Evaluation of the AoR Delineation Modeling Approach for Wabash Valley Resources Class VI Permit Application

This area of review (AoR) delineation modeling evaluation report for the proposed Wabash Carbon Services (WCS) Class VI geologic sequestration project summarizes EPA's evaluation of the modeling performed by the Illinois State Geological Survey (ISGS) and Pacific Northwest National Laboratory (PNNL) as described in the Area of Review and Corrective Action Plan. This review also addresses modeling-relevant site characterization information in the permit application narrative. Clarifying questions for WCS are provided in blue within the text below.

This report describes and evaluates how site-specific data (e.g., geologic data and planned operational conditions) described in the UIC permit application are incorporated into WCS' geomodel and their computational modeling approach. Note that EPA did not perform independent, duplicative modeling of WCS' AoR. Based on the breadth of currently available site-specific data and the description of the modeling effort as provided in the permit application materials, this is not warranted at this time. WCS notes in the permit application that additional pre-operational testing will be performed as the injection wells are drilled. It is assumed that planned pre-operational testing will confirm the site characterization; however, modifications to the model parameters may be needed if this testing yields results that are significantly different than the model inputs.

Evaluation of WCS' Computational Modeling Approach

Model Background

WCS used Petrel for developing the geomodel and the Subsurface Transport of Multiple Phase (STOMP) dynamic subsurface simulation software, Version 3.0 for numerical simulations of plume and pressure front development. Petrel is a software platform that supports development of a site geomodel, allowing synthesis and 3-D visualization of data on reservoir characteristics (e.g., seismic data, structural features, well data, upscaled well properties).

Use of STOMP for numerical simulations is consistent with the requirements of the Class VI Rule at 40 CFR 146.84. It accounts for the multi-phase nature of the injection activity and for the physical and chemical properties of all phases of the injected carbon dioxide (CO_2) stream and displaced fluids. It allows for modeling of geochemical reactions associated with geologic sequestration of CO_2. Use of these modeling programs is appropriate for simulations of plume and pressure front at a GS site.

The Narrative notes that dynamic model simulation is based on porous media theory (Darcy's Law) and uses internal lookup tables to define gas properties vs. pressure. 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 movement of water, CO_2, and pressure within the reservoir was predicted by modeling the multiphase flow of water and CO_2.

Question for WCS:

- Please provide the internal lookup tables used to define gas properties vs. pressure.

Representation of Site Geology and Hydrology

Representation of Site Geologic Features

The geological layering, formation thicknesses, and petrophysical properties of the project site (as described in the permit application narrative and evaluated in the geologic site characterization report) need to be integrated into a geomodel and then a numerical model domain that is consistent with available information to generate predictions of plume and pressure front movement.

WCS used geologic and hydrologic data derived from multiple sources for their geomodel and numerical model approach. These sources include 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 (PFOT), Multirate Tests (MRT), and geochemical analysis of brine swab samples collected from the Wabash #1 stratigraphic test well. Additionally, local geologic knowledge was leveraged to generate the structural and depositional history of the region and site.

The geomodel model is used to represent the depth, areal extent, and thicknesses of the injection and confining zones in the Knox supergroup at the WCS site based on the site-specific data described above. The confining zones cumulatively consist of more than 1,900 ft and include the ~312 ft. thick Maquoketa Group (the primary confining zone), the Shakopee Dolomite with 100 ft of shale, and the Dutchtown Limestone with 70 ft of shale, amongst others detailed in Table 1. The primary injection zone is the 784 ft thick Potosi Dolomite (primary injection zone). There are no currently planned secondary injection zones (pg. 4, AoR CA).[1]

Based on the seismic well reflection data, "the only resolvable faults in the AOR are in the Precambrian and lower Mt. Simon Sandstone," shown on the Wabash 2000 seismic line (pg. 17, Narrative). No faults or fractures were identified in the confining zone based on seismic well reflection data (pg. 5, AOR CA) or logs of the stratigraphic test well and seismic analysis of the site (pg. 2, Narrative). It is stated that faults in the confining formations (Maquoketa to Oneonta) are "irregular to isolated fractures with no distinct indication of interconnectedness." (Pg. 5, AoR CA)

The porosity and permeability data from the Wabash #1 well for all of the confining formations (summarized in Table 1 of the AoR CA) and for the primary injection zone (summarized in Table 2 of the AoR CA) were used to develop the porosity and permeability distributions in the geomodel (pg. 14, AoR CA) including the Potosi Dolomite (the injection zone), Davis Formation (the underlying formation), the Maquoketa Shale (the primary seal), Trenton Limestone, Platteville Limestone, Dutchtown Limestone, St. Peter Sandstone, Shakopee Dolomite, and the Oneota Dolomite. Porosity and permeability distributions developed in Petrel are shown in Figures 11 and 12 of the AoR CA. Visual inspection confirms that the permeability values in the color legend in Figure 11 are generally consistent with the

[1] Throughout this document, references are made to the two applicant submittals reviewed: the 146.82A permit application narrative ("Narrative"), and the AoR and corrective action plan ("AoR CA").

permeability values in Tables 1 and 2. The porosity distribution in Figure 12 could not be cross referenced with Tables 1 and 2 due to the low-resolution of the legend.

The applicant notes that accuracy maybe limited by lack of data from surrounding wells. Site specific data include geophysical logs, petrological and geomechanical analyses of whole core and rotary sidewall core (RSWC) samples, well test data from SRTs, PFOTs, MRTs, and geomechanical analysis of brine swab samples collected from the Wabash #1 stratigraphic test well.

In general, the available geologic site characterization data with respect to layering, thicknesses, and depths appear to have been rendered as faithfully as possible in the geomodel and subsequently for use in the numerical modeling. It is assumed that the workflow used to generate the geomodel and numerical model domain will produce as reasonable representations of the subsurface as possible as new data become available.

Questions for WCS:

- Figures 11 and 12 of the AoR and Corrective Action Plan would benefit from labeling of the tops of the secondary shales that contribute to the 1,900 cumulative feet of confining zone to the extent possible. Please also clarify the resolution or enlarge the text of the legends in these figures.
- If available, please provide an isopach map for the Maquoketa Shale and or the Maquoketa group.

Structural and Depositional History

The applicant states that there are no structural features that would negatively impact the proposed injection site (AoR CA pg. 2). Data used to evaluate structural features includes three 2D seismic reflection profiles (i.e., WVR 20, Wabash 1000, and Wabash 2000). Figure 2 shows the plan view of the lines and Figure 3 shows the seismic reflection profile for WVR 20. Seismic profiles for Wabash 1000 and Wabash 2000 are shown in Figures 11 and 13 of the narrative.

Questions for WCS:

- Please update Figure 11 of Wabash Line 1000 to show the same scale as Figure 12.
- If possible, please provide depths in ft on the y-axis in addition to time.

Stratigraphy

Figure 4 of the AoR and Corrective Action Plan shows a stratigraphic column of the proposed injection site containing the lithologies and formation names of the Maquoketa Shale down through the

Potosi Dolomite Proposed Injection Interval

On page 4 of the AoR and Corrective Action Plan, the applicant states that the injection zone is within the Potosi Dolomite (Upper Cambrian), which is the basal unit of the Knox Supergroup in Indiana (Figure 4 of the AoR and Corrective Action Plan and Page 4 of the Narrative), or Knox Group as it is referred to in Illinois. The Potosi Dolomite is 689 ft thick at Wabash #1 well. However, the stratigraphic column presented in Figure 4 of the AoR and Corrective Action Plan and Figure 1 of the narrative show that the Potosi Dolomite is only the basal unit of the Knox Supergroup in Indiana, and not the basal unit of the Knox Group in Illinois.

Question for WCS:

- Please clarify the difference between the Knox Group in Illinois and the Knox Supergroup in Indiana.

Overlying and Confining Zones

In addition to the stratigraphic column provided in Figure 4 (AoR CA, Pg. 7), the applicant provides a summary of the "significant confining intervals above the Potosi Dolomite injection zone within the Wabash project area, as identified in the Wabash #1 well" in Table 1 (AoR CA, Pg. 7). This summary includes the formation thicknesses, depths, average porosities, average permeabilities, and shale thicknesses of each of the formations between the Potosi Dolomite (injection zone) and "Bainbridge or Salina group, commonly referred to as the Silurian," which is the lowermost USDW, located at 2,000 ft depth. (pg. 3 Narrative). According to Table 1, the cumulative thickness of these formations is 1,992 ft and the cumulative thickness of the shale layers within these formations is 592.5 ft. The Maquoketa shale is the uppermost and the thickest at 312 ft. Seismic reflection within the AOR shows negligible thinning of the confining beds and injection zone (pg. 22 Narrative).

Questions for WCS:

- The thicknesses of the shale layers in the Trenton Limestone and the St. Peter Sandstone are 3.5 ft thick. Is there research that the applicant can cite that supports the addition of these relatively thin shales to the cumulative total "confining unit?"
- Many of the shales used as the confining unit are in limestone formations, which are likely porous and not effective seals. Is it reasonable to assume that the confining zone consists of only the 592.5 ft of shale?
- Please evaluate the integrity of each of the shale layers individually.
- How was dip direction determined in the model?

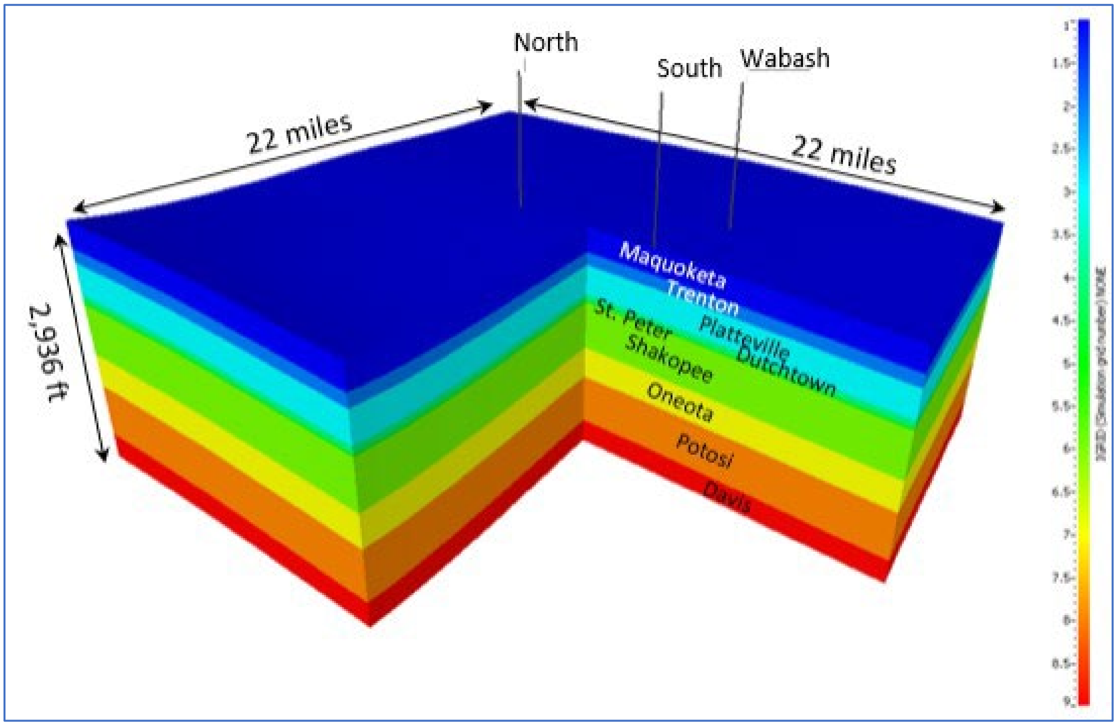
Hydrogeology

Table 1 and Table 2 present the porosities and permeabilities of the Potosi Dolomite (Injection Zone) Maquoketa Shale (primary seal), Trenton Limestone, Platteville Limestone, Dutchtown Limestone, St. Peter Sandstone, Shakopee Dolomite, and the Oneota Dolomite. Permeability for the Potosi Dolomite was found using MRT and PFOTs as well as using Lucia's method of deriving permeability from porosity logs. Porosity was calculated for each of the formations using measurements of bulk density, neutron porosity, photoelectric and acoustic transit time. Values presented in Table 1 appear to agree well with the geophysical log data from Wabash #1, presented in Figures 19-33. The geophysical log data were scaled up along the vertical well path for the geomodel (pg. 23, Narrative).

Model Domain

The Petrel static geomodel, consisting of lateral dimensions of 22 miles X 22 miles (35 km X 35 km) and a vertical thickness of 2,936 ft (895 m), was used as the framework for the STOMP numerical model. The STOMP model incorporated a laterally variable hexahedral mesh grid cell. The grid cells near 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) at the model boundaries. The total grid dimensions were 112 x 112 cells laterally, and 47 layers vertically.

The model's vertical layers include the Maquoketa Shale (the primary seal), Trenton Limestone, Platteville Limestone, Dutchtown Limestone, St. Peter Sandstone, Shakopee Dolomite, Oneota Dolomite, Potosi Dolomite (the injection zone), and Davis Formation. The model consists of 241 layers with cell thickness varying by layer. The Potosi Dolomite layer has cells approximately 3 ft (1 m) thick.



Questions for WCS:

- The "Model Domain" section mentions the use of "47 vertical layers" and "241 layers." Please explain the difference between the referenced numbers of vertical layers.
- The color bar is Figure 9 is not legible. Please revise the figure to include a legible color bar. Additionally, please describe the units being represented by the color bar.

Porosity and Permeability

Potosi Dolomite Well Testing

SRTs, PFOTs, and MRTs were conducted on a 20 ft. (6 m) interval from 4,505 – 4,525 ft. MD within the Potosi Dolomite to determine fracture gradient, permeability, initial pressure, and large-scale geologic features. All tests used freshwater as the injection fluid.

An "in situ" well test at Wabash #1 yielded a permeability value of 2,400 mD for an injection zone within the Potosi Dolomite. Additional well testing yielded much higher permeabilities, around 45,000 mD or greater. Despite this, the applicant states that a lower permeability value of 2,400 mD was used as a conservative input in the dynamic simulation of CO_2 in the Potosi Dolomite. Comparatively, a Class I well injecting waste into the Potosi Dolomite and located approximately 50 miles away has a permeability of 9,600 mD (as cited in Texas World Operation, 1995).

Questions for WCS:

- Ideally, a fluid representative of the injection fluid should be used to perform well tests. Please describe how the use of freshwater may yield representative results when compared to a supercritical CO_2 fluid, similar to the injection fluid. The description should include but is not limited to the following elements: geochemistry and reactive transport effects, and fluid-dependent permeability alteration.
- Please clarify the specific type of test performed and described as an "in-situ" well test on page 15 of the AoR and Corrective Action Plan.
- Please clarify the specific types of "longer well testing" mentioned in the "Potosi Dolomite well testing" section of the AoR and Corrective Action Plan.
- Please specify the depth(s), rock type, and facies in which the permeability measurements were obtained.
- It is understood, based on the Narrative, that the spatial distribution of porosity values with the confining zones and injection zone is assumed to be relatively uniform within the AoR, but confirmation of this assertion is constrained by a lack of available data. Pre-operational testing should yield updated porosity values once core is retrieved and tested at WVCSS1; these should be updated in the modeling parameters.

Porosity and permeability estimation

Porosity and permeability data for the injection zone and the confining zones are shown in Table 1 of the AoR and Corrective Action Plan. The average porosities of the confining zones range from 1.2 to 9.1%, based on measurements of bulk density, neutron porosity, photoelectric, and acoustic transit time. Values presented in Table 1 appear to agree well with the geophysical log data from Wabash #1, presented in Figures 19-33 of the Narrative. Secondary porosity was determined by subtracting sonic porosity from the total porosity.

Question for WCS:

- Please describe or provide a citation for the method used in determining secondary porosity by subtracting sonic porosity from the total porosity.

Vuggy porosity in the injection zone is considered to be laterally extensive in the injection formation based on mud/fluid losses (pg. 15, AoR CA). It is also stated on pg. 4 of the Narrative that, "Many wells in Illinois, Indiana, and Kentucky have injected millions of gallons of liquid waste in the vugular and fractured/cavernous intervals within the Knox carbonates…,"

Questions for WCS:

- Is there other data available (well logs, core data) to support this conclusion, or can the applicant provide research that cites mud/fluid loss as a valid method of determining vuggy porosity to be laterally extensive?
- Please provide a map showing the other locations injecting into the "vugular" carbonates, specifically noting those that inject in the Potosi Dolomite and providing proof that the formation is vugular at those locations.

Permeability for the Potosi Dolomite was found using MRTs and PFOTs as well as using Lucia's method of deriving permeability from porosity logs. Permeability estimates for the shale intervals of the Shakopee Dolomite, Dutchtown Limestone, and Maquoketa Group were based on cores taken from the "correlative intervals" at the Tuscola, Illinois site where the Potosi Formation is also the injection zone (pg. 16, AoR CA).

Geocellular Model

The Geocellular model of the Potosi Dolomite injection zone was generated in Schlumberger's Petrel reservoir modeling software. Wireline log data, discretized at ½ foot intervals, formation tops, and structural surfaces comprise the primary model input. Calculated porosity and permeability data was upscaled from the well path to the 3D model domain using arithmetic averaging, extrapolating values for every grid cell in the model. Quality control was performed on the original and upscaled porosity and permeability values by comparing the distributions of each population of values. The upscaled petrophysical properties were then distributed throughout the model using a moving average method which honors both the vertical and horizontal geologic trends and well data. The 3D model domain was constructed using information from the Wabash #1 stratigraphic test well, resulting in a heterogeneous vertical domain and homogenous lateral domain regarding petrophysical properties.

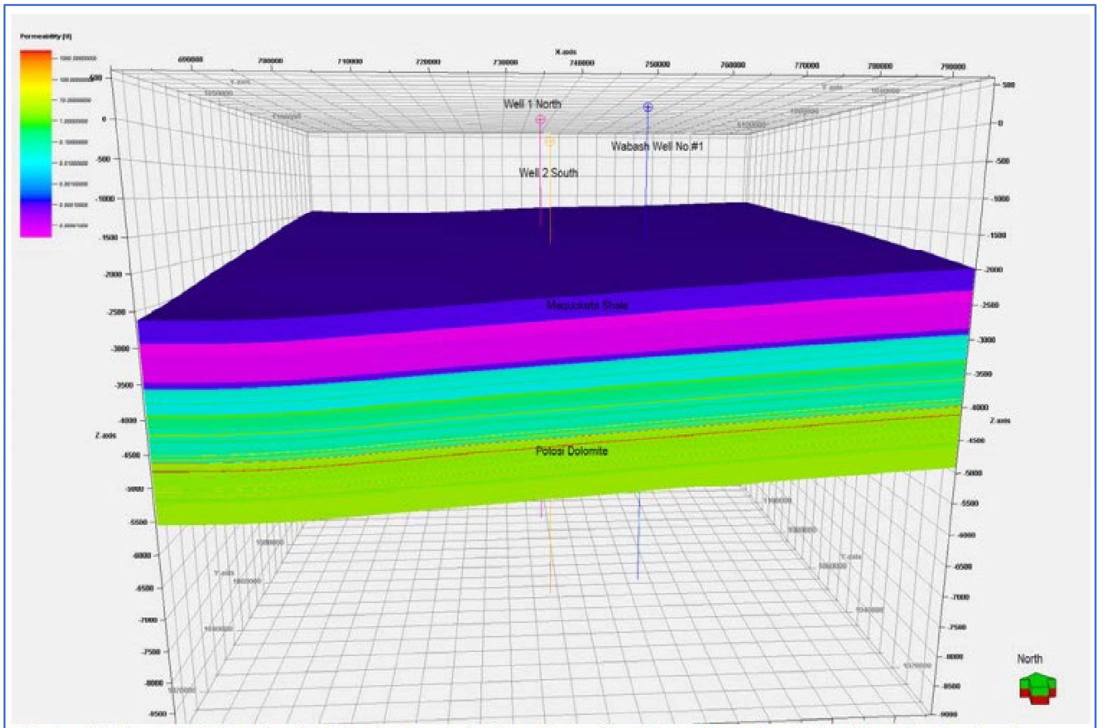


Figure 11. Permeability distribution in the static Petrel model volume. In a clockwise direction beginning with the northeast, the center coordinates of the corner cells in the model are: NE: -87.28467, 39.74204; SE: -87.288718, 39.428321; SW: -87.69399, 39.429763; NW: -87.692678, 39.744527.

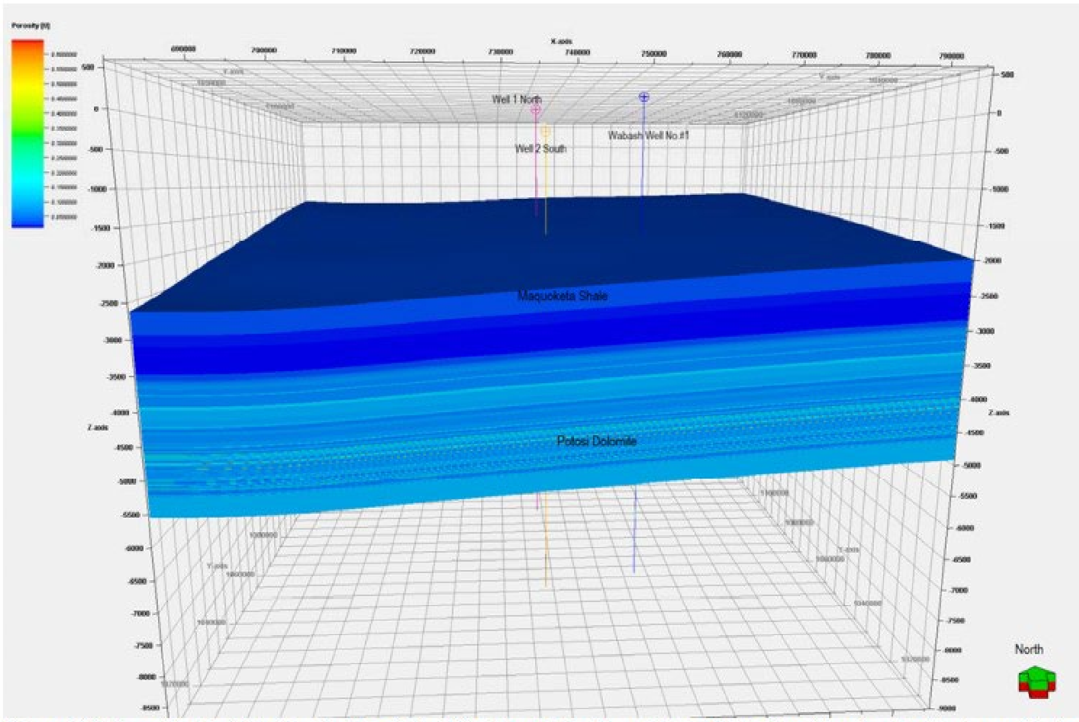


Figure 12. Porosity distribution in the static Petrel model volume. In a clockwise direction beginning with the northeast, the center coordinates of the corner cells in the model are: NE: -87.28467, 39.74204; SE: -87.288718, 39.428321; SW: -87.69399, 39.429763; NW: -87.692678, 39.744527.

Questions for WCS:

- It is noted that porosity and permeability data was calculated and upscaled from the well path to the 3D model domain using the arithmetic averaging method.
    - Does this include the arithmetic averaging of wellbore-measured petrophysical properties over each zone/layer, and extrapolation of such properties to the entire modeled domain? If so, was a single value used per zone/layer for such properties?
    - Please elaborate on the arithmetic averaging method used in this scenario.
    - Additionally, please confirm the use of a homogeneous or heterogeneous reservoir property distribution per zone/layer.
- Figures 11 and 12 have illegible color bars with the units of measure apparently set to “U”. Please update the figures color bar and units of measure.
- What is the time step of the model and how was it selected?

Constitutive Relationships and Other Rock Properties

No cores were retrieved from the Wabash #1 stratigraphic test well, thus no laboratory measurements were conducted of relative permeability, capillary pressure, or rock compressibility. Instead, a set of empirical relationships were used to determine these rock properties.

The application states that Newman’s correlation for limestone (Newman, 1973) was used to determine rock compressibility using the median porosity of 8% within the Potosi Dolomite. Using Newman’s correlation, this median porosity yielded a rock compressibility of 1.0430 * 10-5 psi^{-1}.

Three water-gas relative permeability relationships for different rock types were used in the STOMP model. The “Nisku Formation #2” drainage Corey parameters were used for the dolomite and limestone layers, while the “Colorado Group” drainage Corey parameters were used for the shaley units (Bennion and Bachu, 2008). The Corey exponent 1.1 function was used for the vuggy units within the Potosi Dolomite.

Questions for WCS:

- Please explain how the 8% median porosity for the Potosi Dolomite was derived.
- Please explain why certain functions were used for each of the rock types used in the STOMP model (e.g., “Nisku Formation #2” for dolomite and limestone).

Boundary Conditions

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

Questions for WCS:

- Please define the bottom boundary of the model and explain why it was established as a no-flow boundary, including the relevant geologic data to support this.

Initial Conditions and Operational Information

The tables below summarize the initial conditions and operational information used in the computational model. These parameters appear to be appropriate based on the baseline site characterization data and proposed operating conditions described in the permit application. A discussion of specific conditions is presented below the table.

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

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

Questions for WCS:

- The initial conditions in Table 5 were established at a depth of 4,500 ft MSL. The perforation intervals for Injection Wells 1 & 2 in Table 6 are above 4,500 ft MSL. Please explain how the initial conditions at a depth of 4,500 ft MSL are representative of the perforation intervals in Injection Wells 1 & 2.
- In the Narrative, the discussion of "Operational Procedures" cites a supercritical CO_2 density of 712 Kg/M3. Please explain how this was derived.
- Please add the reference elevation and pressure gradient to Table 5.

Fracture Pressure and Fracture Gradient

Calculated fracture gradient and maximum injection pressure values are provided in Table 7.

Seven (7) SRTs were conducted over a 20-foot interval (4,505 – 4,525 ft MD) in the Potosi Dolomite injection zone to calculate the fracture gradient and fracture pressure. The tests varied in barrels per minute (bpm) increments, from 0.25 bpm to 1.00 bpm. The durations of the tests were 7, 15, 30, and 90 minutes. Four (4) tests were performed before acid injection, and three (3) were performed after.

The applicant states that, during pre-operational testing, open hole mini-frac and cased hole SRTs will be conducted to measure the hydraulic fracture pressure. The results from this pre-operational testing will be used to refine fracture pressure, fracture gradient, the maximum allowable injection pressure, and will be used with injectivity testing to verify the injectivity rates used in the Plume and AoR simulations. Modifications to the model parameters may be needed if the open hole mini-frac and cased hole SRTs yield results significantly different than the model inputs.

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

Questions for WCS:

- There is a typo in the first sentence of the ***"Fracture Pressure and Fracture Gradient"*** section. The calculated fracture gradient and maximum injection pressure values are listed in Table 7, not Table 4 as documented. Please revise this sentence accordingly.
- Please tabulate all SRT tests and corresponding test details in order to clearly demonstrate the nature of such tests and the results.
- What injection fluid will be used in the pre-operational mini-frac and SRT?

Computational Modeling Results

Predictions of System Behavior

The model was used to simulate CO_2 injection into two wells, located five miles apart, over 12 years. Each well had an injection rate of 2,286 t/day (0.83 Mt CO_2/year). After injection ceased, the model further simulated plume behavior for an additional 50 years (for a total simulation period of 62 years). At the end of the simulation period (62 years), the CO_2 plumes' maximum lateral extent is reached. The application asserts that plume expansion around each well effectively ceases when injection ends, and further plume migration occurs only incrementally throughout the PISC period (Figure 13). The model containing the broadest distribution of CO_2 determines the maximum lateral plume extent.

Within the Trenton Limestone directly below the primary confining Maquoketa Group layer, the pressure front resulting from CO_2 injection does not, at any time or location 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 (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).

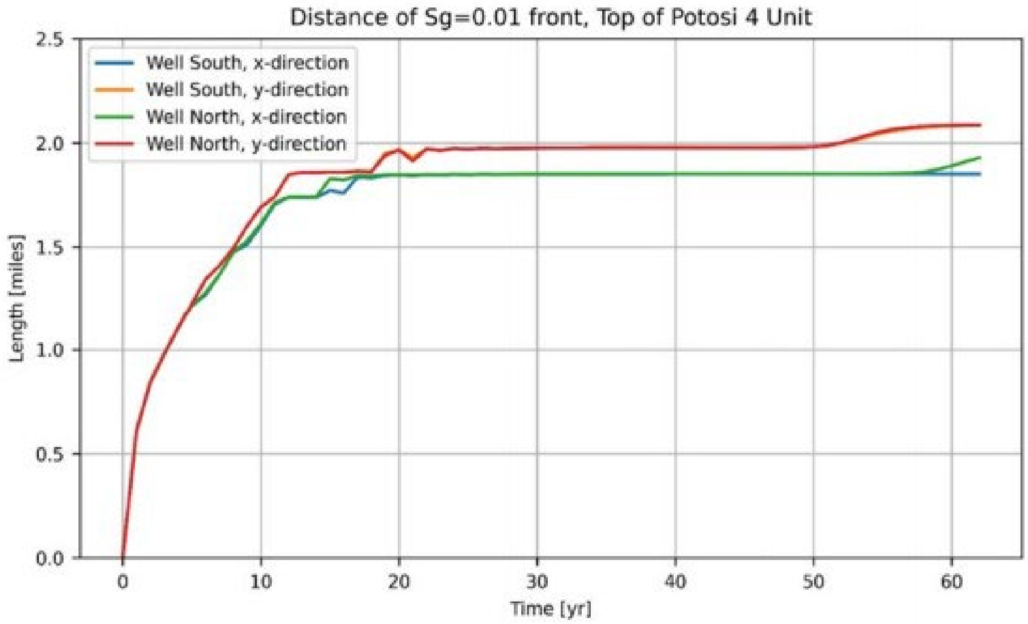


Figure 13. Maximum plume distance from injection wells over time, based on a 1% CO_2 saturation cutoff. The late uptick in plume radius (after stabilization) is due to coarsness of the outer grid cells.

Questions for WCS:

- The maximum lateral extent of the CO_2 plume is noted to be reached at year 62 (the end of the simulation period) and 16 years after injection begins (4 years after injection ceases). It is understood that the maximum lateral extent essentially is constant between years 16 and 62, however it is recommended that this section is clarified regarding the timing of maximum lateral extent cessation.
- Please explain the significance of a 1% CO_2 saturation cutoff used to determine the extent of the CO_2 plume for delineating the AoR.
- Please explain the early changes in slope (i.e., at year 12) demonstrated by the curves in Figure 13.
- Please clearly label the color bar and define units of measure in Figures 14, 15, and 16.
- Please label formation depths/tops in Figures 15, 16, and 17 in cross-sectional views of the predicted CO_2 plume.

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 determined by the maximum lateral extent of the two CO_2 plumes after 62 years, including a 12-year injection period and 50-year PISC period.

The applicant asserts that the calculated critical pressure, 70.4 psi (0.44 MPa), is sufficiently low that it will not affect the AoR throughout the model timeframe; therefore the delineated AoR is defined based on the lateral extent of the CO_2 plume. For example, the maximum ΔP (change in pressure) 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. (See below and in the evaluation of the permit application narrative for additional evaluation of the critical pressure calculation.)

The applicant states that the geographic boundaries and AoR will continuously be updated as new information is required during the drilling of the proposed injection wells. As noted above, if any pre-operational testing yields results that are significantly different than the model inputs, revisions to the model may be needed.

Model Calibration and Validation

The modeled permeability used within the test interval of 4,505 – 4,525 ft. MD was calibrated to the estimated permeability of 25,000 MD-ft., which was derived from PFOT interpretation. The fracture gradient of 0.71 psi/ft was determined from SRT interpretations and limited the maximum bottom hole pressure (BHP).

A sensitivity analysis was conducted for the dynamic parameters of gas trapping and reactive transport. Identical grid geometry and petrophysical properties were used in the sensitivity analysis, and 4 separate models were run to investigate the effect of gas trapping and reactive transport on the model. The models include: 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. The sensitivity analysis yielded no significant difference across the 4 models. The model that included reactive transport and residual gas trapping was used in the application and determined to be most representative of site conditions.

Questions for WCS:

- What is the maximum bottom hole pressure as referenced in the discussion of “Model Calibration and Validation?” EPA: this may be described elsewhere in the application materials; if so, we may be able to delete this question or say more.
- Was sensitivity analysis conducted on grid geometry and petrophysical properties? Please explain why or why not.
- Please include discussion as to why there are no significant differences between the 4 models.

AoR Delineation

Critical Pressure Calculations

The critical pressure, or change in pressure (ΔP) above native reservoir pressure required to potentially impact the lowermost USDW, was determined to be 70.4 psi (0.44 MPa). The applicant states that the critical pressure was calculated using EPA guidance for critical pressure calculation in an overpressured reservoir (Nicot, 2009; USEPA, 2013).

In the critical pressure calculation, the reservoir zone is assumed to extend to the base of the Maquoketa Group, which is the primary seal. Therefore, the hydrostatic reservoir pressure and depth used in the critical pressure calculation were taken from the middle of the Trenton Limestone layer, just below the Maquoketa Group. The fluid density within the Trenton Limestone was calculated using the R_w, R_{wa}, formation pressure and temperature, and salinity. The R_w was calculated from temperature and spontaneous potential logs and was then used in combination with deep resistivity and DPHI logs to calculate R_{wa} (Archie, 1952; Asquith, 2004).

Questions for WCS:

- Please show the calculation for critical pressure.
- Please explain why the reservoir zone is assumed to extend to the base of the Maquoketa Group, causing the Trenton Limestone pressure and depth to be used in the calculation.

AoR Delineation

The maximum AoR extent was determined by the results of the CO_2 plume and pressure front modeling.

The pressure-based AoR was determined by applying a conservative scalar of 0.9 to the critical pressure of 70.4 psi (0.44 MPa), resulting in value of 63.4 psi. This value 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 maximum pressure reached in the Trenton Limestone was 0.137 psi (0.9 * 10-4 MPa) therefore not exceeding the estimated critical pressure. Thus, the AoR was based only on the extent of the CO_2 saturation plumes based on a 1% saturation cutoff.

The calculated critical pressure will be updated as information is gathered during the drilling of the proposed injection wells. The model input parameters and AoR estimation will also be updated using the same data. The data will include well testing results, geochemical analyses of formation fluids, formation depths, and in situ pressures.

Questions for WCS:

- Please show the 63.4 psi contour in a figure within the AoR CA narrative.
- Please describe and map the areal extent over which pressures will increase as a result of injection, even if they are below the calculated critical pressure.
- Additionally, please confirm that the predicted pressure increase as result of CO_2 injection does not exceed 90% of the fracture pressure for the injection or confining zones.
- Please provide a map showing the maximum extent of the area of elevated pressure and the maximum extent of the 1% saturation CO_2 saturation plume to identify the “delineated AoR” that accounts for both elements of the AoR definition for Class VI wells.

Corrective Action

Corrective action will be implemented over the combined AoR for both injection wells at the WCS CCS Project site. Within the combined AoR, there are 61 wells based on an October 2020 website review of Indiana Department of Natural Resources (INDNR) Division of Oil and Gas and the Indiana Geological and Water Survey (IGWS). The application states that there were no wells identified that penetrated the primary seal within the combined AoR.

Tabulation of Wells within the AOR

Out of the 61 wells mentioned in the previous section, water wells are the predominant type of well, accounting for 51 wells. The average water well is 66 feet deep, with one well exceeding 200 feet of depth. The remaining 10 wells are oil, gas, and stratigraphic wells.

There are 8 plugging reports available in the INDNR and IGWS databases for the 10 wells mentioned above. The remaining 2 wells do not have plugging reports however they were reported to reach a total depth (TD) of 197 feet and 294 feet. The closest well to WVCCS1, IGS# 164015, is located 0.57 miles from the wellhead. The well has a TD of 1,768 feet and is a dry oil and gas well that was plugged in 2006. The closest well to WVCCS2, IGS# 124255, is located 0.14 miles from the wellhead. The well has a TD of 197 feet and was drilled as a geologic test well in 1962. No plugging record exists for this well. Given the depth in relation to the depth of the confining zone, this missing information does not appear to be a concern.

The Plan references tabulations of the water wells and oil and gas wells in the AoR that were uploaded to the GSDT. A csv delimited file, containing 231 water wells was identified and reviewed. The 51 water wells (including 6 wells in the northern plume, and 45 wells in the southern plume) are identified. The deepest well in the AoR is 373 feet, which is significantly shallower than the top of the Maquoketa Group confining zone (at 2,386 feet, per Table 4 of the narrative). A csv delimited file, containing 38 oil and gas wells was also reviewed. The deepest well (at 1,850 feet) is nearly 500 feet above the confining zone.

Wells Penetrating the Confining Zone

There are no known wells within the AoR that penetrate the primary confining zone, the Maquoketa Group. The Maquoketa Group ranges in depth from 2,386 – 2700 feet MD, and the deepest well penetration is 1,850 feet.

Plan for Site Access and Corrective Action Schedule

These sections are not applicable due to there not being need for corrective action since no wells penetrate the confining zone.

Reevaluation Schedule and Criteria

The Plan describes the following steps that will be taken by WCS to evaluate project data and make a determination if the AoR will be reevaluated. AoR reevaluations will be conducted during the injection and post-injection phases at a maximum of every 5 years. The reevaluations will consist of:

- A review of monitoring and operational data from the injection wells (WVCCS1 & WVCCS2), the formation monitor wells (FM1 & FM2) and confinement monitor wells (CM1 & CM2), operating data, and any additional site characterization information and other sources to assess modeled vs. actual CO_2 plume behavior. Monitoring activities are described in the Testing and Monitoring Plan and the Post Injection Site Care (PISC) and Closure Plan.
- Compare the modeled AoR delineation results with measured data to demonstrate consistency and accuracy between the measured monitoring data and 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.
- WCS will prepare a report recommending that no AoR reevaluation is needed if newly acquired data confirms the accuracy of modeled predictions of maximum extent of plume and pressure front movement. The report will include the data and results demonstrating that no change is necessary.

- If newly acquired data has caused significant changes (i.e., CO_2 plume behavior or site conditions) such that the actual plume or pressure front extends beyond the modeled plume and pressure front, WCS will re-delineate the AoR. The following steps will be taken:
    - Revise the site conceptual model with newly acquired site data (characterization data, operational data, monitoring data, etc.).
    - Calibrate the model in order to reduce the differences between model predictions and measured data.
    - Perform the AoR delineation as described in the Computational Modeling Section of the AoR and Corrective Action Plan.
- A review of any new wells identified in the revised AoR and the application of corrective action to deficient wells. Specific steps will include:
    - Identifying any new wells within the AoR that penetrate the confining zone. If present, provide a description of each well type, location, depth, date of plugging/completion.
    - Perform corrective action on all deficient wells that penetrate the primary confining zone in order to prevent fluid movement into USDWs.
- WCS will prepare a report documenting the AoR reevaluation process, data evaluated, necessary corrective actions, and the status of corrective action or a schedule for any corrective actions to be performed. The report will 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.

The AoR, Corrective Action Plan, and other related project plans will be updated according to the revised AoR.

Questions for WCS:

- Please confirm that the AoR will be reevaluated in the pre-injection phase once additional site characterization data is acquired.
- Please define what is included in “other sources” that will be reviewed as mentioned in the first bulleted paragraph in the ***Reevaluation Schedule and Criteria section.***
- Please explain how 2D and 3D seismic will be used to track CO_2 plume migration. The discussion should include but is not limited to uncertainties with onshore seismic processing and imaging (especially fluid discrimination in carbonates), and seismic acquisition timeframe. Providing references regarding a similar workflow would be beneficial.
- Please explain the statistical methods that will be used to correlate the modeling results with measured monitoring data.

AoR Reevaluation Cycle

WCS will reevaluate the AoR every 5 years during the injection and post-injection phases. More frequent reviews will 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 data in the deep monitoring wells, including unexpected changes in the following parameters: pressure, temperature, neutron saturation, and deep ground water (>4,600 ft MD) chemistry 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 CO_2 saturation that indicate the movement of the CO_2 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.
- 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.
- 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 necessary 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. EPA: this reflects the "red" level response in the Emergency and Remedial Response Plan; should we recommend an AoR revaluation at a lower trigger level?
- If there is an exceedance of any Class VI operating permit condition (e.g., exceeding the permitted volumes of CO_2 injected); or
- If new site characterization data causes the modeled plume or pressure front 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.

Questions for WCS:

- Please revise this section to include changes in shallow groundwater chemistry to be included as a trigger for AoR reevaluation. If the applicant disagrees that shallow groundwater chemistry should be included as a trigger, please provide supporting discussion as to why.
- What is the significance of three (3) standard deviations from the average for pressure and temperature measurements?

- Please clarify what is determined to be "statistically significant," as mentioned in **the Exceeding Established Baseline Hydrochemical/Physical Parameter Patterns** discussion. Additionally, please clarify what is meant by "significant" in the **Compromise in Injection Well Mechanical Integrity** discussion.

EPA: the following additional triggers reflect other Class VI permits, which you may or may not want to include in the Wabash Plan. We also recommend a reevaluation when the other injection well comes online (if these do not happen concurrently/within a month or so of each other).

- If the arrival time of the plume and/or pressure front at the deep monitoring well and/or when pressure and plume data recorded at the deep monitoring well differs significantly from model projections.
- A change in modeled direction of plume movement or vertical and lateral plume distribution as detected by means other than the monitoring well.
- Initiation of competing injection projects within the same injection formation within a 1-mile radius of the injection well.