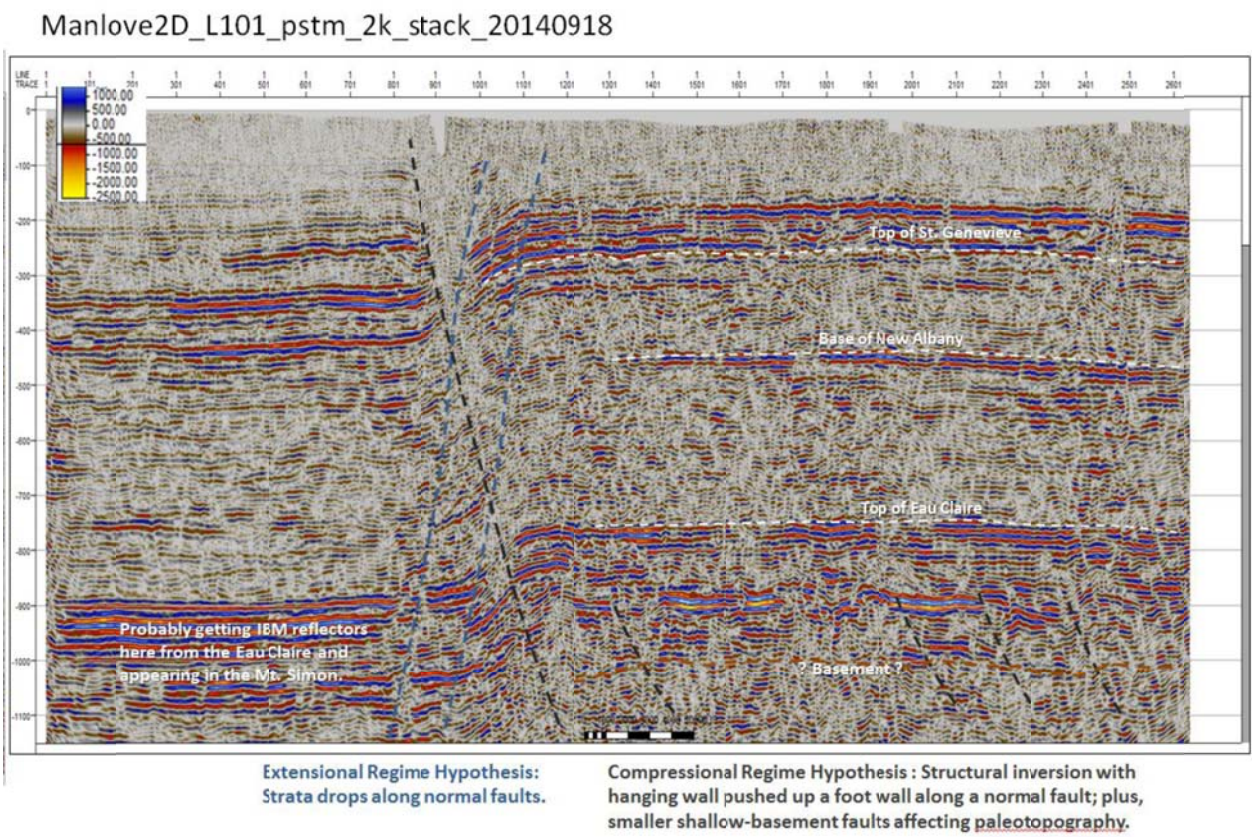



Figure 28 Initial interpretation of the 2D seismic reflection profile across Manlove Field.

### Recommend Best Practices and Lessons Learned

The recommend best practices and lessons learned are given below:

- 2D seismic reflection profiles need to be long enough to evaluate faulting and stratigraphic changes.
- You need nearby well control with velocity information to correlate the seismic traces with stratigraphic information.
- Shallow surface effects can make seismic acquisition difficult by increasing the noise-to-signal ratio and making interpretation difficult.

# Risk Assessment

## Features, Events, and Processes (FEP Analysis)

The topical report DOE/FE0002068-5 (Hnottavange-Telleen, 2013) describes a process and provides seed information for identifying and evaluating risks pertinent to a hypothetical $CO_2$ CCS project. In the envisioned project, the target sequestration reservoir rock is the Potosi Dolomite of the Knox Group. The Potosi Dolomite is identified as a potential target formation because (1), at least locally, it contains vuggy to cavernous layers that have very high porosity, and (2) it is present in areas where the deeper Mt. Simon Sandstone (a known potential reservoir unit) is absent or nonporous. The key report content is discussed in Section 3.3 of the topical report which describes two lists of Features, Events, and Processes (FEPs) that should be considered during the design stage of such a project. These lists primarily highlight risk elements particular to the establishment of the Potosi Dolomite as the target formation in general. The lists are consciously incomplete with respect to risk elements that would be relevant for essentially all CCS projects regardless of location or geology. In addition, other risk elements specific to a particular future project site would have to be identified.

Sources for the FEPs and scenarios listed here include the iconic Quintessa FEPs list developed for the International Energy Agency Greenhouse Gas Program (IEAGHG); previous risk evaluation projects executed by Schlumberger Carbon Services; and new input solicited from experts currently working on aspects of CCS in the Knox geology. The projects used as sources of risk information are primarily those that have targeted carbonate reservoir rocks similar in age, stratigraphy, and mineralogy to the Knox–Potosi Dolomite.

Risks of using the Potosi Dolomite as the target sequestration reservoir for a CCS project include uncertainties about the levels of porosity and permeability of that rock unit; the lateral consistency and continuity of those properties; and the ability of the project team to identify suitable (i.e., persistently porous and permeable) injection depths within the overall formation. Less direct implications include the vertical position of the Potosi Dolomite within the rock column and the absence of a laterally extensive shale caprock immediately overlying the Potosi Dolomite. Based on modeling work done partly in association with this risk report, risks that should also be evaluated include the ability of available methods to predict and track the development of a $CO_2$ plume as it migrates away from the injection point(s). The geologic and hydrodynamic uncertainties present risks that are compounded at the stage of acquiring necessary drilling and injection permits.

It is anticipated that, in the future, a regional geologic study or $CO_2$-emitter request may identify a small specific area as a prospective CCS project site. At that point, the FEPs lists provided in this report should be evaluated by experts for their relative levels of risk. A procedure for this evaluation is provided. The higher-risk FEPs should then be used to write project-specific scenarios that may themselves be evaluated for risk. Then, actions to reduce and to manage risk can be described and undertaken.

The FEPs lists should not be considered complete, as potentially the most important risks are ones that have not yet been thought of. But these lists are intended to include the most important risk elements pertinent to a Potosi Dolomite-target CCS project, and they provide a good starting point for diligent risk identification, evaluation, and management.

### Best Practices

Specific conclusions and best practices are given below:

- FEP analysis should be mandatory for any CCS project. However, using the FEP analysis developed by our project as a template would simplify the processes.
- Bringing in experts before underrating detailed site assessment should be mandatory.

### Visually Reviewing Risk: Regional Screening

To illuminate areas of higher or lower potential for sequestration, example screening criteria were spatially overlain on mapped $CO_2$ storage results from the current Cambro-Ordovician regional assessment. Although the screening criteria may not be the ultimate restrictions for $CO_2$ storage, they represent considerations that may guide the search for a candidate storage site to be studied later in further detail in order to assess and determine geologic suitability for $CO_2$ storage.

Of primary importance to subsurface $CO_2$ storage are adequate reservoir pore volume, depth, and salinity, as well as reservoir-seal continuity absent of major faulting. Additional considerations may include the proximity of wells or subsurface penetrations within the St. Peter Sandstone-Knox Group stratigraphic interval, such as EPA Class I disposal wells, $CO_2$ storage wells, and/or storage fields for natural gas. For the following example, we will use the selected screening criteria to focus on potential $CO_2$ storage areas in the Knox Group.

#### $CO_2$ storage resource

Figure 29 illustrates the spatial distribution of the Knox Group $CO_2$ storage resource from the current Cambro-Ordovician regional assessment ($P_{90}$ estimate). The map shows higher values (storage in tonnes per $km^2$) in the central and southwest portions of the Illinois Basin, which is largely a function of increased Knox thickness, and thus reservoir pore volume available for $CO_2$ storage, throughout this area. Inherent in the resource estimates are spatial screening by reservoir depth and salinity: depths greater than 800 m are specified by DOE assessment methodology (US DOE, 2012) in order to maintain supercritical $CO_2$ within the reservoir's temperature and pressure regime and salinity greater than

10,000 parts-per-million (ppm) of TDS that exceeds the US EPA drinking water standards for potable water.

For this screening example, an additional *buffered area* extending 8 km (5 mi) from the 10,000 ppm TDS line in the St. Peter Sandstone was applied to the Knox storage map results (Figure 30). The buffered area extends southward into the more brine-saturated St. Peter Sandstone of the central Illinois Basin (Young 1992) and serves to isolate an injected $CO_2$ plume and minimize any pressure effects that may be transmitted from a potential injection site toward the 10,000 ppm limit line.

In general, the areal buffering provides some degree of isolation from geologic and geographic features that may be of concern for subsurface $CO_2$ storage. The buffer distance is somewhat arbitrary, but helps to highlight features that should be of concern to projects that intend to inject significant volumes of $CO_2$ into the ground at high pressure. Additional screening criteria to which spatial buffers were applied are discussed as follows.

## Faults

A 8-km (5-mi) buffered restriction was placed around major mapped faults in the Illinois Basin (Figure 31; (Nelson, 1995), (IGS, 2000)]), to indicate potential through-going displacements in both storage reservoir and geologic seal. In addition to known fault lines, the Charleston Monocline was added as a regional screening consideration; this prominent feature of the LaSalle Anticlinorium has been mapped as a north/northwest-trending monoclinal structure in east-central Illinois (Nelson, 1995) and is believed to be a deep-seated basement fault that penetrates most of the shallower horizons.

Faults, in particular, need to be characterized and understood on a site-specific basis; features such as smaller displacements or stratigraphic traps (e.g., as in the case of certain oil fields) may not necessarily be restrictions to $CO_2$ injection and storage, if it is determined that the displacements do not adversely affect storage reservoir and seal integrity.

## Gas storage fields and other sensitive wells

The buffers around natural gas storage fields and deep Class I waste injection wells attempt to isolate the injected $CO_2$ plume from the fields or wells. The purpose of this buffer is to minimize any pressure effects that may be transmitted between the injection site and the natural gas storage field or waste injection well. A buffer radius of 16 km (10 mi) was placed around gas storage fields which targeted the St. Peter-Knox stratigraphic interval (Figure 32); these storage fields were assumed to be active if not explicitly known to be abandoned (Buschbach, 1973).

For the purposes of this study, *sensitive wells* are defined as active Class I disposal wells in the St. Peter-Knox stratigraphic interval and/or deep $CO_2$ injection wells—to which a buffer radius of 8 km (5 mi) was applied (Figure 32). Well location and status information for active Class I disposal wells (hazardous or non-hazardous waste) were obtained from state geological surveys, the Illinois EPA (regulatory agency for Illinois), and the US EPA (regulatory agency for Indiana and Kentucky). Three deep $CO_2$ injection well locations were also highlighted for this screening example; of these, only the Blan #1 well in western Kentucky has injected $CO_2$ into the Knox Group, whereas the in-progress IBDP well[1,2] and the planned FutureGen_2.0 injection well[1] both target the Mt. Simon Sandstone—a saline reservoir stratigraphically lower than the Knox horizon. Although the locations of $CO_2$ injection wells should be considered in regional screening, this study used an 8-km (5-mi) buffer because of the relatively small amount of $CO_2$ injected in the Blan #1 well (293 tonnes) and the presence of a sealing stratigraphic interval (Eau Claire Shale) between the Mt. Simon Sandstone and the overlying Knox Group.

Guidelines for sensitive wells were adapted from the original FutureGen siting proposal that dealt with site-specific selection criteria, where the land above a proposed target formation(s) must not intersect dams, water reservoirs, hazardous materials storage facilities, Class 1 injection wells, or other "sensitive features." Based on the professional judgment of technical experts and in consultation with the Illinois EPA, the FutureGen applicant believes that a 45 million tonne (50 million ton) $CO_2$ plume would have a very low probability of migrating up to 10 mi (16 km) laterally from the bottomhole location of an injection well. Although locating site-specific sensitive features such as dams, reservoirs, etc., was deemed beyond the scope of this regional screening case example, these features would have to be considered (along with other environmental concerns, per US National Environmental Policy Act reporting requirements) if the regional screening results carried forward to detailed site selection and characterization efforts.

## Results

Figure 33 shows an overlay of all screening criteria discussed above, and faulted areas are a dominant visual feature on the map. Faults are generally concentrated in the southern, deeper potion of the Illinois Basin. Gas storage fields and sensitive wells are found along the margins of the Knox storage resource in the Illinois Basin, where the Knox Group reservoir is generally thinner. Thus, an example of potential *sequestration fairway* areas free from our screening criteria and overlays are shown in darker green and blue-green colors in southern Illinois, southwest Indiana, and western Kentucky. Although some thick Knox reservoir is apparent in the extreme southwestern portion of the Illinois Basin in western-most Kentucky, this area is near the limit of the current regional Cambro-Ordovician study and warrants further examination.

As previously stated, the buffer sizes are somewhat arbitrary, but serve to represent selected examples of geological features or conditions that could be considered when regionally identifying areas of relatively higher or lower potential for $CO_2$ storage to be studied in further detail.

[1] Well status at the time of this report.
[2] For regional mapping purposes, planned $CO_2$ injection into the Mt. Simon Sandstone at the Industrial Carbon Capture and Storage well at Decatur, Illinois, is considered to be the same location as the IBDP injection well.

## Recommend Best Practices and Lessons Learned

The recommend best practices and lessons learned are given below:

- Within the broadly favorable areas of the Illinois and Michigan Basins, selection of a specific project site is still a challenge. GIS-based maps apply the current knowledge of Knox reservoir quality, caprock sealing capacity, depth, and other constraints in a layered fashion, to define fairways most favorable for Knox project siting. The GIS format enables adding data layers in the future to further refine siting.
- Some other geographically specific data layers would be helpful toward siting. An important constraint is "monitorability"—that is, the technical ability and budgetary feasibility to locate the plume of injected $CO_2$ and to demonstrate containment. The ability to successfully monitor (using whatever technologies) depends on some geologic characteristics, but depends to an even greater extent on such surface characteristics such as "surface accessibility," "percent land cover by buildings or inaccessible natural features," or "percent land cover by tilled farmland."

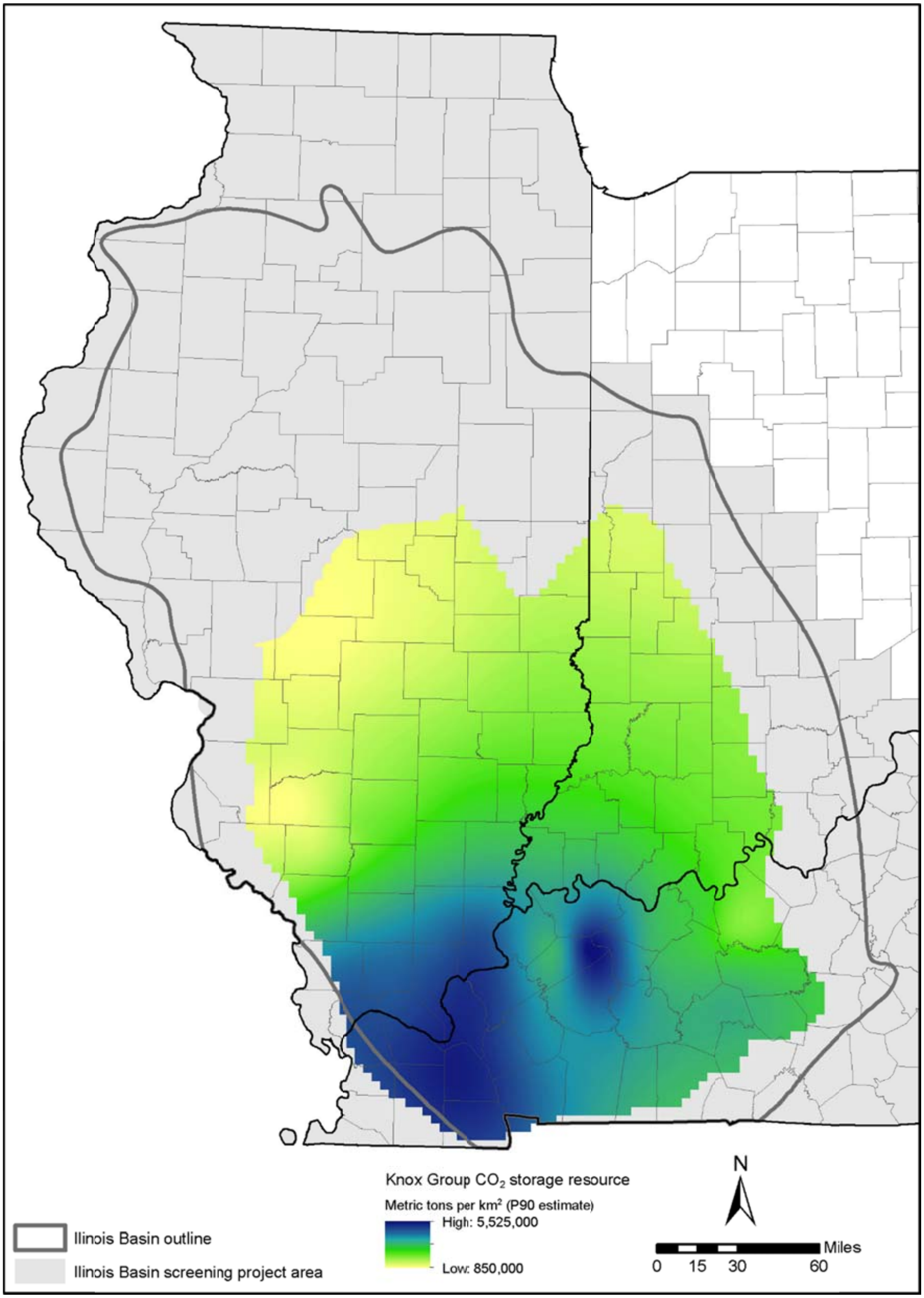



Figure 29 Knox Group $CO_2$ storage resource ($P_{90}$ estimate) in the Illinois Basin.

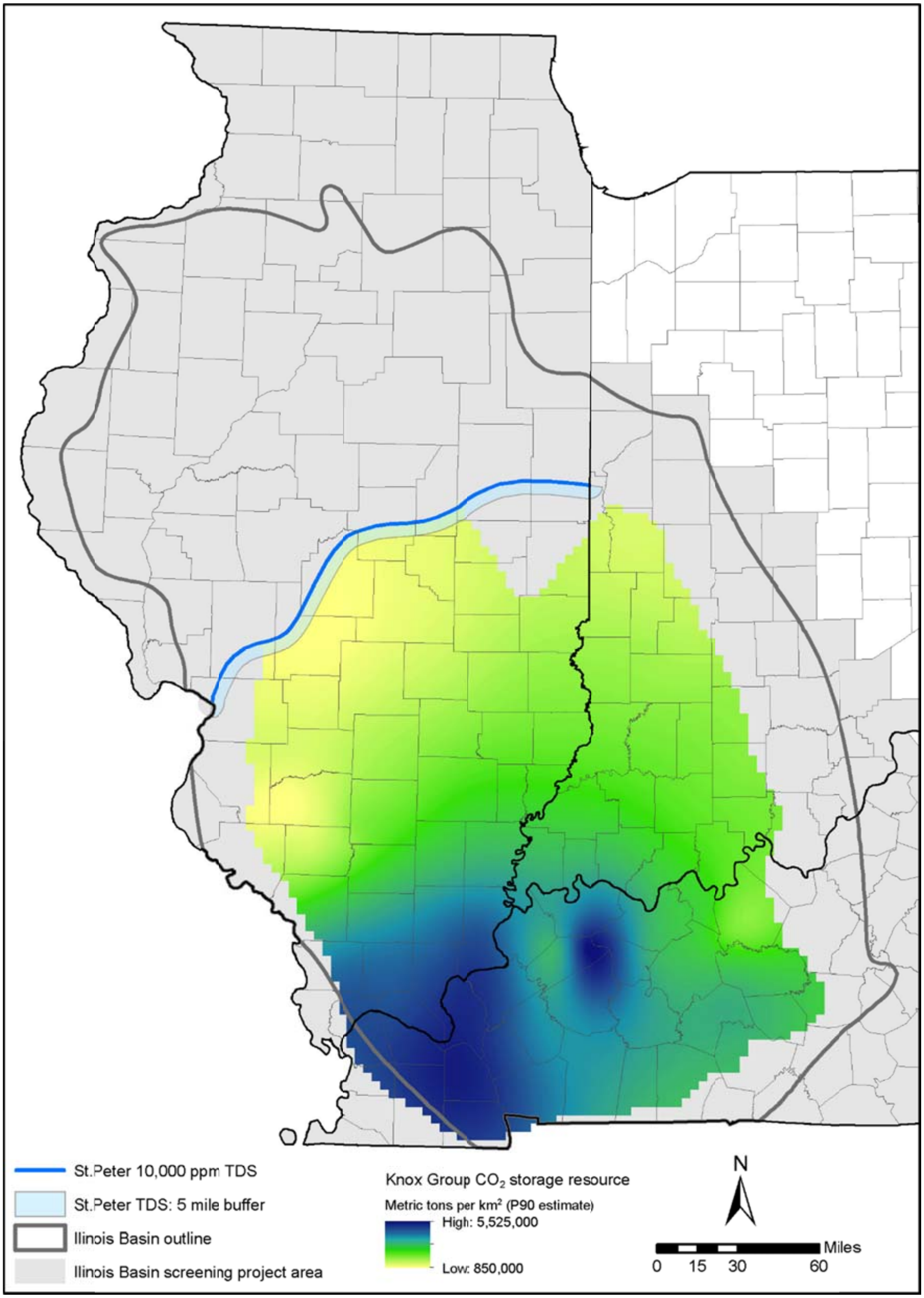



Figure 30 Knox Group $CO_2$ storage screening: 10,000 ppm TDS.

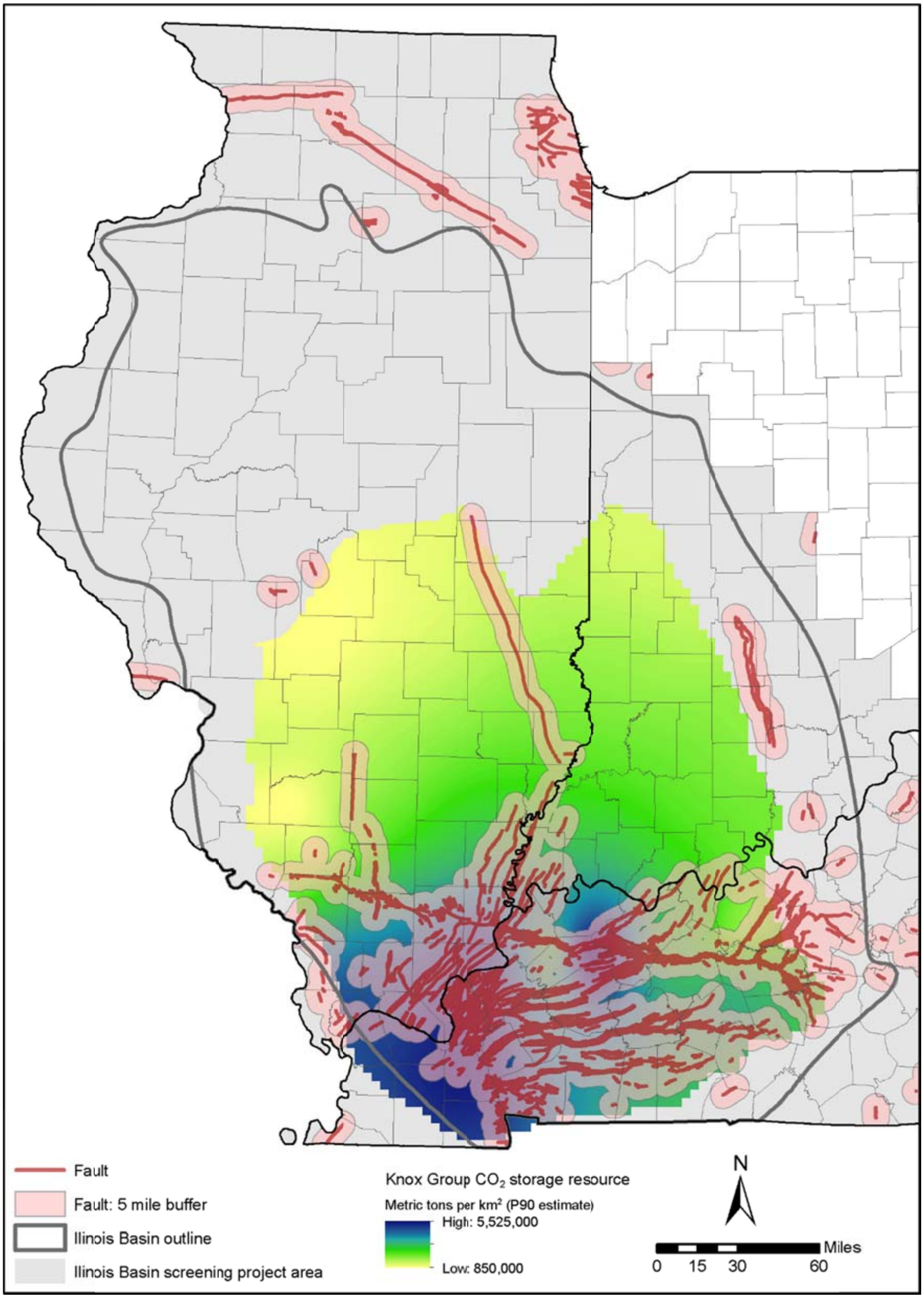



**Figure 31 Knox Group $CO_2$ storage screening: faulted areas.**

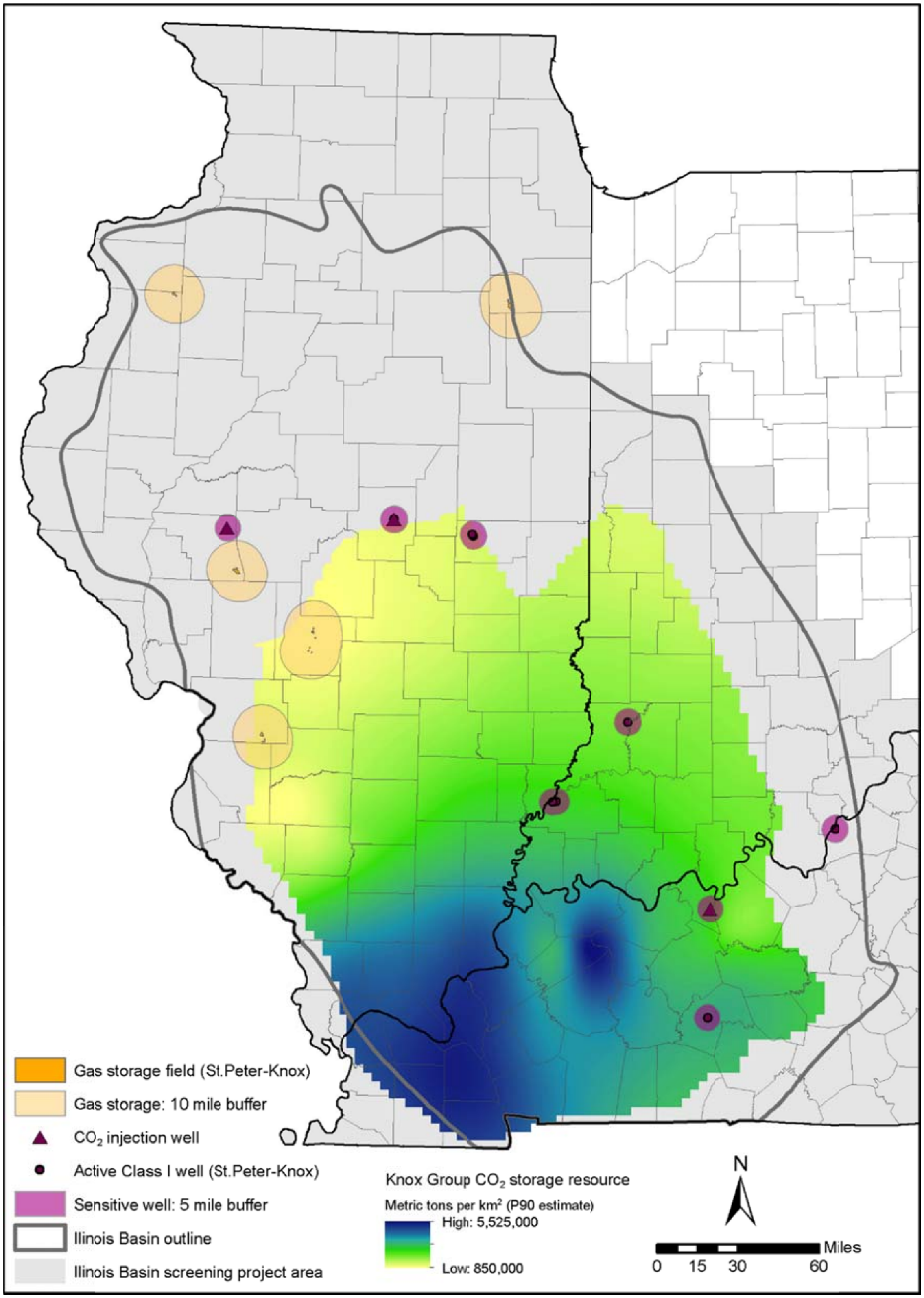



Figure 32 Knox Group $CO_2$ storage screening: gas storage fields and sensitive deep wells.

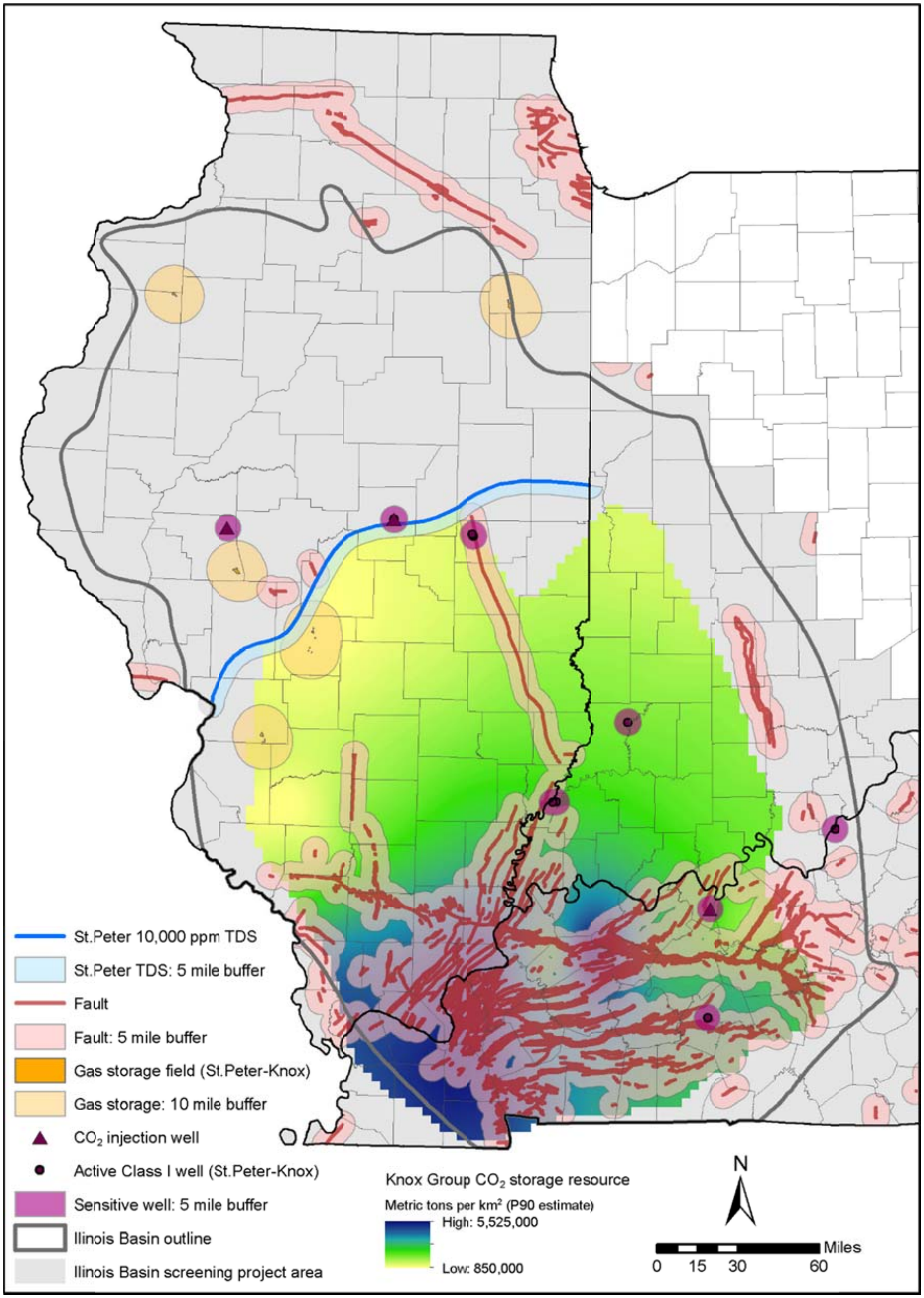



**Figure 33 Knox Group $CO_2$ storage resource showing overlay of all regional screening criteria.**

## Publications and Presentations Completed in the Project

The following table and references are all of the publications and presentations produced during the course of the project.

| Task and Subtask | Report or publication |
|---|---|
| **Task 1 – Project Management and Planning** | This Task was continually updated and does not involve an individual report. |
| **Task 2 – Compile Available Base data and Assess Data Needs** | This Task was continually updated and is included in all of the separate reports |
| **Task 3 – Site Characterization at the Decatur and Hancock Projects** | |
| **Subtask 3.1** Acquire the core from the Decatur project. | Completed and part of multiple publications and reports |
| **Subtask 3.2** Measure reservoir and geomechanical properties of the core from Decatur. | (Leetaru, 2012) |
| **Subtask 3.3** Interpret results of first phase of injection tests at the Hancock site and decide on the specific zone and fluid type for the second injection test | (Bowersox, 2010),(Bowersox, 2012),(Bowersox, 2013) |
| **Subtask 3.4** Design injection test with assistance of outside consultants and request final bids for workover rig, $CO_2$ supply, and injection equipment. | (Bowersox, 2010),(Bowersox, 2012), Bowersox, 2013) |

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| **Subtask 3.5** Perform injection test at the Hancock site. | (Bowersox, 2010),(Bowersox, 2012), (Bowersox, 2013) |
| **Subtask 3.6** Using workover rig while still on location, acquire 3D vertical seismic profile | (Bowersox, 2010), (Bowersox, 2012) |
| **Subtask 3.7** Plug and abandon well and reclaim well site. The costs for plugging and reclamation of the well will be paid by the Kentucky Consortium for Carbon Storage (KYCCS) as cost-share to the project. | (Bowersox, 2010),(Bowersox, 2012) |
| **Subtask 3.8** Interpret results of second injection phase and model the reservoir using data from both injection phases. Compare the results of the 3D VSP with the zero-offset VSP acquired prior to injection. | (Bowersox, 2010),(Bowersox, 2012), (Hickman, 2014b) |
| **Subtask 3.9** Hold an open house for the public at or near the Hancock site. | (Harris, 2012) |

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| **Task 4 – Regional Significance** | |
| **Subtask 4.1** Develop cross sections | (Lasemi, 2014), (Askari, 2013) |
| **Subtask 4.2** Develop regional structure and thickness maps | (Lasemi, 2014) |
| **Subtask 4.3** Evaluate the limits of the Knox and Mt. Simon formations in western Illinois. | (Smith, 2014c) |
| **Subtask 4.4** Prepare topical report summarizing the results of 2-D survey | (Smith, 2014c) |
| **Task 5 – Capacity Estimates** | |
| **Subtask 5.1** Calculate the average porosity of the porous intervals in the Knox and St. Peter Sandstone. | (Will, 2014), (Bowersox, 2011), (Barnes, 2014a), (Barnes, 2014b), (Sosulski, 2013), (Ellett, 2011), (Ellett, 2013) |
| **Subtask 5.2** Develop a depth-to-porosity relationship | (Will, 2014), (Barnes, 2014a) |
| **Subtask 5.3** Use both reflection seismic and seismic modeling | (Will, 2014) |
| **Subtask 5.4** Develop storage capacity maps of the key intervals | (Harris, 2014), |
| **Task 6** Injectivity of the formation | (Harris, 2012), (Leetaru, 2014) |
| **Task 6 – Injectivity of the** | |

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| **formation** | |
| **Subtask 6.1** Evaluate the injectivity from St. Peter natural gas storage projects. | (Will, 2014) |
| **Subtask 6.2** Use available core to develop a porosity vs. permeability relationship. | (Barnes, 2014a) |
| **Subtask 6.3** Carry out numerical reservoir flow simulation of the Knox and St. Peter. | (Adushita, 2014a),(Adushita, 2014c),(Adushita, 2014b),(Smith, 2014a),(Smith, 2014b), (Leetaru, 2014) |
| **Task 7 – Stratigraphic Containment** | |
| **Subtask 7.1** Conduct geomechanical measurements of the Maquoketa and Knox from the newly acquired core from Decatur, Illinois. | (Zaluski, 2014), (Leetaru, 2012) |
| **Subtask 7.2** Conduct seal analysis of the Maquoketa and Knox cores (including core from Decatur Project and Hancock site). | (Zaluski, 2014), (Leetaru, 2012) |
| **Subtask 7.3** Integrate different seal data including: wireline log | (Zaluski, 2014), (Leetaru, 2012), (Zdan, 2013) |

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| properties, geomechanical measurements, whole core, and seismic reflection data. | |
| **Subtask 7.4** Carry out petrophysical analyses of a regionally distributed modern wireline logs in the two basin area to evaluate the continuity of the seal. | (Lasemi, 2014), (Bowersox, 2014) |
| **Task 8 – Brine Containment** | |
| **Subtask 8.1** Use available brine data from the Knox and St. Peter and numerically model the dissolution of $CO_2$ in brine and the interaction with carbonate reservoir rocks. | (Park, 2011b), (Park, 2011a), (Zhu, 2011), (Zhu, 2012), (Zhu, 2013), (Zhu, 2014) |
| **Task 9 – Mineralization Containment** | |
| **Subtask 9.1** Conduct sedimentologic and petrographic analysis of core and outcrop to develop a depositional model that could be a predictive tool for changes in the reservoir. | (Yoksoulian, 2014), (Bowersox, 2014), (Freiburg, 2012), (Freiburg, 2013), (Freiburg, in review) |
| **Subtask 9.2** Carry out laboratory analyses to identify the mineral | (Yoksoulian, 2014) |

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| components of the core. | |
| **Subtask 9.3** Use core from different areas (including the acquired core from the Hancock Kentucky site and the Decatur Site) and do laboratory measurements of $CO_2$ mineral reactions. | (Yoksoulian, 2014) |
| **Task 10 – Leakage Pathways** | |
| **Subtask 10.1** Review petrophysical analyses of all modern logs through the interval to determine possible indications of fractures. | (Smith, 2014b), (Zaluski, 2014) |
| **Subtask 10.2** Evaluate the seal potential of different types of faulting found in the Illinois Basin. Work would involve calculating shale gouge ratios for several intervals using log data from the Hancock well. | (Hickman, 2014a) |
| **Subtask 10.3** Develop a strategy to mitigate possible $CO_2$ release. | (Zaluski, 2014), |
| **Task 11 – Site Selection** | |
| **Subtask 11.1** Using the | In Final Report |

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| results from the previous tasks, develop a best-practices manual for assessing the suitability of a site for $CO_2$ sequestration in the Cambro-Ordovician. | |
| **Subtask 11.2** Develop a series of GIS-compatible maps showing areas of high and low potential for sequestration. | In Final Report |
| **Task 12 – Risk Assessment** | |
| **Subtask 12.1** Use a FEP analysis approach to understand the uncertainty of developing a site. | (Hnotttavange-Telleen, 2013) |
| **Task 13 – Well Bore Management** | |
| **Subtask 13.1** Use geomechanics to assess risk for borehole breakthrough in existing wells. | (Kirksey, 2013) |

**Publications Generated on Project**

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