TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1. CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(a)

HEARTLAND GREENWAY STORAGE PROJECT

1.1. Project Background and Contact Information

1.1.1. Project Background

The Heartland Greenway Storage Project is a Navigator CO_2 Ventures (NCV) proposed carbon capture, transport, and sequestration (CCS) project designed with an objective to develop long-term and cost-effective infrastructure that could assist biofuel and other industrial customers in the five Midwestern states of Iowa, Illinois, Minnesota, South Dakota, and Nebraska in reducing their carbon footprint. NCV is developing this project to assist customers and project partners in reducing their carbon footprint effectively and economically by helping them finance and construct CO_2 capture equipment, transport CO_2 via a pipeline and eventually store if safely in geologic formations. Heartland Greenway Carbon Storage, LLC (HGCS) is a subsidiary of NCV that is seeking to construct and operate multiple CO_2 storage sites in Illinois. NCV plans to construct a 1,300-mile pipeline in the Midwest capable of transporting 10-15 million metric tons per annum (MMTPA) of CO_2. The first phase of the project involves transporting 6 MMTPA to a storage site located in Christian County, Illinois, which seeks to utilize the Mt Simon sandstone as a reservoir. This site is referred to in the project documentation as the Heartland Greenway Storage Site (HGSS).

1.1.2. Partners and Collaborators

Table *1-1* lists key project partners and their roles for HGSS.

Table 1-1. HGSS Partners and Collaborators.

Partner	Role
Navigator CO_2 Ventures	Project developer, pipeline design and construction
Heartland Greenway Carbon Storage, LLC	Wholly owned subsidiary of NCV, operator
BlackRock Global Energy & Power Infrastructure Fund III	Investor
Valero Energy Corporation	Partner and advisor
Tenaska Corporation	Infrastructure development
Advanced Resources International, Inc.	Sequestration system design, regulatory support
Chabina Energy Partners	Strategic advisor

1.1.3. Project Timeframe

HGCS plans on injecting CO_2 for 30 years followed by a post-injection monitoring period of 50 years. The post-injection timeframe has been chosen after evaluating the results of computational modeling. Additional details on the post-injection timeframe can be found in the *AoR and Corrective Action Plan* as well as the *Post-Injection Site Care and Site Closure Plan*.

1.1.4. Proposed Injection Mass and CO_2 Source

HGCS plans on injecting 6 million metric tons per annum (MMTPA) of CO_2 at HGSS using six injection wells with an average injection rate of 1 MMTPA at each injection well. This equates to a total storage volume of 180 MMT for a 30-year injection period at HGSS. CO_2 at HGSS is anticipated to be sourced from multiple project partners and point sources along the proposed 1300-mile pipeline spanning Iowa, Illinois, Minnesota, Nebraska, and South Dakota.

1.1.5. Injection Depth Waiver

No injection depth waiver is currently sought in this application.

1.1.6. Aquifer Exemption

No aquifer exemption is currently sought in this application.

1.1.7. Applicable Permit Information Under 40 CFR 144.31(e)(1) through (6)

Table 1-2 provides information on activities conducted by HGCS which require it to obtain permits under Resource Conservation and Recovery Act (RCRA), Underground Injection Control (UIC), the National Pollution Discharge Elimination system (NPDES) program under the Clean Water Act (CWA), or the Prevention of Significant Deterioration (PSD) program under the Clean Air Act.

Table 1-2. Permit Information Required under 40 CFR144.31(e)(1).

Regulation	Jurisdiction	Activity	Relevant Permits
Resource Conservation and Recovery Act (RCRA)	State	None	None anticipated
Underground Injection Control (UIC) Program	Federal – U.S. Environmental Protection Agency (U.S. EPA) – Region V	CO_2 injection well drilling and operation	Class VI Injection Well Permits
National Pollutant Discharge Elimination System (NPDES) – Clean Water Act (CWA)	State	None	None anticipated
Prevention of Significant Deterioration (PSD) – Clean Air Act (CAA)	State	None	Non anticipated

Contact Details for HGSS

Name: Tyler Durham
Mailing address: 3 Riverway DR, Suite 1540 Houston, TX 77056
Project Location: Taylorville, Illinois USA

Applicable SIC Codes

Per 40 CFR 144.31(e)(3), applicable SIC codes are listed below:

1. 4610 – Pipelines (no natural gas)

Operator Details

Name: Heartland Greenway Carbon Storage, LLC
Address: 13333 California St., Suite 202, Omaha, NE 68154
Telephone number: 402-520-7089
Ownership status: Private
Nature of the entity (Federal, State, private, public): Private

Other permit information required under 40 CFR 144.31(e)(6) is listed in **Table *1-3*** through **Table 1-5**.

Table 1-3. Activities conducted by HGCS, and applicable permits as noted in 40 CFR 144.31(e)(6)

Permit	Jurisdiction	Activity	Relevant Permits and Agreements
Drilling Permits	State	Drilling of characterization and monitoring wells	Illinois Department of Natural Resources (IDNR) Drilling Permit under 225 ILCS 725
Valid Access Agreements	County, Township/City	Construction of project wells, siting injection and monitoring infrastructure	Landowner leases to construct and operate
Encroachment Permits	County, Township/City	Construction of project wells, siting injection and monitoring infrastructure	Special Use Permits from Christian County, IL and/or City of Taylorville, IL
Restricted Lane Use Permits	State, County	Construction of project wells, siting injection and monitoring infrastructure	Road Use Permits with Illinois Department of Transportation (IDOT) and any other applicable county/city offices

Table 1-4. Applicable permits and construction approvals as noted in 40 CFR 144.31(e)(6)

Permit	Jurisdiction	Relevant Permits
Hazardous Waste Management Program under RCRA	Federal, state	None anticipated
U.S. EPA UIC Program under SWDA	Federal	Class VI Injection Well Permits from U.S. EPA Region V
NPDES under CWA	State	Management of Stormwater During Construction – IEPA NPDES Permit No. ILR10
PSD Program under CAA	State	None anticipated
Nonattainment Program under CAA	State	None anticipated
Dredge and Fill Permits under Section 404 of the CWA	Federal	Nationwide permits for temporary or permanent impacts to jurisdictional waters
Other permits	Federal, state, county, city	Building permits from county and city-level offices, Endangered Species Act (ESA) Section 7 and Section 10 review, National Historic Preservation Act (NHPA) Section 106 review

Table 1-5. Applicable permits and construction approvals required by NCV as noted in 40 CFR 144.31(e)(6)

Permit	Jurisdiction	Relevant Permits
Hazardous Waste Management Program under RCRA	Federal, state	None anticipated
U.S. EPA UIC Program under SWDA	Federal	Class VI Injection Well Permits from U.S. EPA Region V
NPDES under CWA	State	Management of Stormwater During Construction – IEPA NPDES Permit No. ILR10, IA, NE, MN, SD
PSD Program under CAA	State	Small Unit Exemption for mainline booster station in IA
Nonattainment Program under CAA	State	None anticipated
Dredge and Fill Permits under Section 404 of the CWA	Federal	Nationwide Permits 58 (Omaha District, Rock Island District, and St. Louis District; Utility General Permit – St. Paul District, MN

Permit	Jurisdiction	Relevant Permits
Other permits	Federal, state, county, city	***Federal*** • Section 14 Rivers Harbor Act (408 Permit): levee crossings- Green Bay, Magee Creek, Willow Creek/Coon Run; Managed Channels: Missouri River, Mississippi River. • Section 10 Rivers Harbor Act: Missouri River, Des Moines River (2x), Mississippi River, Illinois River • Endangered Species Act: Section 7 Formal Consultation, Biological Opinion ***Illinois*** • Certificate of Authority, • IL Statewide Permit 8, • IL State Antiquities Act Review, • IL Endangered Species Incidental Take Permit • Hydrostatic Test Discharge Permit (ILG67) ***Iowa*** • Hazardous Liquid Pipeline Permit, • Sovereign Lands Permit, • Hydrostatic Test Discharge Permit (GP8), • Dewatering Permit (GP9), • Walter Allocation ad Use Registration ***South Dakota*** • State Siting Permit, • Dewatering permit (GP SDR 070000), • SD Threatened and Endangered Species Consultation, ***Nebraska*** • Conservation and Environmental Review, • Nebraska Nongame and Endangered Species Consolation, • Dewatering permit (NEG671000 2017), • Hydrostatic Test Discharge (NEG672000 2017) ***Minnesota*** • Environmental Assessment Worksheet (EAW) • Public Water Permit • Water Appropriation • Wetland Conservation Act Multiple County and Municipal/Township Zoning Permits;

Permit	Jurisdiction	Relevant Permits
		Multiple FEMA Floodplains: No Rise Certificates; Local Levee crossing permits: Pigeon Creek Levee, Little Sioux West Fork

1.2. Site Characterization

The proposed storage site is within the Illinois Basin, where the target storage reservoir is the Precambrian Mt. Simon Sandstone. This deep saline formation has limited well penetrations; thus, data density describing its character is sparse. Still, there are a number of wells showing great promise for CO_2 storage in the Mt. Simon. The following characterization for the Heartland Greenway Storage Site (HGSS) draws on interpolation of regional well data and is supplemented by inferences from the nearest wells. Fortunately, some of the closest Mt. Simon wells were drilled to characterize this formation for CO_2 storage and include valuable insights from the FutureGen 2 project, a CarbonSAFE well in Christian County, and the Illinois Basin Decatur Project (IBDP).

1.2.1. Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]

An evaluation of the local geology was conducted using geologic maps, reports, and databases from the Illinois State Geological Survey (ISGS) to perform an initial characterization of the geologic properties near the facility and to estimate CO_2 storage resources and containment feasibility. Saline storage and feasibility evaluations were created by analyzing geological, petrophysical, and storage potential for HGSS and are described in this section.

The HGSS project is located in the central portion of the Illinois Basin, which comprises sedimentary rock that spans Illinois, western Indiana, and western Kentucky. An outline of the Illinois Basin is shown in **Figure 1-1**. This region has favorable geology for carbon storage in the Mt. Simon Sandstone, which is known to be a porous and permeable deep saline formation. Four other notable CO_2 storage assessment projects have occurred within the region, including the Illinois Basin Decatur Project (IBDP)[1], Industrial Carbon Capture and Storage (ICCS)

[1] Bauer, R.A., Will, R., Greenberg, S.E., and Whittaker S.G., 2019, Illinois Basin–Decatur Project, Geophysics and Geosequestration, (Chapter 19) from Part III - Case Studies, pp. 339 – 370, https://doi.org/10.1017/9781316480724.020

project, the FutureGen2 program[2], and the CarbonSafe TR McMillen 2 well[3]. These wells were drilled in nearby counties and were logged and cored, and the data produced at these sites provided high-quality characterization of the Mt. Simon Formation reservoir and the confining Eau Claire Formation in central Illinois. The Cambrian-aged sandstone of the Mt. Simon is the target saline reservoir for HGSS and represents favorable intervals for CO_2 storage based on depth, thickness, composition, and salinity. The Mt. Simon Sandstone is quartz-rich and offers pore space between quartz grains. Primary caprocks here are the mudstones and shales of the Eau Claire Formation that are clay-rich and comprised of small particles that are tightly packed and impermeable.

Much of the deep subsurface understanding for HGSS project originated from the Illinois Basin Decatur Project (IBDP) injector well CCS#1, located approximately 30 miles northeast of Taylorville, Illinois. Between 2011 and 2014, the IBDP successfully injected 1 million metric tons of CO_2 into the Mt. Simon via the CCS#1 well. Moreover, this well was drilled to basement rock, fully penetrating the Mt. Simon Sandstone. More recently, as part of a CarbonSAFE project, the TR McMillen 2 was drilled in late 2018 and is located several miles northeast of the proposed HGCS CO_2 storage site **Figure 1-1**. Data acquired from logging and rock cores collected from the TR McMillen 2 well provides crucial subsurface information regarding the lithology and quality of the reservoir rock and caprock being evaluated for this project.

[2] Gilmore T., et al, 2016, Characterization and design of the FutureGen 2.0 carbon storage site, International Journal of Greenhouse Gas Control, Vol 53, pp.1-10, https://www.sciencedirect.com/science/article/abs/pii/S1750583616303851

[3] Whittaker, S. et al., 2019, CarbonSAFE Illinois–Macon County, Addressing the Nation's Energy Needs Through Technology Innovation, ISGS, DE-FE0029381, CarbonSAFE, DOE Review Meeting Pittsburgh, 2019

Figure 1-1. Illinois Basin map showing HGSS location and nearest wells that penetrate the Mt. Simon Sandstone. The well logs from the TR McMillen 2 well were used as an analog to model the caprock and reservoir for HGSS. The red box represents the 35x35 mile Static Earth Model footprint prepared for this permit.

The saline Mt. Simon sandstone reservoir is the preferred storage interval in this region. The top surface of the Mt. Simon formation is presented in **Figure 1-2** and is based on the interpolation of Mt. Simon Sandstone formation structural data from the FutureGen Alliance and the ISGS database. The contours show that Mt. Simon's elevation depth [Z] at HGSS is approximately 4,860 feet below mean sea level (msl). Adding a local ground elevation places the Mt. Simon at an estimated depth of 5,485 ft, which would cause the injected CO_2 to be in a supercritical phase at the site.

Figure 1-3 shows HGSS study area's stratigraphic succession, along with the target storage zones and confining zones. The Mt. Simon Formation rests on the thin Argenta Formation comprised of tight marine sandstone, which is underlain by weathered basement and crystalline basement rock. Together, these represent the underlying confining zone. Overlying the Mt. Simon Formation is the primary caprock, the Eau Claire Shale. Overlying the Eau Claire Shale is the Ironton Sandstone. Above this unit are the carbonate units of the Knox Supergroup, which are approximately 1,200 ft thick and largely comprised of limestone and dolomite from the Shakopee down through the Potosi Formations. Overlying Shakopee, the water-bearing St. Peter sandstone has good pore space, and in some areas in Illinois, it is used for the storage of natural gas. At HGSS, the St. Peter is believed to be the deepest underground source of drinking water (USDW) where total dissolved solids are less than 10,000 mg/L. The St. Peter is overlain by Ordovician dolostone, followed by another potential cap rock, the Maquoketa Shale, which is approximately 150 feet thick. Above this is more dolostone of Silurian and Devonian age.

At the transition of the Devonian and Mississippian is the regionally known New Albany Shale. Above the New Albany are alternating units of Mississippian limestone and sandstone. Though these intervals have some oil reservoirs, the sandstones are too shallow for CO_2 storage. Moving upward into the Pennsylvanian, there are numerous coal seams. These coal seams are interbedded along with intervals of sandstone, shale, and limestone, as indicated in **Figure 1-3**.

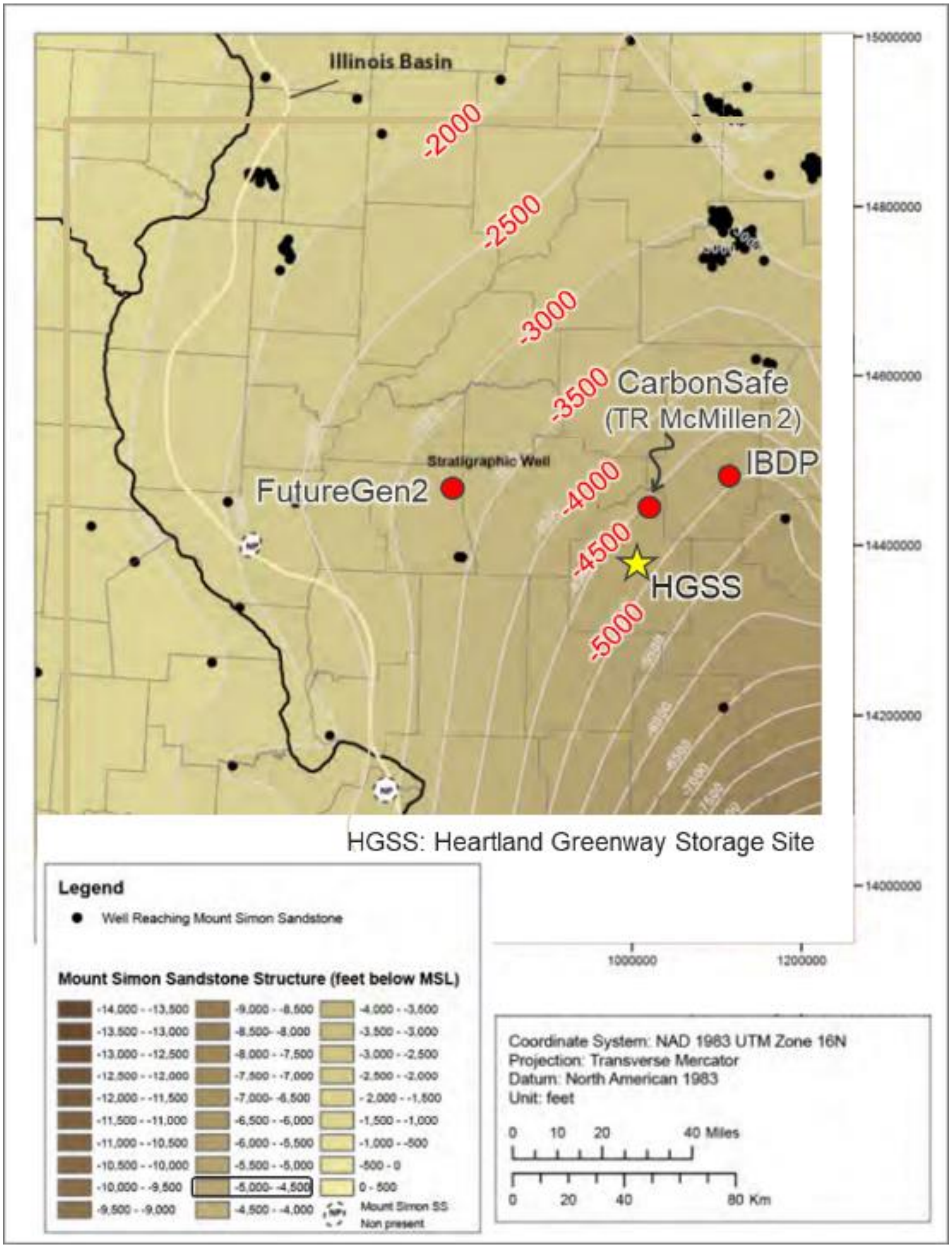

Figure 1-2. Mt. Simon structural map. The contour elevation is the depth below mean sea level. The Illinois Basin is observed to deepen to the SE. Modified after FutureGen2 UIC Class VI Permit.

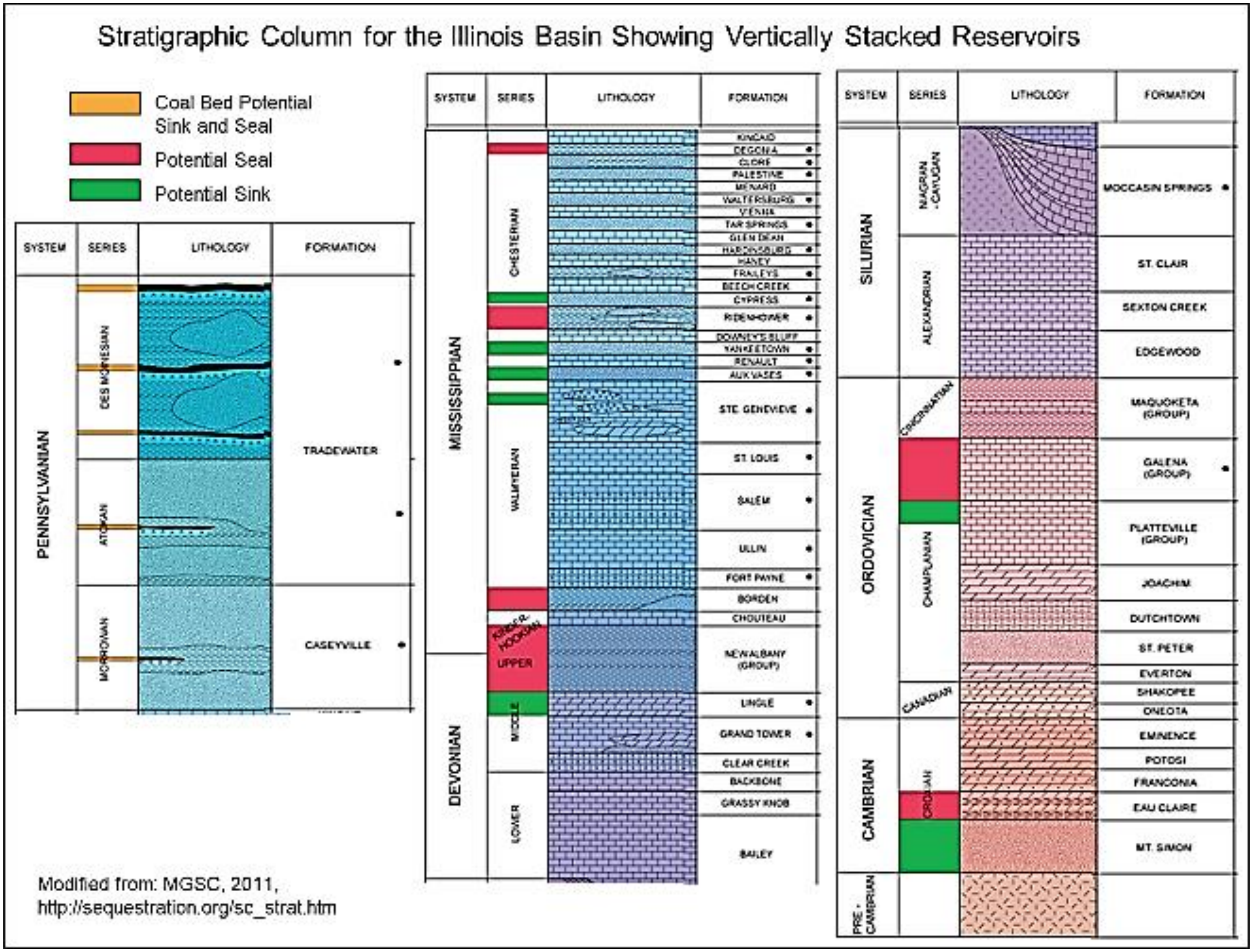

Figure 1-3. Generalized stratigraphic intervals of the Illinois Basin showing vertically stacked reservoirs. The stratigraphic column illustrates potential reservoir/seal pairs for CO_2 storage (modified, Midwest Geological Sequestration Consortium).

A generalized west-east cross section through the Illinois Basin shows the configuration of Paleozoic sediments in **Figure 1-4**. Note that this cross-section is a couple of counties south of the proposed injection site near Taylorville, Illinois. Both the Mt. Simon and Eau Claire are of Cambrian age.

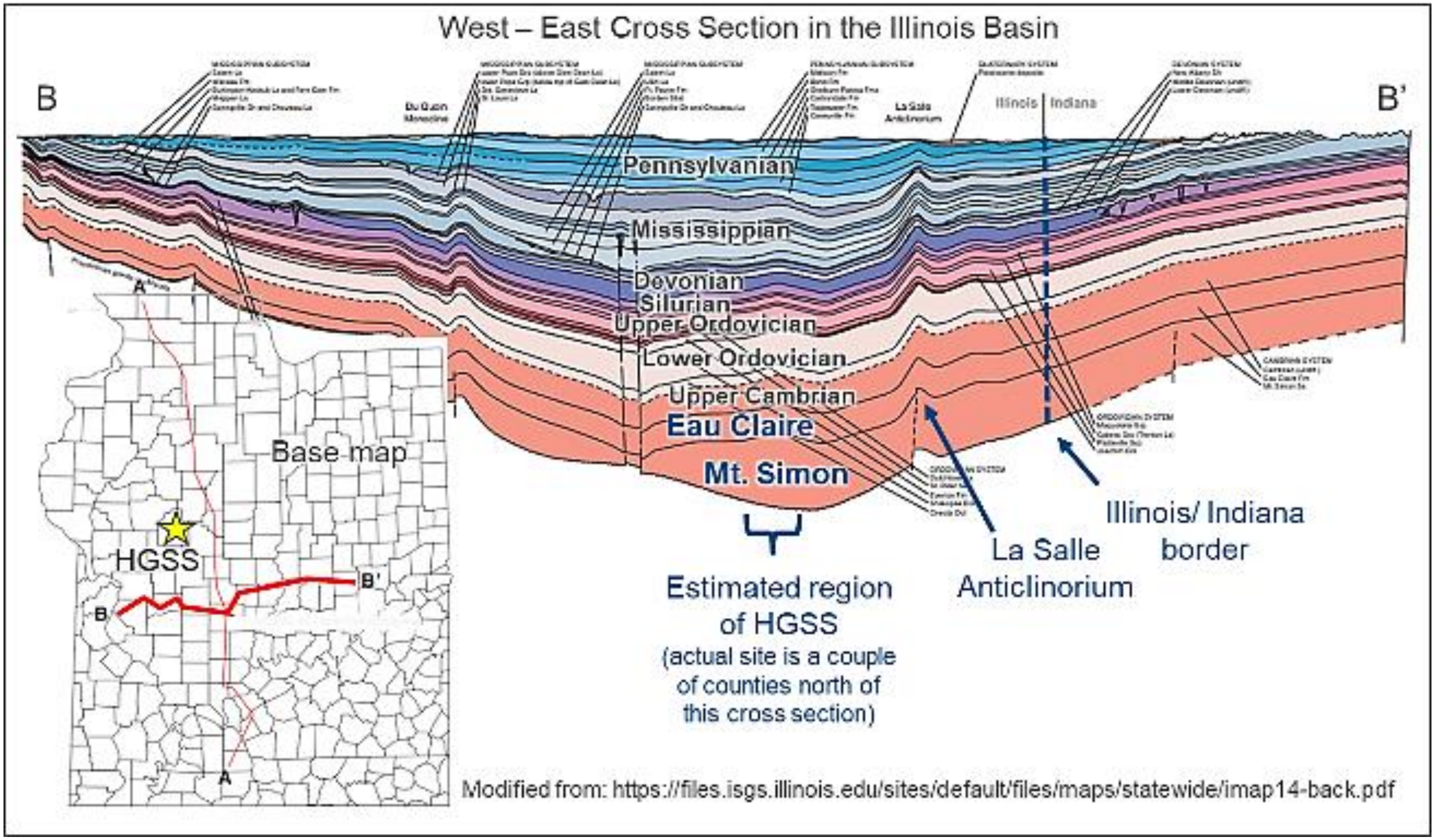

Figure 1-4. Generalized west-east cross-section of the Illinois Basin (Modified from ISGS poster titled: *Wireline logs and stratigraphic columns West – East Cross Section in the Illinois Basin*).

The local bedrock surface strata are Pennsylvanian in age and consist of interbedded shale, sandstone, limestone, and coal seams, **Figure 1-5**. At HGSS, the Pennsylvanian rock has a subtle dip to the southeast into the Illinois Basin.

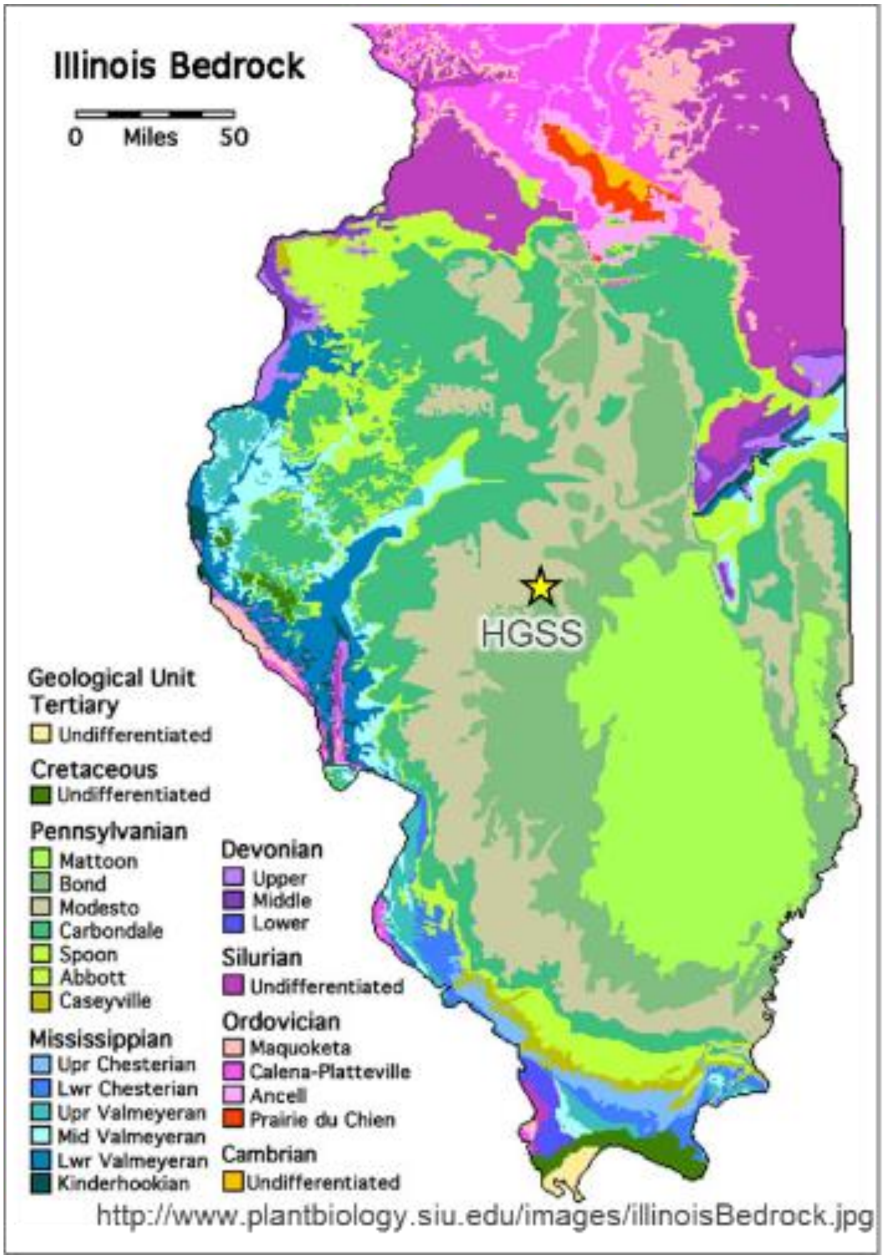

Figure 1-5. Map showing the regional surface bedrock geology surrounding HGSS.

The primary structure near the Heartland Greenway Storage Site is the La Salle Anticlinorium, located 50 miles to the east, **Figure 1-6**. This anticlinal structure (fold) developed during the Late Mississippian and Pennsylvanian periods. There are relatively small faults on and close to the fold, with no anticipated faulting near HGSS. The structurally subtle Louden Anticline is located approximately 45 miles SE of HGSS. Taylorville is located in an area where structural features are not known to exist and where the Mt. Simon is thick.

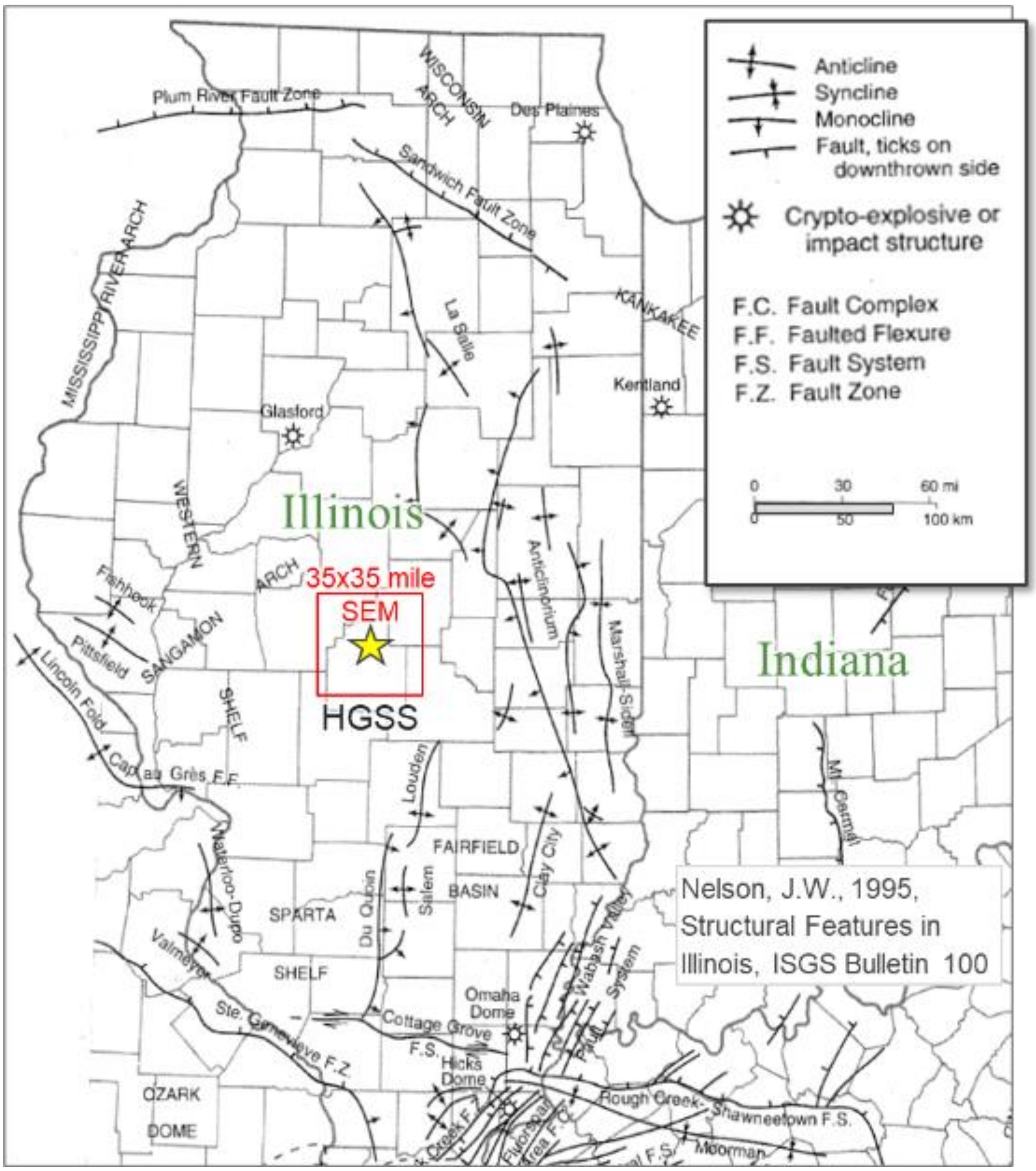

Figure 1-6. Precambrian basement contour map with La Salle Anticlinorium to the east. The red box represents the 35x35 mile Static Earth Model area prepared for this permit. Modified from Nelson, 1995.

1.2.2. Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]

HGCS's subsurface interpretation for HGSS has leveraged data from other CO_2 storage projects in the Illinois Basin where the Mt. Simon Sandstone and overlying units were characterized. An interpretation of Cambrian-aged Mt. Simon Sandstone in the Illinois Basin includes four main depositional environments as noted in **Figure 1-7**. These environments include fluvial braid plains (proximal, medial, and distal) and marine braid delta. Within the regional fluvial braid plain, there are playa (flat "ponding" areas) and eolian sedimentary areas (Leetaru and Freiburg, 2014).

The Mt. Simon Formation consists of generally clean, well-sorted, and porous sandstones. Variations in sediment grain size depend on how far sediments were transported from their source and whether they were reworked by wind (eolian sandstone) or water (shallow marine sandstones modified and sorted by wave action). Another factor that affects the reservoir quality of the Mt. Simon Sandstone is diagenesis – how the rock has changed since its original deposition. Various processes can either increase the primary porosity or destroy it. Most notably for sandstones, diagenesis can result in the loss of porosity due to mineralization within the pore spaces. Although the Mt. Simon Formation is very thick at HGSS, different portions of the reservoir feature better reservoir quality than others, and diagenesis in the lower Mt. Simon sections has aided the preservation and development of porosity.

The estimated formation tops for the proposed HGSS Injection well are summarized in **Table 1-6**. The Mt. Simon is estimated here at 945 feet thick and occurs at a depth of 5,485 feet and deeper, making it suitable for CO_2 storage at supercritical conditions. The Eau Claire Shale unit represents the primary caprock at the site and is approximately 538 feet thick, with its top occurring at approximately 4,948 ft measured depth. Based on regional contour mapping of well tops, the Mt. Simon and Eau Claire are expected to have a gentle dip of less than 1-degree towards the southeast and be laterally extensive over the project's area of review. Apart from the sedimentary section's contact with Precambrian basement rock, no domes, folding, or noteworthy stratigraphic pitchouts are likely to be found at the HGSS. A secondary caprock may be represented by tighter sections within the Knox Supergroup and this would be determined during the implementation of the *Formation Testing and Logging Plan.* Furthermore, it can be argued that portions of the Mt. Simon, for example, the Mt. Simon C and D, may affectively act as containing units. Data characterizing these units will be acquired during the execution of the *Formation Testing and Logging Plan.*

A large 35 by 35-mile modeling area was selected for the HGSS project, primarily to enable the simulation of subtle pressure changes at a distance from HGSS injection area. No Mt. Simon injection wells currently exist within our model area. Consequently, geological modeling for deep sedimentary intervals such as the Mt. Simon is based on the TR McMillen 2 well. The proposed injection wells are shown in **Figure 1-8**.

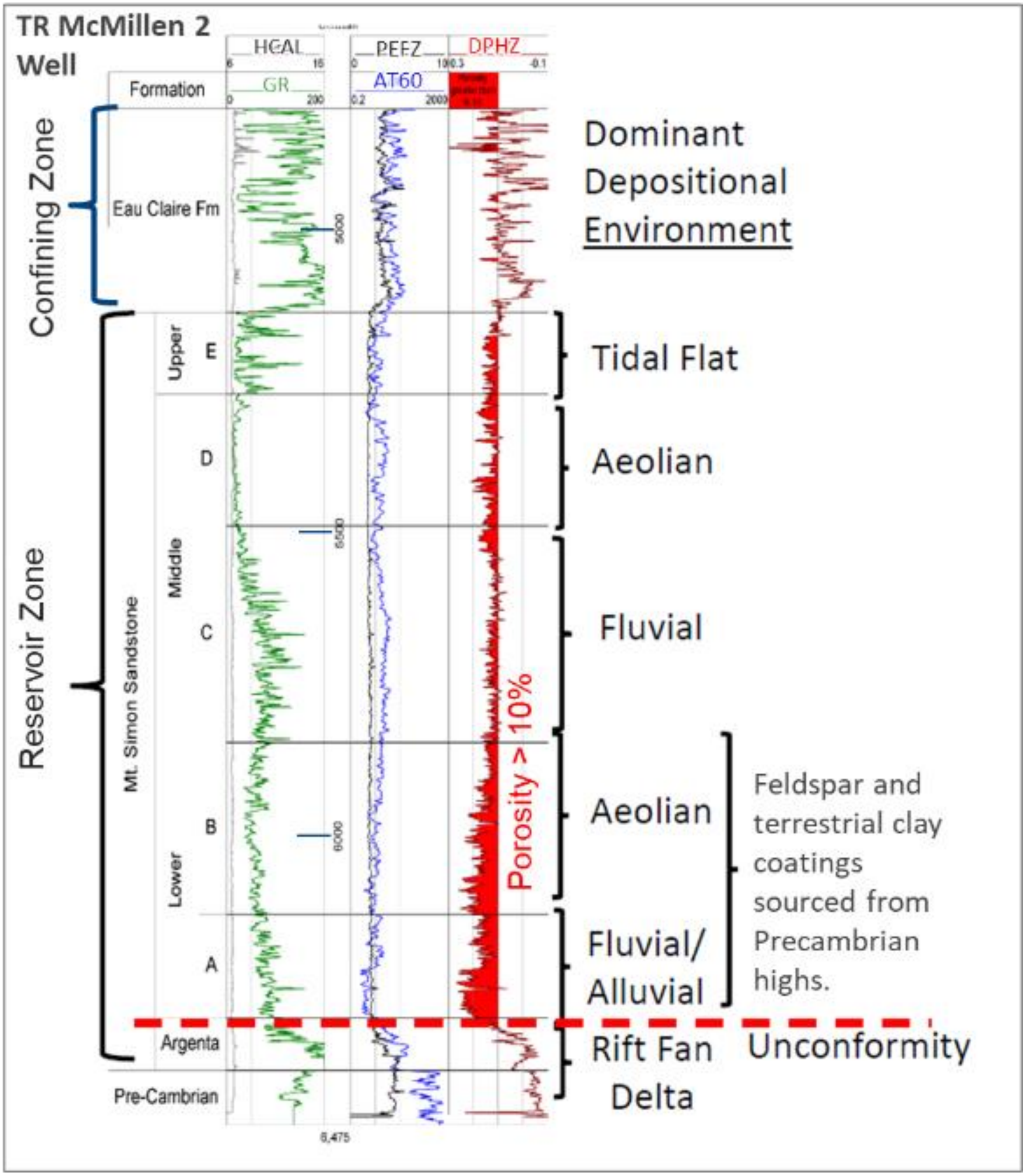

Figure 1-7. Depositional environments of the Mt. Simon storage complex based on well logs and subsurface data from the nearby TR McMillen 2 well. Modified from Whittaker *et al*., 2019.

Table 1-6. Stratigraphic table for the proposed HGSS injection wells.

System	Stratigraphic Unit	Lithology	Depth (ft)	Thickness (ft)
Mississippian	St. Louis	Limestone		
	Burlington-Keokuk	Limestone		
Devonian	New Albany	Shale		
Ordovician	Maquoketa	Dolomite & Shale		
	Galena-Platteville Dolomite	Dolomite		
	Peter Sandstone	Sandstone	3179	252
	Shakopee Dolomite	Dolomite, Limestone	3431	
	New Richmond Sandstone	Sandstone & dolomite		
	Oneota Dolomite	Dolomite		
	Gunter Formation	Dolomite		
Cambrian	Eminence Dolomite	Dolomite		
	Potosi Dolomite	Dolomite		
	Ironton Sandstone	Sandstone	4796	152
	Eau Claire Formation (Confining Interval)	Shale, Siltstone, Sandstone	4948	538
	Mount Simon Sandstone (Reservoir Interval)	Sandstone, Siltstone, Shale	5486	945
	Argenta Formation	Marine Sandstone	6431	38
Weathered Precambrian Basement		Granite	6469	31
Precambrian Basement		Granite	6500	

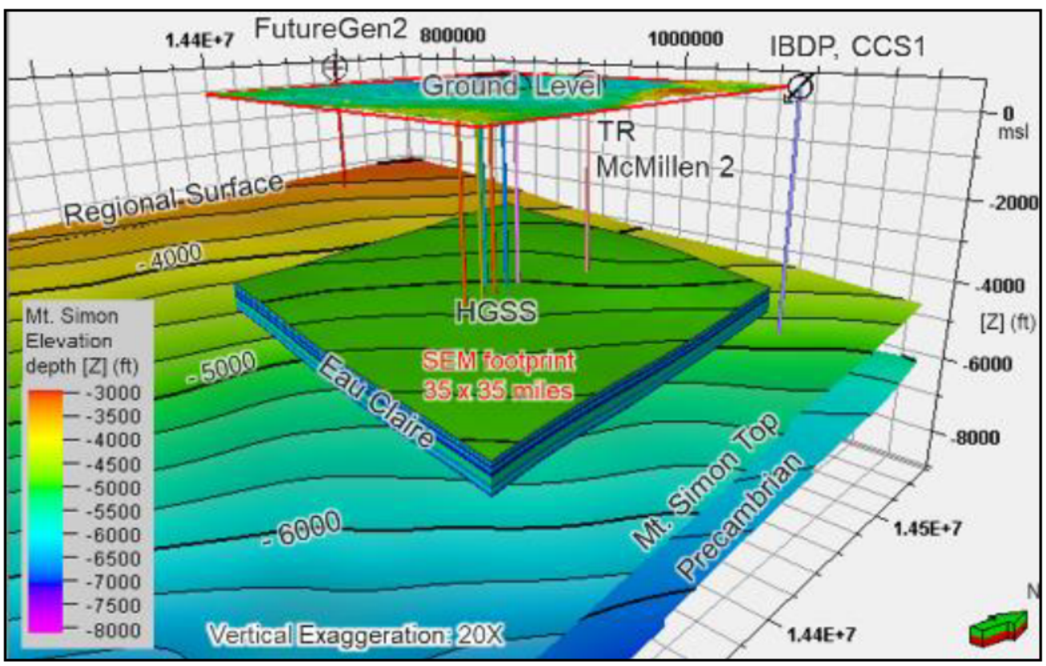

Figure 1-8. Oblique map view of the 35x35 mile geologic SEM footprint for HGSS. This cut-away view shows the proposed CO_2 injection wells for HGSS arranged south to north and penetrating the top of the Eau Claire Shale. Formation tops indicate that the Mt. Simon dips gently to the southeast.

A site-specific stratigraphic column identifying the confining zones and storage units along with depth estimates for formation tops is provided in **Figure 1-9**. The depth estimates are for the NCV-1 injection well, the first of the six proposed injectors. A geologic cross-section at HGSS depicts these stratigraphic units as shown in **Figure 1-10**. This cross section is based on the Static Earth Model that was prepared for this permit; some overlying stratigraphic zones have been lumped together as a simplification.

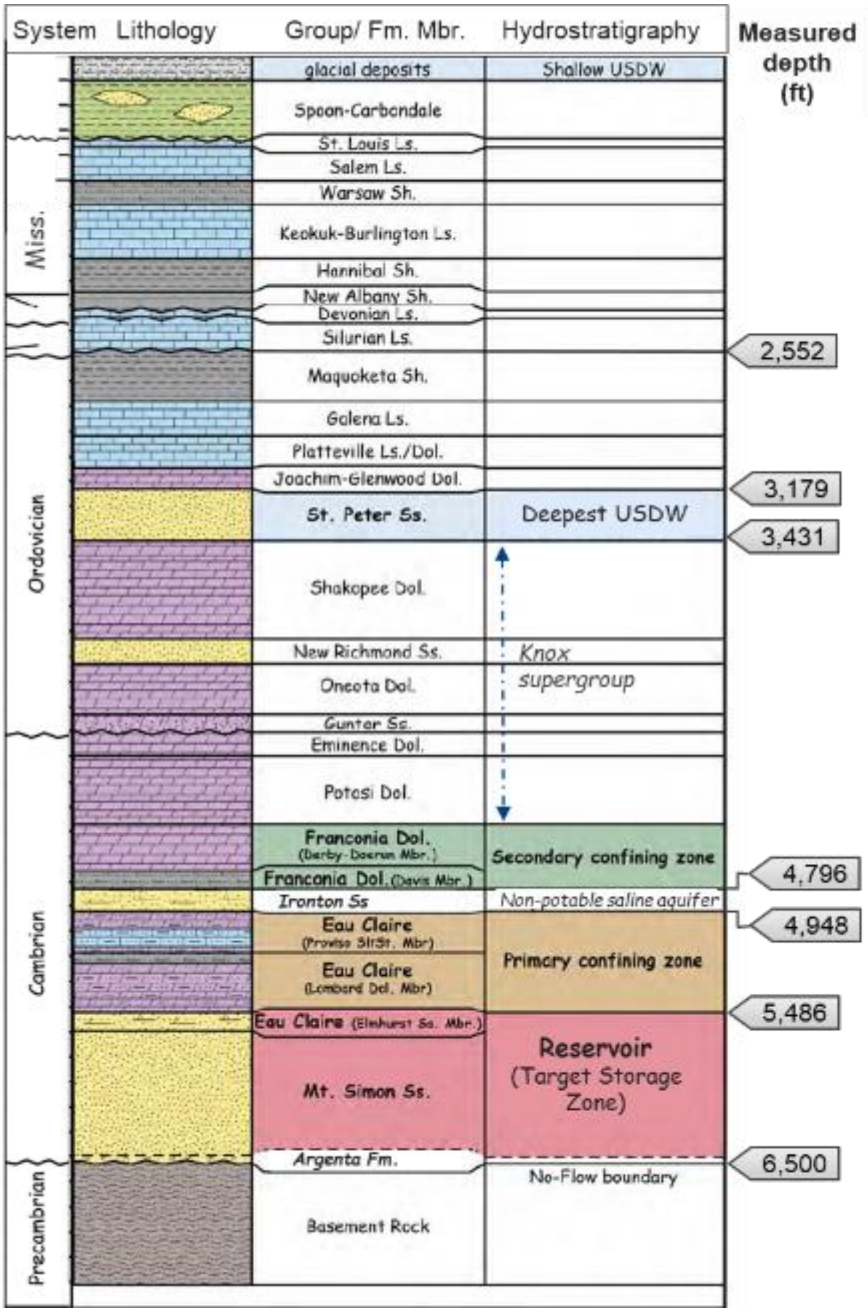

Figure 1-9. Stratigraphic column for HGSS. The Mt. Simon at the Heartland Greenway Storage Site is estimated at 945-ft gross thickness. Image modified from FutureGen2 UIC Class VI Permit.

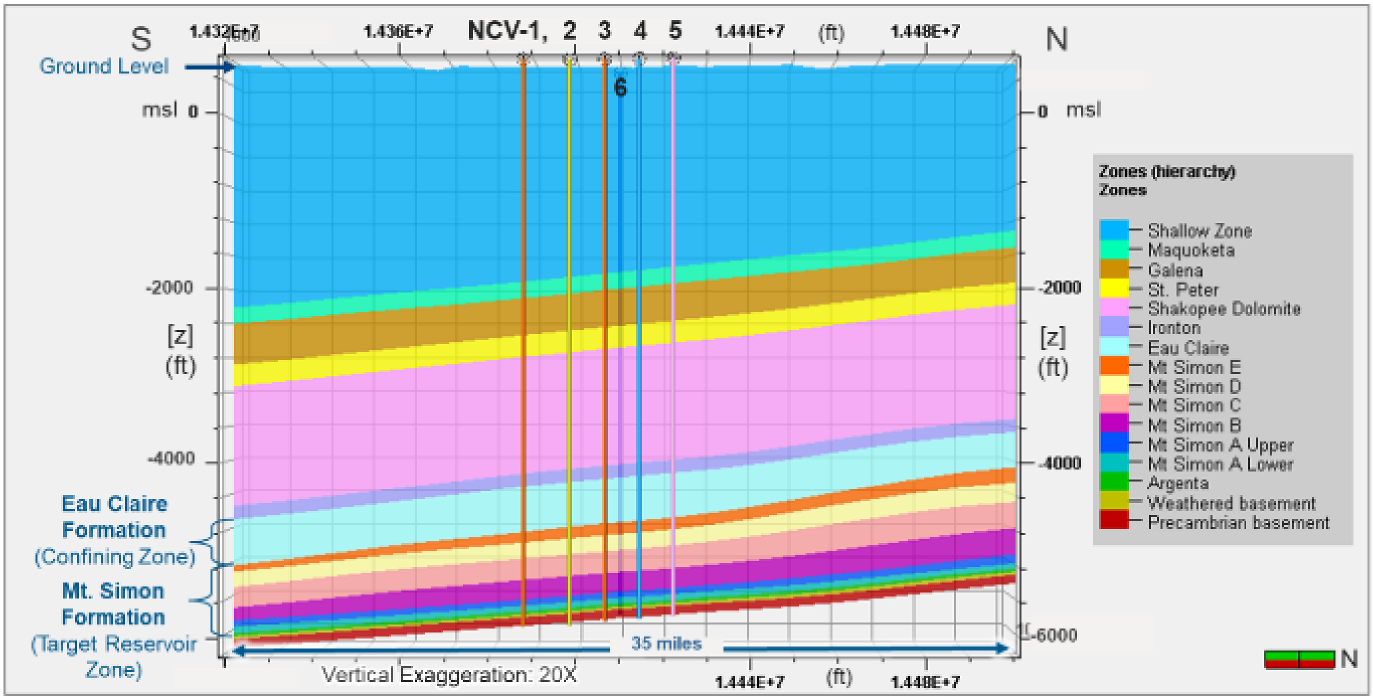

Figure 1-10. Cross-section through storage complex and proposed HGSS injection wells.

1.2.3. Faults and Fractures [40 CFR 146.82(a)(3)(ii)]

Containment and sealing capacity at the HGSS are believed to be favorable as there are no known faults at or near the site. Basement topography and its proximity to the Lower Mt. Simon injection zone is one structural consideration that could affect the selected depths for well perforations. Located 50 miles west of the La Salle Anticlinorium, the HGSS is positioned where there is little geologic evidence to support noteworthy structural features that would compromise CO_2 containment. The HGCS team reviewed and incorporated 2D seismic lines that were previously acquired by Tenaska in 2009 and processed by WesternGeco (**Figure 1-11**). The proposed injection wells for HGSS are placed along these 2D lines. A preliminary seismic interpretation revealed a gentle stratigraphic dip present in the area trending to the south and east, as noted in **Figure 1-12** and **Figure 1-13**. The dip was estimated to be less than one degree with a southeast strike. Additional investigations of the 2D seismic lines collected at the site revealed relatively uniform bedding for the Mt. Simon formation (the target storage reservoir), the Eau Claire confining zone, and the shallower formations. Subtle sedimentary features were noted in the Mt. Simon and is consistent with our understanding that this formation consists of a braided fluvial system paired with eolian and playa deposits. Seismic line 101 appears to have disruptions of its reflectors near the north end of the survey, which could be an artifact of the seismic processing. These seismic reflectors will be reexamined when the HGSS collects its first 3D seismic survey to determine whether any faults and/or fractures could affect preferential fluid flow.

The preliminary interpretation was based on inferences from seismic data and wells present at the IBDP site approximately 30-miles to the northeast. Updated seismic interpretations are planned with the arrival of site-specific sonic and density logs as part of the *Formation Testing and Logging Plan* for HGSS. This plan also calls for borehole imaging which can provide evidence for any fracturing or faulting that may be present and is part of the characterization plan.

The preliminary geological interpretations of the reservoir and seals near the proposed injection wells are presented in **Figure 1-12** and **Figure 1-13**. The Mt. Simon rests on an interval referred to as the Argenta, which is a tight marine sandstone. Few wells penetrate the Argenta; it is believed that this zone is well cemented and offers little to no opportunity for CO_2 migration.

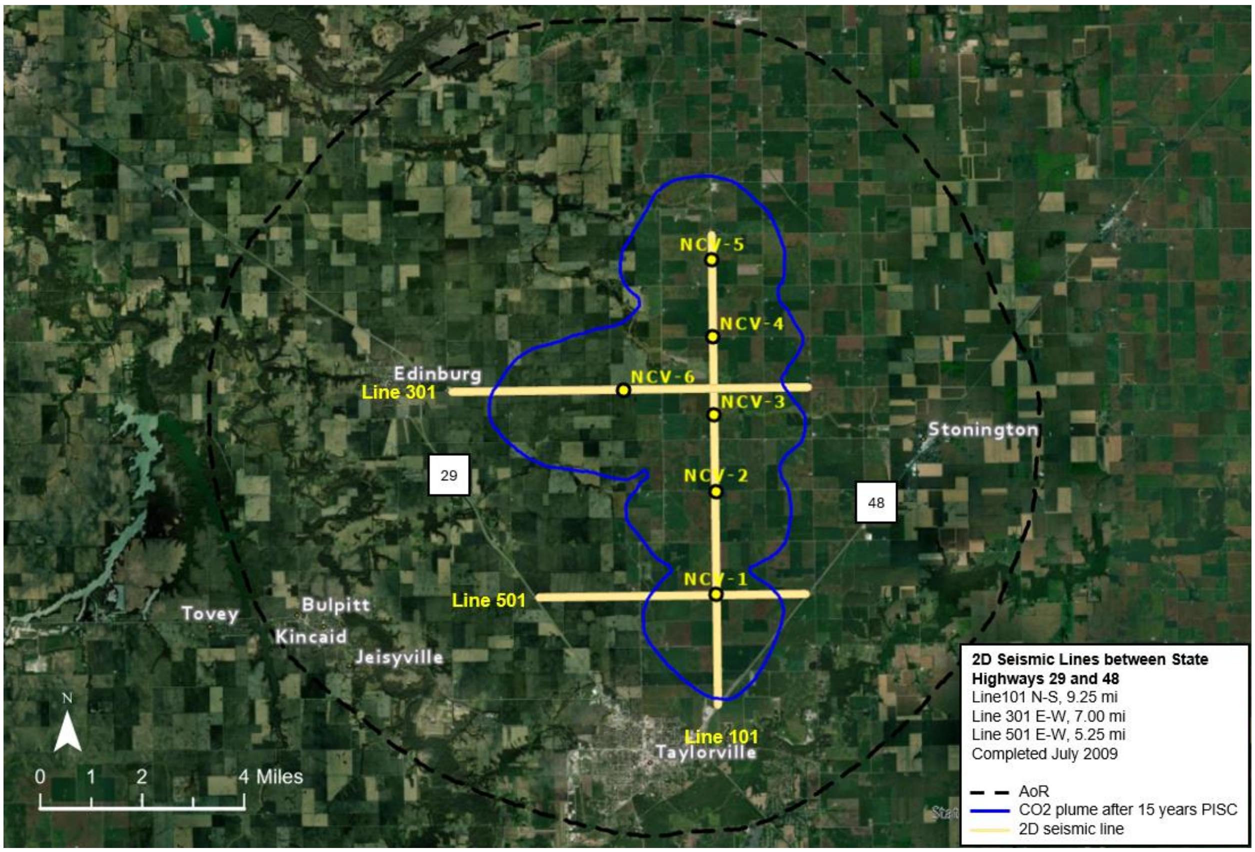

Figure 1-11. Existing 2D seismic lines at HGSS northeast of Taylorville, IL. These three lines were shot, gathered, and processed in 2009. Black dashed line represents the Area of Review.

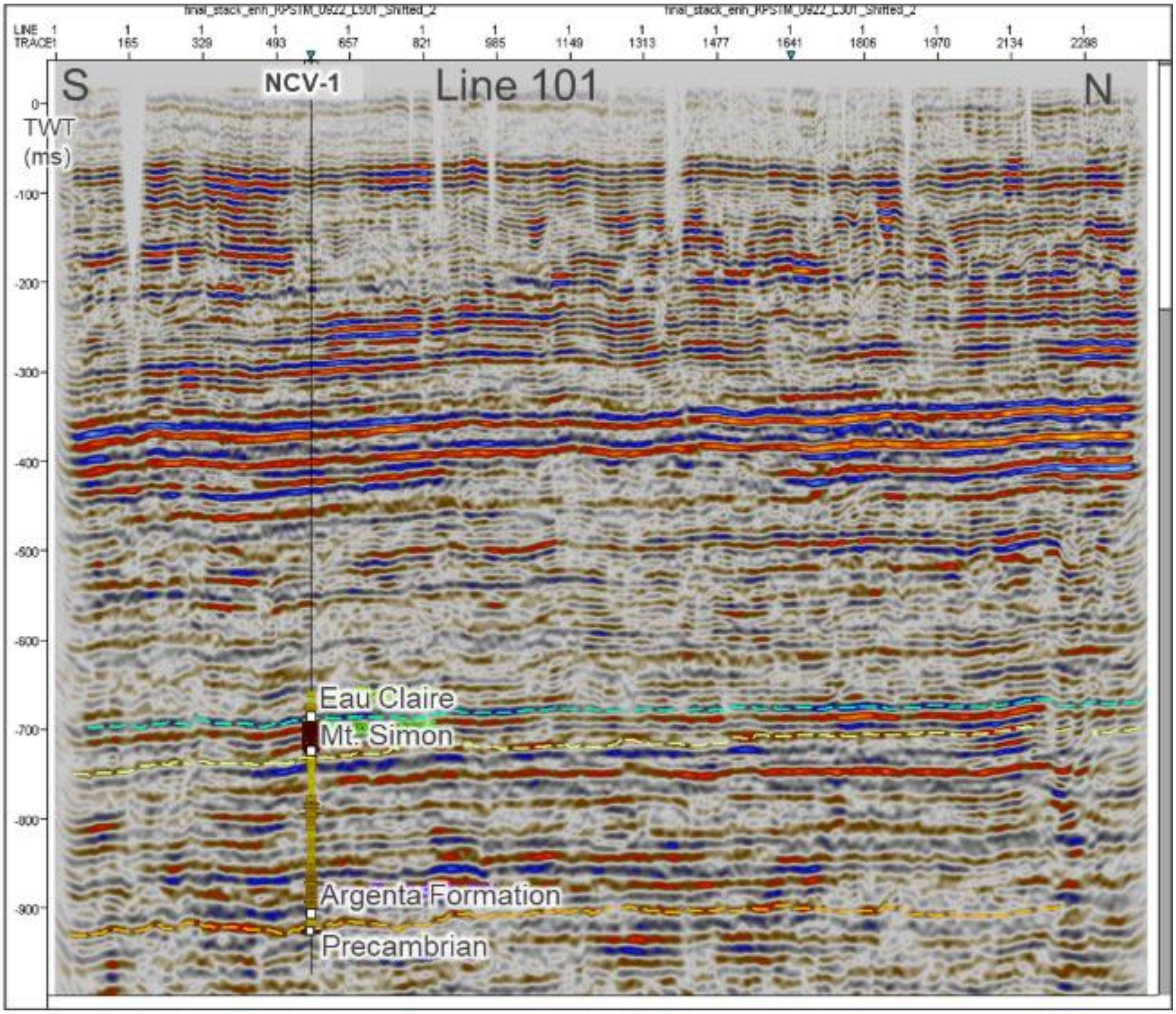

Figure 1-12. 2D seismic line 101 trends north to south and appears to have a gentle dip to the south. The Mt. Simon interval is shown here along with its seal, the Eau Claire Shale. Here, the base of the Mt. Simon is the Argenta formation which sits on top of the Precambrian basement.

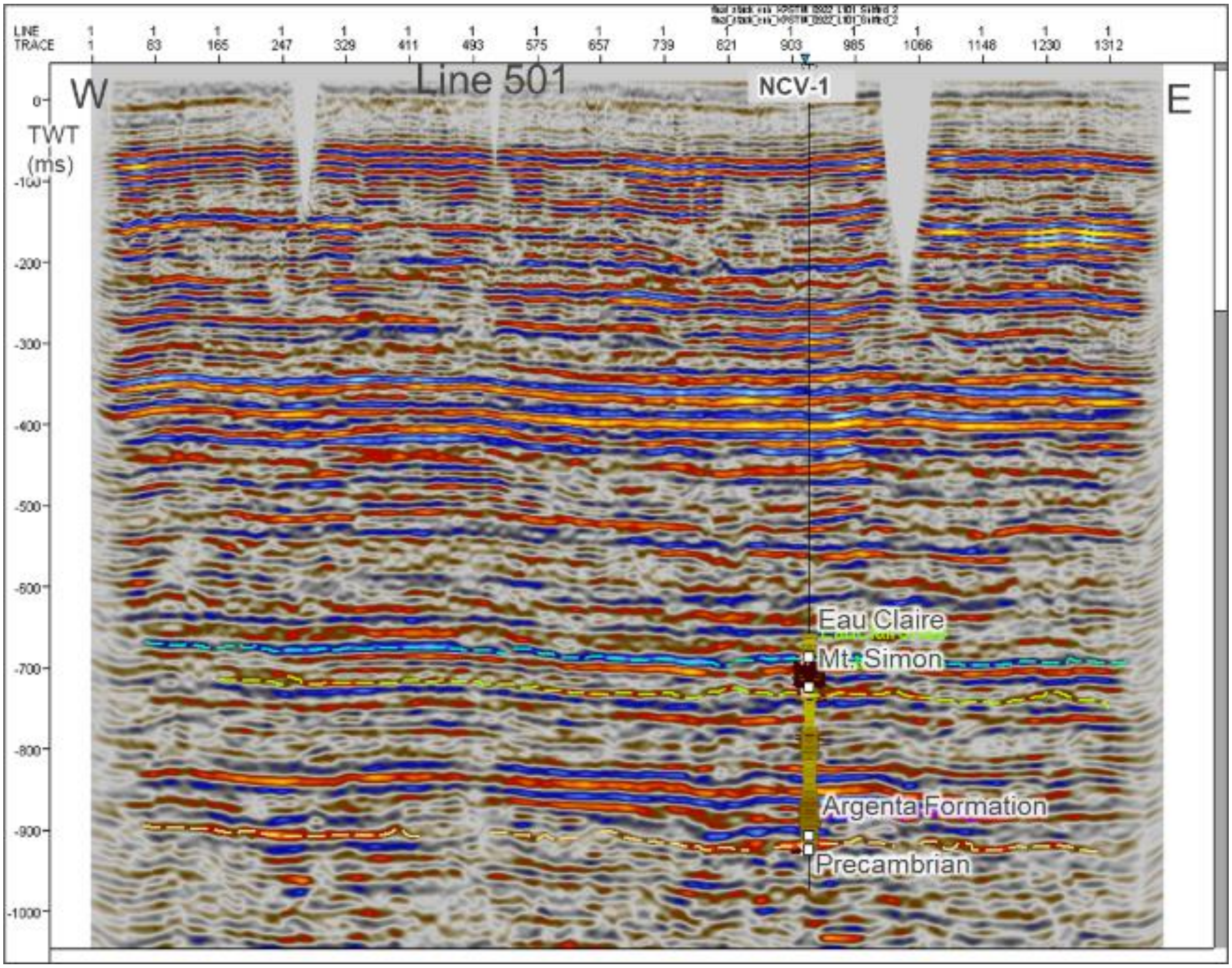

Figure 1-13. 2D seismic line 501 trends east to west and appears to have a gentle dip to the east. The Mt. Simon interval is shown here along with its seal, the Eau Claire Shale. Here, the base of the Mt. Simon is the Argenta formation which sits on top of the Precambrian basement.

1.2.4. Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]

Site-specific data describing the injection and confining zones will be gathered during the drilling of wells and is described in the section detailing the *Formation Testing and Logging Plan*. Currently, estimations of porosity and permeability are based on well logs and core test results from the nearby TR McMillen 2 well. The petrophysical data values are summarized in **Table 1-7** and are representative of the modeling work conducted for the HGCS.

Table 1-7. Average porosity and permeability values by Mt. Simon model zone and vertically adjacent formations. The averages are derived from the nearby TR McMillen 2 well.

Model Zone	Average Zone Porosity (ft^3/ft^3)	Average Zone Permeability (milliDarcies)**
Ironton	0.077	12.864
Eau Claire	0.059	2.932
Mt. Simon E	0.127	20.373
Mt. Simon D	0.145	3.349
Mt. Simon C	0.120	0.489
Mt. Simon B	0.173	144.689
Mt. Simon A Upper	0.157	283.512
Mt. Simon A Lower	0.228	1278.112
Argenta	0.078	0.073
Weathered basement	0.014	0.005
Precambrian basement	0.001	0.005
Model Base	-	-

** Average permeability computed by the arithmetic mean method.

Injection and confining zone details, including maps and cross-sections, have been described in earlier sections and are summarized in **Table 1-8.**

Table 1-8. Summary of injection and confining zone parameters.

Parameter	Estimated value or comment
Depth, areal extent, and thickness of the injection zones.	5,486 ft depth and 945ft thick as determined by contouring regional well tops, with the nearby TR McMillen 2 well approximately 7 miles away.
Depth, areal extent, and thickness of confining zones.	4,948 ft and 538 ft thick as determined by contouring regional well tops, with the nearby TR McMillen 2 well approximately 7 miles away.
Thickness variability of the injection and confining zones within the AoR.	Thickness is expected to vary by 10's of feet; this variability is not expected to affect containment.
Injection and confining zone samples for characterizing mineralogy porosity and permeability.	Mt. Simon's mineralogy and petrophysical properties are inferred by the nearby (7 miles) TR McMillen 2 well. The HGCS's *Formation Testing and Logging Program* aims to fill data gaps by providing site-specific data.
Mineralogy and petrology of the injection and confining zones.	Injection zone: Arkosic sandstone Confining zone: Mudstones and shale
Mineralogy and geochemical reactions affecting carbon dioxide storage and containment.	The injection and confining zones are not expected to have any adverse reactions that would compromise their respective purpose. Carbonates may be present in the confining unit, the Eau Claire. However, the CO_2 plume is expected to reside much deeper, below the Mt. Simon C.
Compatibility of the mineralogy of the injection and confining zones with the proposed carbon dioxide stream.	The injection zone's mineralogy is anticipated to be similar to that encountered at the IBDP site where 1 million tonnes

Parameter	Estimated value or comment
	of CO_2 has been sequestered with no known compatibility issues.
Spatial distribution of porosity and permeability values within the injection and confining zones.	Best estimates of porosity and perm are obtained from the TR. McMillen 2 well. The spatial distribution is currently modeled as "layer cake style," where each layer is isotropic.
Data used to determine permeability and porosity.	TR McMillen 2 well porosity logs plus porosity and permeability based on core samples. Lower Mt. Simon has porosity averaging greater than 15%; permeability is greater than 100mD but less than 1,500 mD. The gathering of site-specific petrophysical data is planned and described in the *Formation Testing and Logging* section.
Estimated storage capacity and injectivity of the injection zone? What is the integrity of the confining zone?	The reservoir has sufficient storage capacity and injectivity required to meet the injection targets requested in this permit as indicated in the AoR and Corrective Action Plan.
Capillary pressure of the confining zone. Determined by. Does this significantly affect the ability of carbon dioxide to penetrate the confining zone?	No site-specific capillary pressure data was available for the site. Multi-phase fluid flow effects were modelled using two sets of relative permeability curves. For more details, please refer the AoR and Corrective Action Plan.
Additional information for characterizing the injection and confining zones?	Pre-operational subsurface testing will be used to fill site-specify data gaps.

1.2.5. Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]

Site-specific geomechanical data for HGSS are absent; however, acquisition of this data is planned and detailed in HGCS's *Formation Testing and Logging Program*. These testing and logging activities will be undertaken during the during and construction of any new monitoring and injection wells at the HGSS. The closest geomechanical understanding of the sequestration zone and primary confining layer comes from the IBDP 30-miles away and is summarized below.[4]

Core samples from three deep drill holes at the IBDP site were tested to determine a suite of physical properties including bulk density, porosity, permeability, Young's modulus, Poisson's ratio, and failure strength. Representative samples of the shale cap rock, the sandstone reservoir, and the Precambrian basement were selected for comparison. Physical properties were strongly dependent on lithology. Bulk density was inversely related to porosity, with the caprock (Eau Claire) and basement samples being both least porous (<3%) and densest (~2.6 g/cc)[4]. Permeability was highest in the reservoir sandstones (10-15 to 10-18 meters squared [m^2]) relative to the cap rock and basement rocks (<10-21 m^2).[4] Young's modulus was distinctly higher in the basement rocks (45 to 80 gigapascal [GPa]) compared to the cap rock and sandstones (19 to 57 GPa). Poisson's ratio for the Mt. Simon reservoir sandstones varied widely

[4] Morrow, C.A., Kaven J.O., Moore, D.E, and Lockner, D.A., 2017, Physical Properties of Sidewall Cores from Decatur, Illinois, Open-File Report 2017–1094

(0.14 to 0.27), but the highest values were similar to the cap rock and basement rocks (0.24 to 0.28). [4] These physical properties reflect the layered structure of the reservoir and adjacent rocks at the Decatur site. However, within the sandstone there is a great deal of lithologic variety, accounting for the large range in physical parameters for this geologic unit. Density, porosity, permeability, and elastic moduli are strongly influenced by sample lithology.

Mount Simon Sandstones (Reservoir) [4]:

- Bulk densities of 2.0 to 2.5 g/cc,
- Porosities from 6 to 21 percent,
- Permeability from 1.8×10^{-15} to 9.1×10^{-19} m^2,
- Young's modulus from 19 to 57 GPa,
- Poisson's ratio of 0.13 to 0.27.

The confining zone (Eau Claire) and Precambrian basement rocks are both low porosity and high density, with extremely low permeabilities and generally higher Young's modulus and Poisson's ratios. The in situ stresses found in the bedrock are fairly consistent in the northern three-quarters of the state of Illinois, with the highest stress in the horizontal direction as shown by in situ stress measurements that nearly surround the IBDP site from 44 to 174 mi distance.[5] Stress values are from a variety of measurement techniques, including hydraulic fracturing, coring, and a borehole pressure meter, and show SHmax > Shmin > Sv (**Figure 1-14**). These are consistent in direction and principal stress orientations as found throughout much of the Upper Midwestern USA.

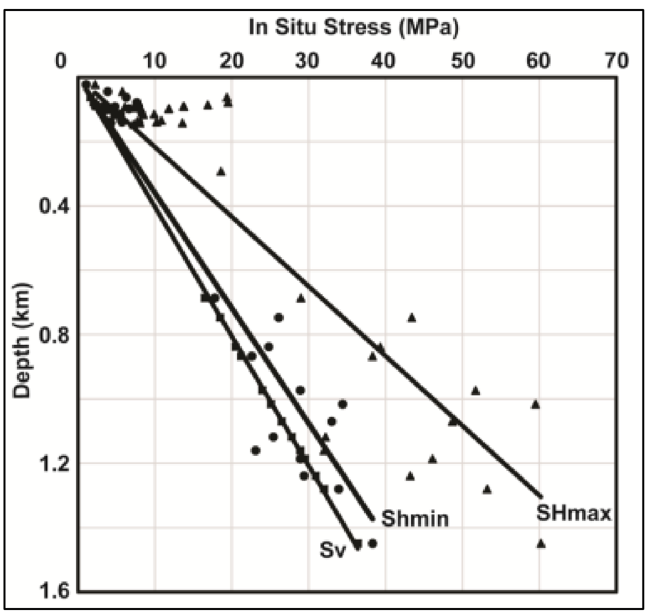

Figure 1-14. In situ stresses showing principal stresses of measured sites surrounding the IBDP from 44 to 174 mi away. Measurements were made specifically for in situ stresses using the hydraulic fracturing, coring, and borehole pressure meter methods. Image from Bauer et al., 2015.

[5] Robert A. Bauer, Michael Carney, Robert J. Finley, 2015, Overview of Microseismic Response to CO2 Injection into the Mt. Simon Saline Reservoir at the Illinois Basin-Decatur Project.

The modeling work for the HGCS assumes a fracture pressure gradient of 0.7 psi/ft. The *AoR and Corrective Action Plan* detail current assumptions regarding formation temperature, pressure, and pore pressure gradient. The resulting simulations from the action plan indicate the maximum allowable injection rate, injection pressure, CO_2 mass that can be injected at the HGSS.

A site-specific characterization of natural fractures is planned through the use of Full-bore Micro Imaging in wells for the HGCS as detailed in the *Pre-Operational Testing Program*. This program describes core tests and field tests to determine:

- Fracture/parting pressure of the sequestration zone and primary confining layer and the corresponding fracture gradients are determined via step rate or leak-off tests.
- Rock compressibility, or measure of rock strength, for the confining layer(s) and sequestration zone.
- Rock strength and the ductility of the confining layer(s). Rock strength is usually
- Ductility of the confining layer(s).
- Unconfined compressive strength (UNC) of the confining layer as measured from intact samples.

Local structure features like basement topography will be characterized as part of a 3D seismic survey for the site.

1.2.6. Seismic History [40 CFR 146.82(a)(3)(v)]

The HGSS area appears to be relatively aseismic with minimal risk of seismic activity that would compromise the containment of the CO_2. The majority of the natural seismic activity occurs in the southern and southeastern parts of Illinois, where two seismic zones (Wabash Valley and New Madrid) are found. Central Illinois has been historically low in terms of earthquake frequency and seismic event magnitude as indicated in **Figure 1-15**. The largest recorded earthquake in the state (M5.4) occurred on April 18, 2008, and caused minor structural damage in the southeastern part. The closest known earthquake to HGSS had a magnitude of 2 to 3 and was located approximately 45 miles to the southeast. Most of the seismic events in Illinois occurred at depths greater than 3 km (1.9 mi); these were likely related to existing basement faults.

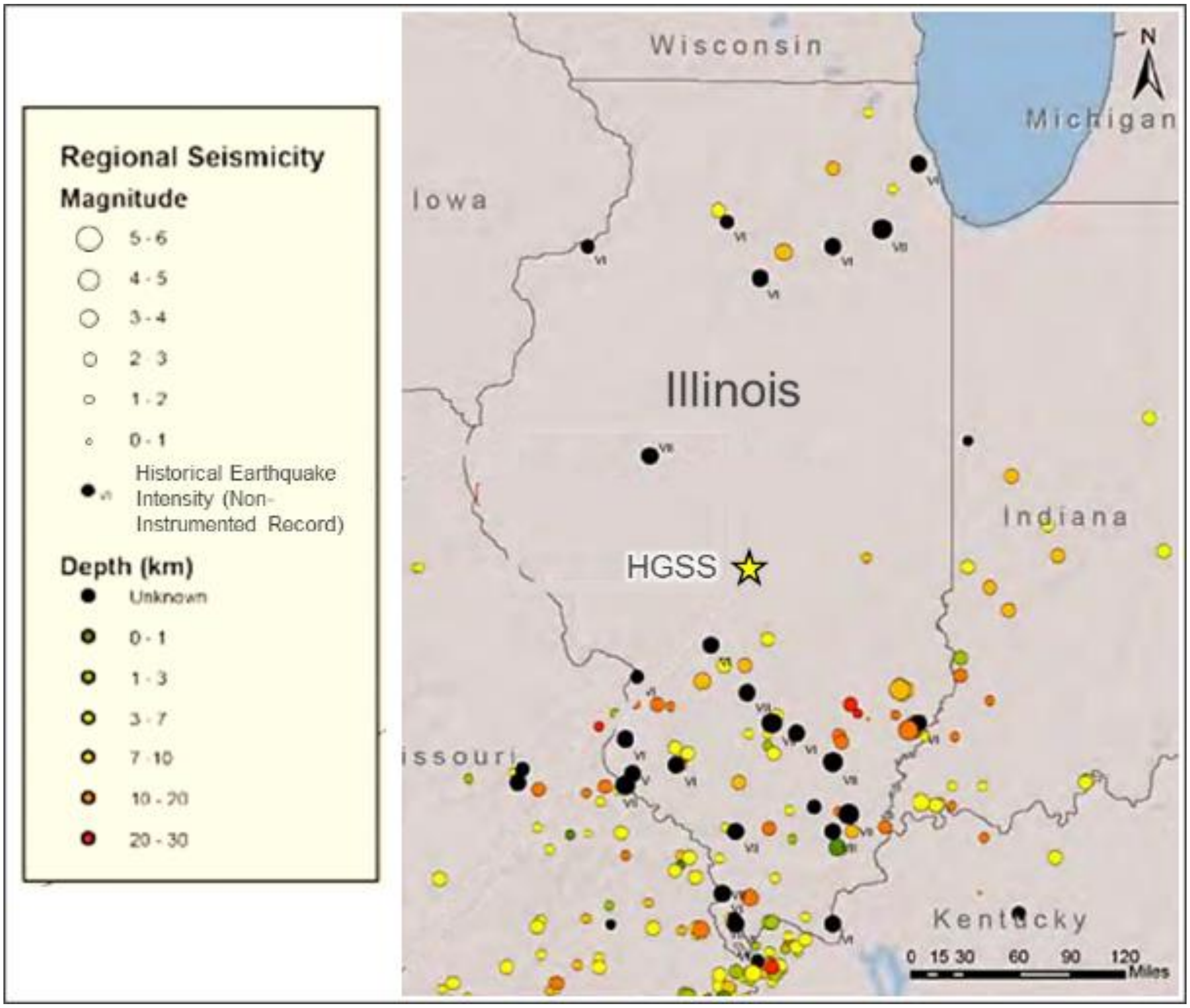

Figure 1-15. Regional Historic Earthquakes in Illinois and adjacent states. Image modified after FutureGen2 UIC VI permit application.

The USGS has prepared seismic hazard maps representing the chance that natural seismicity will occur within the next 50 years. A seismic hazard map from 2014 indicates the risk level for the state of Illinois as illustrated in **Figure 1-16**. At HGSS site, in the 50-years following the year 2014, there is a 2% chance that a seismic event will produce a ground motion (acceleration) of 10-14%g.

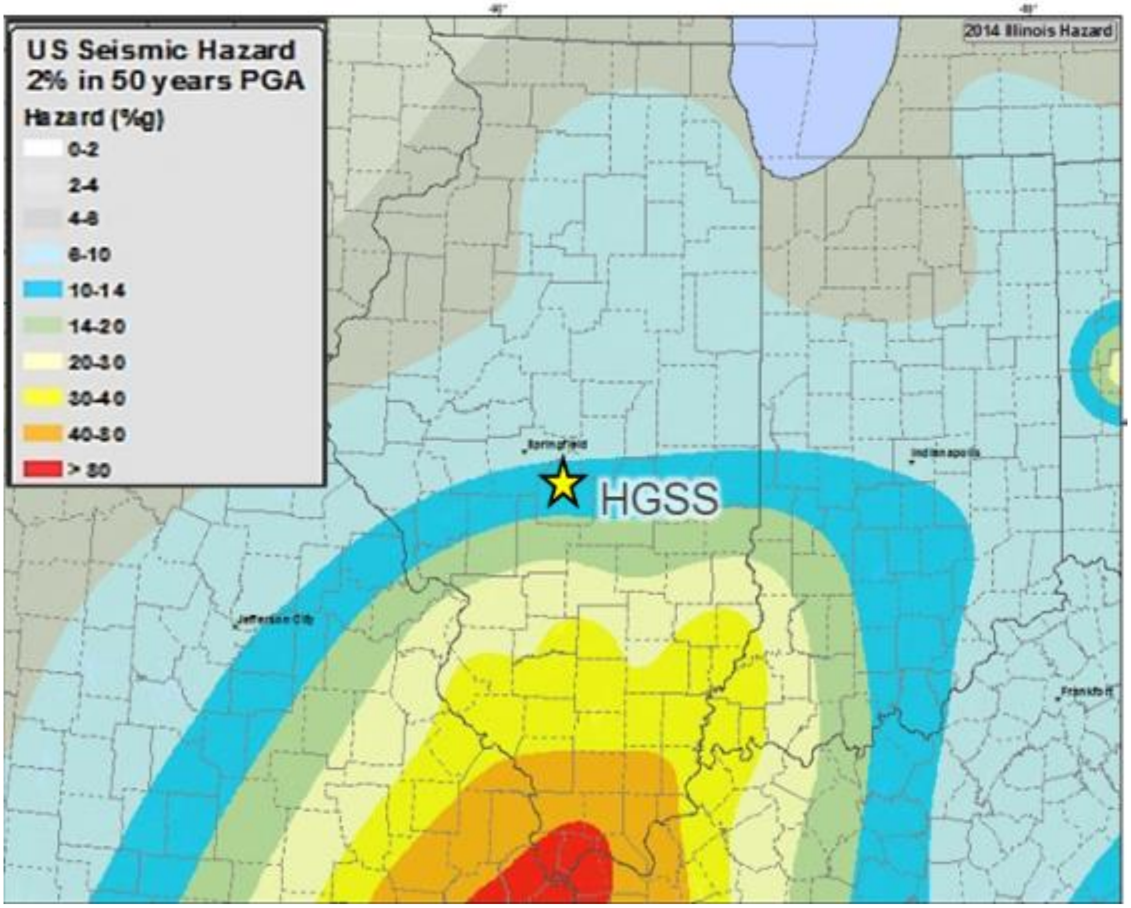

Figure 1-16. 2014 Seismic Hazard Map for Illinois. Seismicity in this region is primarily attributed to the New Madrid Fault zone located in southeastern Missouri; PGS: peak ground acceleration. g: gravitational acceleration; Image modified from the USGS, 2014.

1.2.7. Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

The HGSS includes six proposed injection wells located a little over two miles northeast of Taylorville, Illinois, in Christian County (**Figure 1-17**). Taylorville's population is approximately 10,000 and situated along State Route 48 and approximately 30 miles to the southwest of the city of Decatur (pop. ~72,000). Land use of the area is predominantly agricultural, the terrain is flat, and the land is held mostly by private landowners for growing row crops. There is minimal present-day oil field infrastructure in the area. Access to the HGSS site area is from State Hwy 48 or 29, with numerous gravel roads, farm access roads, and paved roads existing within the project area (**Figure 1-17**). The area lies in the glaciated region of Illinois and is covered by glacial till deposited as ground moraine. As such, there is relatively little relief. Within a 12-mile radius of the proposed site, the average elevation is 600.24 feet with a standard deviation of 18.46 feet. The land use (**Figure 1-18**) in the area is largely agricultural, with row crops and pasture. There are 14 incorporated areas that have commercial and residential land uses, including Taylorville.

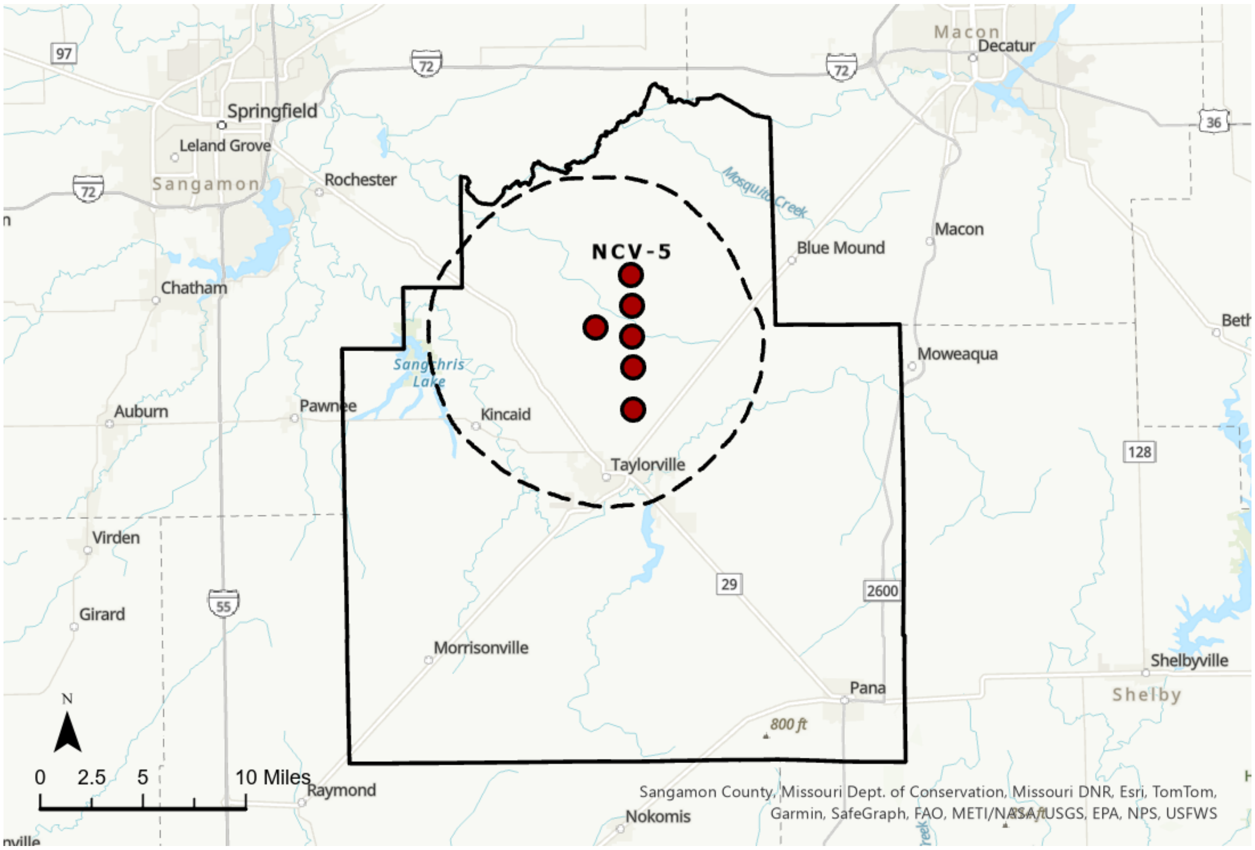

Figure 1-17. Topographic map showing proposed injection wells for the HGSS which is located northeast of Taylorville, Illinois. The solid black line represents the boundary of Christian County, and the dashed black line represents the AoR boundary.

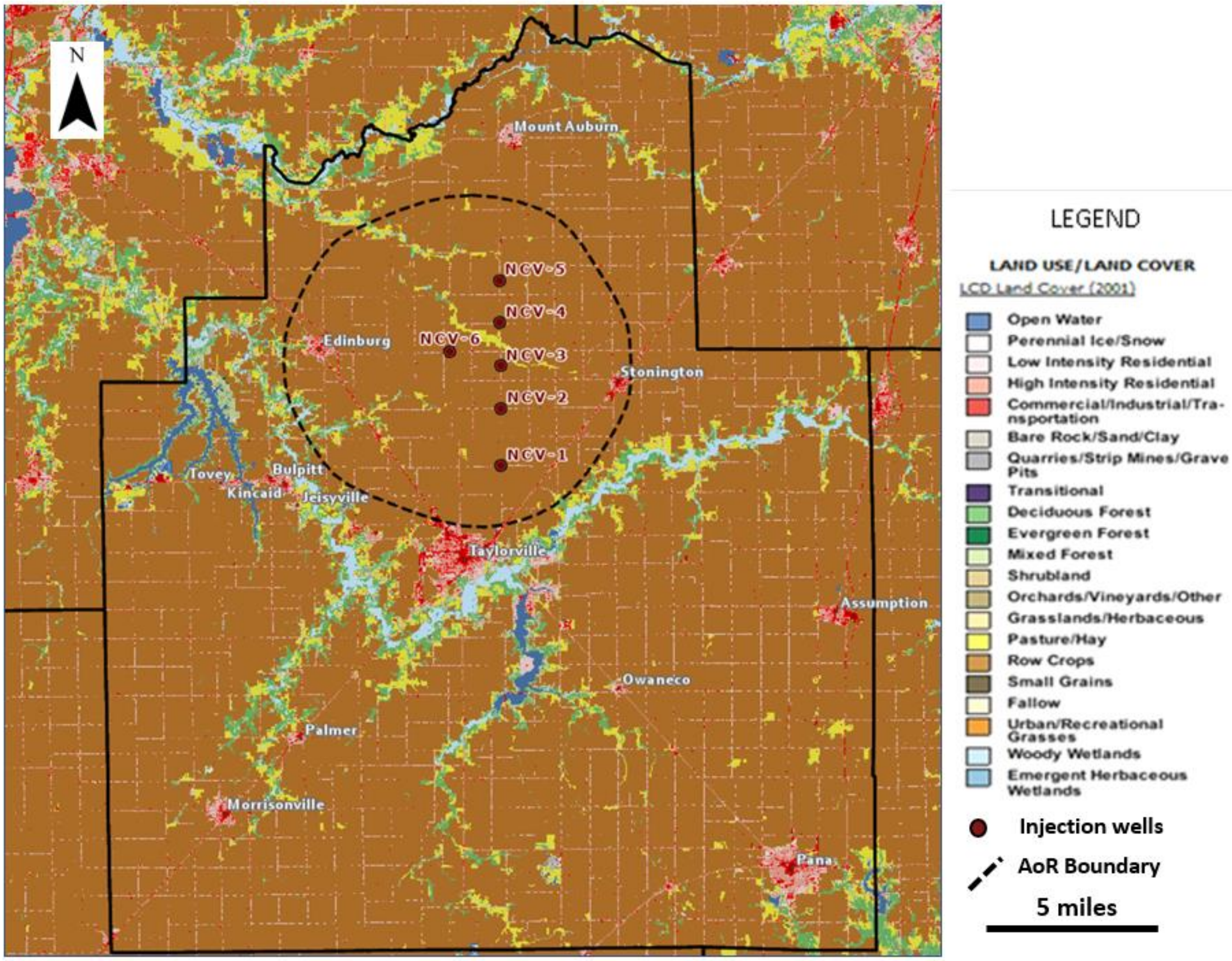

Figure 1-18. Land use in the vicinity of HGSS. Modified from USGS NLCD 2019.

The relevant near-surface and subsurface features in and around the proposed site include shallow aquifers, mineral resources, and mines. There are sand and gravel aquifers in the area (**Figure 1-19**) that act as a water source.[6] [7] Although most groundwater in the area is withdrawn from shallow unconsolidated formations, it is expected that the St. Peter Formation could be the deepest USDW; locally it is not tapped for human use. Further study would be required to determine how far down-dip the reservoir remains fresh.

Christian County's aquifers are comprised of Pleistocene surficial deposits. Of these, the Hagarstown aquifer is located approximately 3 miles to the SE of HGSS. Many of the Hagarstown aquifer deposits trend in a northeast-southwest direction (**Figure 1-19**). The Hagarstown deposit forms a nearly continuous ridge of sand and gravel with the characteristic northeast-southwest trend. Tested groundwaters in the region exhibit a little arsenic at less than 3

---

[6] Midwest Technology Assistance Center, 2009, "Groundwater Resource Assessment for Small Communities: Groundwater Availability at Morrisonville, Illinois (Christian County)

[7] Burris, C.B., Morse, W.J., and Naymik, T.G., 1981, Assessment of a Regional Aquifer in Central Illinois, ISGS Cooperative Ground water Report 6

micrograms per liter. Major aquifers and the location of local water wells are shown in **Figure 1-20**. The sand and gravel were deposited by a meltwater stream which was initially channeled upon or within the Vandalia ice sheet by a large linear ice crevasse. The stream cut a deep, narrow valley (**Figure 1-21**), reaching bedrock at some locations. The sand and gravel are probably in contact with the bedrock surface throughout most of the length of the deposit (**Figure 1-22**). A tabulation of readily available geochemical data for shallow groundwater aquifers near Taylorville is given in **Table 1-9**.

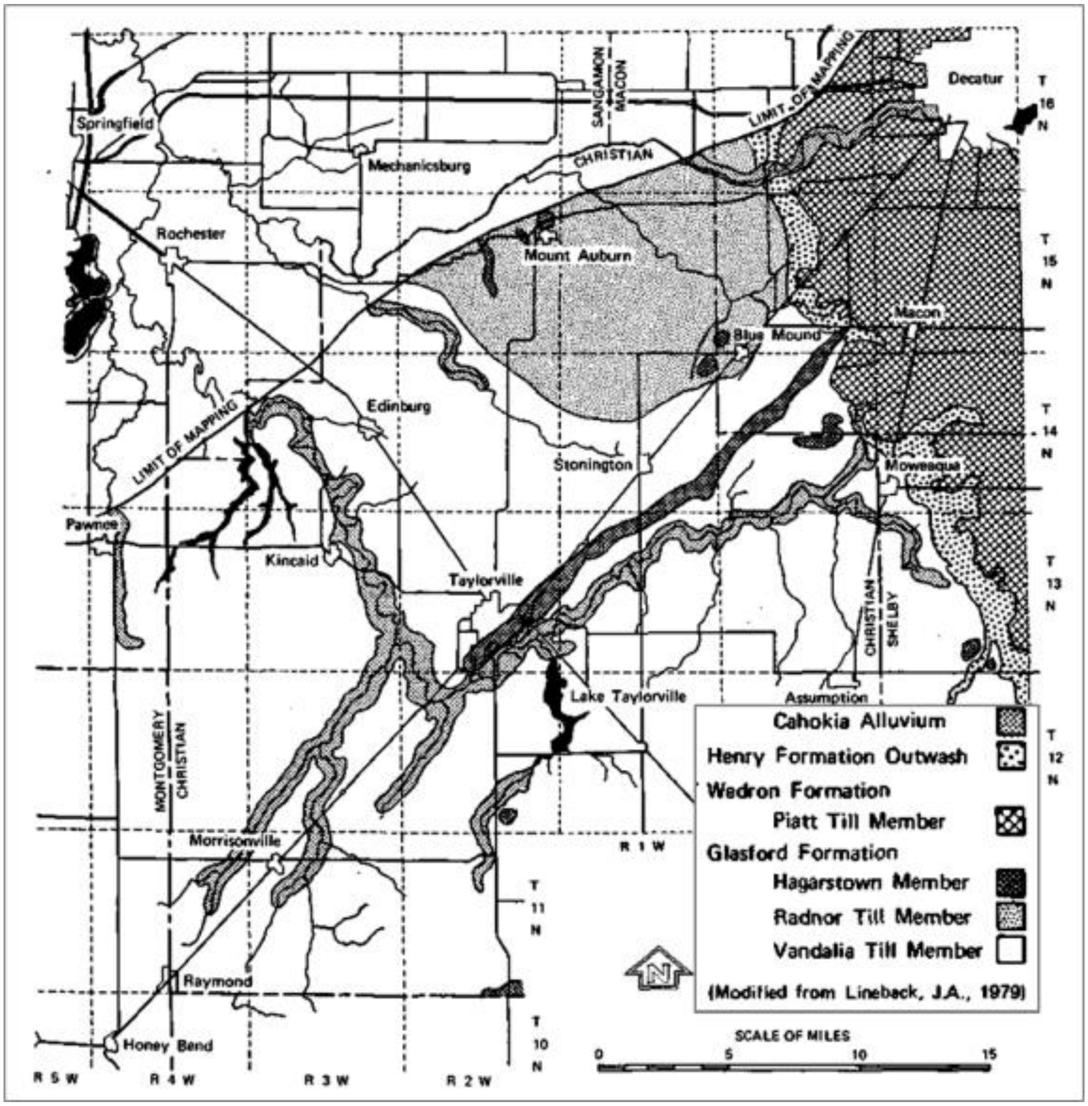

Figure 1-19. Map of local Pleistocene surficial deposits. From Burris et al., 1981, Assessment of a Regional Aquifer in Central Illinois.

Table 1-9. Chemical Analyses of Water from Selected Wells (milligrams per liter). From Burris et al., 1981, Assessment of a Regional Aquifer in Central Illinois.

Township	Well Number	Owner	Depth (ft)	Date Collected	Iron (Fe)	Manganese (Mn)	Ammonia (NH_4)	Sodium (Na)	Calcium (Ca)	Fluoride (F)	Boron (B)	Nitrate (NO_3)	Chloride (Cl)	Sulfate (SO_4)	Alkalinity	Hardness	Total Dissolved Minerals	Temperature (°F)
14N1W	25.5 c	Harold Garwood	70	3/9/79	2.3	0.02	0.2	-	-	-	-	0.5	2	-	202	200	221	-
	34.1 h1	Stonington (V)	124.5	2/26/69	1.3	0.09	-	-	-	-	-	1.7	11	-	262	324	389	52
	34.1 h2	Stonington (V)	104	1/24/74	0.2	0.11	-	-	-	-	-	0.4	5	-	220	226	250	54.1
13N1W	18.6 d	Taylorville (C)	96	6/14/74	0.2	0.01	0	10.7	63.2	22.5	0.1	18.9	9	54.5	196	250	337	-
	18.9 a	Taylorville (C)	88	2/19/51	0.1	0.1	Tr.	15.9	45.7	15.2	-	1.8	5	18.3	184	177	237	54.2
	18.8 c	Taylorville (C)	88	6/14/74	0.5	0.11	Tr.	14.2	91.2	30.8	0.1	12.2	7	99.6	270	354	463	-
13N2W	23.2 b	Taylorville Country Club	80	10/17/47	0.1	Tr.	-	-	-	-	-	-	4	71.0	184	243	285	55
	32.2 f3	Allied Mills	92	8/7/48	1.6	0.1	0.2	15.4	72.8	20.3	-	0.6	7	46.9	240	266	300	55.5
	24.2 g	Taylorville (C)	118	1/26/51	0.2	-/1	Tr.	12.7	55.5	18.1	-	10.4	9	34.6	184	214	270	54.5
	27.2 h5	Taylorville (C)	119	5/19/47	2.8	-	-	-	-	-	-	-	35	-	328	656	798	-
	27.3 f	Capitol Theatre	100±	10/17/47	0.3	0.4	-	-	-	-	-	-	47	336.1	348	678	858	55

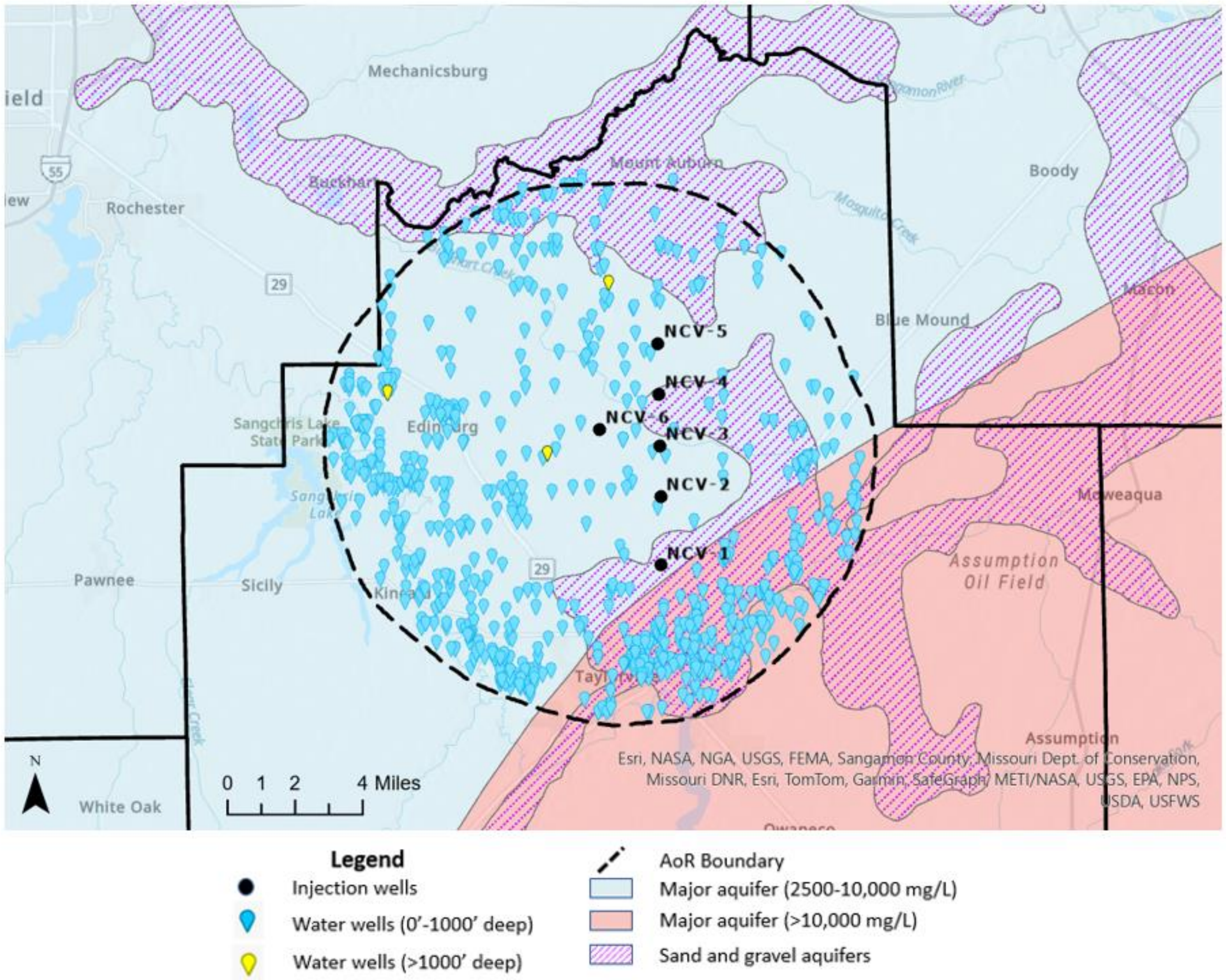

Figure 1-20. Hydrogeologic map of northern Christian County in the vicinity of the storage site.

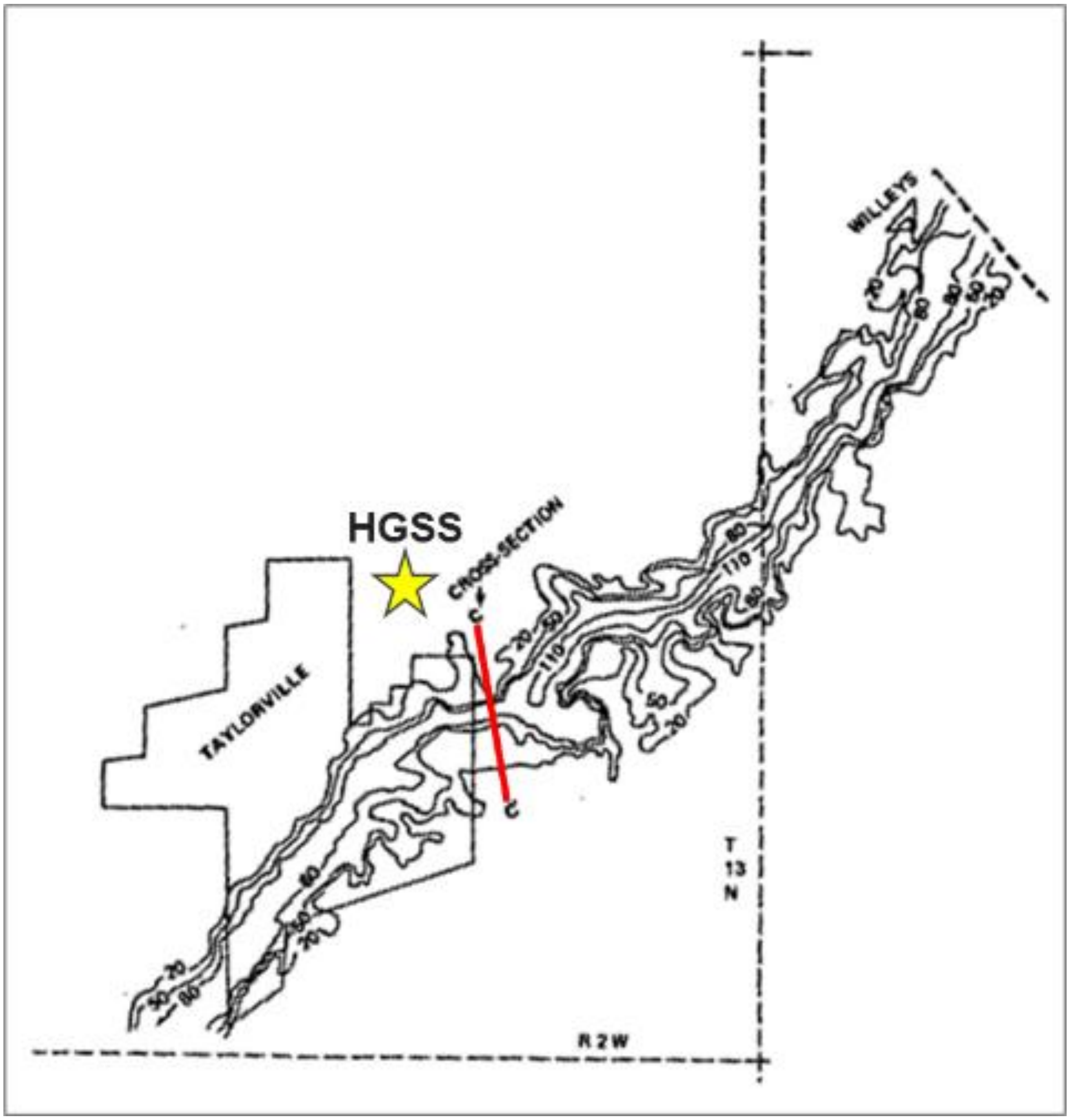

Figure 1-21. Base map of the Hagarstown aquifer. Cross-section C-C' in following figure. From Burris et al., 1981, Assessment of a Regional Aquifer in Central Illinois.

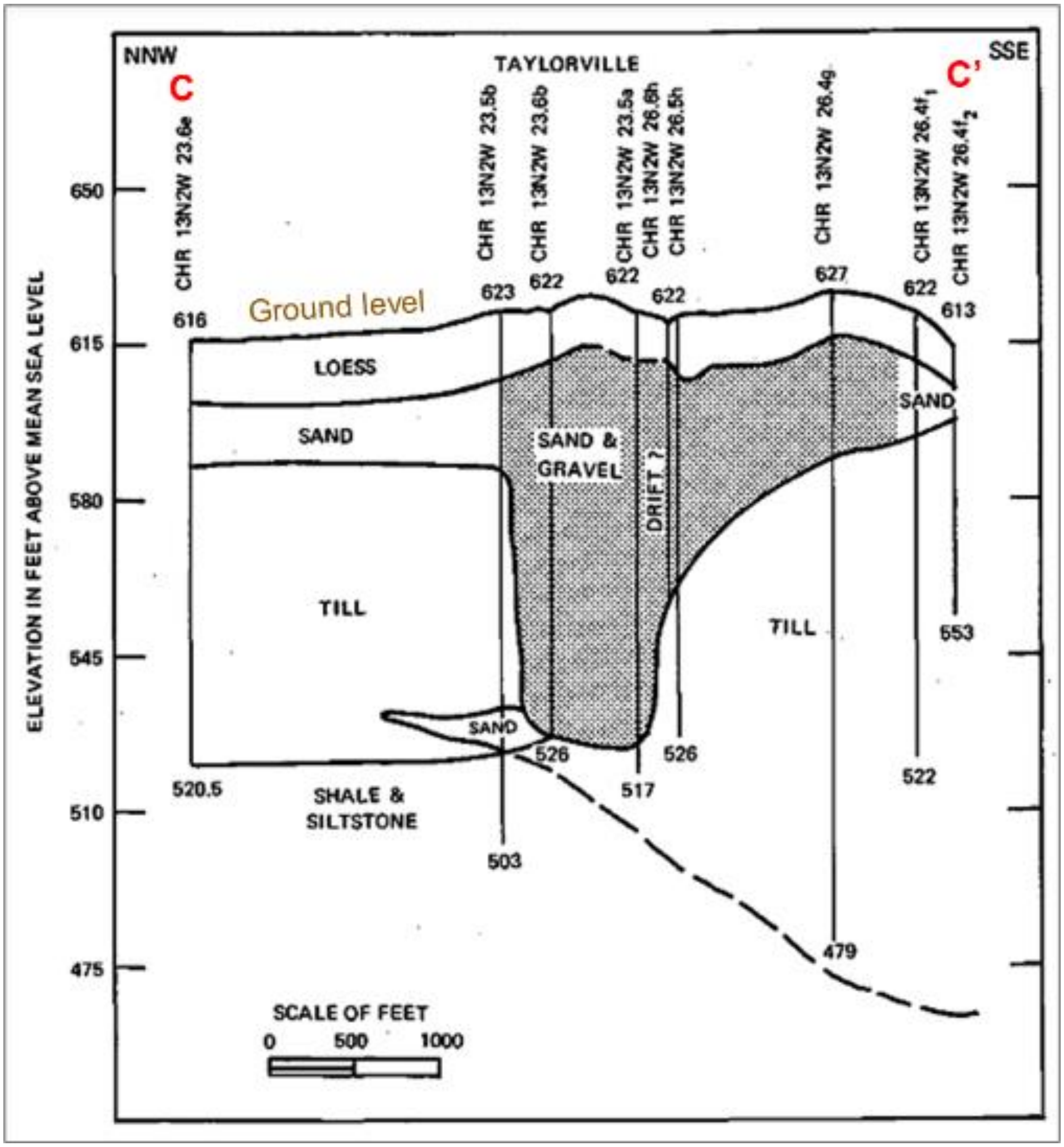

Figure 1-22. Hagarstown aquifer cross-section C-C' at Taylorville. From Burris et al., 1981, Assessment of a Regional Aquifer in Central Illinois.

The hydrographic features in the area consist of natural and man-made drainage and rivers, and there are also a few bodies of water. **Figure 1-23** shows drainage ditches, streams, rivers, and bodies of water in the area surrounding the HGSS.

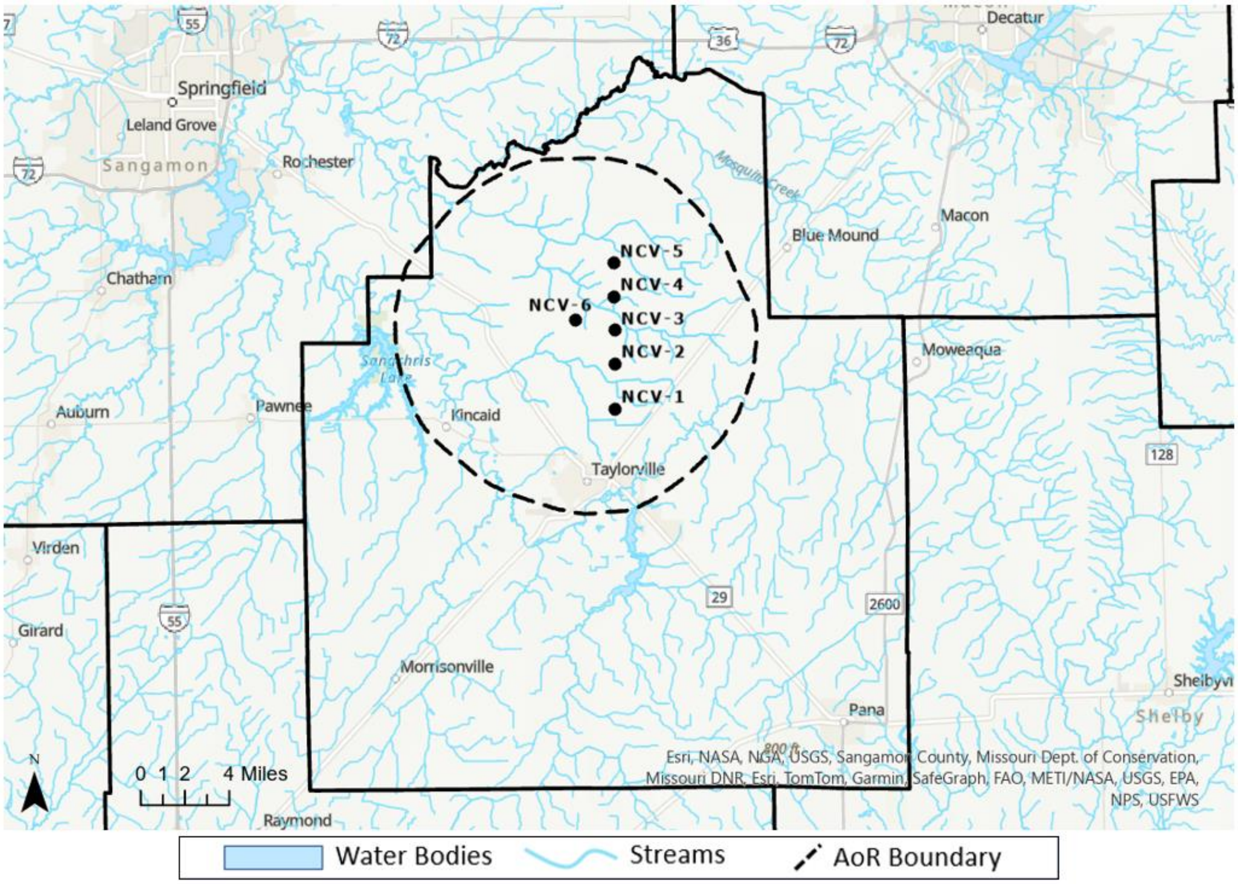

Figure 1-23. Rivers and water bodies in the vicinity of the proposed HGSS. Modified from the ISGS.

1.2.8. Geochemistry [40 CFR 146.82(a)(6)]

HGCS has evaluated the results from the literature available and has determined that there is no conclusive evidence that supports the inclusion of geochemical modeling for this application, specifically in the context of CO_2 injection into the Mt Simon sandstone. There is little evidence of major alterations that would risk the trapping mechanism to become ineffective. In the simulations conducted by Liu *et al.* (2011)[8] and Berger *et al.* (2019)[9], long-term modeling results (~ 10,000 years) indicated that potential geochemical alterations do not increase porosity and permeability enough to affect CO_2 migration within the reservoir or towards the confining zone.

[8] Liu, Faye, et al., 2011. Coupled Reactive Flow and Transport Modeling of CO_2 Sequestration in the Mt. Simon Sandstone Formation, Midwest U.S.A. *International Journal of Greenhouse Gas Control*, Vol. 5, No. 2, 2011, pp. 294–307, doi:10.1016/j.ijggc.2010.08.008.

[9] Berger, Peter M., et al. 2019. Carbon Sequestration at the Illinois Basin-Decatur Project: Experimental Results and Geochemical Simulations of Storage. *Environmental Earth Sciences*, Vol. 78, No. 22, 2019, doi:10.1007/s12665-019-8659-4.

These studies suggested there was almost complete feldspar dissolution and the precipitation of alunite and anhydrite, which triggered minor changes in porosity of the Mt. Simon sandstone. Variations in porosity and pore space geometry thus caused slight changes in permeability over the simulation. They also postulated that major CO_2 trapping mechanisms will remain structural, dissolution, and residual trapping to for 10,000 years of injection. The input parameters of these simulation studies mirror those expected of the Mt. Simon at the HGSS site as:

- A high quartz content of greater 63% as well as a feldspar content lower than 22% for the simulated sandstone formation; this is on par with what is inferred at the HGCS site based on data obtained from the TR McMillen 2 well.
- Average porosity of 15% and a permeability of 100 mD which compares with the porosity obtained from the TR McMillen 2 (averaging slightly greater than 15%) and permeability measuring greater than 100 mD but less than 1,500 mD.

Harbert et al. (2020)[10] suggest that some geochemical alterations are possible leading to potential migration through existing fractures that act as flow conduits.

While site-specific geochemical modeling is left out of this application, examination of literature sources simulating the potential for geochemical alterations that could affect CO2 migration within the reservoir or towards the confining zone was completed. In the simulation conducted by Liu et al. (2011) over a 10,000-year period, Liu et al. (2011) found though that the potential geochemical alterations do not increase porosity and permeability enough to affect CO2 migration within the reservoir or towards the confining zone. These results can be applied to the Mt. Simon sandstone at the HGSS site to learn of potential negative interactions and migrations of the CO2.

HGCS understands that these inferences are dependent on site-specific formation lithology and mineralogy. Therefore, HGCS plans to collect whole and rotary sidewall core samples at all injection wells in order to compare the mineralogy tested in literature to that at HGSS and determine the need for additional geochemical testing. As indicated in the *Pre-Operational Testing Program*, HGCS will also test the reservoir and confining layer rock samples for compatibility with CO_2 and brine through routine and specialized core analyses. These tests could include analyzing effluents from core flooding experiments as well as assessing relative changes in pore structure of reservoir and confining layer rocks after exposure to CO_2 and brine during specialized core analyses. Brine samples will reflect fluid chemistry of samples collected from the injection zone during wireline and well testing activities.

HGCS also plans to monitor CO_2 plume movement, leaks and groundwater quality as indicated in the *Testing and Monitoring Plan*. If plume monitoring results indicate there is a disagreement with forecasted plume movement or if there is a leak within the storage system, HGCS will promptly implement a geochemical compatibility study to assess the interaction between reservoir and caprock samples and CO_2 in presence of brine. Any alterations in porosity,

---

[10] Harbert, William, et al., 2020. CO_2 Induced Changes in Mount Simon Sandstone: Understanding Links to Post CO_2 Injection Monitoring, Seismicity, and Reservoir Integrity. *International Journal of Greenhouse Gas Control*, Vol. 100 (2020) pp. 103109., doi:10.1016/j.ijggc.2020.103109.

permeability or brittleness of the samples will be factored into subsequent iterations of the HGSS model and AoR will be re-evaluated.

1.2.9. Other Information (Including Surface Air and/or Soil Gas Data, if Applicable)

There is no soil gas or surface air data currently available at HGSS. However, HGCS will collect surface air measurements throughout the project area at all injection well locations in order to obtain a baseline of surface air CO_2 concentrations prior to injection.

1.3. Site Suitability [40 CFR 146.83]

The subsurface distribution of Mt. Simon Sandstone lithological facies is comprised of braided, eolian, and playa deposits of the Cambrian age. Although this potentially represents a significant amount of heterogeneity, lower Mt. Simon sandstones in this area are found to have very favorable porosity and permeability in zones A and B. The potential for interconnected migration pathways among these facies should enable the CO_2 plume to develop near the injection zone in a circular region. In terms of upward CO_2 migration, the overlying low permeability Mt. Simon C is expected to provide significant permeability contrast with the underlying Mt. Simon B injection zone. The implication for upward carbon dioxide migration is that the CO_2 may never make it to the Eau Claire Shale. Furthermore, potential leakage pathways such as faulting should be absent at the site as there are no known structural features. Currently, artificial penetrations (wells) into the caprock at the HGSS are also absent. The Eau Claire formation represents the primary caprock at the site and is approximately 538 feet thick, with much of this unit comprised of shale, which is considered very tight based on core tests and logs from the FutureGen 2 site, the CarbonSAFE T.R. McMillen 2 well, and the wells that were drilled in support of the IBDP.

As discussed in earlier sections, adverse reactions between the carbon dioxide stream and the target reservoir, the Mt. Simon Sandstone, are not known to exist. The injection zone's mineralogy is anticipated to be similar to that encountered at the IBDP site, where over 2.5 million tonnes of CO_2 has been sequestered with no known compatibility issues. Additionally, HGCS will select corrosion resistance alloys (CRAs) for select well tubulars in order to mitigate corrosive effects of the CO_2 stream and formation fluids. All well materials such as pipe and cement will be chosen to be compatible with CO_2 in compliance with API 6A standard.

Within the Illinois Basin, the Mt. Simon has a CO_2 storage capacity estimated at 10's to 100's of Gigatonnes.[11] This capacity is more than adequate for the target injection objectives of the HGSC, which is likely to be near 5 Megatonnes/year. While the Eau Claire Shale has been identified as the primary confining zone, it is likely that CO_2 will be confined deeper down by the tighter portions of the Mt. Simon C and D zones. It is doubtful that further confining zones above the Eau Claire would be necessary to ensure the protection of the shallower USDW.

[11] Ellett K., Zhang G., Medina C., Rupp J., Wang G., Carr T., 2013, Uncertainty in Regional-scale Evaluation of CO2 Geologic Storage Resources—comparison of the Illinois Basin (USA) and the Ordos Basin (China), Energy Procedia, Vol37, Pp 5151-5159

1.4. AoR and Corrective Action

The information and files submitted in the *AoR and Corrective Action Plan* satisfy the requirements of 40 CFR 146.84(b). This plan addresses the details of computational modeling to delineate Area of Review (AoR), corrective action in the AoR, and triggers for AoR re-evaluation. The AoR is created to encompass the entire region surrounding HGSS where USDWs may be endangered by injection activity. The AoR is delineated by the lateral and vertical migration extent of the CO_2 plume, formation fluids, and pressure front in the subsurface. A computational model was built to model the subsurface injection of CO_2 into the Mt Simon sandstone at HGSS. Computer Modeling Group's General Equation of State Model, widely known as GEM, was used as the simulator. A multi-component and multi-phase fluid flow process was employed to assess the development of the CO_2 plume, the pressure front, and the long-term fate of the injection. The AoR is delineated by the full lateral and vertical extent of the CO2 plume in the subsurface and used to monitor where USDWs may be compromised by injection activity. Details of the computational modeling, assumptions that are made, and the site characterization data that the model is based on satisfy the requirements of 40 CFR 146.84(c). HGCS also notes that there are currently no wells penetrating the storage system. HGCS will periodically monitor the AoR for wellbores that could interfere with the storage project and develop corrective actions, as necessary. All the relevant surface and subsurface features within the AoR are shown in **Figure 1-24**.

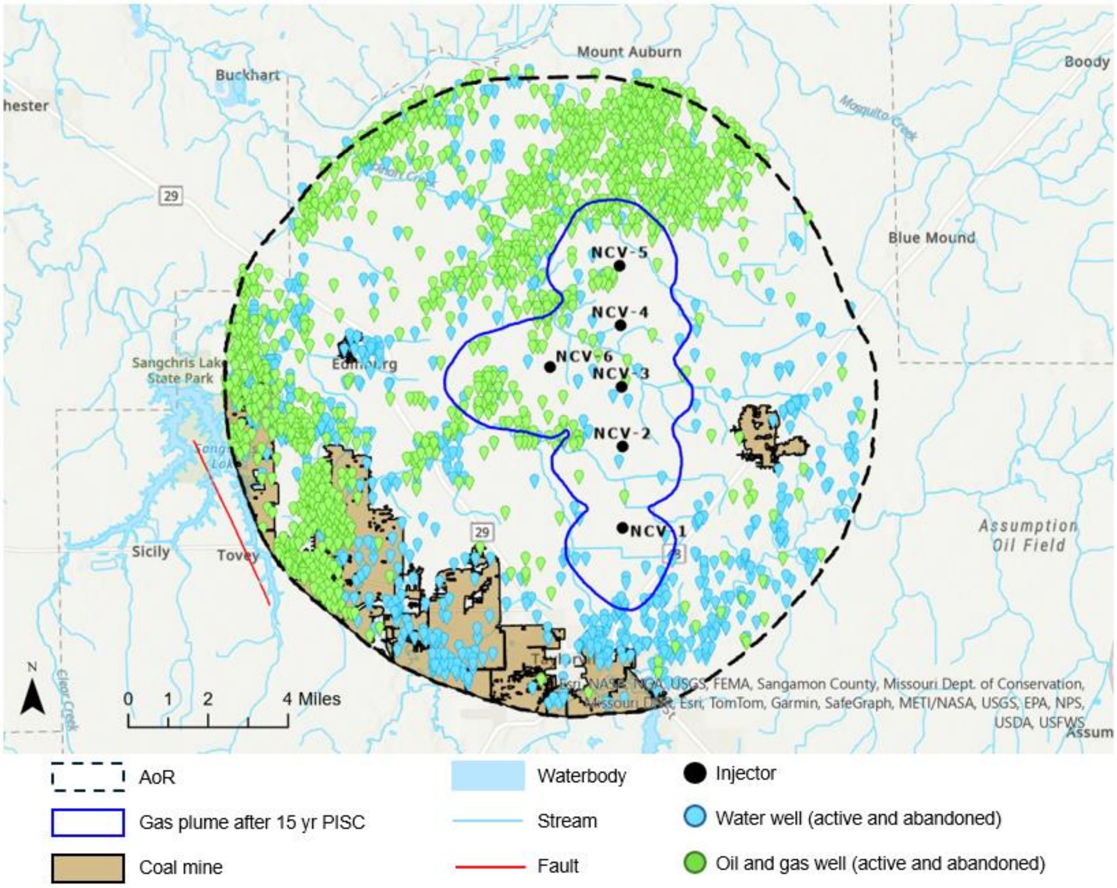

Figure 1-24. Map showing injection wells, project AoR, and relevant surface and subsurface features as required by 40 CFR 146.82(a)(2).

1.5. Financial Responsibility

The *Financial Responsibility* document demonstrates the financial responsibility for injection well plugging/conversion, Post-Injection Site Care (PISC) and site closure, and emergency and remedial response according to 40 CFR 146.85. As mentioned earlier, no corrective action is anticipated at HGSS as there are no penetrations into the confinement interval currently. Injection well plugging costs are estimated according to the Injection Well Plugging Plan, and PISC and site closure costs are presented to reflect a 50-year PISC period. The Emergency and Remedial Response costs cover one (1) unmitigated leakage event throughout the project life. For more details, refer directly to the *Financial Responsibility* document where the financial instrument(s) are outlined, and costs are presented in more detail.

1.6. Injection Well Construction

Heartland Greenway Carbon Storage LLC. (HGCS) seeks to drill and construct six new Class VI CO_2 injection wells within the Heartland Greenway Storage Site (HGSS) to support CO_2 storage operations and has designed this well construction plan in accordance with 40 CFR §146.86, pursuant to 40 CFR §146.82. HGCS has implemented well design strategies and materials focused on (1) preventing movement of fluids into or between USDWs or into any authorized zones; (2) permitting the use of appropriate testing devices and workover tools; and (3) permit continuous monitoring of the annulus space between the tubing and long string casing. Any necessary changes to this well plan due to logistical or geological conditions encountered within the field will be communicated to the Director prior to well construction.

1.6.1. Proposed Stimulation Program [40 CFR 146.82(a)(9)]

While not anticipated based on existing interpolations of reservoir quality, a well stimulation program (such as an acid wash) may be proposed by HGCS based on geologic conditions and data identified during drilling and well testing/logging operations. If well stimulation is determined to be required to meet injection goals, HGCS will complete the required stimulation plan [attached to this permit] and communicate the details of the well stimulation program to the Director. HGCS will not proceed with well stimulation operations until approval is received.

1.6.2. Construction Procedures [40 CFR 146.82(a)(12)]

The HGSS injection wells have been designed to accommodate the mass of CO_2 that will be delivered to them, while considering critical characteristics of the CO_2 storage reservoir which affect the well design. Well design principles and materials detailed in subsequent sections were selected and vetted to ensure construction materials have sufficient structural strength to provide sustained mechanical integrity throughout the life of the CCS project. The injection wells will permit the use of appropriate testing devices, workover tools and continuous monitoring of the annulus space between the injection tubing and long string casing. All well construction materials were selected to be compatible with fluids of which they may be expected to come into contact (e.g., corrosion-resistant cement) and meet or exceed API and ASTM International standards.
This plan illustrates the comprehensive analysis performed to comply with and exceed the standards detailed in 40 CFR §146.86 and other related sections (§146.87, 146.88, 146.89, 146.90, 146.94 (a), 146.91), in pursuant to 40 CFR § 146.82 regarding the design of the injection well casing, cement, and wellhead and their relation to subsequent testing, monitoring, and reporting activities.

The construction of injection wells at HGSS will be performed using best practices and will conform to all requirements of Class VI Rule VI at 40 CFR 146.86(b). The drilling of the injection wells in this part of the Illinois Basin is straightforward with very few known drilling hazards apart from a possible lost circulation zone in the Potosi formation within the intermediate section of the wells. The surface casing will be set to +/-500 ft below ground surface and will be cemented to surface so that any shallow USDW aquifers will be protected. A normal 8.5 ppg-9.0 ppg mud weight will prevent any movement of fluids from one aquifer to another. An intermediate section is planned from the base of the surface casing to the top of the Eau Claire formation which will also cover the St. Peter formation. This section will pass through the Potosi formation, previously recognized as a potential lost circulation zone. If a loss of circulation is encountered, lost circulation materials will be used to regain circulation. If lost circulation materials are not successful, cement plugs will be placed across the zone to enable the well to be drilled to casing point. The intermediate casing will be cemented in two stages with the first stage covering from T.D. at the top of the Eau Claire formation to just above the Potosi formation. The wells will be circulated until the first stage cement is set through a stage collar and then the second stage will place cement from the stage collar to surface. The T.D. section will then be drilled through the Eau Claire formation, through the Mt. Simon formation and reaching total depth in basement rocks. The long string casing will then be cemented from T.D. back to surface. While drilling each section of the wells, the deviation will be checked to ensure that the wells stay as close to vertical as possible with the deviation staying below five degrees and no section of each well will have a dog-leg severity greater than 1.9 degrees/100 ft. Should a deviation correction be required directional drilling tools will be employed. There are no known abnormal pressure formation in this area so mud weights of +/- 9,0 ppg will provide well control. The casing and cement fluids to be used in construction of the injection wells will be compatible with the injected CO_2. A minimum of CR-13 casing will be used across the injection zone and caprock and on the lower section of the intermediate casing. This design has been confirmed with manufacturer testing performed to ASTM and Corrosion Standards. Cement across these sections will be CO_2 resistant.

The targeted injection formation will be tested prior to final completion by step-rate and pressure fall-off testing. These tests will confirm that the proposed injection zone will be able to receive the required volume of CO_2 while injection pressures will stay below fracturing pressure. The injection tubing will be a minimum of CR-13 and will be sized to accommodate the expected injection rate. The size of the wellbore will allow monitoring equipment to be placed in the wellbore so that injection and annular pressure can be monitored. The tubing will also be sized such that surveillance logging can be accommodated. More detail on the well construction methods and materials will be found in the following sections.

Casing and Cementing

The HGSS injection well design has been developed to accommodate a 5 1/2-inch outer diameter (OD) tubing string, based on the nodal analysis results (presented in the well construction section), and was designed to accommodate the concentric casing sizes required to isolate the injection reservoir from USDWs and prevent fluid flow into any unauthorized zones. In accordance with 40 CFR §146.87, prior to running each casing string, all open-hole logging and testing operations (deviation surveys, open hole logging, formation testing) will be completed.

Please see the *Pre-operations Formation Testing section* of this permit for a detailed breakdown of which specific methods and tools will be utilized for each injection well.

The casing specifications for the injections well are detailed below in **Table 1-10**. To prevent unintended fluid migration and protect USDW integrity, the surface casing string will extend through shallow USDWs, the intermediate casing string will extend through the deepest USDW (St. Peter Sandstone), and the long string casing will extend from the surface through the injection interval with casing centralizers. The metallurgy for each casing string was selected to be compatible with the fluids and stresses encountered within the well and meet or exceed API and ASTM standards. The tubing will be 25CrL80 steel which is 25% chrome and will be corrosion resistant. The 9 5/8-inch-long string casing will be constructed of 25CrL80 steel from the injection zone to 500 feet above the confining zone (top of Eau Claire) where the casing grade will change to L80 (mild steel). Casing loadings were modelled using Schlumberger's Tubing Design and Analysis (TDAS) software to ensure sufficient structural strength and mechanical integrity throughout the life of the HGSS project, where stresses were analyzed and calculated according to worst-case scenarios and tubular specifications were selected accordingly.

In accordance with 40 CFR §146.86, the cement and cement additives were designed to have sufficient quality and quantity to maintain seal integrity throughout the life of the HGSS project and are compatible with the fluids (CO_2 stream and formation fluids) with which the materials may be expected to come into contact. The cementing program has been designed to prevent the movement of fluids out of the sequestration zone into overlying USDWs. After cementing each casing string to the surface, the integrity and location of cement will be verified using a cement-bond log capable of evaluating the cemental quality radially and identifying the presence/location of channels to ensure against the likelihood of unintended release of CO_2 from the sequestration zone. Any changes to the cement program will be communicated to the Director prior to well construction operations. Each casing string will be cemented to the surface in one or more stages. Casing centralizers will be used on all casing strings to centralize the casing in the hole and help ensure that cement completely surrounds the casing along the entire length of pipe. Except for the conductor casing, a guide shoe or float shoe will be run on the bottom of the bottom joint of casing and a float collar will be run on the top of the bottom joint of casing.

Due to the technical challenges involving cementing within geologic formations such as the Potosi Dolomite, the intermediate casing string of each HGSS injection well will be cemented in two stages. To facilitate a two-stage cement job, a multiple-stage cementing tool will be installed approximately 200 ft above the top of the Potosi Formation. After the completion of the first-stage cement job for the intermediate casing string, the multiple-stage cementing tool will be opened and fluid will be circulated down the casing and up the annulus above the cementing tool for a minimum of 8 hours to allow the first-stage cement job to acquire sufficient gel strength.

Due to its presence within the storage complex, the lower 2153 ft (approximately 4447 to 6600-ft from terminal depth to 500 ft above the confining layer) of the 9 5/8–inch long string casing will be cemented with "EverCRETE" (or a similar product) CO_2 corrosion-resistant cement. Additionally, the excess space ("rathole") from the top of the Argenta to the well's terminal depth will be plugged back with EverCRETE to avoid unintended pressure transmission from the injection zone into the basement or near-basement zones. This will likely be accomplished by setting the float shoe just above the top of the Argenta during long string cementing operations, however other methods may be considered. After an appropriate amount of setting time, cement-bond logs will be run and analyzed for each casing string as detailed in *Pre-operations Formation Testing Plan.*

Table 1-10. Casing details.

Casing String	Casing Depth (ft. MD)	Borehole Diameter (in.)	Wall Thickness	External Diameter (in.)	Casing Material	String Weight (lb/ft)
Conductor	0-40	34	0.5	30	B-grade/welded	157
Surface	0-500	24	0.438	20	J-55/BTC	94
Intermediate	0-4948	17.5	0.430	13.375	J-55	61
Long-String	0-4448	12.25	0.472	9.625	L80 or N80/LTC	47
Long-String	4448-6090	12.25	0.472	9.625	25CrL80 or 25CrN80/*JFE BEAR	47

** JFEBEAR™ or similar premium connection*

Tubing and Packer

The tubing connects the injection zone to the wellhead, providing a pathway for safely injecting and storing CO_2. In accordance with 40 CFR § 146.86 (c), the tubing and packer material used for construction of the injection wells will be compatible with fluids with which the material may be expected to come into contact with and will meet or exceed API and ASTM international standards. HGCS will inject CO_2 through corrosion-resistant tubing with a packer set at a depth opposite a cemented interval, a location approved by the Director. Any change to the tubing and packer specifics detailed in the below will be communicated to the Director.

The HGSS injection wells will utilize 5 ½-inch 17 lb/ft, 25CrL80 or 25CrN80 tubing, which will resist corrosion from the injectate. Specifications of tubing and packer are detailed in **Table 1-11** below. The packer for injection wells will consist of a Baker Hughes 3-foot long, 8.218" OD, 6.0" ID, Model F Permanent Packer with a BMS-S210 25Cr80 Mandrel and 70hd Nitrile Element System rated for pressures up to 5000 psi. The packer will be connected to a 10 foot-long, 6.250" OD, 4.875" ID model G-22 locator type seal assembly for easy workover operations. Both the packer and locator seal assembly with feature VAM couplings and will be comprised of 25CR80 alloy. The annulus between the tubing and long-string casing will be filled with noncorrosive fluid described in further detail within the well construction section of this permit.

Table 1-11. Tubing and packer details.

Material	Setting Depth	Tensile Strength	Burst Strength	Collapse Strength	Material
Tubing	0-6090	95,000	7,740	6,290	17 lb ft^{-1}/25Cr80 or N80 / **JFEBEAR™
Packer (Baker Hughes Model F Permanent Packer or similar)	6060	-	7,000	5,000	25Cr80/ VAM Coupling

1.7. Pre-Operational Logging and Testing

The pre-operational testing and logging plan is designed to gather confining layer and reservoir data as well as baseline monitoring confirm HGCS' understanding of subsurface conditions and establish an accurate baseline dataset of pre-injection site conditions. All subsurface models will be kept up to date with the latest data as they are gathered.

HGCS will also utilize the *Pre-Operational Logging and Testing Program* to verify depths and physical characteristics of geologic formations germane to the injection and confining zones and ensure that injection well construction satisfies requirements outlined in section 40 CFR 146.86.

During the drilling and construction phase of the project, appropriate log suites, surveys, and tests will be deployed to verify the depth, thickness, porosity, permeability, and lithology of pertinent geologic formations, as well as the salinity of formation fluids within them. Deviation checks will be performed during drilling at frequent intervals to keep track of the borehole location in the subsurface and serve as a reference for steering purposes in order to achieve as near to vertical wellbore as possible. These checks will also assist in assuring that avenues for vertical fluid movement are not created in the form of diverging holes while drilling. Resistivity, spontaneous potential, and caliper logs will be run before casing is run. A cement bond log along with variable density and temperature logs will be run to evaluate radial cement quality once the casing is cemented in place. At a minimum, resistivity, and spontaneous potential logs, along with porosity, caliper, gamma ray, and fracture finder logs will be run prior to the installation of the long string casing. Cement bond, variable density, ultrasonic image, and temperature logs will also be run after long string casing is cemented in place to verify the quality of the cement job.

Internal and external mechanical integrity of the injection wells will be tested to demonstrate the absence of leaks in the wellbore that could result in migration of CO_2 out of the injection zone. An annular pressure test will be performed within 24 hours of cementing casing. Core samples will be taken from the confining and injection zones while drilling the characterization and monitoring wells. Analysis of these cores will be coupled with analysis of well logs to demonstrate consistency in subsurface geology, including presence, thickness, porosity, and permeability of the reservoir across the AoR. Fluid samples will be collected from the injection zone and analyzed to establish baseline measurements for fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone.

Upon completion and before operation, hydrogeologic characteristics of the injection zone will be determined by performing a composite injectivity evaluation test in the injection interval to determine the large-scale transmissivity through the reservoir.

1.8. Well Operation

Pursuant to the Class VI 40 CFR §146.82, HGCS prepared *Injection Well Operations Plan* to describe the planned operation of CO_2 injection wells for the HGSS. The HGSS injection wells will be constructed as indicated in the *Injection Well Construction Plan*.

1.8.1. Operational Procedures [40 CFR 146.82(a)(10)]

The CO_2 will come into the site meeting the specifications presented in the Testing and Monitoring Plan. The CO_2 will enter a header and be piped to each injection well. Each well will inject continuously throughout the injection period. The CO_2 will be in the liquid phase as it enters the wellhead and will transition to a supercritical phase in the wellbore. The wells will not be fitted with pumps. Injection will be facilitated through tubing set in the long-string casing in a packer above the perforations in the Mt. Simon A and B zones.

The injection wells will be monitored to ensure safe operations. Safety monitoring includes monitoring the injection pressure at the wellhead and bottomhole, monitoring the pressurized annulus, continuous fiberoptic temperature monitoring along the well, and corrosion coupon monitoring to identify corrosion. Each system is fully described in the *Testing and Monitoring Plan.* HGSS injection wells will have a wellhead pressure gauge and data logger, both tied into the injection control system and set to trigger an alarm at the project control room and shut down injection in the wells if the MASP is reached. Injection parameters including pressure, rate, volume and/or mass, and temperature of the CO_2 stream will be continuously measured and recorded. The pressure and fluid volume of the annulus between the tubing and long-string casing will also be continuously measured. All automatic shutdowns will be investigated prior to bringing injection back online in the wells to ensure that that no integrity issues were the cause of the shutdown. If an un-remedied shutdown is triggered or a loss of mechanical integrity is discovered, the HGCS will immediately investigate and identify as expeditiously as possible the cause of the shutdown. If, upon such investigation, the injection wells appear to be lacking mechanical integrity, or if monitoring indicates that the injection wells may be lacking mechanical integrity, HGCS will:

> (1) Immediately cease injection in the affected well(s) and in any other wells that may exacerbate the leakage risk of the affected well;
>
> (2) Take all steps reasonably necessary to determine whether there may have been a release of the injected CO_2 stream or formation fluids into any unauthorized zone;
>
> (3) Notify the Director in writing within 24 hours;

(4) Restore and demonstrate mechanical integrity prior to resuming injection; and

(5) Notify the Director when injection can be expected to resume.

The annular space between the tubing and the long string casing of the injection wells will be pressurized with a non-corrosive fluid. The annulus of each injection well will be monitored continuously to ensure the integrity of the wells. The annuli will be filled with a 11.65 pounds per gallon (ppg) sodium chloride brine with a corrosion inhibitor and oxygen scavenger additives. The minimum pressure held on each injection well annulus at the wellhead will be 100 psi, including times of shut-in. Additional pressure may be required on the annuli; if this is the case, the value will be set in conjunction with US EPA Region V.

The fiber optic line cemented into the annulus on the outside of the long-string casing will be used to continuously monitor the temperature along the length of the casing. Rapid temperature changes or other excursions from a normal operating temperature profile will be investigated to ensure that there has been no breach of wellbore integrity.

HGCS will monitor and maintain the mechanical integrity of the HGSS injection well at all times. Well maintenance and workovers will be treated as normal operations to keep the injection wells in a safe operating condition. Procedures for well maintenance will vary depending on the nature of the procedure. All maintenance and workover operations will be monitored to ensure there is no loss of mechanical integrity. Barriers will be kept in place to ensure leakage risk is minimized. The injection wells are designed to allow the installation of a temporary plug below the tubing to allow the tubing to be removed and replaced as needed while keeping a barrier in place. The bottomhole temperature and pressure gauge are set above the packer to allow for replacement, if needed, without removing the packer from the wells.

The operational values detailed in **Table 1-12** were obtained by constructing a PIPESIM model, built to conduct a nodal analysis presented in the *Injection Well Construction Plan* was used to determine the range of possible injection rates. Using the analysis, an average injection rate of one million metric tons per year (2,740 metric tons per day) of CO_2 per well on average and a maximum rate of 1.34 million metric tons per year (3,671 metric tons per day) of CO_2 per well was selected to meet project requirements. The total annual injection rate for the project will be 6 million metric tons per year (the sum of all six injection wells) of CO_2. The expected wellhead pressure during injection operations will likely be between 1,200 psi and 1,400 psi. At a wellhead pressure of 1,200 psi, these rates have bottomhole pressures of 3,111 psi and 3,369 psi, respectively.

The maximum allowable surface pressure (MASP) was estimated by using the same PIPESIM injection model to calculate the wellhead pressure, assuming the maximum allowed bottomhole pressure was reached as the CO_2 entered the formation through the perforations at the maximum injection rate (3,671 metric tons per day) of CO_2. The bottomhole pressure was set to 80% of the estimated hydraulic fracture pressure, 3,395 psi. The estimated hydraulic fracture gradient and the hydraulic fracture pressure at the mid-perforation depth in the model was 4,244 psi (0.7 psi/ft * 6063 ft), and 90% of the fracture pressure is 3,819 psi. The results estimate the MASP at 1,857. Except during Director-approved well-stimulation events (if required), HGCS will ensure that the downhole pressures will not exceed 90% of the fracture pressure in order to maintain the integrity of the HGSS storage complex. Operational parameters are expected to remain constant throughout the duration of the injection period. The only possible changes to operational parameters may stem from variations in the volume of the CO_2 source, which may lead to lower injection volumes during limited periods of time.

1.8.2. Proposed Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

The CO_2 will be sourced from several biofuel and fertilizer plants located in South Dakota, Minnesota, Iowa, Nebraska, and Illinois, which feed into the primary pipeline transporting CO2 to the HGSS storage sites. **Table 1-13** below displays the chemical composition of the anticipated CO_2 stream. The CO_2 stream will contain less than 50 ppm of water and is likely not to cause any corrosion. The CO_2 will be in the liquid phase as it enters the wellhead and will transition to a supercritical phase in the wellbore. On Average, the CO_2 stream will be at 50 ºF and under 1400 psi, with an estimated density of 57.26 lb/ft^3 at the wellhead. After injection downhole into the reservoir zone, the CO_2 stream is anticipated to heat to near formation temperature of 131ºF under 3,395 psi, with an estimated density of 49.65 lb/ft^3. Upon injection into the reservoir formation, the CO_2 will remain in the supercritical phase, which will allow for minimal interaction with the formation.

Table 1-12. Proposed Operational Parameters.

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure		
Surface	1,857	psi
Downhole	3,819	psi
Average Injection Pressure		
Surface	1,200-1,400	psi
Downhole	3,111-3,369	psi
Maximum Injection Rate	3,671	Metric tons/day
Average Injection Rate	2,740	Metric tons/day
Maximum Injection Volume and/or Mass (30-year period)	40,197,450	Metric tons
Average Injection Volume and/or Mass (30-year period)	30,003,000	Metric tons
Maximum Annular Pressure	4,069	psi
Annulus Pressure/Tubing Differential	250	psi

Table 1-13. Specifications of the Anticipated CO_2 Stream Composition

Component	Specification	Unit
Minimum CO_2	98	mole%, dry basis
Water content	</= 20	lb/MMscf
Impurities (dry basis):		
Total Hydrocarbons	</= 2	mol%
Inert Gases (N_2, Ar, O_2)	</= 2	mol%
SOx	</= 100	ppmv
NOx	</= 100	ppmv
Hydrogen	</= 1	mol%
Alcohols, aldehydes, esters	</= 500	ppmv
Hydrogen Sulfide	</= 100	ppmv
Total Sulfur	</= 100	ppmv
Oxygen	</= 100	ppmv
Carbon monoxide	</= 100	ppmv
Glycol	</= 1	ppmv

1.9. Testing and Monitoring

The Testing and Monitoring Plan describes how HGCS will monitor injection operations at HGSS, pursuant to 40 CFR 146.90, for the duration of the injection phase of this project. This plan will serve to demonstrate that the well is operating as planned, that the sequestered Carbon Dioxide (CO_2) plume and pressure front are moving as predicted and ensure that the CO_2 plume does not become a contamination risk to underground sources of drinking water (USDWs). Monitoring data collected will also be used to validate and adjust geological models used to predict the movement of CO_2 within the storage zone to support AoR re-evaluations. The injection phase monitoring will include monitoring for CO_2 stream quality, gas leaks in the wellheads and valves, external mechanical integrity testing, groundwater sampling, direct pressure, and temperature measurements, indirect and direct plume tracking, surface and near-surface CO_2 leak monitoring, and seismicity monitoring for induced and natural seismic events.

The CO2 stream will be analyzed at a frequency sufficient to generate data representative of its physical and chemical characteristics.

Continuous recording devices will be installed and used to monitor injection parameters, including pressure, rate, and volume. Annular pressure between tubing and long string casing, as well as the annulus fluid volume added will also be monitored.

Well materials will be monitored and assessed on a quarterly basis for loss of mass, thickness, cracking, pitting, or other signs of corrosion. Sample material coupons will be placed in contact with the CO_2 stream. Materials analysis will be compared with standards outlined in section 40 CFR 146.86(b) to ensure that all physical parameters continually meet or exceed minimum requirements for material strength and performance.

Shallow groundwater quality and chemistry will be monitored yearly for any changes that may be a result of CO_2 injection at HGSS.

An external mechanical integrity test, as outlined by section 40 CFR 146.89(c), will be performed at least annually until the injection well is plugged or more frequently if requested by the Region V UIC Program Director.

A pressure fall-off test will be performed at minimum once every five years or as often as is requested by the Region V UIC Program Director.

The spatial nature and extent of the CO_2 plume will be monitored indirectly using a combination of three-dimensional vertical seismic profiling (3D VSP) and pulsed neutron logging (PNC) at injection and monitoring wells. Bottomhole pressure and temperature in the AoR will be monitored using downhole gauges deployed in injection and monitoring wells.

This testing and monitoring plan will be reviewed periodically, at least every five years. The plan will be adjusted accordingly to meet any changes to the facility or site conditions over time. Amended plans will be sent to the Region V UIC Program Director for approval as outlined in the permit modification requirements in sections 40 CFR 144.39 or 144.41, as appropriate.

1.10. Injection Well Plugging

Prior to plugging the injection wells, HGCS will demonstrate mechanical integrity to ensure no pathway has been established between the injection zone and the underground sources of drinking water (USDWs) or ground surface according to 40 CFR 146.82(a)(16) and 40 CFR 146.92(b). HGCS will utilize at least one temperature log, oxygen activation log, and noise log that will be run over the entire depth of the injection wells to ensure fluid is not migrating outside of the injection interval. Further, this data will be compared to the pre-injection and operational phases of the project. Bottomhole pressure measurements will be recorded during the project, and the post-injection bottomhole pressure will be utilized to select a brine weight to maintain well control during logging activities. Additionally, this data will inform the cement weight for plugging operations. HGCS will remove the tubing and packer from the well after injection. The wells will be plugged with corrosion resistant cement (EverCRETE or similar) across the injection interval and above the confinement interval and Class A cement from that point to surface. Following plugging, the casing will be cut off three (3) feet below ground surface and have a steel plate welded across the top. For more specific information on well plugging procedures, please refer to the *Injection Well Plugging Plan*.

1.11. Post-Injection Site Care (PISC) and Site Closure

The 50-year PISC phase will begin when all CO_2 injection ceases and ends with site closure. Per 40 CFR 146.93(b), HGCS will monitor HGSS for CO_2 plume movement and pressure fall-off to demonstrate non-endangerment of USDWs until plume stabilization (15 years after cessation of injection). Shallow groundwater will be monitored for another 35 years. The *PISC and Site Closure Plan* describes the post-injection modeling that was completed to determine the pressure differential, position of the CO_2 plume, and prediction of CO_2 migration. Additionally, there is a detailed description of the post-injection monitoring plan and the site-closure plan. The numerical reservoir model used for calculating the AoR was also used for the post-injection site-care and site-closure analysis.

The predicted positions of the CO2 storage zone and pressure front at the end of 30 years of injection, 10 years after injection, and 20 years after injection were simulated in the model. The simulation indicates that the CO2 plume would remain within 2.5 miles from the injection well at the time of site closure. Most of the CO2 mass is concentrated around the injection well, with some thin streaks of CO2 extending further away to the northeast of the injection wells in the up-dip direction.

Following the cessation of injection, all injection wells will be converted to monitoring wells and will continue to contribute to the collection of data as part of the HCSS monitoring program. No monitoring technologies will be added during the PISC phase of the project. The post-injection phase will include monitoring for gas leaks in the wellheads and valves, external mechanical integrity testing, groundwater sampling, direct pressure and temperature measurements, indirect and direct plume tracking, surface and near-surface CO_2 leak monitoring, and seismicity monitoring for induced and natural seismic events. Every five years during the post-injection phase of the project, the monitoring data will be incorporated into computational models and the monitoring plan will be reviewed and updated, if needed, based on modeling results.

Once HGCS demonstrates plume and pressure stabilization, as well as non-endangerment of local USDWs, well plugging and abandonment will commence. Abandonment shall be performed to not allow the movement of injection or formation fluids out of the storage complex. Prior to well plugging, the mechanical integrity of the wells will be verified by the distributed temperature sensing (DTS) and distributed acoustic sensing (DAS) fiber optic systems emplaced in the monitoring wells. The well plugging and abandonment will follow the methodology described in the *Injection Well Plugging Plan*, except CO_2-resistant cement need not be utilized in wells that do not encounter CO_2 at depth. See *PISC and Site Closure Plan* for more details.

1.12. Emergency and Remedial Response

The *Emergency and Remedial Response Plan (ERRP)* details actions that HGCS shall take to address the movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods, pursuant to 40 CFR 146.82(a)(19) and 146.94(a). Examples of potential risks include (1) injection or monitoring well integrity failure, (2) injection well monitoring equipment failure, (3) natural disaster, (4) fluid leakage into a USDW, (5) CO_2 leakage to USDW or land surface, or (6) an induced seismic event. In the case of one of the listed risks, site personnel, project personnel, and local authorities will be relied upon to implement this ERRP. HGCS will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether there are any environmental or safety implications. This will include a detailed description of the event, any impacts to the environment or other local resources, how the event was investigated, what actions were taken, and the status of the remediation. The ERRP will be reviewed at least once every five years following its approval, within one year of an AoR reevaluation, within the timeframe indicated by the Region V UIC Program Director following any significant changes to the injection process or the injection facility, or an emergency event, or as required by the permitting agency. Periodic training will be provided to well operators, plant safety and environmental personnel, the plant manager, the plant superintendent, and corporate communications to ensure that the responsible personnel have been trained and possess the required skills to perform their relevant emergency response activities described in the ERRP.

1.13. Injection Depth Waiver and Aquifer Exemption Expansion

Not applicable.

1.14. Other Information

None.