CONFERENCE PROCEEDINGS

Geologic Storage Options and Capacities for Carbon Dioxide Sequestration in the Midwest Regional Carbon Sequestration Partnership (MRCSP)

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ABSTRACT

The Midwest Regional Carbon Sequestration Partnership (MRCSP), one of seven regional CO_2 sequestration partnerships funded by the U.S. Department of Energy, has concluded an initial (Phase I) geologic assessment of the carbon dioxide (CO_2) storage potential in the seven-state region (Indiana, Kentucky, Maryland, Michigan, Ohio, Pennsylvania, and West Virginia). The region includes the area encompassing the Michigan basin, Cincinnati and Kankakee arches, and parts of the northern and central Appalachian basin. Physical and chemical data on the geologic units in these basins have been mapped for nine potential regional reservoirs and five regional seal (cap rock) intervals that provide multiple options for CO_2 sequestration. Digital geologic databases, maps, and calculations were created to evaluate various sequestration technologies, aid in site-selection decisions, and estimate available CO_2-sequestration capacities. *Deep saline formations* are estimated at 450 gigatonnes of storage capacity (hundreds of years at present CO_2 output levels within the MRCSP) and represent the region's largest sequestration option. Carbon dioxide can be used in "value-added" enhanced oil recovery from *petroleum fields*—presently estimated at 2.5 gigatonnes of CO_2 sequestered concurrent with the production many millions of barrels of oil. Using CO_2 for enhanced recovery of natural gas stored in *unmineable coal beds* and *organic-rich shales* is estimated to sequester, at minimum, 45 gigatonnes. These four types of geological sequestration systems provide many options for the utilization and disposal of anthropogenic carbon dioxide within the MRCSP. Phase II work by the partnership will include refining these data and maps as well as testing different potential reservoirs via pilot injection projects.

1.0 INTRODUCTION

1.1 Project Team

The Midwest Regional Carbon Sequestration Partnership (MRCSP) is one of seven, regional carbon dioxide (CO_2) sequestration partnerships supported by the U.S. Department of Energy (DOE) in the nation. Led by Battelle Memorial Institute of Columbus, Ohio, this partnership is a consortium of several leading universities, state geological surveys, non-governmental organizations, and private companies charged with assessing the technical potential, economic viability, and public acceptability of carbon sequestration within the MRCSP region. Specifically, the geologic team for the MRCSP consists of a multifaceted collaboration of geologic, geographic information system (GIS), and computer scientists from the geological surveys of Indiana, Kentucky, Ohio, Maryland, Pennsylvania, and West Virginia, as well as the Michigan Basin Core Research Laboratory of Western Michigan University. These agencies are the major repositories for publicly available, geologic data throughout the MRCSP region, and have significant experience in the characterization and interpretation of their respective state's subsurface geologic resources.

1.2 Study Area

The geographic area represented by the MRCSP includes the seven contiguous states of Indiana, Kentucky, Maryland, Michigan, Ohio, Pennsylvania, and West Virginia. This region includes the area encompassing the Michigan basin, Cincinnati and Kankakee arches, and parts of the northern and central Appalachian basin (Figs. 1 and 2). The MRSCP region is a critical component of the nation's economy and a major producer of CO_2. The region generates almost 21 percent of our country's electricity, 78 percent of which is derived from coal. For this reason, this region is appropriately considered America's "engine" room. The region also contains a wide array of facilities classified as CO_2 point sources that produce 26 percent of the nation's CO_2 emissions from power plants and 12 percent of the nation's total CO_2 emissions (Ball, 2005). Phase I of the MRCSP study identified over 600 stationary facilities that are considered CO_2 point sources, of which at about 300 are classified as large sources (>100,000 tons of CO_2/year) that emit over 800 million tons of CO_2 per year (Fig. 3). These facilities include plants that produce ammonia, cement, ethanol, ethylene, ethylene oxide, hydrogen, and power, as well as petroleum refineries, gas processing facilities, and iron and steel mills. The large volumes of CO_2 emissions from these many point sources, along with their potential environmental liability, supplicate the need for a sequestration technology that can accommodate such CO_2 emissions in the study area. During Phase I of the project (2003 through 2005), the MRCSP's geologic team studied the regional geology of the area, created a regional correlation chart showing the various geologic units present in the subsurface, and delineated the most promising prospective geologic reservoirs and sinks for CO_2 sequestration through data collection, interpretation, and mapping.

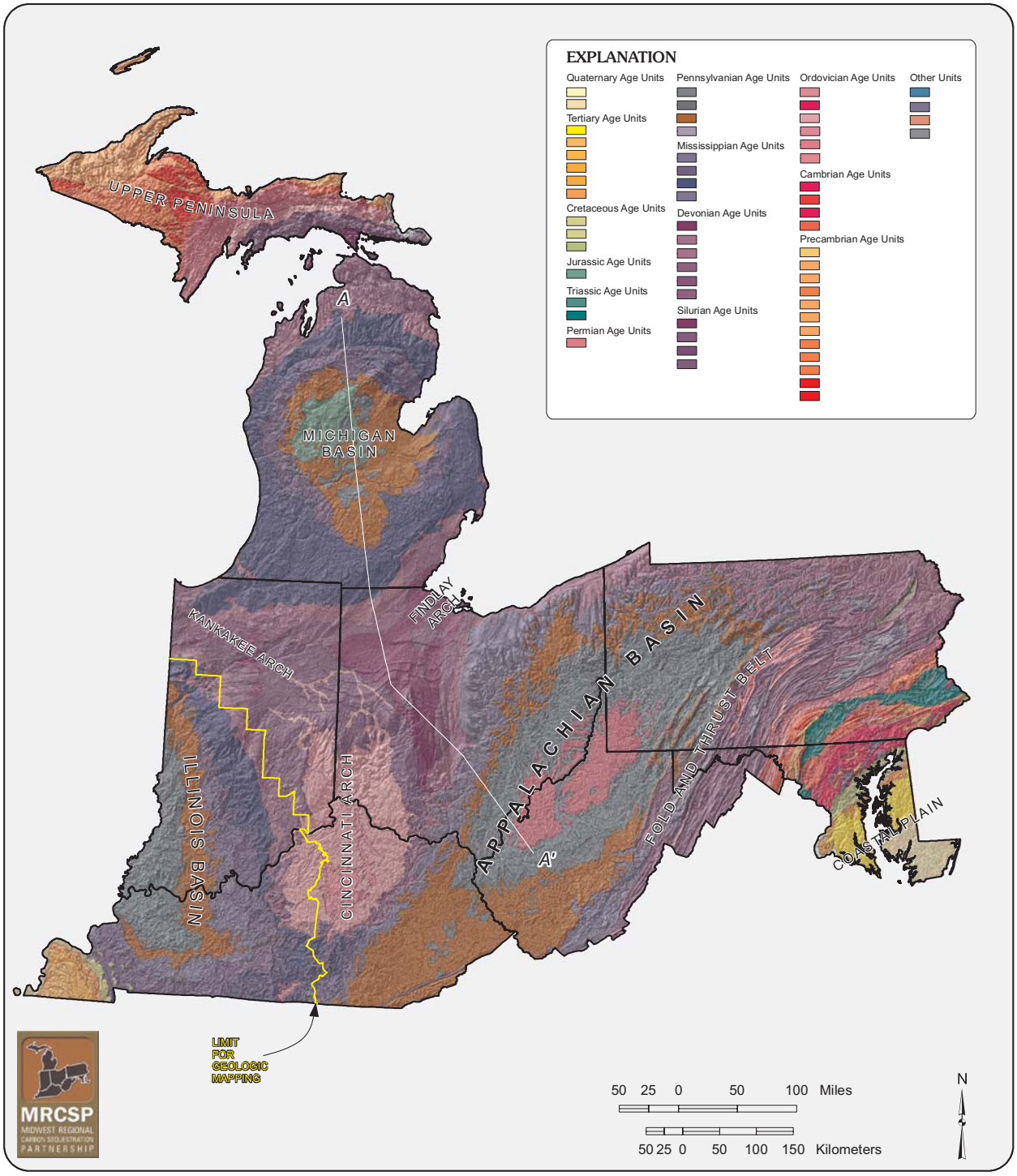

Figure 1.— Shaded topographic relief map showing generalized bedrock geology units (by system) found at or near the surface and bedrock contacts. Major geologic features (folds, arches, and basins) of the MRCSP study area are also labeled (from Schruben and others, 1997). A-A' line is location of cross section shown in Fig. 2.

1.3 Regional Assessment

Until recently, the major options under consideration for mitigation of greenhouse-gas emissions included switching to non-carbon-based fuels, increasing energy efficiency (thereby reducing greenhouse-gas emissions), and terrestrial or biotic sequestration of CO_2. However, during the last several years, the idea of storing CO_2 in geologic reservoirs has gained increased prominence as a result of research funded by the DOE, similar agencies in other countries of the world, and a growing interest of CO_2-producing industries. The primary attraction of the geologic sequestration option is due to the potential for direct and long-term storage of captured CO_2 emissions in close proximity to the CO_2 source. However, to achieve this objective,

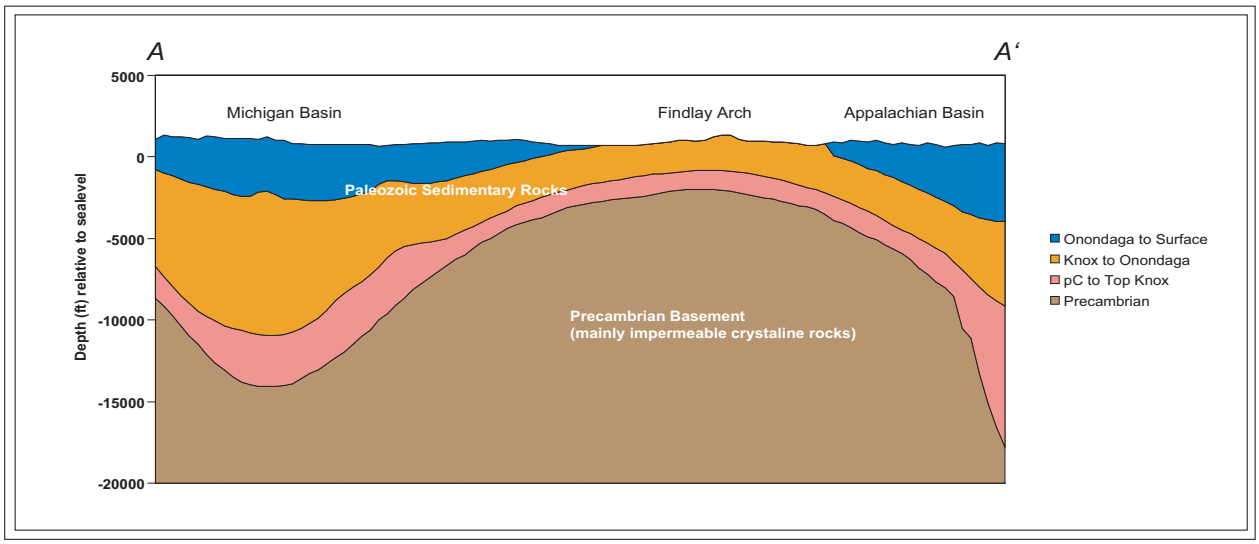

Figure 2.— Generalized cross section across the Michigan and Appalachian basins. Profile line is shown on Fig. 1. Layer elevations for this cross section were obtained directly from geologic maps produced during Phase I of this project.

the potential capacity of any geologic reservoir must be verified by a detailed regional assessment, as well as by a site-specific investigation to insure that decision-makers fully understand the characteristics of the geologic sequestration system. Accordingly, a major task of the Phase I study was a first-round regional assessment of the potential capacity for geologic sequestration of CO_2 in the MRCSP area.

The MRCSP completed its initial assessment of the CO_2 storage potential in the seven-state region in September 2005. The resulting work identified nine potential geologic reservoirs and five potential confining units that may be used for geologic CO_2 sequestration. In total, the MRCSP used over 85,000 data points to generate 30 original structure and thickness maps, nine regional thematic maps, and 14 derivative sequestration capacity maps. One of the more significant thematic map layers created was a new, digital oil- and gas-fields map for the MRSCP region, the first ever compiled for the seven-state area.

1.4 Potential Geologic Reservoirs

The DOE has identified several categories of geologic reservoirs for potential CO_2-sequestration (U.S. Department of Energy, 1999, 2004, 2005). Of these categories, four are considered important for the MRCSP region: (1) deep saline formations, (2) oil and gas fields, (3) unmineable coal beds, and (4) organic-rich (i.e., carbonaceous) shales. During Phase I of the project, the MRCSP focused its data collection, interpretation, mapping, and subsequent geologic sequestration capacity modeling efforts on these four reservoir types, whose formation, injection, and storage characteristics are discussed below.

1.3.1 Deep Saline Formations

Saline formations are natural, salt-water-bearing intervals of porous and permeable rocks that occur beneath the level of potable groundwater. Currently, a number of the saline formations in the MRCSP region are used for waste-fluid disposal (especially in Indiana, Michigan, and Ohio); thus, a long history of technological and regulatory factors exist that could be applied to CO_2 injection/disposal. Saline formations are widespread (Fig. 4), close to many large CO_2 sources, and are thought to have large pore volumes available for injection (Reichle and others 1999; U.S. DOE, 2004, 2005). In order to maintain the injected CO_2 in a supercritical phase (i.e., liquid), the geologic unit must be at least 2,500 feet or greater in depth. Maintaining the CO_2 in a liquid phase is desirable because as such, it occupies less volume than in the gaseous phase. For example, one tonne of CO_2 at surface temperature and pressure (i.e., in gaseous phase) occupies approximately 18,000 cubic feet. The same amount of CO_2, when injected to approximately 2,600 feet in depth, will occupy only 50 cubic feet. Deep sequestration depths also help insure there is an adequate thickness of rocks (i.e., confining layers) above the potential injection zones to act as a geologic seal. For the purposes of the MRCSP Phase I study, no consideration was given to the potential use of shallow saline formations for CO_2 sequestration.

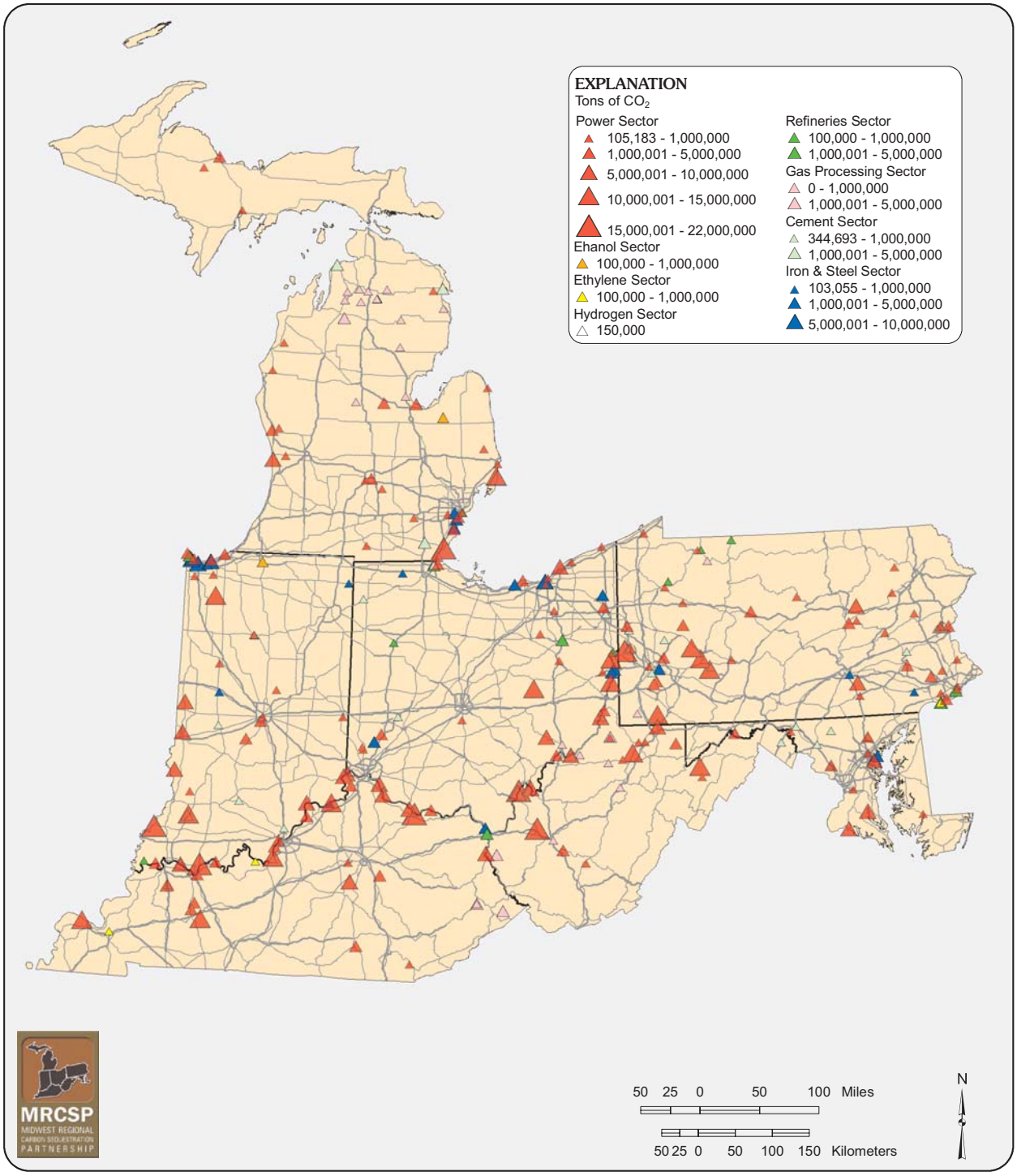

Figure 3.— Large (>100,000 tons per year) point sources of CO_2 within the MRCSP region.

In this type of reservoir, CO_2 is injected under pressure down a specially constructed well where it displaces and mixes with saline water, filling the pore spaces between the mineral grains of the reservoir rocks, thus becoming trapped within minerals in the rock matrix. Depth, permeability, injectivity, reservoir pressure, reservoir integrity, and water chemistry are some of the variables that control the sequestration potential in deep saline formations (Reichle and others, 1999; Bachu and Adams, 2003). In addition to favorable properties of the injection zone in the reservoir, an overlying seal unit (confining layer) is necessary. The injected CO_2 has a lower specific gravity, and thus, is more buoyant than the natural formation fluids. This difference in buoyancy which causes the injected CO_2 to rise to the top of the porous zones. Hence, all cap

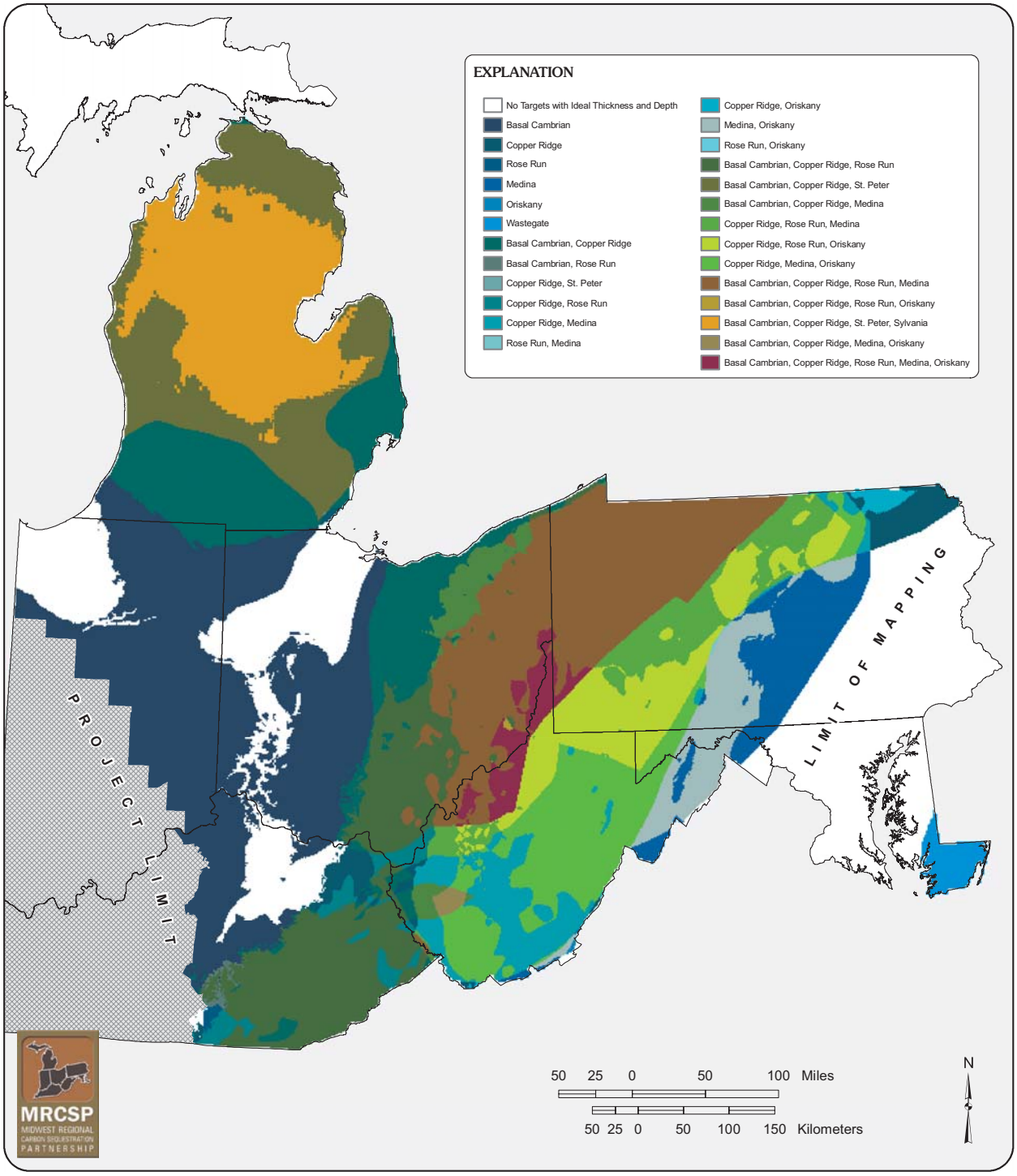

Figure 4.— Screening map summarizing the location and characteristics of saline formations in the MRCSP study area.

rock units must be relatively impermeable and sufficiently thick to arrest any appreciable vertical movement of the CO_2 within the sequestration interval, thereby trapping it in the deep subsurface.

Storage of CO_2 in such a reservoir can be in either subsurface traps or in unconfined strata. In subsurface traps, the more buoyant CO_2 will occupy the highest portion of any structural (e.g., anticline) or stratigraphic (e.g., pinch-out) feature. This same mechanism of trapping is found in many of the natural gas and oil reservoirs that occur in the MRCSP study area. Within such traps, only the pore volume available in the rock and the size of the trap limits the volume of CO_2 that can be injected. In unconfined storage units, the CO_2

is injected in regional aquifers located in rocks without specific structural closures or stratigraphic traps. Once injected, the CO_2 will migrate to the highest portion of the saline formation where it accumulates against the cap rock, which prevents further vertical movement (Bentham and Kirby, 2005). At that point the injected CO_2 then will migrate laterally, following the normal hydrodynamic flow regime of the region (usually towards shallower areas).

1.3.2 Oil and Gas Fields

Oil and gas fields represent known geologic (structural or stratigraphic) traps containing hydrocarbons within one or more reservoirs that are confined by a known cap or seal. In depleted or abandoned petroleum fields, CO_2 would be injected into a reservoir to fill the pore volume left by the extraction of the oil or natural gas resource (Westrich and others, 2002). The injected CO_2 would be trapped by the natural limits of the reservoir for secure storage. Volume, permeability, injectivity, pressure, reservoir integrity, water chemistry, the nature of the cap rock or reservoir seal, and the field's production history are some of the variables that control the sequestration potential in depleted oil and gas fields (Reichle and others, 1999). This option may be attractive in many parts of the MRCSP study area because vast areas of this region have a long history of oil and gas production that dates back to the mid- to late- 1800's (Fig. 5). In addition, the MRCSP region includes four of the top seven natural-gas storage states (i.e., Michigan, West Virginia, Pennsylvania, and Ohio) in the nation (Natural Gas Monthly, 2002). Such large volumes of gas storage capacity strongly suggest that CO_2 gas can be successfully managed in subsurface reservoirs within the region.

In active oil fields, it has been demonstrated that CO_2 can be used for enhanced oil recovery (EOR). In this process, some of the oil that remains in reservoirs after primary production is recovered by injecting CO_2 that either (1) repressurizes the reservoir and also displaces and drives the remaining oil to a recovery well (i.e., immiscible flooding), or (2) directly mixes and chemically interacts with the remaining oil as it also pushes it to the producing well (i.e., miscible flooding). Approximately 70 oil fields worldwide currently inject CO_2 for EOR (U.S. DOE, 2004), which demonstrates the effectiveness of this value-added sequestration option. Moreover, EOR, while sequestering CO_2, could provide an economic incentive to storage in several parts of the MRCSP region where CO_2 sources are proximal to oil fields.

1.3.3 Unmineable Coal Beds

The Appalachian basin comprises a sizeable portion of the MRSCP study area and contains the second- (West Virginia), third- (Kentucky), fourth- (Pennsylvania), and fourteenth- (Ohio) leading coal-producing states in the nation (Energy Information Administration, 2005). Unmineable coal beds offer an alternative option for geologic sequestration in the region because, unlike the previously described reservoir types, CO_2 injected into a coal bed would not only occupy pore space, but would adsorb onto the carbon in the coal itself. The adsorption ratio for CO_2 in coals is approximately twice that of methane; thus, in theory, the injected CO_2 would displace methane, allowing for the potential of enhanced gas recovery (Reznik and others, 1982; Gale and Freund, 2001; Schroeder and others, 2002). Because of the adsorption mechanism, miscibility concerns that exist for oil and gas reservoirs are not an issue in coal bed sequestration. Thus, the injection of CO_2 and resulting enhanced recovery of coalbed methane could occur at shallower depths than for depleted oil reservoirs. Hydrogeologic flow, water chemistry, coal thickness and quality, and subsurface temperature-pressure conditions are some of the variables that control the potential use of coal beds for CO_2 sequestration and enhanced coalbed methane recovery (Pashin and others, 2003). Although there is currently only limited coalbed methane production in the MRCSP region, rising gas prices have led to growing interest in this energy resource in the last decade, and secondary recovery of methane may provide an economic incentive for sequestration of CO_2 from sources in the Appalachian coal fields.

1.3.4 Carbonaceous Shales

The MRCSP study area also contains widespread, thick deposits of carbonaceous shales. These shales are interesting in that they are often multifunctional—acting as seals for underlying reservoirs, as source rocks for oil and gas reservoirs, and as unconventional gas reservoirs themselves. Analogous to sequestration in coal beds, CO_2 injection into unconventional carbonaceous shale reservoirs could be used to enhance existing gas production. As an added bonus, it is believed the carbonaceous shales would adsorb the CO_2 into the shale matrix, permitting long-term CO_2 storage, even at relatively shallow depths (Nuttall and others, 2005a).

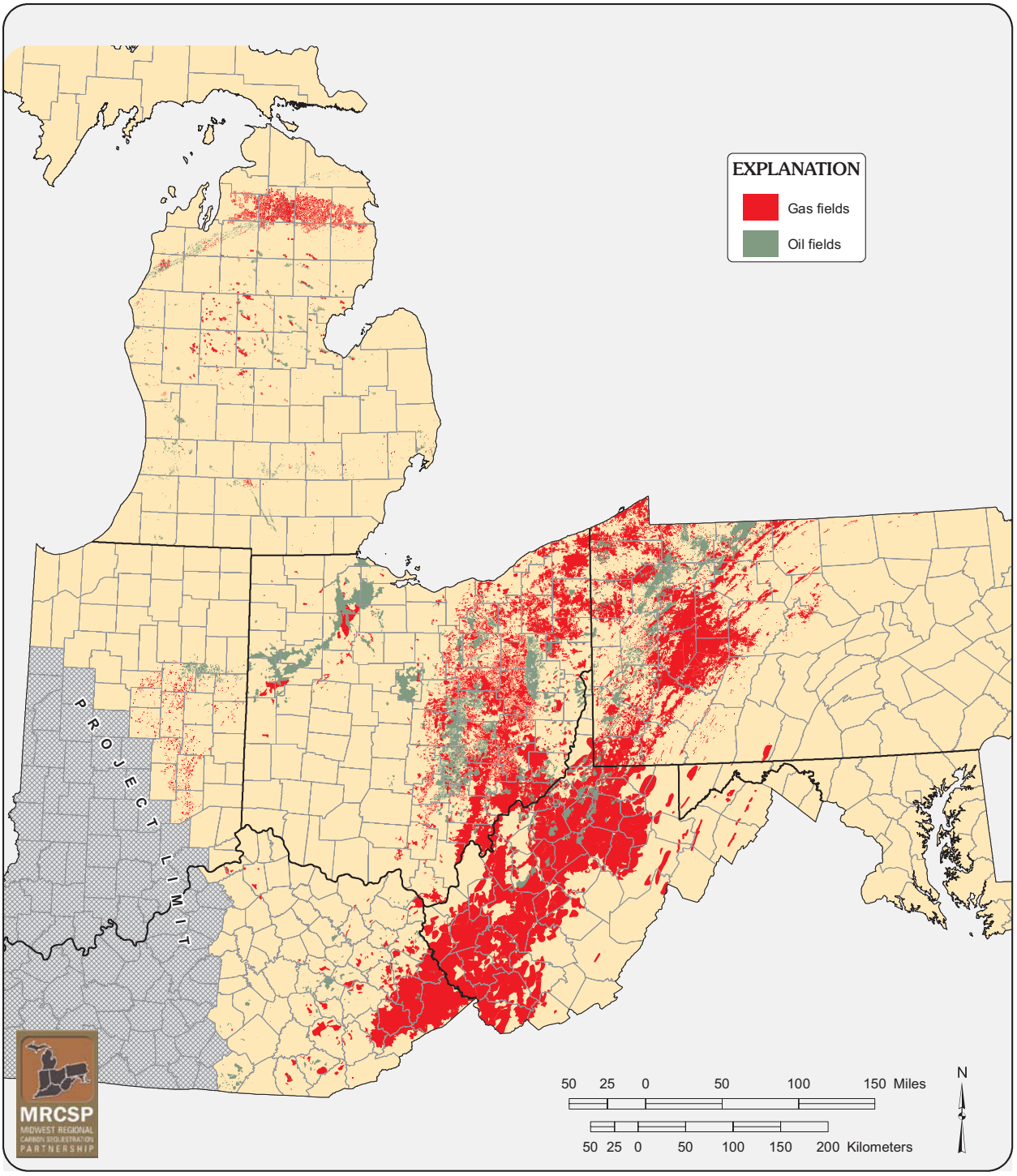

Figure 5.— Oil and gas fields of the MRCSP region.

2.0 METHODOLOGY

2.1 Digital Geologic Mapping

The central products of the MRCSP's Phase I geologic tasks were a series of regional-scale, digital, spatial models and maps, with the overall goal to create a GIS to support regional planning for CO_2 sequestration. The GIS provides spatial data that can be used to evaluate the potential for geologic sequestration of CO_2 at any particular site within the MRCSP study area by digitally analyzing which underlying geologic units might be suitable for further analyses as a CO_2 reservoir and/or seal, their depths and overall thickness, and

providing an estimate of sequestration capacities. Selected sites that appear suitable must still be subjected to further, more detailed studies and site-specific testing and analyses. Digital maps were compiled for the depth and thickness of target and confining geologic layers, the extent of major oil and gas fields, the locations of industrial injection wells, and other geochemical and petrophysical data needed to calculate CO_2 sequestration capacity.

Most of the mapping effort focused on generating structure and isopach maps for those intervals identified as a potential geologic sequestration target and confining unit in the MRCSP region (Table 1). Structure contour and isopach maps were created by interpolating the tops of these units as identified in oil and gas well records that were compiled by the individual partnership states. The MRCSP geologic database contains a total of 85,650 individual wells (Fig. 6) and approximately 162,000 formation tops. Control points (i.e., wells) available for mapping individual layers ranged from less than 500 points for very deep layers (e.g., Lower Cambrian age rocks), to over 23,000 points for shallower layers (e.g., the Silurian-Devonian age Lockport-Onondaga interval). Well-point data were converted to isoline maps using different, commercially available software packages that utilize a range of interpolation methods/algorithms. Unfortunately, these computer interpolations occasionally resulted in the generation of surface trends that contradicted known geologic surfaces. In these cases, isolines were manually edited. Final contour maps were sent to the Ohio Division of Geological Survey, where grids (rasters) were created for every layer to facilitate spatial analyses, modeling, and cartographic display.

2.1.1 Data Gathering

The primary dataset consisted of well data provided by each MRCSP partner state; the bulk of this originated from oil-and-gas-well completion records. Each organization supplemented these datasets, where possible, with data from previous works that were based on detailed geophysical log-based interpretations. The resultant data files—which included the geographic position of the well, its elevation, and the depth of the top of each mapped interval—were used to create each structure map. Due to the range of data sources, the quality of the data on the depth of each unit varied across the region. For example, some formation tops were determined by experienced drillers, others or by industry or government geologists, while others had an unknown origin. Because of this, filtering procedures were needed to remove errors and irregularities from the dataset.

Map Layer	Sequestration Target or Confining Layer
Wastegate Sandstone	Target
Coal	Target
Devonian Shales	Target/Confining layer
Needmore Shale	Target/Confining layer
Sylvania Sandstone	Target
Oriskany Sandstone	Target
Lockport to Onondaga	Confining layer
Medina Sandstone	Target
Knox to Lower Silurian	Confining layer
St. Peter Sandstone	Target
Rose Run Sandstone	Target
Top of basal sandstones to Copper Ridge	Confining layer
Cambrian basal sandstones	Target
Precambrian	Confining layer

Table 1.—List of mapped geologic layers that serve as sequestration targets and/or confining layers. The Cambrian basal sandstones include the Mount Simon Formation, the Potsdam Sandstone, the unnamed Conasauga sandstones, and the Rome Trough sandstones.

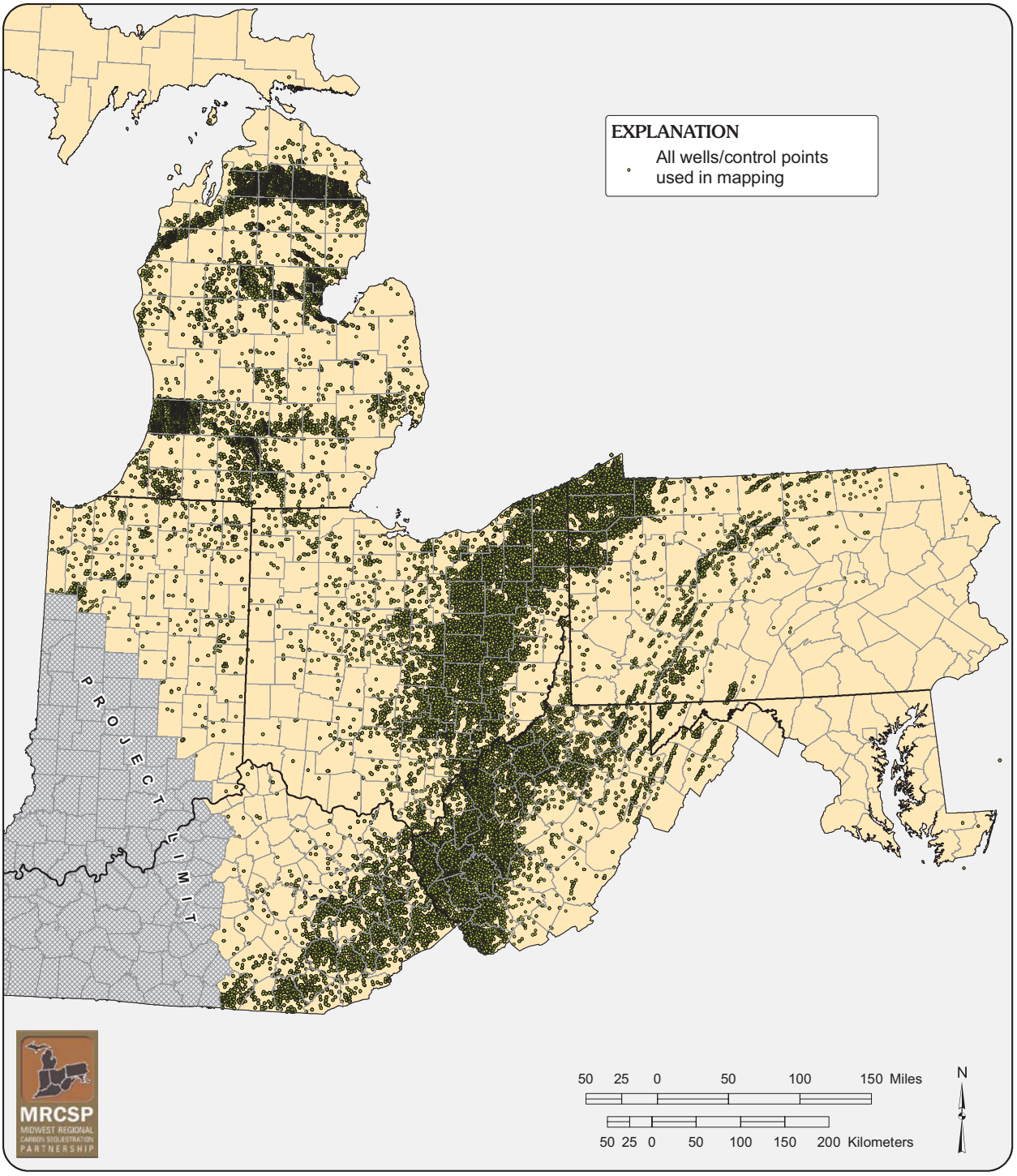

Figure 6.— Map showing the distribution of all wells (85,650 unique locations) used for creating the geologic structure and isopach maps for the MRCSP Phase I study.

2.1.2 Data Filtering

Data filtering was accomplished by a variety of means, depending upon factors such as the complexity of the geologic layer to be mapped, the volume of available well point data, and the mapping software used to prepare the data and create the maps (for example, one approach utilized Geostatistical Analyst—an ArcGIS product). A preliminary variogram was modeled and an initial surface created. Cross validation was conducted and points with residuals of two standard deviations or more from the mean residual value were flagged as potential outliers. Those points deemed valid, yet flagged because of the influence of bad neighboring points were left in the system; erroneous data were removed. The data sets were also corrected

by searching for output that did not conform to projected geologic trends across a region. If the error could not be resolved using just the data and map, geophysical log-based cross sections were constructed to reconcile the areas of conflict. This filtering and inspection process was repeated until all erroneous wells were removed or resolved. Other approaches relied mostly on manual evaluations of data outliers, and in cases where geologic structure were particularly complex or point data were lacking, additional datasets (i.e., hand-drawn structure contours, previously published geologic maps, or the like) were used to supplement and improve the geologic quality of the resulting maps.

2.1.3 Interpolation Methods

Computer-based and manual interpolation methods were needed to convert the point data into isoline maps and grids. Each state chose an interpolation algorithm that gave the best representation of the geologic layer to be mapped and fit within the individual software (ArcGIS, PETRA, or Surfer) capabilities of each state's mapping team. For all methods, the end result was a set of digital isolines that required considerable manual editing in GIS software to remove edge effects, repair errors caused by data scarcity, and rectify match-up errors with pre-existing digital surface and near-surface geologic maps of specific mapped intervals.

2.1.4 Manual Editing of Contour Maps

Considerable manual manipulation of contour lines was needed to create geologic maps that conformed to both the data and geologic knowledge. Line editing was generally accomplished digitally using ArcEdit (an ArcGIS product). The bulk of the editing was done to fill in data gaps and rectify contour-line variations as the lines approached the surface crop line of those units exposed at the surface in the MRCSP region.

More extensive editing and interpretations were conducted in the faulted areas of Kentucky, especially on the deeper units. In order to account for the structurally complex Rome trough, mapping in this area followed a separate procedure. Namely, initial isolines were created using Inverse Distance Weighting in Spatial Analyst (an ArcGIS product). Next, the contour lines were manually adjusted to account for known offsets along the faults. These lines were then blended and joined to contours from the rest of the study area. Final contour intervals for these areas were based mainly on cartographic and ArcIMS display considerations rather than on data accuracy.

2.1.5 Geologic Map Review

Digital versions of each map were made available to MRCSP team members for review through a web-based comment system. Additionally, project team members with expertise is specific areas subjected each map to a more extensive review. In addition, two group meetings were held to review large-format map prints and to also evaluate the geologic correctness and cartographic quality of each map; noted corrections were applied as needed.

2.1.6 Gridding Methods

A consistent method of converting both computer-generated and hand-edited structure contour and isopach lines back into grid format is essential for sequestration capacity modeling, GIS analysis, and cartography. Capacity calculations and many analyses within the GIS environment must have the data in grid format, and in some cases, use grid-to-grid operations. Gridding algorithms for this project also had to be capable of handling the geologic complexities introduced by faulting. For these reasons, two gridding methods were compared as part of this project. In the first approach, contours were converted to a triangulated irregular networks (TIN) dataset, which, in turn, was converted to a grid using 3-D Analyst (an ArcGIS product; ESRI, 2005). In the TIN model, contours were modeled as mass points and faults as hard break-lines. The second approach involved the use of a software package named ANUDEM (version 5.1; Hutchinson and Gallant, 2000), which combines localized splining with an ability to introduce vertical discontinuities (i.e., cliffs) into the final grids. Hence, ANUDEM can be used for geological modeling where faulting can be assumed to be vertical. A comparative study (Venteris and others, 2005) found that the ANUDEM-based method was superior to the TIN-conversion method, as long as high grid-resolutions (<15,000-feet grid squares) were used. The study also found that the optimal grid resolution for these data sets was best between 2,000 and 10,000 feet. Based on these results, a grid cell resolution of 5,000 feet was adopted for all the geologic layers in this study, which also provided a consistent grid size for grid-to-grid operations within the GIS environment.

The methodology for creating salinity grids differed from the ANUDEM approach described above because of certain data limitations. In many situations, a salinity grid can be generated from mapping, either by direct interpolation (e.g., kriging) or by exploiting the general relationship of increasing salinity with depth. However, mapping salinity accurately in the MRCSP region proved difficult because of a paucity of data (this type of data is not routinely gathered and submitted to state agencies). In addition, formation waters are continuously modified by filtration through clay membranes, ion exchange reactions, precipitation of minerals, and by the dissolution of the surrounding rocks (Blatt and others, 1980), causing further uncertainty. For these reasons, a statistical salinity verses depth model was used to create the salinity grids used in capacity calculations for the Phase I study. The model was constructed from existing sample data using least-squares regression. Individual models were created for each formation and used with the overburden (depth) maps to make a continuous salinity-grid for each formation.

The third component required for geologic sequestration capacity calculations involves grids of surface temperature and geothermal gradient at depth. This study used the thirty-year surface temperature average for over 275 cities in the conterminous United States (NOAA, 2000), and interpolated them into a grid using a minimum curvature algorithm. For the geothermal gradient, a number of datasets were investigated for gridding purposes. These included the American Association of Petroleum Geologists (AAPG) bottom-hole temperature dataset (AAPG, 1994), the Southern Methodist University (SMU) dataset (Blackwell and Richards, 2004a), and the 2004 AAPG heat flow dataset (Blackwell and Richards, 2004b). For this study, the SMU dataset (Blackwell and Richards, 2004a) was deemed best because it combined the best combination of data coverage and quality for the region. A regional correction was applied, which significantly reduced the spatial variance. In areas where the SMU dataset was missing data, such as Pennsylvania, data from the AAPG bottom-hole-temperature dataset (AAPG, 1994) augmented the SMU dataset. This blended dataset was then used to create the geothermal gradient grid for the region using kriging in Geostatistical Analyst (an ArcGIS product).

2.2 Calculation of CO_2 Sequestration Capacities

Carbon dioxide sequestration in geologic reservoirs like the types studied by the MRCSP relies upon a number of different storage mechanisms related to site-specific geologic conditions. Based on the geologic sequestration research conducted over the last decade by a number of researchers, these mechanisms are now fairly well described in published papers and proceedings of conferences such as the Greenhouse Gas Control Technology (GHGT) series organized by the International Energy Agency Greenhouse Gas R&D Programme (for example, see www.ieagreen.org.uk) or in the Special Report on Carbon Dioxide Capture and Storage prepared by the Intergovernmental Panel on Climate Change (IPCC) (see, Houghton and others, 1996; 2001). The commonly discussed storage mechanisms include volumetric storage, solubility storage, adsorption storage, and mineral storage. Volumetric storage refers to the amount of CO_2 that is retained in the pore space of a geologic unit, generally as a supercritical phase retained by structural or stratigraphic traps or by the overlying cap rock layers. Solution storage involves dissolution of part or all of the CO_2 into the formation waters of the geologic unit. Adsorption storage involves the retention of CO_2 molecules on the fracture faces and matrix of organic-rich rock units such as coal or black shale. Mineral storage involves the chemical reaction of CO_2 with the minerals and brine in the geologic unit Mineral storage was not investigated as part of the Phase I study because the complex nature of the reactions and the uncertainty in reaction rates makes it difficult to determine the storage volumes on a regional scale. In addition, basalt layers and salt caverns are also potential repositories for CO_2 storage; however, due to the early state of research for these options, they were not evaluated at this time for the MRCSP region.

Calculation of the storage capacities in various geologic formations has been attempted by a number of research projects during the last ten years. However, single accepted methodology for determining capacities at local, regional, basin, or even global scales has been developed. Moreover, the estimates in existing studies are wide ranging. This uncertainty is most likely is the result of the lack of detailed geologic data on formation thickness, lithology, pressure, fluid density, salinity, and the like in most sedimentary basins, save areas where extensive oil and gas exploration has occurred. Almost of all of the methods involve estimating the total pore volume for the subject formation and using an assumption for the storage efficiency and mechanism to evaluate the fraction of the total capacity that may be available for actual storage. For example, an early estimate of the global storage capacity developed by Hendricks and Blok

(1993) ranges from 400 to 10,000 gigatonnes of CO_2, and Bergman and Winter (1995) estimated U.S. saline-reservoir storage capacity ranges from 5 to 500 gigatonnes of CO_2. In addition to the regional rock volume-based approaches, detailed reservoir simulations (e.g., Gupta and others, 2004a) have also been used to more accurately determine site-specific storage and injection rates. Such detailed studies based on site characterization (e.g., Gupta and others, 2004b) will certainly be a requirement for actual project implementation. The remainder of this section presents the methods used during Phase I of this project for calculating possible storage capacity for volumetric, solution, and adsorption-based storage in the MRCSP study area.

2.2.1 Volumetric Storage

Storage of CO_2 as a free phase in the pore spaces of rocks is herein referred to as volumetric storage. CO_2 is injected into the geologic unit and occupies some portion of the pore space. For the saline formations associated with this study, it was initially assumed that CO_2 will completely displace some fraction of the brine pore waters. A wide range of factors, including reservoir chemistry, heterogeneity, cementation, and structure, will constrain the actual amount of CO_2 that can be stored at any site. For depleted oil and gas fields, it was assumed that there is residual-water saturation occupying pore space, which decreases the amount of pore space available for CO_2 to occupy. Accordingly, the volumetric capacity calculation was modified to reflect the residual-water saturation.

Injection into the pore space of a target geologic unit will initially displace the pore fluids. These pore fluids include brine waters, oil, and/or gas. The injection will initially be as a separate phase of CO_2 liquid or supercritical gas. Only over a long period of time will CO_2 dissolve into the formation fluids and possibly react with the matrix and formation fluids to precipitate carbonate minerals. In addition, the amount of CO_2 that dissolves into the pore fluids will be limited by the temperature and salinity of the fluid. Due to the long time intervals for the CO_2 to react with the geologic unit and its formation fluids and the high brine concentrations associated with the formation fluids, volumetric storage was considered the primary storage mechanism for CO_2 sequestration capacity calculations reported as part of this study.

Equation (1) for volumetric storage CO_2 sequestration capacity essentially provides an estimate of the total pore volume in the formation:

$$Q_{CO_2} = \rho_{CO_2} * \theta * Vb \quad (1)$$

where:
Q_{CO_2} = CO_2 sequestration capacity for the total pore volume
ρ_{CO_2} = Density of CO_2 under reservoir conditions
θ = Porosity
Vb = Bulk reservoir volume

For the Phase I study, the equation was slightly modified to (2), due to the use of English units of measurement:

$$Q_{CO_2} = \rho_{CO_2} * \theta * A * H / 2200 \quad (2)$$

where:
Q_{CO_2} = CO_2 sequestration capacity (metric tonnes)
ρ_{CO_2} = Density of CO_2 under reservoir conditions (lbs/ft^3)
θ = Porosity (%)
A = Area (ft^2)
H = Thickness of the geologic sequestration unit (ft)
2200 = Conversion from lbs to metric tonnes

Other variations of this volumetric approach have been used by Van der Straten (1996) to estimate saline-reservoir capacity in Europe and by Gupta and others (1999; 2001) to estimate storage capacities for the Mt. Simon Sandstone and the Rose Run sandstone in the U.S. Both of these use factors such as storage

efficiency (six percent) and net-to-gross-ratios to adjust the calculated pore volumes.

The calculations for the saline formations were conducted using Spatial Analyst (an ArcGIS product). The general procedure for performing the calculations was to first create a structure contour grid and an isopach grid for the saline formation sequestration unit (Venteris and others, 2005). The structure elevation grid was then subtracted from a surface digital elevation model (DEM) grid to obtain a depth grid. This depth grid was used to obtain the pressure and temperature of the saline formation at depth. The reservoir pressure was obtained by multiplying the fresh water pressure gradient of 0.433 psia/ft (9,792.112 Pa/m) with the depth grid, which resulted in the formation fluid pressure at depth. To obtain the reservoir temperature, the geothermal gradient grid was multiplied with the depth and the surface temperature grid was added to this result. Using a customized macro (modified from Radhakrishnan and others, 2004), the new reservoir pressure and temperature grids were used to determine the reservoir CO_2 density from a database table. , The CO_2 density, along with the isopach grid and the average porosity for the sequestration unit were then used to calculate the CO_2 sequestration capacity.

The equation for volumetric storage CO_2 sequestration capacity in depleted oil and gas fields is similar to the saline formation capacity calculation, except that the volumetric capacity calculation was modified to reflect the residual-water saturation of the petroleum reservoir. The residual-water saturation is expected to reduce the amount of pore space initially available for CO_2 to occupy (3).

$Q_{CO_2} = \rho_{CO_2} * \theta * A * H (1 - S_W) / 2200$ (3)

where:
Q_{CO_2} = CO2 sequestration capacity (metric tonnes)
ρ_{CO_2} = CO2 density (lbs/acre-ft)
θ = Porosity (%)
A = Area (acres)
H = Net thickness (ft)
S_W = Water saturation (%)
2200 = Conversion from lbs to metric tonnes

Unlike the GIS and raster modeling techniques of the saline formations discussed above, the calculation methodology for depleted oil and gas fields involved database techniques. Here, the reservoir temperature, pressure, thickness, porosity, and irreducible-water saturation for each oil and gas field were calculated from available data for wells associated with the particular oil and gas pool/field. The assumptions for missing temperature and pressure data, which are incorporated into equations (4) and (5) below, is a surface temperature of 61° F (16.11° C), geothermal gradient of 0.007° F/ft (0.01276° C/m), and hydrostatic pressure gradient of 0.433 psi/ft (9,792.112 Pa/m). Assumptions for missing thickness, porosity, and irreducible-water saturation data were also made for those oil and gas pools/fields lacking such data.

$T (F) = 61 + 0.007 (F/ft) \times depth (ft)$ (4)

$P (psia) = 0.433 (psi/ft) \times depth (ft)$ (5)

The area for the particular pool or field was based on its respective polygon area from the oil and gas fields GIS, with the unit of measurement converted from ft^2 to acres. Once all the information on each oil and gas field had been populated in a database table, the calculations were performed. The reservoir pressure and temperature were used to find the density of CO_2 in the reservoir. These data were then used to calculate the CO_2 sequestration capacity of the oil and gas field with equation (3).

The equations described above provide an estimate of the total pore volume available for storage. The actual volume of storage will depend on factors such as storage efficiency, porosity, and net-to-gross ratio. Each of these factors will reduce the amount of CO_2 that can be sequestered at any specific site, so the total pore volume must be further adjusted for these factors. Modeling studies by van der Meer (1995) and Holt and others (1995) have predicted storage efficiencies ranging from one to six percent (van der Meer, 1995) to 30

percent (Holt and others, 1995). Thus, the 10-percent total sequestration capacity represents an estimate that the MRCSP anticipates is more realistic for the actual amount of CO_2 that could actually be sequestered in the region's reservoirs. Given the spatial variability in parameters and the lack of detailed data on the deep formations, this Phase I study has assumed that 10 percent of the pore volume will be available for actual storage within any individual reservoir.

2.2.2 Solution Storage

Carbon dioxide can dissolve into formation fluids, but it is expected that large amounts of solution storage will only occur over long time periods due to high salinity, extremely slow mixing rates in the deep formations, limited interaction face between the CO_2 plume and surrounding brine, and slow solution rates. For example, Gupta and others (2004a) used compositional reservoir simulations for CO_2 injection in the Mt. Simon Sandstone to show that over a period of 500 years, only 8 percent of the total CO_2 injected has moved into dissolved phase. As stated above, most salinity measurements of potential storage reservoirs within the MRCSP are very high, and CO_2 solubility is inversely proportional to salinity. Because of the low solution rates, high salinities, and generally increasing salinities with depth in the MRCSP region, solubility calculations were not performed systematically for the Phase I study. Instead, one representative solution calculation for the Mt. Simon Sandstone was performed for comparison purposes using the following equation (6), derived from Carr and others (2003).

$$Q_{CO_2} = 1.1023 * ((7758 * (\theta * A * H) * S_{CO_2} * B_{CO_2})/(1000 * 17.25) \quad (6)$$

where:

Q_{CO_2} = CO_2 sequestration capacity (metric tonnes)
7758 = Conversion from acre * ft to bbl
θ = porosity (%)
A = area (acres)
H = thickness (ft)
S_{CO_2} = CO_2 solubility in fresh water (SCF/bbl water)
B_{CO_2} = CO_2 solubility in brine (%)
1000 = Conversion from ft^3 to MCF
17.25 = Conversion from MCF to short tons
1.1023 = Conversion from short tons to metric tonnes

The values for CO_2 solubility in fresh water and CO_2 solubility in brine were derived from Jarrell and others (2002). To determine the CO_2 solubility in fresh water and CO_2 solubility in brine, the reservoir temperature, pressure, and salinity (NaCl in ppm) were needed. Reservoir temperature and pressure were used to determine CO_2 solubility in fresh water using a database look-up table. The salinity data were used in a database look-up table to determine the CO_2 solubility in brine. The CO_2 solubility in brine was multiplied by the CO_2 solubility in fresh water to determine the CO_2 solubility in the formation fluids (Jarrell and others, 2002).

The solution storage calculations for the representative saline formation (i.e., Mt. Simon Sandstone) were conducted using GIS software and a methodology very similar to that used for the volumetric calculations. The general procedure was to first create a structure contour grid and an isopach grid for the saline formation sequestration unit (Venteris and others, 2005). The structure elevation grid was then subtracted from a surface DEM grid to obtain a depth grid. This depth grid was used to obtain the pressure and temperature of the Mt. Simon Sandstone at depth. A customized macro (modified from Radhakrishnan and others, 2004) was used to determine the CO_2 solubility in fresh water from a database table using the temperature and pressure, and the salinity was used to determine the CO_2 solubility in brine from a database table. These solubility values were then used, along with the isopach grid and the average porosity for the Mt. Simon Sandstone, to calculate the CO_2 sequestration capacity.

2.2.3 Adsorption Storage

Carbon dioxide sequestration in organic-rich rocks, such as coal beds and black shales, could potentially

provide both long-term CO_2 storage and a method to increase natural gas production in a manner analogous to CO_2-enhanced oil recovery. Carbon dioxide, when introduced to such rock units, preferentially displaces methane, which is adsorbed to the coal surface within the cleat system and onto organic matter and clay mineral surfaces that occur in the matrix of the coal or shale. Previous studies on CO_2 sequestration and methane recovery indicate that, for coals of the type found in the Appalachian and Michigan basins, at least two molecules of CO_2 can be injected for every one molecule of methane released from the coal bed (Gale and Freund, 2001). On average, more than twice as much CO_2 can be stored on a volumetric basis than the amount of methane extracted (Gluskoter and others, 2002; Mastalerz and others, 2004). In fact, CO_2 and methane adsorption isotherm data suggest that this ratio may be much higher. The use of coal beds and black shales could provide a larger area in which CO_2 can be sequestered or offer multiple options for sequestration at some locations. The production of methane from these organic-rich rock units will also help to offset costs of sequestering CO_2.

The Phase I study utilized GIS techniques for computing adsorption storage CO_2 sequestration capacity in coal beds and organic-rich black shales. Due to the nature of the gas-trapping mechanism in these types of reservoirs, the MRCSP used the standard methodology for gas-in-place calculations in non-conventional reservoirs developed by the Gas Research Institute (Mavor and Nelson, 1997). The CO_2 sequestration potential calculations were basically a series of simple mathematical operations on defined GIS raster grids. Raster grids were created for the following themes:

H_{coal} = Coal thickness or isopach map (ft)
G_{coal} = Gas content of the coal (SCF/short Ton)

The calculation of adsorption storage CO_2 sequestration potential in coal beds was based upon the observation that CO_2 preferentially displaces and replaces methane adsorbed on the coal-bed cleats and in the coal matrix. To calculate the CO_2 sequestration potential, the coalbed methane resources were first calculated using the coal bed gas-content values for a given volume of coal at a given density using equation (7):

$$R_{cbm} = \rho_{coal} * V * G_{coal} / 1000 \quad (7)$$

where:
R_{cbm} = Coalbed methane resources (MCF)
ρ_{coal} = Coal density (short tons/ft^3)
V = Volume of coal (ft^3)
G_{coal} = Coal bed gas-desorption value (SCF/short Ton)
1000 = Conversion from SCF to MCF

and the coalbed methane resources can be expressed as:

$$R_{cbm} = (\rho_{coal} * A * H_{coal} * G_{coal}) / 1000 \quad (8)$$

where:
A = Area (ft^2)

Initial studies have shown that CO_2 displaces methane at a ratio of 2:1. Further studies (Gluskoter and others, 2002; Mastalerz and others, 2004) have shown that CO_2:methane adsorption ratios will vary from 2:1 to 16:1, depending on the coal rank. Consequently, the preliminary estimate for CO_2 sequestration potential in all coal beds was given as at least twice that of the coalbed methane resources for the same area (9):

$$Q_{CO_2} = C_{CO2CH4} * R_{cbm} \quad (9)$$

where:
Q_{CO_2} = CO_2 sequestration potential in all coal beds (MCF)
C_{CO2CH4} = carbon dioxide:methane ratio (given as 2 for this study)

The final step in this calculation for coal beds involves the conversion of the volume of gaseous CO_2 to short tons, which is 17.25 MCF/short ton at surface conditions of 60º F (15.55º C) and 1 atm (101,325.01 Pa). This yields equation (10):

$$Q_{CO_2} = 1.1023 * C_{CO2CH4} * (\rho_{coal} * H_{coal} * A * G_{coal}) / (1000 * 17.25) \quad (10)$$

where:

1.1023 = Conversion factor for short tons to metric tonnes

The calculation of adsorption storage CO_2 sequestration potential in organic-rich shales requires the consideration of two different storage strategies. Injected CO_2 will occupy the natural fracture system as either a free gas or a supercritical fluid, depending on reservoir pressure and temperature conditions. Standard volumetric methods can be used to estimate this capacity, as described above, but should only be applied within the extent of known gas-producing areas of the shale. A second storage strategy, and one which likely accounts for a much larger volume of CO_2, involves the adsorption of gas onto organic matter and clay minerals in the shale matrix. The method used to estimate this CO_2 sequestration capacity involves the conversion of a given volume of shale to an equivalent weight of shale using its density, followed by the calculation of CO_2 volume using gas content data.

For the purposes of this study, the shale volume was estimated from gridded isopach data imposing the limitations that the top of the shale must be a minimum drilling depth of 1,000 feet and the shale is a minimum of 100 feet thick. The strict application of these conditions eliminated areas in Ohio and Pennsylvania where the shale is shallower than 1,000 feet, but exceeds several thousand feet in thickness. For this reason, additional areas in those two states were added to the evaluation. These limits were arbitrarily selected to ensure sufficient reservoir and seal capacity for CO_2 sequestration. Data for shale density and gas content were gathered from other DOE-funded work being conducted by the Kentucky Geological Survey on Devonian-age black shales (Nuttall and others, 2005b). Specifically, a shale density of 2.62 grams per cubic centimeter (g/cc) was used in the calculations, along with an average shale adsorption capacity of 42.9 standard cubic feet of CO_2 per ton (scf/ton) (Nuttall and others, 2005b).

To determine gas content of the shale, CO_2 adsorption isotherm data were collected as part of a separate DOE-funded project being conducted by the Kentucky Geological Survey. These data indicate the adsorption capacity of the shale averages 42.9 standard cubic feet of CO_2 per ton (scf/ton) of shale (1.134 m^3/tonne) and ranges from 13.9 to 135.7 scf/ton (0.43 to 4.24 m^3/tonne) (Nuttall and others, 2005b). Observed adsorption data are log-normally distributed. For comparisons with the other reservoir types, a gas content value of 42.9 scf/ton was used to calculate CO_2 storage capacity for Phase I of this study. This value is a reasonable average for regional calculations based on available CO_2 isotherms (Nuttall and others, 2005b), but actual values would obviously vary with organic content.

Although this methodology is reasonable for a first pass at a regional assessment for the MRCSP study area, it can be improved. Original calculations assumed storage capacity to be proportional to density and suggested increasing density yielded higher sequestration capacities. In actuality, the adsorbed gas capacity (and thus sequestration potential) is inversely proportional to density, which itself is a function of total organic content (TOC). Schmoker (1993) described the relationship between density and TOC in his method to determine total organic matter content from density logs. The relation between measured TOC and adsorption capacity is being investigated in current shale research at the Kentucky Geological Survey (Nuttall and others, 2005b).

There are a number of factors that will reduce the amount of CO_2 that can be adsorbed to coal beds. These include the amount of moisture, the heating value (BTU) and vitrinite reflectance, maceral composition, surface area and pore throat size, and cleat and fracture permeability (Drobmiak and others, 2005). Presumably, these factors will also affect organic-rich shales. Each of these factors will affect the amount of CO_2 that can be sequestered at any specific site, so the total pore volume must be evaluated further and adjusted for these factors. Tables 2 and 3 show the total CO_2-sequestration capacity at the 10 percent level. This is an estimate

of the amount of CO_2 that will ultimately be adsorbed by coal beds and organic-rich shales.

3.0 RESULTS

3.1 CO_2 Sequestration Capacity Estimates

The primary results of the volumetric storage capacity calculations indicate that the MRCSP region has a large, potential capacity for CO_2 sequestration. However, actual capacity will ultimately be constrained by reservoir-specific data such as spatial extent, net vs. gross thickness, porosity, adsorption characteristics, and the like. As a result, actual storage capacity values will likely be less than those estimates reported herein. Even so, these results are important in that they provide a basis for a comparison between rock formations, different states, and other regions using similar methods to determine future CO_2 storage capacity.

The total amount of potential CO_2 sequestration capacity for the MRCSP region is estimated at approximately 520 gigatonnes (Table 2). The majority of this sequestration capacity, about 470 gigatonnes (approximately 90 percent of the total estimated CO_2 storage capacity), represents the potential of deep saline formations. This storage option alone could accommodate regional CO_2 output levels for hundreds of years. The black shales exhibit the next largest storage potential (45.4 gigatonnes, or about 9 percent of the total estimated CO_2 storage capacity), which may also be useful for secondary recovery of natural gas adsorbed to shale surfaces. Oil and gas fields have a potential sequestration capacity of about 2.5 gigatonnes (roughly 0.5 percent of the total estimated CO_2 storage capacity). This particular reservoir type is attractive not only for CO_2 sequestration but also for "value-added" EOR operations, where CO_2 may be used with gas drive techniques to produce many millions of barrels of oil from existing oil fields. The smallest sequestration capacity is associated with coal beds, which offer a total of 0.25 gigatonnes (approximately 0.5 percent of the total estimated CO_2 storage capacity).

3.2 Assessment of Sequestration Potential By State

Each state in the MRCSP has their own set of geologic conditions and reservoirs that can be used to sequester CO_2. Accordingly, Table 3 provides the breakdown of CO_2 sequestration potential by reservoir type and state.

The largest potential sequestration capacity occurs in the state of Michigan (approximately 220 gigatonnes; Table 3). This corresponds to 42 percent of the total capacity in the MRCSP region. Almost all of this capacity is associated with deep saline formations, where the Sylvania, St. Peter, and Mt. Simon Sandstones provide the majority of the sequestration capacity.

The state with the next largest sequestration capacity is Pennsylvania with a potential capacity of nearly 90 gigatonnes (Table 3). This corresponds to 17 percent of the MRCSP regional sequestration capacity. Unlike Michigan, the sequestration capacity in Pennsylvania is unequally distributed between five different deep saline formations, the Devonian black shales, the Needmore Shale, oil and gas fields, and coal beds. Pennsylvania also has the largest potential oil-and-gas-field sequestration capacity (0.8 gigatonnes), which accounts for approximately one-third of the entire MRCSP region's sequestration capacity for this reservoir type.

The eastern part of the state of Indiana has the third largest sequestration capacity in the MRCSP region with a potential sequestration capacity of about 80 gigatonnes (Table 3). Almost all of Indiana's capacity is in the Mt. Simon Sandstone. Minor amounts of sequestration capacity are found in another saline formation, the St. Peter Sandstone, and the state's oil and gas fields. Indiana's coal fields are outside of the MRCSP study area (Fig. 1) and were not evaluated.

West Virginia has the fourth largest potential sequestration capacity with a total of approximately 60 gigatonnes (Table 3). The deep saline formations have a potential sequestration capacity of over 40 gigatonnes, while the organic-rich shales have a potential capacity of about 20 gigatonnes. These shale and coal bed sequestration capacities are the largest among the MRCSP partner states. It should also be noted that the area in which coal sequestration was considered possible in West Virginia was limited to non-mining areas; thus, the total potential coal-CO_2-sequestration capacity may be greater than herein estimated.

Sequestration Target	Porosity (%)	Density (g/cc)	Gas Content (scf/ton)	Area (mi^2)	Total (GT)	10% of Total
Oil and Gas Fields					25.1	2.51
Waste Gate Formation	10			1,342	43.8	4.38
Net Coal		1.32	100	25,578	2.5	0.25
Antrim and Ohio shales		2.62	42.9	109,043	453	45.3
Needmore Shale		2.62	42.9	850	0.5	0.05
Sylvania Sandstone	10			25,324	151.1	15.11
Oriskany Sandstone	10			57,313	194.3	19.43
Medina/Tuscarora SS	8			72,328	705.3	70.53
St. Peter Sandstone	10			41,796	881.3	88.13
Rose Run sandstone	8			57,493	492.7	49.27
Potsdam Sandstone	2			9,298	17.1	1.71
Conasauga Formation	2			24,973	42.5	4.25
Rome trough sandstone	1			18,452	12.3	1.23
Mt. Simon Formation	8			85,916	2,171.8	217.18
Total					**5,193.5**	**519.35**

Table 2.—Summary of estimated CO_2 storage capacity by geologic interval or reservoir type (in gigatonnes).

State	Saline	10% Saline	Coal	10% Coal	Shales	10% Shales	Oil & Gas	10% Oil & Gas	Total	10% Total
Eastern Indiana	807.1	80.7	0	0	0	0	0.14	0.01	807.3	80.7
Eastern Kentucky	108.7	10.9	0.21	0.02	16.8	1.7	6.5	0.65	132.3	13.2
Maryland	95.1	9.5	0	0	0.09	0.009	0	0	95.2	9.5
Michigan	2,160.8	216.1	0	0	41.8	4.2	0.48	0.05	2,203.1	220.3
Ohio	373.4	37.3	0.37	0.04	85.0	8.5	4.2	0.4	462.9	46.3
Pennsylvania	756.0	75.6	0.81	0.08	120.4	12.0	7.6	0.8	884.9	88.5
West Virginia	411.1	41.1	1.1	0.11	189.5	19.0	6.2	0.6	607.9	60.8
Total	**4,712.2**	**471.2**	**2.5**	**0.25**	**453.6**	**45.4**	**25.1**	**2.5**	**5,193.4**	**519.3**

Table 3.—Estimated CO_2 storage capacity by reservoir type and state (in gigatonnes).

Ohio has the fifth largest potential sequestration capacity with over 45 gigatonnes, of which deep saline formations account for over 35 gigatonnes (Table 3). The saline formations with the largest potential capacity are the Mt. Simon Sandstone (20 gigatonnes) in western Ohio, and the Rose Run (8 gigatonnes) and Medina (5.6 gigatonnes) sandstones in eastern Ohio. These three reservoirs contain 71 percent of the state's total potential sequestration capacity, and 89 percent of the saline formation capacity. Ohio's Devonian shales offer a potential capacity of 8.5 gigatonnes.

Eastern Kentucky has the sixth largest potential sequestration capacity (over 13 gigatonnes; Table 3). The majority of this capacity (82 percent) is in deep saline formations, with a total of nearly 11 gigatonnes. The three largest deep saline formations include the Rose Run sandstone (5 gigatonnes, or 41 percent of the total capacity), Mt. Simon Sandstone (4 gigatonnes, or 33 percent of the total capacity), and basal sandstones in the Rome Trough (1 gigatonne, or 8 percent of total capacity). The next largest type of reservoir is the Devonian black shales, which offer a potential capacity of almost 2 gigatonnes (13 percent of the total capacity).

The estimated total potential-storage capacity in Maryland is nearly 10 gigatonnes (Table 3). Almost all of this capacity occurs in deep saline formations (i.e., Waste Gate Formation, Oriskany Sandstone, and Medina/Tuscarora Sandstones). The Waste Gate Formation has the largest capacity, with over 4 gigatonnes (46 percent of the total capacity). The next largest is the Medina Sandstone at 3 gigatonnes (36 percent of the total capacity). There is also a minor amount of sequestration potential in the organic-rich Needmore Shale. Additional storage capacity may be present in the offshore reservoirs along the Maryland coast; however, these reservoirs were not evaluated for this study due to the lack of data.

4.0 DISCUSSION AND CONCLUSIONS

4.1 Data Interpretation and Reliability

This Phase I study has shown that the MRCSP region has approximately 450 to 500 gigatonnes of storage potential in deep saline formations for future deployment of geologic CO_2 sequestration technology. In fact, our region can easily accommodate many hundreds of years' worth of CO_2 emissions at current or expanded levels within this one type of reservoir. This region also has the potential to store at least 2.5 gigatonnes of CO_2 in existing and depleted oil and gas fields. By using anthropogenic CO_2 in enhanced oil recovery operations in current and recently abandoned oil fields, the region could realize hundreds of million of barrels of additional oil production. In addition, unmineable coal beds in the northern Appalachian basin have the potential to sequester approximately 0.25 gigatonnes of CO_2. Only recently have operators started development and utilization of the vast amount of coalbed methane found beneath the northern Appalachian basin. Application of enhanced gas recovery methods using CO_2 early in this endeavor could add significantly to the amount of gas produced from the deep unmineable portions of this resource while sequestering millions of tons of CO_2 in its place. Finally, the use of organic shales as a CO_2-storage medium is still an untested research topic. Should this technology prove practical, the MRCSP region has one of the richest holdings of organic shale deposits in the world. In summary, the MRCSP is particularly poised to offer a variety of storage reservoirs for CO_2 sequestration that can be used not only to contain the equivalent of hundreds of years' work of CO_2 emissions, but also possibly offer enhanced oil and gas recovery opportunities in some areas.

Although these Phase I findings are promising, they cannot substitute for site-specific studies in those areas where local CO_2 sources and subsurface geologic sequestration targets have been tentatively identified. The following paragraphs address several, possible limitations to successful CO_2 injection, whether it's for permanent storage or enhanced petroleum recovery.

One of the potential shortcomings of this Phase I project is related to our estimates of a CO_2 storage efficiency factor. Although we have reported reservoir storage capacities at 10 percent of total assumed volumes, we do not believe these estimates to be sufficiently conservative. It should also be noted that many other restrictions that have not yet been accounted for in studies of this type would likely be emplaced on the use of any subsurface storage space. Such restrictions may include: inability to inject below large metropolitan areas or large bodies of water; inability to inject below or within specific offsets (both vertically and horizontally) of producing oil and gas fields or active mines; and the inability to inject within specific offsets (both vertically and horizontally) of other injection (Class I, II, or III) operations. In addition, it should be stress that large-scale CO_2 injection operations should not be permitted too close to one another in order to avoid any possibility of interaction of their related pressure fronts. Many of these restrictions will fall under the purview of regulatory agencies to enact. As with the entire carbon capture and storage technology arena, regulations for CO_2 injection and storage are still in an early, formative stage. Once regulations are known, restrictions can be applied to our capacity maps to calculate CO_2 storage potentials that are sufficiently conservative and appropriate for more local, site-specific land use and subsurface conditions.

Another caviat to our findings is that the storage potential reported herein is not distributed evenly over the MRCSP region. Some areas have very significant storage potential, while others have very little known storage potential. Mapping the distribution of this potential is just as significant to the region as calculating the potential for storage. The existing, large, stationary, CO_2 sources of the region (Fig. 3) are not all situated over areas of sufficient, known, storage potential. Therefore, it is hoped that this and future studies will be

used by utility and industrial decision-makers to plan future plant locations with the necessary subsurface conditions in mind. Further, the maps and results of this investigation can be used to start planning for future pipelines to match existing CO_2 sources with appropriate geologic sinks.

4.2 Future Work

The Phase I MRCSP study made great strides in characterizing the stratigraphy, geology, and reservoir characteristics of the seven-state project area, particularly for those reservoir types deemed potential CO_2 sequestration targets by DOE (i.e., deep saline formations, oil and gas fields, carbonaceous shales, and unmineable coal beds). Through this work, the project team also identified data gaps for certain reservoirs that showed particular promise for sequestration potential (e.g., the Mt. Simon and St. Peter Sandstones), as well as a number of additional, potential, sequestration target formations that were not individually mapped as part of the Phase I study (e.g., the Bass Island and Lockport Dolomites). Accordingly, Phase II of this project will focus on filling as many existing data gaps as possible in order to refine reservoir property and injectivity data for potential geologic reservoirs, and delineating the structure and thickness of other reservoirs exhibiting CO_2 sequestration potential in the region. Further, the MRCSP will plan and implement pilot injection projects aimed at testing different, potential reservoirs throughout the study area. For this task, detailed site studies will be performed in advance of injection to evaluate site-specific geology and reservoir properties, the type and proximity of CO_2 sources, and detailed engineering and pipeline considerations.

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