AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR 146.84(b)

Wabash CCS Project

INSTRUCTIONS

This template provides an outline and recommendations for the AoR and Corrective Action Plan.

In this template, examples or suggestions appear in **blue text**. These are provided as general recommendations to assist with site- and project-specific plan development. The recommendations are not required elements of the Class VI Rule. This document does not substitute for those provisions or regulations, nor is it a regulation itself, and it does not impose legally-binding requirements on the EPA, states, or the regulated community.

Please delete the **blue text** and replace the yellow highlighted text before submitting your document. Similarly, please adjust the example tables as necessary (e.g., by adding or removing rows or columns). Appropriate maps, figures, references, etc. should also be included to support the text of the plan.

Remember that, pursuant to 40 CFR 146.84(b), the requirement to maintain and implement an approved AoR and Corrective Action Plan is directly enforceable regardless of whether the requirement is a condition of the permit. For more information, see the Class VI guidance documents at https://www.epa.gov/uic/class-vi-guidance-documents. It is the responsibility of the owner or operator to maintain records of previous revisions to this plan.

Note for all images and maps: Please document the location of each image using consistent latitude/longitude coordinates. This applies to images in both plan view and cross section including, but not necessarily limited to: model grid, rock properties and regional geologic information, AoR plume and pressure front maps, and maps documenting the locations of other wells within the AoR.

Facility Information

Facility name:	Wabash Carbon Services WVCCS1 and WVCCS2
Facility contact:	Rory Chambers Vice President Operations 444 W. Sandford Ave, West Terre Haute, IN 47845 (812) 281-2810 RChambers@wvresc.com
Well location:	WVCCS1 Clinton, Vermillion, Indiana 39 37’ 27.88” N, 87 29 19.17” W (Decimal Degrees X, Y: -87.48866, 39.62441) WVCCS2 West Terre Haute, Vigo, Indiana 39 33’ 3.72” N, 87 29’ 16.60” W (Decimal Degrees X,Y: -87.48794, 39.55103)

Computational Modeling Approach

Model Background

The Illinois State Geological Survey (ISGS) and Pacific Northwest National Laboratory (PNNL) authored this model using Subsurface Transport of Multiple Phase (STOMP) dynamic subsurface simulation software, Version 3.0. The model was built to dynamically simulate the flow of water and CO_2 throughout a twelve-year injection period and a subsequent 50-year Post Injection Site Care (PISC) period. The model accounts for multiphase (brine and CO_2) flow and reactive transport.

The dynamic model simulation is based on porous media theory (Darcy's Law), and uses internal lookup tables to define gas properties vs. pressure. The CO_2 properties are based on an equation of state (Span and Wagner, 1996); the CO_2/H_2O phase equilibria are based on a model developed by Spycher and Pruess, et al (Spycher et al., 2003; Spycher and Pruess, 2010). The multiphase flow of water and CO_2 was modeled to predict the movement of water, CO_2, and pressure evolution within the reservoir. Carbon dioxide saturation and spatial pressure differentials over time were used to estimate and delinate the Area of Review (AoR). The selection of modeled processes is unlikely to change during AoR reevaluations.

Site Geology and Hydrology

Available site-specific data include a full suite of geophysical logs, petrological and geomechanical analyses of whole core and rotary sidewall core (RSWC) samples, well test data from Step Rate Tests (SRT), Pressure Fall-Off Tests (PFO), and Multirate Tests (MRT), and geochemical analysis of brine swab samples collected from the Wabash #1 stratigraphic test well. The structural and depositional history of the region and site come from regional geologic knowledge.

Structural and Depositional History

The intracratonic Illinois Basin was formed in the Late Cambrian Period over the northeast extension of the Reelfoot Rift System. At that time, lithospheric thinning had largely concluded and the New Madrid Rift System gradually transitioned to a slowly subsiding cratonic trough plunging southwest towards the deeper ocean (Kolata and Nelson, 2010). Marine and near-shore environments dominated the Cambrian through Permian sedimentary rocks in the Illinois Basin. These rocks are primarily marine carbonates and to a lesser extent sandstone, shale, and siltstone (Leighton et al., 1990).

There are no known structural features that would negatively impact the proposed injection site. The nearest large geologic structure is the LaSalle Anticlinorium, which extends into Edgar and Clark counties in Illinois, approximately 20 miles (32 km) away (Figure 1). The area near the proposed injection site is tectonically stable, and modern occurrence of earthquakes magnitude 3.0 or greater are rare. Three 2D seismic reflection profiles were acquired to evaluate structural features and continuity of strata within the Wabash Project study area. There are no identified faults that transect the Potosi reservoir or in overlying units (Figure 2; Figure 3).

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Figure 2. Base map of the Wabash area showing the location of the seismic reflection profiles and major roads. In[redacted] Sensitive, Confidential, or Privileged Information

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Stratigraphy

Note the names of some regionally extensive units change across the Illinois-Indiana state line boundaries (Figure 4). For consistency with previous log analysis and reservoir simulations work in Illinois and through the Illinois Basin, the Illinois stratigraphic names will be preferentially used here when discussing details about the injection zone, confining zones, and reservoir simulation related to AoR delineation. Further, because petrophysical properties are similar and differentiation difficult, the Joachim Dolomite was considered together with the Platteville Limestone as a single layer in the model.

The injection zone is within the Potosi Dolomite (Upper Cambrian), the basal unit of the Knox Supergroup in Indiana (Figure 4),or Knox Group as it is referred to in Illinois (Lasemi 2014; Lasemi 2020). Stratigraphic units that comprise the confining zone cumulatively exceed 1,900 ft (759 m) thick; their individual thickness and depths are shown in Table 1. All the zones listed in Table 1 contain strate that exhibit characteristics for effective restriction of vertical movement of fluids through negligible permeabilities. Thick shale intervals within this package are considered the most effective barriers to vertical movement because their ductile nature inhibits fracturing and they have extremely low vertical permeabilities. Notable among these confining strata are the Shakopee Dolomite, with over 100 ft (30 m) of shale, and the Dutchtown Limestone, with over 70 ft (21 m) of shale. The Maquoketa Group has 312 ft (95 m) of shale and is considered the primary seal for the Potosi Dolomite injection interval. The thickness and depth of the Potosi Dolomite that contains the injection interval is provided in Table 2.

The confining and injection zones were identified and located based on downhole wireline logs recovered from the Wabash #1 well (Figure 5) and from regional geologic knowledge. All the confining zones and the injection zone are present throughout the AoR as indicated by geological and geophysical data. Regional cross sections show lateral continuity of injection and confining strata broadly across 10’s to 100’s of miles, with a slight thinning to the east (Figure 6) and north (Figure 7). Seismic reflection data suggest that within the AoR there is negligible thinning of the confining and injection formations. Thus, thickness variations in confining beds or injection zones will have negligible impact on storage and containment at this site. Seismic reflection data also indicate that there are no faults penetrating the confining zones within the AoR. A Formation Micro Images (FMI) log acquired in Wabash #1, from the Maquoketa Group to the Oneota Dolomite shows that, in general the strata have irregular to isolated fractures, with no distinct indication of interconnectedness.

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Table 1. List of significant confining intervals above the Potosi Dolomite injection zone within the Wabash project area, as identified in the Wabash #1 well.

Confining Zone	Formation Thickness (ft)	Depth (ft)	Avg. Porosity (%)	Avg. Permeability (mD)	Shale Thickness (ft)
Maquoketa Group	314	2,386	3.0	0.0001	312
Trenton Limestone	163	2,700	1.3	0.00000273	3.5
Platteville Group	379	2,863	1.2	0.00000475	16
Dutchtown Limestone	84	3,242	2.8	0.0000840	70.5
St. Peter Sandstone	28	3,326	4.0	0.0039	3.5
Shakopee Dolomite (upper)	346	3,354	2.8	0.022360406	101
Shakopee Dolomite (lower)	270	3,700	9.1	0.098032	71
Oneota Dolomite	408	3,970	7.1	2.585488	15

Table 2. Proposed formation for injection reservoir at the Wabash project area, as identified in the Wabash #1 well.

Injection zone	Formation Thickness (ft)	Depth (ft)	Avg. Porosity (%)	Avg. Permeability (mD)	Reservoir Thickness (ft)
Potosi Dolomite	784	4,378	30 for tested interval (4,505 to 4,525 ft)	24,000 md-ft over 10 ft (2,400 md) from early short well test* Later and longer well tests suggest 45,000 md or higher.	Total of 149.5 ft greater than 10% porosity

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Figure 5. Geophysical log of the Cambro-Ordovician rocks from Davis Formation through the Maquoketa Group, Wabash #1 Well, Vigo County, Indiana. The St. Peter Sandstone is not labeled in this figure, but is represented in the relatively thin zone between the Shakopee Dolomite and the Dutchtown Limestone. Coordinates for the Wabash #1 well are: -87.427426, 39.531626.

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Figure 6. Southwest-northeast correlation of the units in the upper part of the Knox Group from east-central Illinois to west-central Indiana. The Dutchtown Limestone through Davis Formation section is shown to thin eastward, over the 53 mile cross section, from approximately 2,250 ft (685 m) thick to 1,900 ft (580 m) thick. The southwesternmost well, API 120232522802, is at -87.9919030, 393.3890780 and the northeasternmost well, IGWS ID 157501, is at -87.0488981, 39.616094.

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Figure 7. North-south correlation of the units in the upper part of the Knox Group in west-central Indiana. The Dutchtown Limestone through Davis Formation section is shown to thin northward, over the 87 mile cross section, from approximately 2,950 ft (900 m) thick to 1,900 ft (580 m) thick. The northernmost well, IGWS ID 125110, is at -87.422848, 39.850230 and the southernmost well, IGWS ID 164778, is at -87.253157, 38.799755.

Potosi Dolomite Proposed Injection Interval

The **Potosi Dolomite** is a fine to coarsely crystalline, commonly dense, dolomite, but contains characteristic drusy quartz and intercalations of vugular, brecciated, fractured, and/or cavernous intervals. Petrophysical analysis of wireline log data suggest that only a few intervals in the Potosi Dolomite are porous and permeable. In Wabash #1, there are 6 porous intervals within the

Potosi Dolomite that range from about 5 ft (1.5 m) up to about 20 ft (6 m) in thickness. The evaluation of the 20-ft (6 m) test interval in Wabash #1 wireline log data (Figure 5) shows the zone the to be primarily dolomite and quartz. The neutron-density porosity in the tested interval is estimated to be over 30 percent, with a permeability, determined through well testing, of potentially greater than 45,00 mD.

The top of the Potosi Dolomite is difficult to identify from wirelines logs. For petrophysical analysis and reservoir simulation, the top of the Potosi was considered to be the first porous and permeable interval below the Oneota Dolomite. Therefore, the top of the Potosi Dolomite in the reservoir simulation and log interpretations used to construct the static model may differ from the top of the Potosi Dolomite as shown in regional maps and cross sections.

Overlying and Confining Zones

The ***Oneota Dolomite*** predominantly consists of fine- to medium-grained dolomite, but includes chert and, particularly near its base in some places, sporadic quartz sand and thin interbeds of green shale. In Wabash #1, the Oneota Dolomite is primarily carbonate, with a few interbedded shale intervals, as observed with the gamma ray wireline tool.

The ***Shakopee Dolomite*** of Indiana is a pure to impure, and generally very fine- to fine-grained dolomite containing some chert and interbeds of shale, siltstone, and sandstone (IGWS, 2020). In Wabash #1, the Shakopee Dolomite is a dolomitic zone with extensive quartz mineralization. In this report, the Shakopee Dolomite has been separated into upper and lower units. The lower Shakopee Dolomite is defined as below 3,700 ft (1128 m). The Shakopee Dolomite is considered a highly effective confing zone because of the extensive number of shale layers and significant total shale thickness (Table 1).

Generally, the ***St. Peter Sandstone*** in Indiana is composed of fine to medium well-rounded and well-sorted frosted grains of quartz that are weakly cemented (Droste, Abdulkareem, and Patton, 1982; Droste, Patton, and Rexroad, 1986). In Wabash #1, the St. Peter Sandstone is primarily a quartz-rich zone with some dolomitic carbonates. The zone is 28 ft (8.5 m) thick in Wabash #1, and has very poor porosity with no reservoir characteristics.

The ***Dutchtown Limestone*** is composed of generally light-gray and brown, partly argillaceous dolomite and some interbeds of green shale (IGWS, 2020). The Dutchtown Limestone (Table 1) is primarily a shale in this AoR, and is also an effective barrier to upwards CO_2 movement.

The ***Platteville Group*** and ***Trenton Limestone*** are primarily limestones, dolomitized extensively along the axis of the Kankakee Arch in Indiana, with the proportion of dolomite decreasing to the south and southeast of the Arch (Yoo et al., 2000). In this report, the Joachim Dolomite and Platteville Group limestones, with the Trenton Limestone, are considered as a grouped confining interval for modeling purposes because the rock properties are similar, and differentiation among the units is difficult. In this locale, these formations are primarily tightly-cemented limestones with little to no measured porosity or permeability.

The ***Maquoketa Group*** in Indiana consists principally of shale (about 80 percent); limestone content is minimal throughout most of Indiana but increases prominently in the southeast, such that parts of the group are, in places, dominantly limestone (Gray, 1972; IGWS, 2020). In this region, the Maquoketa Group generally thickens towards the east (Figure 8). The Maquoketa Group is the primary seal for the Potosi Dolomite injection interval. At Wabash #1, the Maquoketa Group is a thick shale (Table 1) that has been shown to be a regional confining zone (Panno et al., 2018).

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Figure 8. Regional thickness (ft) of Maquoketa Group around Wabash #1 (star). In this region, the Maquoketa generally thickens toward the east. In a clockwise direction beginning in the northeast, the map corner coordinates are: NE: -86.506277, 40.194803; SE: -86.517846, 38.532409; SW: -88.438547, 38.524564; NW: -88.473048, 40.186483.

Hydrogeology

The Upper Ordovician Maquoketa Group constitutes a confining unit between the underlying Cambrian-Ordovician and overlying Silurian strata (Panno et al., 2018). Above the Maquoketa Group, the Silurian-Devonian carbonate bedrock aquifer is expected to be the lowermost underground source of drinking water (USDW) within the AoR. At Wabash #1, the base of the Silurian (top of Maquoketa Group) is 2,386 ft (727 m) deep (Table 1); the top of the proposed Potosi Dolomite injection interval lies at a depth of 4,378 ft (1,334 m), which is approximately 1,992 ft (607 m) below the lowermost USDW.

Model Domain

Model domain information is summarized in Table 3.

Table 3. Model domain information.

Coordinate System	Illinois State Plane		
Horizontal Datum	North American Datum, 1927		
Coordinate System Units	Feet		
Zone	Eastern		
FIPSZONE	1201	**ADSZONE**	3776
Coordinate of X min	680,048.56	**Coordinate of X max**	796,208.56
Coordinate of Y min	1,005,730.40	**Coordinate of Y max**	1,121,890.40
Elevation of top of domain	-2,386.0079	**Elevation of bottom of domain**	-5012.646

The dynamic reservoir simulation was run using PNNL's Subsurface Transport Over Multiple Phases (STOMP) numerical simulation software, Version 3.0. The STOMP model, adapted from a static geologic model created in Petrel (discussed further in this document), was 22 miles x 22 miles (35 km x 35 km) laterally and 2,936 ft (895 m) vertically (Figure 9); the model incorporated a laterally variable hexahedral mesh, coarsening outward from the injection wells. The grid cells around the injection well were 660 ft x 660 ft (201 m x 201 m), gradually coarsening outward to a maximum cell size of 10,560 ft x 10,560 ft (3219 m x 3219 m) (Table 4). Total grid dimensions were 112 by 112 cells laterally, and 47 vertical layers.

Table 4. Domain grid cell counts and dimensions.

Dx, Dy (ft)	Repeated Cells	Total cells	Total Dx, Dy (ft)
10,560	1	1	10,560
5,280	1	2	15,840
2,640	2	4	21,120
1,320	4	8	26,400
660	96	104	89,760
1,320	4	108	95,040
2,640	2	110	100,320
5,280	1	111	105,600

10,560	1	112	116,160

The model includes the Potosi Dolomite, underyling Davis Formation, and the overburden formations (listed in descending order) the Maquoketa Shale, Trenton Limestone, Platteville Limestone, Dutchtown Limestone, St. Peter Sandstone, Shakopee Dolomite, and Oneota Dolomite. There are 241 layers contained in the model, and cell thickness varies by layer. Cells within the Potosi Dolomite layers are approximately 3 ft (1 m) thick.

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Figure 9. Dynamic simulation model areal (22 miles x 22 miles) and vertical extent (2,936 ft), and included formations. In a clockwise direction beginning with the northeast, the center coordinates of the corner cells in the model are: NE: -87.28467, 39.74204; SE: -87.288718, 39.428321; SW: -87.69399, 39.429763; NW: -87.692678, 39.744527.

Porosity and Permeability

Table 1 and Table 2 summarize the porosity and permeability of the injection and confining zones. The spatial distribution of the collective confining zones and injection zone is assumed to be relatively uniform within the AoR. However, this interpretation is constrained by a lack of nearby data.

Petrophysical analyses of geophysical logs obtained at Wabash #1 are the primary method of determining injection and confining zone properties. A detailed suite of geophysical logs collected in this well enable a continuous evaluation of mineralogical, lithological, and petrophysical characteristics across the injection formation and confining zones. *In situ* well tests were conducted in the Potosi Dolomite injection zone to determine injectivity characteristics.

Potosi Dolomite well testing

A 20 ft. (6 m.) interval (4,505 – 4,525 ft. MD) in the Wabash #1 well was perforated and a series of tests were completed in the Potosi Dolomite. Step rate tests (SRT) were used to estimate the fracture gradient. Pressure fall-off (PFO) tests were used to estimate permeability, initial pressure, and large-scale geologic features. Multirate tests (MRT) were used to estimate permeability. All tests used freshwater as the injection fluid.

An early *in situ* well test at Wabash #1 provided a permeability value of 2,400 mD for an injection unit within the Potosi Dolomite (24,000 mD-ft over 10 ft). Subsequent longer well testing indicated that much higher permeabilities of 45,000 mD or greater exist within the Potosi Dolomite. The low permeability value of 2,400 mD was used in the present dynamic simulation of CO_2 injection into the Potosi Dolomite. For regional comparison, a Class I well using the Potosi Dolomite for waste injection near Tuscola, IL, approximately 50 miles (80 km) west-northwest of the Wabash location, has a permeability of 9,600 mD (Texas World Operation, 1995).

Porosity and permeability estimation

Modeling the porosity of the Potosi Dolomite included consideration of both primary and secondary porosity. Mud/fluid losses when drilling the Potosi Dolomite, throughout the Illinois Basin, indicate that the vugular porosity encountered in the formation is laterally extensve and the dominant porosity type therein. The density-porosity (DPHI), neutron porosity (NPHI), and cross plot of neutron vs density porosity from the Wabash #1 stratigraphic test well were used to estimate the total porosity of the Potosi Dolomite and its confining zones. No core was collected in the Potosi Dolomite during drilling of the well, so geophysical logs were used to estimate the secondary porosity of the Potosi Dolomite by subtracting sonic log values from the cross plot of neutron-density porosities (total porosity – sonic porosity).

The permeabilities of the Potosi Dolomite and overlying rocks were estimated using well test data, geophysical well logs, and the method of Lucia (1995; 2007) that links rock fabrics to petrophysical properties. An integer model array porosity model was included to differentiate connected vs. unconnected vugs. Using Lucia's method, carbonates of the Potosi Dolomite and overlying strata were categorized into three classes (Figure 10). The petrophysical classes were initially characterized using core and thin section studies from wells at Decatur, Illinois, then calibrated with well logs from Wabash #1. The equations for estimating the permeability from porosity logs for each petrophysical class are as follows:

$$\text{Class 1: } K = (45.35 * 10^{8}) * \phi_{ip}^{\,8.537}$$
$$\text{Class 2: } K = (1.595 * 10^{5}) * \phi_{ip}^{\,5.184}$$

$$\text{Class 3: } K= (2.884*10^3)* \phi_{ip}^{\ 4.275}$$

where K= md and ϕ_{ip} = fractional porosity.

Permeability estimates of the shale intervals within the Shakopee Dolomite, Dutchtown Limestone and Maquoketa Group were based on routine core analyses results derived from correlative intervals at the Tuscola, Illinois, site which used the Potosi reservoir as the injection zone. The geophysical log data (porosity and permeability) was scaled-up along the vertical well path to populate grid cells in the 3D static geological model.

Geocellular model

The geocellular model of the Potosi Dolomite was constructed in Petrel, Schlumberger's reservoir modeling software. The primary model construction input comprises wireline log data at ½ foot intervals, formation tops, and structural surfaces. Porosity and permeability data calculated along the well path were upscaled into the 3D model domain using arithmetic averaging, which weights all averaging values equally, to calculate values for every grid cell in the model. Quality control was confirmed by comparing the data distributions of the original and upscaled porosity and permeability values. The upscaled petrophysical properties were distributed within the model using a moving average method which honors both vertical and horizontal well data and trends. The 3D model domain was built using information from the Wabash #1 stratigraphic test well, which is reflected in the vertical heterogeneity and lateral homogeneity of the distributed petrophysical properties (Figure 11; Figure 12).

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Figure 10. Composite-air permeability cross plot for nonvuggy limestones and dolostones showing statistical reduced-major axis transforms for each class (see text for equations; from Lucia, 1995).

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Figure 11. Permeability distribution in the static Petrel model volume. In a clockwise direction beginning with the northeast, the center coordinates of the corner cells in the model are: NE: -87.28467, 39.74204; SE: -87.288718, 39.428321; SW: -87.69399, 39.429763; NW: -87.692678, 39.744527.

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Figure 12. Porosity distribution in the static Petrel model volume. In a clockwise direction beginning with the northeast, the center coordinates of the corner cells in the model are: NE: -87.28467, 39.74204; SE: -87.288718, 39.428321; SW: -87.69399, 39.429763; NW: -87.692678, 39.744527.

Constitutive Relationships and Other Rock Properties

No core was obtained from the Potosi Dolomite from the Wabash #1 well, thus no site-specific laboratory measurements of relative permeability, capillary pressure, or rock compressibility were available. Rock compressibility was estimated using Newman's correlation for limestone (Newman, 1973), using the median porosity within the Potosi Dolomite. The median porosity is 8%, which corresponds to a rock compressibility value of $1.0430 * 10^{-5}$ psi^{-1}.

Three water-gas relative permeability relationships for different rock types were used in the STOMP model: two analogous sets of drainage Corey parameters and one set of approximately straight line functions. For the dolomite and limestone units, the "Nisku Formation #2" drainage Corey parameters were used, and for the shaley units, the "Colorado Group" drainage Corey parameters were used (Bennion and Bachu, 2008). For vuggy units within the Potosi Dolomite, the Corey exponent 1.1 function was used.

Boundary Conditions

The top and bottom boundaries of the reservoir model were no-flow boundaries while the side boundaries were fixed phase pressures (held constant at their initial values). Applying fixed-pressure open boundaries to large boundary cells is analogous to setting infinite acting aquifer boundaries.

Initial Conditions

Initial conditions for the model are given in Table 5.

Table 5. Initial conditions.

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	108	F	4,500 ft.	Borehole temperature log
Formation pressure	1,940	psi	4,500 ft.	Pressure fall-off testing
Fluid density	63.33	lb/ft^3	4,500 ft.	Calculated from salinity, pressure, and temperature (SPE 18571)
Salinity	34,250	ppm	4,500 ft.	Swab sample from Potosi Dolomite

Operational Information

Details on the injection operation are presented in Table 6.

Table 6. Operating details.

Operating Information	Injection Well 1	Injection Well 2	Injection Well 3
Location (global coordinates) X Y	 -87.48864 39.62437	 -87.48792 39.55099	N/A
Model coordinates (ft) X Y	 737945.4413 1078177.671	 738399.8078 1051450.913	N/A
No. of perforated intervals	1	1	N/A
Perforated interval (ft MSL) Z top Z bottom	 3,621 4,256	 3,846 4,481	N/A
Wellbore diameter (in.)	8.75	8.75	N/A
Planned injection period Start End	2024	2036	N/A
Injection duration (years)	12	12	N/A
Injection rate (t/day)*	2,286	2,286	N/A

Fracture Pressure and Fracture Gradient

Calculated fracture gradient and maximum injection pressure values are given in Table 4.

Seven step rate tests (SRT) over a twenty foot interval (4,505 – 4,525 ft MD) in the Potosi Dolomite were used to determine the fracture gradient and pressure for the injection zone. Calculated fracture gradient maximum injection pressure values are given in Table 7. Across the tests, the increment in barrels per minute (bpm) was varied from 0.25 bpm to 1.00 bpm. The test durations were 7, 15, 30, and 90 minutes. Four of the tests were performed before an acid injection, and three were performed after acid injection

Pre-operational testing will measure hydraulic fracture pressure both during open hole testing ("mini frac" tests in sealing units) and cased hole testing (SRT in injection formation). Results will be used to refine fracture pressure, gradient, and the highest allowable injection pressure, and will be used with injectivity testing to verify the injectivity rates used in the Plume and AoR simulations.

Table 7. Injection pressure details.

Injection Pressure Details	Injection Well 1	Injection Well 2	Injection Well 3
Fracture gradient (psi/ft)	0.71	0.71	N/A
Maximum injection pressure (90% of fracture pressure) (psi)	2,672	2,815	N/A
Elevation corresponding to maximum injection pressure (ft MSL)	3,621	3,846	N/A
Elevation at the top of the perforated interval (ft MSL)	3,621	3,846	N/A
Calculated maximum injection pressure at the top of the perforated interval (psi)	2,672	2,815	N/A

Computational Modeling Results

Predictions of System Behavior

The model was used to simulate CO_2 injection into two wells five miles apart over 12 years. Each well had an injection rate of 2,286 t/day (0.83 Mt CO_2/year). The model further simulated behavior for an additional 50 years after injection stopped (i. e. total simulation period of 62 years). Although the CO_2 plumes' maximum lateral is extent is reached at the end of the simulation period (62 years), expansion around each well effectively ceases when injection ends, and further plume migration occurs only incrementally throughout the PISC period (Figure 13). The maximum lateral plume extent is determined from the model layer having the broadest distribution of CO_2.

Within the Trenton Limestone directly below the primary confining Maquoketa Group layer, the pressure front resulting from CO_2 injection does not anywhere or at any time within the model domain exceed 90% of the calculated pressure threshold that would be required to potentially impact the lowermost USDW (discussed below). Thus, the AoR is functionally based only on the lateral extent of the CO_2 saturation above a 1% cutoff. The AoR is expected to reach its maximum lateral extent 16 years after injection begins, i.e. 4 years post injection (Figure 13). The lateral extent of the AoR remains essentially constant from 12 through to 62 years after the start of injection (Figure 13; Figure 14, Figure 15; Figure 16). Vertical movement of CO_2 over the course of 62 years is restricted to the base of the Oneota Dolomite (Figure 15; Figure 16; Figure 17).

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Figure 13. Maximum plume distance from injection wells over time, based on a 1% CO_2 saturation cutoff. The late uptick in plume radius (after stabilization) is due to coarsness of the outer grid cells.

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Figure 14. Plan view snapshots of predicted CO_2 plumes using a 1% gas saturation cutoff (white contour) for selected years. Twelve years of simulated injection begins at year 0. The domain of the depicted model grid is a square of dimension 22 miles, represented by the coordinates at the corners of: NE: -87.280032, 39.742713; SE: -87.284850, 39.423859; SW: -87.696005, 39.426835; NW: -87.693074, 39.745722.

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Figure 15. North-South cross sectional snapshots of predicted CO_2 plumes for a 1% saturation cutoff at years 0, 6, 12, 13, 14, and 15. Twelve years of simulated injection begins at year 0. The injection wells are spaced five miles apart (WVCCS1: -87.48866, 39.62441; WVCCS2: -87.48794, 39.55103).

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Figure 16. North-South cross sectional snapshots of predicted CO_2 plumes for a 1% saturation cutoff at years 17, 22, 32, 42, 52, and 62. Twelve years of simulated injection begins at year 0. The injection wells are spaced five miles apart (WVCCS1: -87.48866, 39.62441; WVCCS2: -87.48794, 39.55103).

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Figure 17. Maximum CO_2 plume extent after 12 years injection period and 50 years PISC period, in plan view and cross section, using a 1% CO_2 saturation cutoff. The domain of the plan view is 22 miles by 22 miles, represented by the coordinates at the corners of: NE: -87.280032, 39.742713; SE: -87.284850, 39.423859; SW: -87.696005, 39.426835; NW: -87.693074, 39.745722. The two injection wells are spaced five miles apart (WVCCS1: -87.48866, 39.62441; WVCCS2: -87.48794, 39.55103).

Geographic boundaries of delineated AoR

The two modeled injection wells are 5 miles (8 km) apart in the north-south direction. The geometry of the AoR is delineated by the maximum lateral extent of the two CO_2 plumes after 62 years (12 years injection and 50 years PISC period). The geographic bounding coordinates around each CO_2 plume in the AoR geometry are provided in Table 8.

Table 8. Bounding coordinates around the AoR geometry, in Decimal Degree coordinates (North American Datum [NAD] 1983.

AoR Plume	Extent Direction	Approximate Distance from Well	DD_N83_X	DD_N83_Y
North Plume	North	2.0 mi (3.2 km)	-87.489491	39.653941
North Plume	East	1.9 mi (3.0 km)	-87.453164	39.625353
North Plume	South	1.6 mi (2.6 km)	-87.488965	39.600567
North Plume	West	2.0 mi (3.2 km)	-87.525984	39.625967
South Plume	North	1.6 mi (2.6 km)	-87.487620	39.574432
South Plume	East	2.0 mi (3.2 km)	-87.451105	39.549354
South Plume	South	2.1 mi (3.3 km)	-87.488291	39.521079
South Plume	West	1.9 mi (3.0 km)	-87.523691	39.549787

The calculated critical pressure, 70.4 psi (0.44 MPa) is low enough that the ΔP pressure front AoR component has no impact on the AoR throughout the model time frame: the maximum ΔP reached in the Trenton Limestone was 0.137 psi ($0.9 * 10^{-4}$ MPa). Thus the lateral extent of CO_2 saturation, based on a 1% cutoff, comprises the entirety of the delineated AoR. This extent has been assessed throughout the modeling time frame, from year 1 through year 62.

While data is available from the Wabash #1 well, data collected during drilling of the proposed injection wells will provide an opportunity to further refine modeling with site-specific injection well borehole data. Data collected during drilling of the injection well will be used to iteratively update the computational model. In addition, downhole pressure monitoring during and after injection can provide near-continuous information to compare the predicted and actual pressure response to CO_2 injection. These data will be used to recalculate the AoR as new data is incorporated for reevaluation.

Model Calibration and Validation

The model permeability within the well test interval (4,505 – 4,525 ft. MD) was calibrated to the estimated permeability based on the early pressure fall-off test interpretation of 24,000 mD-ft. Maximum bottom hole pressure (BHP) was limited by fracture pressure using a fracture gradient of 0.71 psi/ft. The fracture gradient was based on well test interpretations of step rate testing (SRT).

A sensitivity analysis was conducted using a set of models with varied dynamic parameters; identical grid geometry and petrophysical properties were used, but four models were run to examine the effects of gas trapping and reactive transport within the reservoir. The four models included: 1) gas trapping with reactive transport, 2) gas trapping with no reactive transport, 3) no gas trapping with reactive transport, and 4) no gas trapping with no reactive transport. At year 12, the end of the injection period, CO_2 saturation with a 1% cutoff (Figure 18) and pressure differential (Figure 19) indicated no significant difference across the four models. The model that included both reactive transport chemistry and residual gas trapping was selected for use in this document as the model most representative of subsurface conditions and chemical interactions.

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Figure 18. North-South cross section view of the CO_2 plume with a 1% gas saturation cutoff at year 12, the end of the injection period. The two injection wells are spaced five miles apart (WVCCS1: -87.48866, 39.62441; WVCCS2: -87.48794, 39.55103).

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Figure 19. North-South cross section view of the pressure differential between baseline preinjection reservoir pressure and reservoir pressure at year 12, the end of the injection period. The two injection wells are spaced five miles apart (WVCCS1: -87.48866, 39.62441; WVCCS2: -87.48794, 39.55103).

AoR Delineation

Critical Pressure Calculations

The pressure front for AoR delineation was calculated using the EPA-Guidance method for critical pressure calculation in an overpressured reservoir (Nicot, 2009; USEPA, 2013). Calculations indicated that the change in pressure (ΔP) above native reservoir pressure required to potentially impact the lowermost USDW is 70.4 psi (0.44 MPa).

The input parameters and their sources are provided in Table 9. For the purposes of critical pressure calculation and AoR delineation, the reservoir zone was defined to extend to the base of the primary seal, the Maquoketa Group. Therefore, hydrostatic reservoir zone pressure and depth were extracted from the layer immediately below the Maquoketa Group, the Trenton Limestone. Because the Trenton Limestone was represented in the model by a single layer, and the ΔP reported was from the middle of that layer of grid cells, hydrostatic reservoir zone pressure, and depth, were also extracted from the middle of the Trenton Limestone layer of grid cells. The depth to the reservoir zone below the lowermost USDW, the Trenton Limestone, was determined using the formation top determined at the Wabash #1 well. The fluid density within the Trenton Limestone was calculated by estimating R_{wa} from the deep resistivity and DPHI logs, and confirmed by calculating R_w from temperature and spontaneous potential logs (Archie, 1952; Asquith, 2004). Finally, fluid density (Table 9) was estimated using the R_w, R_{wa}, formation pressure and temperature, and salinity.

Table 9. Parameters and values used as input in the critical pressure calculation.

Parameter	Value	Units	Source
Pressure at the base of the lowermost USDW	1033.138	psi	Calculated using freshwater gradient of 0.433 psi/ft
Depth to base of lowermost USDW	2,386	ft	Base of Silurian (top of Maquoketa Group), Wabash #1 well
Depth to reservoir zone below lowermost USDW	2,783	ft	Middle of Trenton Limestone model layer, Wabash #1 well
Hydrostatic reservoir zone pressure below lowermost USDW	1,140	psi	Calculated from Wabash #1 Pressure Fall Off testing fracture gradient
Fluid density within the reservoir zone below lowermost USDW	64.3	lb/ft3	Calculated from formation P and T, and deep resistivity, SP, and DPHI logs

AoR Delineation

As indicated by EPA in GDST, "The boundaries of the AoR are based on simulated predictions of the extent of the separate-phase (i.e., supercritical, liquid, or gaseous) plume and pressure front" (USEAP, 2013). Model results were used to calculate the extent of the CO_2 plumes and pressure front, and those results were used to delineate the maximum AoR extent.

The critical pressure 70.4 psi (0.44 MPa) was scaled by 0.9 to provide a conservative estimate of the pressure-based AoR, and the resulting value of 63.4 psi was applied as a contour to the modeled ΔP in the Trenton Limestone, which is the model layer directly below the primary confining zone. The ΔP pressure front in the Trenton Limestone does not laterally, nor at any modeled time, exceed the estimated critical pressure required to endanger the lowermost USDW; the maximum pressure reached in the Trenton Limestone was 0.137 psi ($0.9 * 10^{-4}$ MPa). Therefore, the AoR was based only on the extent of the CO_2 saturation plumes based on a 1% saturation cutoff.

Figure 20 outlines the predicted maximum lateral extent of the CO_2 plume(s) at year 62 (following 12 years injection and 50 years PISC period), based on a 1% gas saturation cutoff, shown overlain on a topographic map of the immediate area around the project wells. The combined polygon outlines for the CO_2 plumes at both wells were used to delineate the AoR as shown.

Data collected during drilling of the proposed injection well will be used to inform and update the calculated critical pressure as it relates to the AoR determination. These same data will be used to update the model input parameters and thus CO_2 plume extent estimations. The maximum extents of the updated pressure front and/or CO_2 plume(s) will be combined to provide an estimate of any changes to the AoR based on the data collected during drilling of the proposed wells. These data will include well testing results, geochemical analyses of formation fluids, formation depths, and *in situ* pressures.

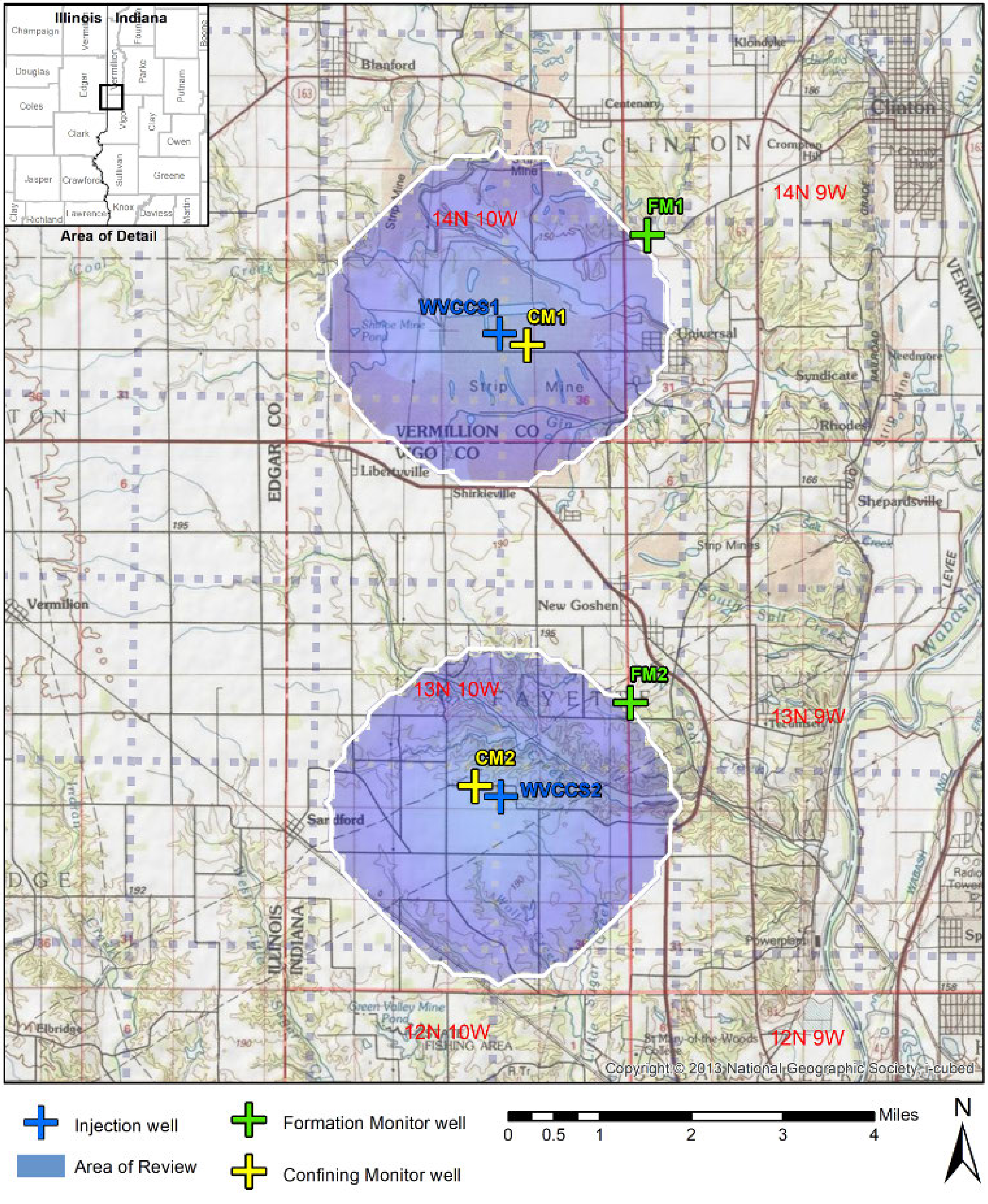

Figure 20. Predicted maximum lateral extent of CO_2 plume(s) at year 62 (following 12 years injection and 50 years PISC period), based on a 1% gas saturation cutoff from the simulation grid results, shown overlain on a topographic map of the immediate area around the project wells. In a clockwise direction beginning in the northeast, the map corner coordinates are: NE: -87.389794, 39.677004; SE: -87.388837, 39.506008; SW -87.589207, 39.505165; NW -87.590657, 39.676156.

Corrective Action

The WCS CCS Project will be utilizing two injection wells. Due to this fact, the AoR will be based on the combined effects from injection into both wells. Based on information from the Indiana Department of Natural Resources (INDNR) Division of Oil and Gas and the Indiana Geological and Water Survey (IGWS) gathered in October of 2020, WCS identified a total of 61 wells within the AoR. Except for the wells proposed as part of this application, no wells were identified that penetrated the primary seal within the combined AoR. A tabulation of wells located within the AoR has been uploaded to the GSDT tool which includes the status, type, depth, location and owner (if known). Figure 20 shows the location of all wells in the AoR of WVCCS1 and WVCCS2.

Tabulation of Wells within the AoR

Wells within the AoR

Research shows that a total of 61 wells are located within the AoR (*Table 10*). Water wells are the predominate factor in this tally, accounting for 51 of documented wells. The domestic water wells average a depth 66 ft with only 1 well exceeding 200 ft to a depth of 373 ft. Other wells include stratigraphic test wells and oil & gas wells.

Ten oil and gas wells are located within the search area. Of the 10 wells identified, 8 have plugging reports available through the INDNR and IGWS databases. The remaining 2 wells do not have plugging records available, however the reported depths of these two wells are 197 ft and 294 ft. Both wells were drilled as stratigraphic test well. The closest well to WVCCS1 is IGS# 164015 which is located 0.57 miles from the wellhead. The well was drilled to a depth of 1,768 Ft as a production well in 2006 but was a dry hole. It was plugged in 2006. The closest well to WVCCS2 is IGS# 124255 which is located 0.14 miles from the wellhead. The well was drilled to a depth of 197 FT as a geologic test well in 1962. No plugging record exists for this well. Figure 20 shows the location of all oil & gas and water wells within the AoR. Tables detailing the depths and status of both water wells and oil & gas wells has been uploaded to the GSDT tool.

Table 10 Total Number of Wells in AoR

	[redacted]	Oil & Gas Wells	[redacted]
North Plume	[redacted]	6	[redacted]
South Plume	[redacted]	4	[redacted]
Total	[redacted]	10	[redacted]

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Figure 20 Water and Oil/Gas wells located within the Area of Review (AoR). Well data are from Indiana Department of Natural Resources and Indiana Geological & Water Survey databases. USGS topographic map base shows land surface features, water bodies, and infrastructure through the area.

Wells Penetrating the Confining Zone

There are no known wells within the Area of Review that penetrate deeper than 1,850 ft. The primary seal, the Maquoketa Group, is located from 2,386 ft MD to 2,700 ft MD, well below the deepest known well within the AoR.

Plan for Site Access

This is not applicable because no corrective action is required at this time due to no wells penetrating the confining zone.

Corrective Action Schedule

This is not applicable because no corrective action is required at this time due to no wells penetrating the confining zone.

Reevaluation Schedule and Criteria

WCS will take the following steps to evaluate project data and, if necessary, reevaluate the AoR. AoR reevaluations will be performed during the injection and post-injection phases at a maximum of a 5-year cycle. WCS will:

- Review available monitoring data and compare it to the model predictions. WCS will analyze monitoring and operational data from the injection wells (WVCCS1 & WVCCS2), the formation monitor wells (FM1 & FM2) and confinement monitor wells (CM1 & CM2), and other sources to assess whether the predicted CO_2 plume migration is consistent with actual data. Monitoring activities to be conducted are described in the Testing and Monitoring Plan and the Post Injection Site Care (PISC) and Closure Plan. Specific steps of this review include:
    - Reviewing available data on the position of the CO_2 plume and pressure front (including pressure and temperature monitoring data and Reservoir Saturation Tool (RST) and seismic survey data). Specific activities will include:
        - Correlating data from seismic surveys (e.g., 2D and 3D surveys) to locate and track the movement of the CO_2 plume. A good correlation between the data sets will provide strong evidence in validating the model's ability to represent the storage system.
        - Reviewing downhole reservoir pressure data collected from various locations and intervals using a combination of surface and downhole pressure gauges.
    - Reviewing ground water chemistry monitoring data taken in the shallow (i.e., in the Pennsylvanian strata) monitoring wells, the Silurian/Devonian, and the St. Peter to verify that there is no evidence of excursion of CO_2 or brines that represent an endangerment to any USDWs.

  - Reviewing operating data, e.g., on injection rates and pressures, and verifying that it is consistent with the inputs used in the most recent modeling effort.

  - Reviewing any geologic data acquired since the last modeling effort, e.g., additional site characterization performed, updates of petrophysical properties from core analysis, etc. Identifying whether any new data materially differ from modeling inputs/assumptions.

- Compare the results of computational modeling used for AoR delineation to monitoring data collected. Monitoring data will be used to show that the computational model accurately represents the storage site and can be used as a proxy to determine the plume's properties and size. WCS will demonstrate this degree of accuracy by comparing monitoring data against the model's predicted properties (i.e., plume location, rate of movement, and pressure decay). Statistical methods will be employed to correlate the data and confirm the model's ability to accurately represents the storage site.

- If the information reviewed is consistent with, or is unchanged from, the most recent modeling assumptions or confirms modeled predictions about the maximum extent of the plume and pressure front movement, WCS will prepare a report demonstrating that, based on the monitoring and operating data, no reevaluation of the AoR is needed. The report will include the data and results demonstrating that no changes are necessary.

- If material changes have occurred (e.g., in the behavior of the plume and pressure front, operations, or site conditions) such that the actual plume or pressure front may extend beyond the modeled plume and pressure front, WCS will re-delineate the AoR. The following steps will be taken:

  - Revising the site conceptual model based on new site characterization, operational, or monitoring data.

  - Calibrating the model in order to minimize the differences between monitoring data and model simulations.

  - Performing the AoR delineation as described in the Computational Modeling Section of the AoR and Corrective Action Plan.

- Review wells in any newly identified areas of the AoR and apply corrective action to deficient wells. Specific steps include:

  - Identifying any new wells within the AoR that penetrate the confining zone and provide a description of each well type, location, depth, date of plugging/completion.

  - Performing corrective action on all deficient wells that penetrate the primary confining zone using methods designed to prevent the movement of fluid into USDWs.

- Prepare a report documenting the AoR reevaluation process, data evaluated, any corrective actions determined to be necessary, and the status of corrective action or a schedule for any corrective actions to be performed. The report wil be submitted to EPA within one year of the reevaluation. The report will include maps that highlight the similarities and differences in comparison with previous AoR delineations.

Update the AoR and Corrective Action Plan to reflect the revised AoR, along with other related project plans, as needed.

AoR Reevaluation Cycle

WCS will reevaluate the above described AoR every 5 years during the injection and post-injection phases. More frequent reviews may occur if any of the events described in the next section occur.

Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

Unscheduled reevaluation of the AoR will be based on quantitative changes of the monitoring parameters in the deep monitoring wells, including unexpected changes in the following parameters: pressure, temperature, neutron saturation, and deep ground water (>4,600 ft MD) constituent concentrations indicating that the actual plume or pressure front may extend beyond the modeled plume and pressure front. These changes include:

- **Pressure:** Changes in pressure that are unexpected and outside three (3) standard deviations from the average will trigger a new evaluation of the AoR.

- **Temperature:** Changes in temperature that are unexpected and outside three (3) standard deviations from the average will trigger a new evaluation of the AoR.

- **RST Saturation:** Increases in CO2 saturation that indicate the movement of the CO2 into or above the confining zone will trigger a new evaluation of the AoR unless the changes are found to be related to the well integrity. (Any well integrity issues will be investigated and addressed.)

- **Deep ground water constituent concentrations:** Unexpected changes in fluid constituent concentrations that indicate movement of the CO2 or brines into or above the confining zone will trigger a new evaluation of the AoR unless the changes are found to be related to the well integrity. (Any well integrity issues will be investigated and addressed.)

- **Exceeding Fracture Pressure Conditions:** Pressure in any of the injection or monitoring wells exceeding 90 percent of the geologic formation fracture pressure at the point of the measurement. This would be a violation of the permit conditions. The Testing and Monitoring Plan and the operating procedures in the Narrative provides a discussion of pressure monitoring and specific procedures that will be completed during the injection start-up period and continuing operations.

- **Exceeding Established Baseline Hydrochemical/Physical Parameter Patterns:** A statistically significant difference between observed and baseline hydrochemical/physical parameter patterns (e.g., fluid conductivity, pressure, temperature) immediately above the confining zone. The Testing and Monitoring Plan provides extended information regarding how pressure, temperature, and fluid conductivity will be monitored.

- **Compromise in Injection Well Mechanical Integrity:** A significant change in pressure within the protective annular pressurization system surrounding each injection well that indicates a loss of mechanical integrity at an injection well.

An unscheduled AoR reevaluation may also be needed if it is likely that the actual plume or pressure front may extend beyond the modeled plume and pressure front because any of the following has occurred:

- Seismic event greater than M3.5 within 8 miles of either injection well.

- If there is an exceedance of any Class VI operating permit condition (e.g., exceeding the permitted volumes of CO2 injected); or

- If new site characterization data changes the computational model to such an extent that the predicted plume or pressure front exceeds, or is expected to exceed, vertically or horizontally beyond the predicted AoR.

WCS will discuss any such events with the UIC Program Director to determine if an AoR reevaluation is required. If an unscheduled reevaluation is triggered, WCS will perform the steps described at the beginning of this section of this Plan.

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