# ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN

## Facility Information

| | |
|---|---|
| Facility name: | Archer Daniels Midland, CCS#2 Well<br>IL-115-6A-0001<br>4666 Faries Parkway, Decatur, IL |
| Well location: | Decatur, Macon County, IL;<br>39º53’09.32835”, -88º53’16.68306” |

## Computational Modeling

### *Model Name and Authors/Institution*

ECLIPSE 300 (v2011.2) reservoir simulator with the CO2STORE module, Schlumberger.

### *Description of Model*

*Model Description*

ECLIPSE 300 is a compositional finite-difference solver that is commonly used to simulate hydrocarbon production and has various other applications including carbon capture and storage modeling. The $CO_2$STORE module accounts for the thermodynamic interactions between three phases: an $H_2O$-rich phase (i.e., ‘liquid’), a $CO_2$-rich phase (i.e., ‘gas’), and a solid phase, which is limited to several common salt compounds (e.g. NaCl, $CaCl_2$, and $CaCO_3$). Mutual solubilities and physical properties (e.g. density, viscosity, enthalpy, etc.) of the $H_2O$ and $CO_2$ phases are calculated to match experimental results through a range of typical storage reservoir conditions, including temperature ranges between 12°C-100°C and pressures up to 60 MPa. Details of this method can be found in Spycher and Pruess (2005). Additional assumptions governing the phase interactions throughout the simulations are as follows:

- The salt components may exist in both the liquid and solid phases.
- The $CO_2$-rich phase (i.e., ‘gas’) density is obtained by using the Redlich-Kwong equation of state. The model was accurately tuned and modified as further described below (Redlich and Kwong, 1949).
- The brine density is first approximated as pure water then corrected for salt and $CO_2$ concentration by using Ezrokhi’s method (Zaytsev and Aseyev, 1992).
- The $CO_2$ gas viscosity is calculated per the methods described by Vesovic et al. (1990) and Fenghour et al. (1999).

The gas density was obtained using a modified Redlich-Kwong equation of state following a method developed by Spycher and Pruess, where the attraction parameter is made temperature dependent:

$$P = \left(\frac{RT_K}{V - b_{mix}}\right) - \left(\frac{a_{mix}}{T_K^{1/2} V (V + b_{mix})}\right)$$

where $V$ is the molar volume, $P$ is the pressure, $T_K$ is the temperature in Kelvin, $R$ is the universal gas constant, and $a_{mix}$ and $b_{mix}$ are the attraction and repulsion parameters.

The transition between liquid $CO_2$ and gaseous $CO_2$ can lead to rapid density changes of the gas phase; the simulator uses a narrow transition interval between the liquid and gaseous density to represent the two phase $CO_2$ region.

Because the compression facility controls the $CO_2$ delivery temperature to the injection well between 80°F and 120°F, the temperature of the injectate will be comparable to the reservoir formation temperature within the injection interval. Therefore, the simulations were carried out based on isothermal operating conditions. With respect to time step selection, the software algorithm optimizes the time step duration based on specific convergence criteria designed to minimize numerical artifacts. For these simulations, time step size ranged from $8.64 \times 10^1$ to $8.64 \times 10^5$ seconds or 0.001 to 10 days. In all cases, the maximum solution change over a time step is monitored and compared with the specified target. Convergence is achieved once the model reaches the maximum tolerance where small changes of temperature and pressure calculation results occur on successive iterations. New time steps are chosen so that the predicted solution change is less than a specified target.

*Description of AoR Delineation Modeling Effort*

The 3D geologic model developed for the initial injection simulations was based on the interpretation of a diverse collection of geological, geophysical, and petrophysical data acquired throughout the construction of the IBDP wells (CCS#1 and VW#1). Structurally, the model is also based on the interpretation of both two dimensional (2D) and three dimensional (3D) seismic survey data in conjunction with dipmeter log data acquired from the IBDP wells. Petrophysical and transport properties based on the interpreted well log data and the analysis of core samples recovered from the IBDP wells were then distributed throughout each layer in the geocellular model. Following the collection of testing and logging data during construction and pre-operational testing of CCS#2 and VW#2, the geologic model was updated pursuant to 40 CFR 146.82(c)(1).

The original, pre-construction phase model implemented porosity and permeability well logs from CCS#1, VW#1, and VW#2. Seismic inversion was performed on the 3D surface seismic cube resulting in a seismic porosity cube. This seismic porosity cube was integrated with logs to guide interpolation of porosity throughout the 3D model. For the Mt. Simon, the PorosityCube was sampled into the geomodel's 3D grid and was also used to describe lateral heterogeneity beyond the seismic survey's footprint. A workflow was prepared to document log upscaling and property modeling. To update the reservoir model following pre-injection testing, logs from CCS#2 were used to update the 3D geologic model to reflect new information while remaining true to the original seismic property-driven distributions that did not require updates. The following steps were followed to incorporate CCS#2 well log data into the model domain permeability and porosity distributions:

1. Log (ELAN) permeability curves were upscaled into the static geologic model.
2. Permeability was log transformed.
3. General distribution was developed from log-permeability data.
4. The log permeability distribution was updated through co-simulation of VW#2 and CCS#2 log-permeability data with the existing 3D model log-permeability distribution and using the general log-permeability pdf developed from the data. The result honors the new log data at and near the wells and honors the seismic driven distribution as a trend away from VW#2 and CCS#2.
5. Permeability was inverse log transformed.
6. Steps 3 through 5 were done on a zone-by-zone basis.
7. The new permeability distribution was upscaled into a reservoir model grid and the existing permeability distribution for the CCS#2 injection zone was replaced with the newly computed permeability distribution within the CCS#2 injection zone across the entire lateral extent of the reservoir model grid.

In November 2011, injection of $CO_2$ into CCS#1 began and, as of project completion in November 2014, 999,215 metric tons of $CO_2$ had been injected. Operational data from this project was used to calibrate the reservoir model being used for both the IBDP and IL-ICCS projects. Data obtained includes injection well bottom hole pressure (BHP), multi-zone pressure data from VW#1, Spinner data, i.e. injection profile logs in CCS#1, and reservoir saturation tools (RST) from both IBDP wells. These datasets have provided additional information to allow calibration of various reservoir parameters including intrinsic permeabilities, relative permeabilities, wellbore skin values, vertical to horizontal permeability ratios, and rock compressibility. These calibrations allow the model to be updated periodically to improve the accuracy between the model prediction versus the actual result.

Monitoring data used for pressure matching includes:

- Injection rate;
- Injection bottom hole pressure – real-time data collected from a down hole gauge in the injection well about 600 ft above the perforations;
- Westbay multilevel ground water characterization and monitoring system pressures – real-time pressures located at specific zones in the verification well 1000 ft. north of the injection well. Five out of ten zones were used for model calibration;
- Spinner data-flow partitioning between perforations – log run in injection well through March 2013; and
- RST well logs – $CO_2$ saturations around CCS#1 and VW#1 – logs run through March 2013.

More detailed information on model inputs and assumptions is given in the following subsections.

***Model Inputs and Assumptions***

The geologic/hydrogeologic and operational information that serve as inputs to the model are described in the following subsections. The model update meets the requirements of 40 CFR 146.82(c)(1) and simulates three years of injection in CCS#1, followed by five years of injection in CCS#2, followed by a 50-year post-injection period.

*Site Geology and Hydrology*

The Class VI well targets an injection zone in the Cambrian Mt. Simon Sandstone of the Illinois Basin (see coordinates above under "Facility Information"). Information on the injection and confining zones was collected during the drilling and testing of the nearby IBDP injection well CCS#1, as well as existing Illinois State Geological Survey (ISGS) studies and reports. Data from an ISGS database of core sample data and additional core sample analyses from sites within approximately 30–80 miles of the injection well were also used. Wireline log results from CCS#2 and VW#2 and core analyses from VW#2 were compared to data collected from CCS#1 and the ISGS database. The results show good agreement, validating the local site geology and hydrogeology as defined by data from CCS#1 and other nearby wells.

The Mt. Simon Sandstone is the first formally recognized sedimentary unit overlying the Precambrian granitic basement rock. The depositional environment of the Mt. Simon has "commonly been interpreted to be a shallow, sub-tidal marine environment," based on surface study of the upper Mt. Simon or studies of Wisconsin or Ozark Dome outcrops. However, based on core sample and log analysis from the CCS#1 well, and verified from pre-injection testing on CCS#2 and VW#2, the upper Mt. Simon is interpreted to have been deposited "in a tidally influenced system similar to the reservoirs used for natural gas storage in northern Illinois," while the basal 600 ft (the target injection zone) represents an "arkosic sandstone that was originally deposited in a braided river-alluvial fan system." In this lower zone, "abundant amounts" of secondary porosity occur due to the dissolution of feldspar grains. A sedimentary interval known as the "pre-Mt. Simon" is present at the base of the Mt. Simon, bounded by a disconformity (between the Mt. Simon and the pre-Mt. Simon). The pre-Mt. Simon is lithologically similar to the Mt. Simon but with significantly lower porosity and permeability than the overlying Mt. Simon (Freiburg, Morse, Leetaru, Hoss and Yan, 2014).

Directly overlying the Mt. Simon Sandstone is the Cambrian Eau Claire Formation. Based on data from CCS#1, in the area of the injection well, the Eau Claire consists of a basal shale layer overlain by very fine-grained limestone interbedded with thin siltstone layers. The Eau Claire serves as a confining zone for gas storage projects elsewhere in the Illinois Basin. Two other regional shale units are identified as secondary confining zones—the Ordovician Maquoketa Formation and the Devonian New Albany Shale—though these units lie above the lowermost USDW. No resolvable faults or folds were identified in the injection or confining zones based on 3D seismic data collected in 2011. Pre-injection testing in CCS#2 and VW#2 confirmed the absence of faults and folds based on the results of fracture finder logs.

Only limited data and modeling results are available on ground water flow in the deep Illinois Basin, which is based on modeling results from Gupta and Bair (1997). Flow patterns in the Mt. Simon are "influenced by the geologic structure with flow away from arches such as the

Kankakee Arch and toward the deeper parts of the Illinois Basin." In the model, an initial fluid pressure of 3,205 psi (at elevation -6,345 ft MSL), an initial temperature of 112ºF (at elevation -5,365 ft MSL; gradient 1ºF/ft), and an initial salinity of 200,000 ppm were used. MSL is defined as mean sea level. Like other areas with humid climates (Freeze and Cherry, 1979), the water table in central Illinois is expected to reflect the elevation of the land surface. Steady-state ground water flow modeling for the IBDP site indicates that shallow ground water flows toward the east and southeast toward the Sangamon River and Lake Decatur.

The lowermost USDW is the Ordovician St. Peter Sandstone, based on TDS sampling of the upper St. Peter during the drilling of CCS#1.

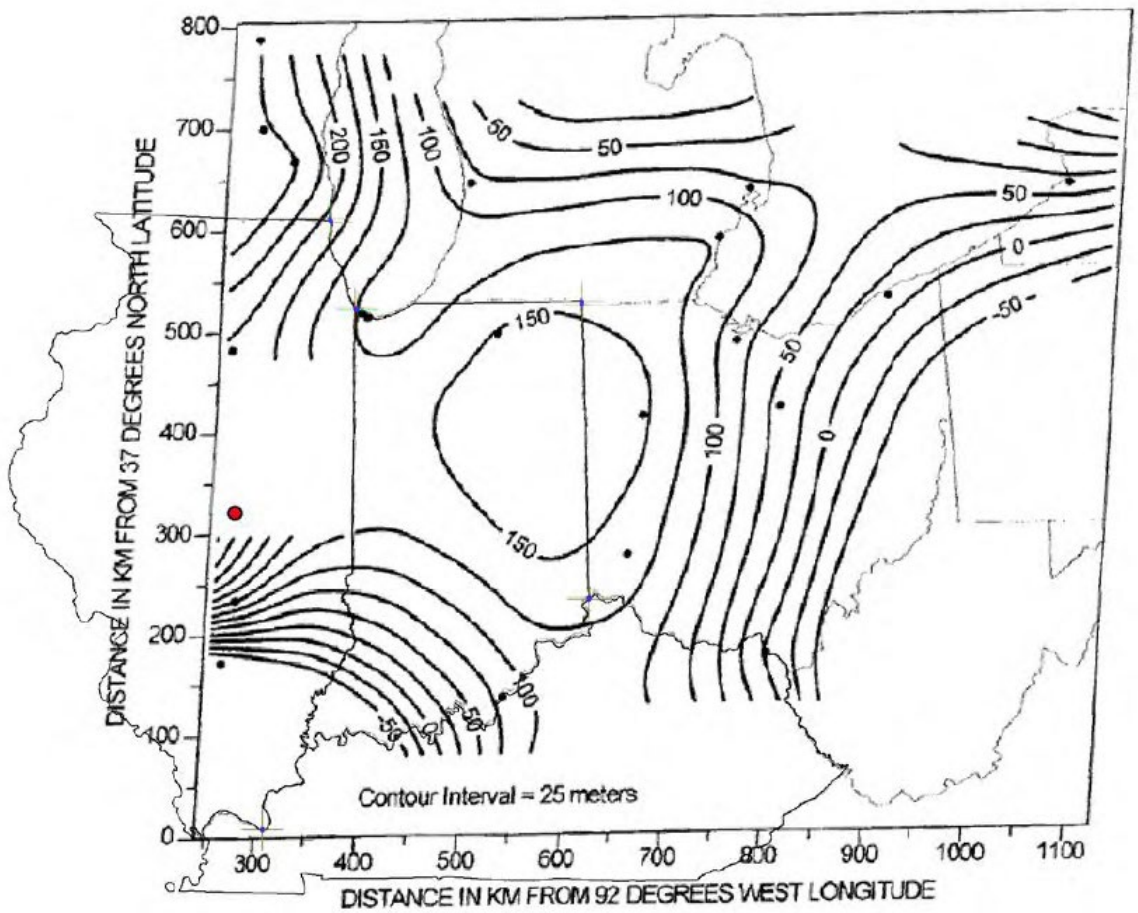


**Figure 1. Observed head in the Mt. Simon Sandstone. The red dot represents the location of CCS#1 (potentiometric surface = 76 m/249 ft above mean sea level).**

## *Model Domain*

The static geological model includes the entire Mt. Simon and the overlying seal (the Eau Claire), spanning a 40 × 40 mile area. The final reservoir model was represented by a 146 × 146 × 148 grid in a Cartesian system with 146 grid points in the x-direction, 146 grid points in the y-direction, and 148 grid points in the z-direction, for a total of 3,154,768 grid points. Model domain information is summarized in Table 1.

**Table 1. Model domain information.**

| | | | |
|---|---|---|---|
| **Coordinate System** | State Plane | | |
| **Horizontal Datum** | NAD27 | | |
| **Coordinate System Units** | ft | | |
| **Zone** | SPCS27-1201 | | |
| **FIPSZONE** | 1,201 | **ADSZONE** | 3,776 |
| **Coordinate of $x_{min}$** | 277,028.18 | **Coordinate of $x_{max}$** | 408,692.78 |
| **Coordinate of $y_{min}$** | 1,103,729.25 | **Coordinate of $y_{max}$** | 1,235,364.89 |
| **Coordinate of $z_{min}$** | -7113.19 | **Coordinate of $z_{max}$** | -4272.78 |

<u>Porosity</u>

*Injection Zone Porosity*

The total porosity of the injection zone was determined based on neutron and density logs of CCS#2, while effective porosity was determined from helium porosimetry on a "limited number" of core samples. The results of these methods compared well to each other, and so neutron-density crossplot porosity was used to approximate effective porosity. Pre-injection testing in CCS#2 identified an optimal injection interval of 6,630 to 6,825 ft KB, with multiple perforations of 6,630 – 6,670; 6,680 – 6,725; 6,735 – 6,775; and 6,781 – 6,825 (all in ft KB). The AoR was modeled using these perforation intervals, with an average effective porosity throughout the injection zone of 22%. Within the AoR, KB (Kelly Bushing) is approximately 682 ft above MSL.

Additionally, the open-hole log based porosity was classified using Schlumberger Elemental Log Analysis (ELAN) as described in the CCS#2 Geophysical Log Descriptive Report. In the log analysis, the log analyst stated that the lower zone of the Mt. Simon has an average porosity of 22%, though there are intervals where the porosity approaches 30%.

Based on the analysis of log results from CCS#2, ADM identified five porosity/permeability zones within the Mt. Simon.. These zones, with the average porosity and permeability values indicated by ADM, are illustrated in Figure 2. Pre-injection testing identified a high porosity/permeability region extending from the base of the Mt. Simon at 7,043 ft KB up to 6,427 ft KB; this overall interval included two sub-units with similar but varying porosity and permeability. The middle section of the Mt. Simon had lower porosity and permeability, extending from 6,427 to 5,907 ft KB. The upper unit from 5,907 to 5,553 ft KB also has high porosity and permeability, but was determined to be too close to the confining zone for injection.

*Confining Zone Porosity*

The median porosity of the Eau Claire Formation is 4.7%, based on information from an ISGS database of UIC well core samples. Pre-injection testing in CCS#2 and VW#2 indicated very small pore sizes based on CMR data, resulting in generally very low permeability (see "Confining Zone Permeability" below).

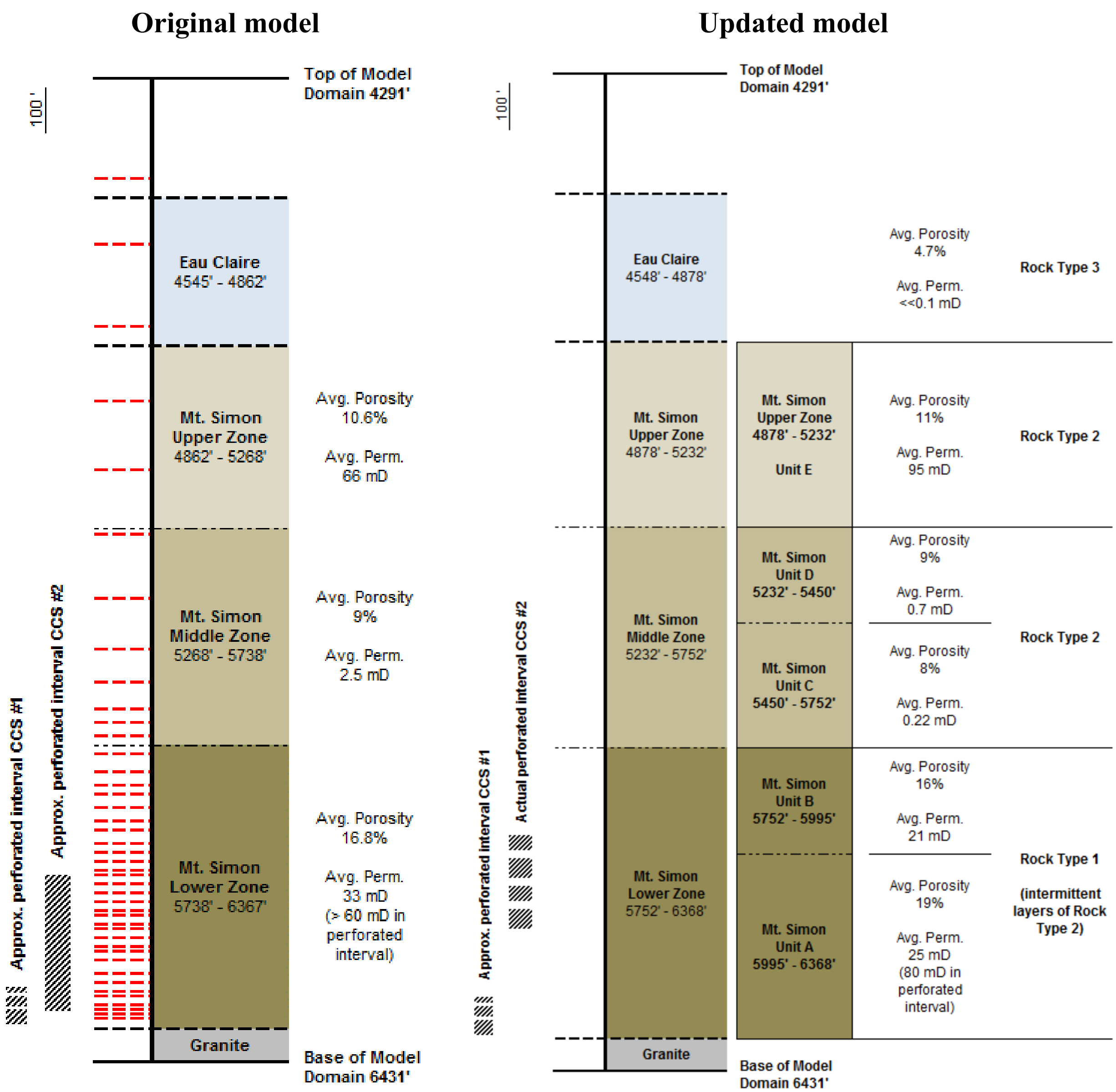


**Figure 2. Reproduced layers of the geologic model and average porosity/permeability values, as identified by ADM based on log analysis, along with the approximate screened intervals of CCS #1 and CCS #2. The column on the left was produced during evaluation of the final AoR model prior to pre-injection testing; the right column incorporates the results of geophysical testing in CCS#2 and VW#2 during pre-injection testing. The updated column shows both the three primary rock types and the five rock types indicated by the wireline logs. The pre-Mt. Simon, not discretely depicted, is accommodated in the model as the four lowest layers of the model (i.e., the base of Mt. Simon Lower Zone/Mt. Simon Unit A in this Figure). Horizontal distances are not to scale, and the representation of layer thickness is approximate.**

## Permeability

### *Injection Zone Permeability*

For the pre-construction modeling effort, ADM determined intrinsic permeability for areas of the injection zone based on available core analyses and CCS#1 well testing results, and developed a core porosity-permeability transform based on grain size to estimate permeability over intervals without core samples. From this method, ADM calculated a geometrical average intrinsic permeability of 194 mD for the CCS#1 injection interval. In the updated modeling effort following pre-operational testing and logging, ADM incorporated the logging and core analyses in CCS#2 and VW#2 using the methods described earlier in this plan. The well log data collected during pre-operational testing were simulated with the existing 3D permeability distribution to develop a new geological model.

ADM also reported additional permeability values based on pressure transient analysis of data from CCS#1 pressure fall-off tests. Using PIE pressure transient software, ADM estimated permeability of 185 mD over 75 ft of vertical thickness in the injection zone. ADM also directly calculated permeability for this interval from core samples and well log analyses, with a result of 80 mD in the perforated interval. Multiple regions in the perforated interval had much higher permeability (above 100mD), as shown in Figure 2.

*Confining Zone Permeability*

During pre-operational testing, ADM collected 33 horizontal and 3 vertical whole core samples, and 2 rotary sidewall core samples, all from VW#2. Three hundred fifty-one (351) core plugs were drilled from the whole core collected from VW#2 and were suitable for routine core property measurements. The rock properties derived from these samples were primarily used to validate and calibrate the ELAN petrophysical model based on well logs. While no core samples were taken from the shale zone of the Eau Claire A at VW#2, 36 plugs of the upper interval Eau Claire C (very fine sandstone, microcrystalline limestone, and siltstone) were available for testing. Of the plugs tested for vertical permeability, the average permeability was 0.036 mD. While no core samples were taken from the shale zone of the Eau Claire A at CCS#1, 12 plugs of the lower portion of the upper interval Eau Claire B/C (very fine sandstone, microcrystalline limestone, and siltstone) were available for testing. Average horizontal permeability for these sidewall rotary core samples was determined to be 0.000344 mD. However, the vertical permeability of the actual shale interval is expected to be much lower because vertical permeability of plugs "is generally lower than horizontal permeability and shale permeability is generally much lower than sandstone, limestone, and siltstone." Based on the analysis of log results from CCS#1 and confirmed by well logs in CCS#2, the Eau Claire, extending from the top of the Mt. Simon to -4,545 ft MSL (-5,227 ft KB), is described as having "only a few small intervals of less than a few feet that have any permeability greater than 0.1 mD," which do not appear to be continuous.

ADM also cited a median permeability value of 0.000026 mD from the ISGS UIC core database. In addition, based on a set of core samples from a site approximately 80 miles to the north of the proposed Class VI location, of the 110 analyses conducted, most were in the range of < 0.001 to 0.001 mD, with five in the range of 0.100 to 0.871 mD (the maximum value in the data set). This indicates that even the more permeable beds in the Eau Claire Formation are expected to be relatively tight and tend to act as sealing lithologies.

*Operational Information*

The proposed injection well, CCS#2, is part of the IL-ICCS project. The other $CO_2$ injection well on ADM's property, IDBP well CCS#1, was completed in 2009. The AoR modeling accounts for both injection operations, and the details are presented in **Error! Reference source not found.**.

**Table 2. Operating details for CCS#1 and CCS#2, as used in the model.**

<table>
<tr><th colspan="2">Parameters and units</th><th colspan="3">CCS#1</th><th colspan="4">CCS#2</th></tr>
<tr><td rowspan="2">Model coordinates (ft)</td><td>X</td><td colspan="3">342,848.58</td><td colspan="4">344,366.37</td></tr>
<tr><td>Y</td><td colspan="3">1,169,545.00</td><td colspan="4">1,172,887.91</td></tr>
<tr><td colspan="2">Screened intervals</td><td colspan="3">3</td><td colspan="4">4</td></tr>
<tr><td rowspan="2">Screen depth<br>(ft, KB = 682 ft)</td><td>Ztop</td><td>6976</td><td>6982</td><td>7024</td><td>6630</td><td>6680</td><td>6735</td><td>6787</td></tr>
<tr><td>Zbottom</td><td>6978</td><td>7012</td><td>7050</td><td>6670</td><td>6725</td><td>6775</td><td>6825</td></tr>
<tr><td rowspan="2">Screen elevation (ft)</td><td>Ztop</td><td>6294</td><td>6300</td><td>6342</td><td>5948</td><td>5998</td><td>6053</td><td>6105</td></tr>
<tr><td>Zbottom</td><td>6296</td><td>6330</td><td>6368</td><td>5988</td><td>6043</td><td>6093</td><td>6143</td></tr>
<tr><td colspan="2">Screened interval length (ft)</td><td>2</td><td>30</td><td>26</td><td>40</td><td>45</td><td>40</td><td>38</td></tr>
<tr><td colspan="2">Wellbore diameter (in.)</td><td colspan="3">12.25</td><td colspan="4">12.25</td></tr>
<tr><td colspan="2">Injection duration (years)</td><td colspan="3">3</td><td colspan="4">5</td></tr>
<tr><td colspan="2">Injection rate (MMT/year)</td><td colspan="3">0.333</td><td colspan="4">1</td></tr>
<tr><td colspan="2">Fracture gradient (psi/ft)</td><td colspan="3">0.715</td><td colspan="4">0.715</td></tr>
<tr><td colspan="2">Max. injection pressure, as submitted (psi)</td><td colspan="3">5,024</td><td colspan="4">4,266</td></tr>
<tr><td colspan="2">Elevation (subsurface depth - KB) corresponding to max. pressure, as submitted by ADM (ft)</td><td colspan="3">6,343</td><td colspan="4">6,630</td></tr>
<tr><td colspan="2">Max. injection pressure (90% of frac. pres.) at the top of the screened interval, calculated from frac. gradient (psi)</td><td colspan="3">4,489.06</td><td colspan="4">4,266.41</td></tr>
<tr><td colspan="2">Subsurface elevation at the top of the screened interval, calculated from frac. gradient (ft)</td><td colspan="3">6,976</td><td colspan="4">6,630</td></tr>
</table>

*Fracture Pressure and Fracture Gradient*

*Injection Zone*

A step rate test at CCS#1, in the interval of -7,025 ft KB to -7,050 ft KB was conducted to estimate the fracture pressure of the injection zone. The result from the uppermost perforation of CCS#1 (-7,025 ft KB) was 5,024 psig, corresponding to a fracture gradient of 0.715 psi/ft. Based on this result, ADM estimated the maximum injection pressure for CCS#1 as 3,995 psi based on the calculated fracture pressure at -6,345 ft MSL. As shown in Table 2, the elevation that corresponds to the top of the injection interval at CCS#1 is -6,283 ft MSL, which corresponds to a fracture pressure of 4,398.1 psi using the 0.7 psi/ft fracture gradient. Therefore, a maximum injection pressure of 3,958.29 psi at the top of the perforated interval (90% of the fracture pressure) is used for CCS#1.

Using the same approach for CCS#2, the maximum injection pressure value is calculated to be 4,266 psi at elevation -6,630 ft MSL. Similarly, the maximum injection pressure is calculated for the top of the injection interval, which corresponds to an elevation of -5,948 ft MSL. Based on the fracture gradient of 0.715, the maximum injection pressure at this point is calculated to be 3,792.6 psi. These values are given in **Error! Reference source not found.** above.

It was determined that these values (calculated based on CCS#1 results) accurately represent the system and will continue to be used for the fracture gradient and fracture pressure for CCS#2, until and unless more accurate project-specific data are available. A step-rate test run after the construction of CCS#2 yielded results that do not contradict initial fracture pressure gradient estimates, although some testing did produce inconclusive results. Injection pressure limits based upon this fracture pressure gradient should not create new fractures or extend any existing fractures. However, additional precautions for initial injection operations and monitoring have been added to Attachment A of this permit.

*Confining Zone*

A “mini-frac” field test was used to determine in-situ fracture pressure in the confining zone. Fracture pressure results (from four short-term injection/fall-off test periods, 15 to 60 minutes each) ranged from 5,078 to 5,324 psig, corresponding to a fracture gradient ranging from 0.93 to 0.98 psi/ft in the Eau Claire shale zone.

<u>*Initial Conditions*</u>

Fluid sampling and testing were conducted in August 2015 in VW#2, including in-situ measurements of formation pressure and temperature and the collection of eight fluid samples at five depths. A temperature log was run in CCS#2 in 2015. The results are as follows:

- Temperature increased consistently with depth from 60 °F at 50’ to 100 °F at 6,950 KB with an average temperature gradient of 0.0058 °F/ft.
- Formation pressure was 3,200 psi at 6,980 KB with a pressure gradient of 0.46 psi/ft. The pressure ranged from 2,626 psi at 5,848 KB to 3,211 psi at 7,041 KB.
- Fluid density ranged from 1,101 g/L to 1,136 g/L, with an average of 1,124 g/L (of the four samples collected).
- TDS ranged from 149,830 ppm at 5,848 KB to 199,950 ppm at 7,041 KB with an average of 184,053 ppm (of the four samples collected).

**Original initial condition information submitted by ADM during permitting:**

- Temperature ranged from 119.8°F at 5,772 ft to 125.8°F at 6,912 ft.
- Formation pressure ranged from 2,583 psi at 5,772 ft to 3,206 psi at 7,045 ft.
- Fluid density ranged from 1,090 g/L to 1,137 g/L, with an average of 1,119 g/L (of the five samples taken).
- TDS ranged from 164,500 ppm at 5,772 ft to 228,100 ppm at 7,045 ft, with an average of 196,700 ppm.

The values presented above from pre-operational testing activities are consistent with the values presented in the initial permit application and pre-construction modeling effort.

_Boundary Conditions_

No-flow boundary conditions were applied to the upper and lower boundaries of the model, with the assumption that the reservoir and the caprock are continuous throughout the region. A pore volume multiplier of 10,000 was applied to each cell in the horizontal boundaries of the ECLIPSE model in order to simulate an extensive reservoir. The horizontal boundaries were selected as: hydrostatic initial conditions for the aqueous phase, no-flow conditions for the gas phase, and initial conditions for salt. No changes were made to the boundary conditions following pre-operational testing.

_AoR Pressure Front Delineation_

To delineate the pressure front, the minimum or critical pressure ($P_{i,f}$) necessary to reverse flow direction between the lowermost USDW and the injection zone—and thus cause fluid flow from the injection zone into the formation matrix—must be calculated. ADM calculated $P_{i,f}$ using the method provided in the March 2011 draft of the *UIC Program Class VI Well Area of Review and Corrective Action Evaluation Guidance*, where the pressure front is given by:

$$P_{i,f} = P_u \cdot \frac{\rho_i}{\rho_u} + \rho_i g \cdot (z_u - z_i)$$

Where:

$P_u$ = initial pressure of the lowermost USDW,
$\rho_i$ = fluid density of the injection zone,
$\rho_u$ = fluid density of the lowermost USDW,
g = acceleration due to gravity,
$z_u$ = elevation of the lowermost USDW, and
$z_i$ = elevation of the injection zone.

Using this method, ADM calculated a $P_{i,f}$ value equal to 171 psi (1.18 MPa).

As an alternative approach for estimating a critical pressure in the injection zone, in December 2013, ADM applied a method developed and published by Nicot et al. (2008):

$$\frac{\Delta P}{g} = \frac{\xi}{2}(z_u - z_i)^2$$

This method estimates a pressure differential that would displace fluid initially present in a hypothetical borehole into the lowermost USDW and is based on two assumptions: (1) hydrostatic conditions; and (2) initially linearly varying densities in the borehole and constant density once the injection zone fluid is lifted to the top of the borehole.

ADM used the Nicot method to calculate the pressure differential based on an injection depth of -6,628 ft KB and a lowermost USDW depth of approximately -3,450 ft KB. The results yield an estimate of approximately 62.2 psi (0.43 MPa).

### *Model Calibration*

The site model has been calibrated using operational data obtained from the IBDP project through January 2013. The IBDP injection rate was input into the simulation to calculate the bottom hole pressures and pressures at five different zones at the verification well. The simulated pressures compared well to the observed pressures. Reservoir permeability and skin were the main parameters impacting the injection pressure calibration and were used as fitting parameters. Actual spinner data was used to set the fractions of the total injection between the two sets of perforations in the injection well. These data along with the simulation allowed for fine tuning of the well bore skin values at respective perforations together with the permeability to match injection bottom hole pressure (Figure 3). Once the injection bottom hole pressure was calibrated, simulated pressures at five different zones at the verification well were fine-tuned calibrating the $k_v/k_h$ ratio of the tight sections and compressibility of the reservoir rock (Figure 4).

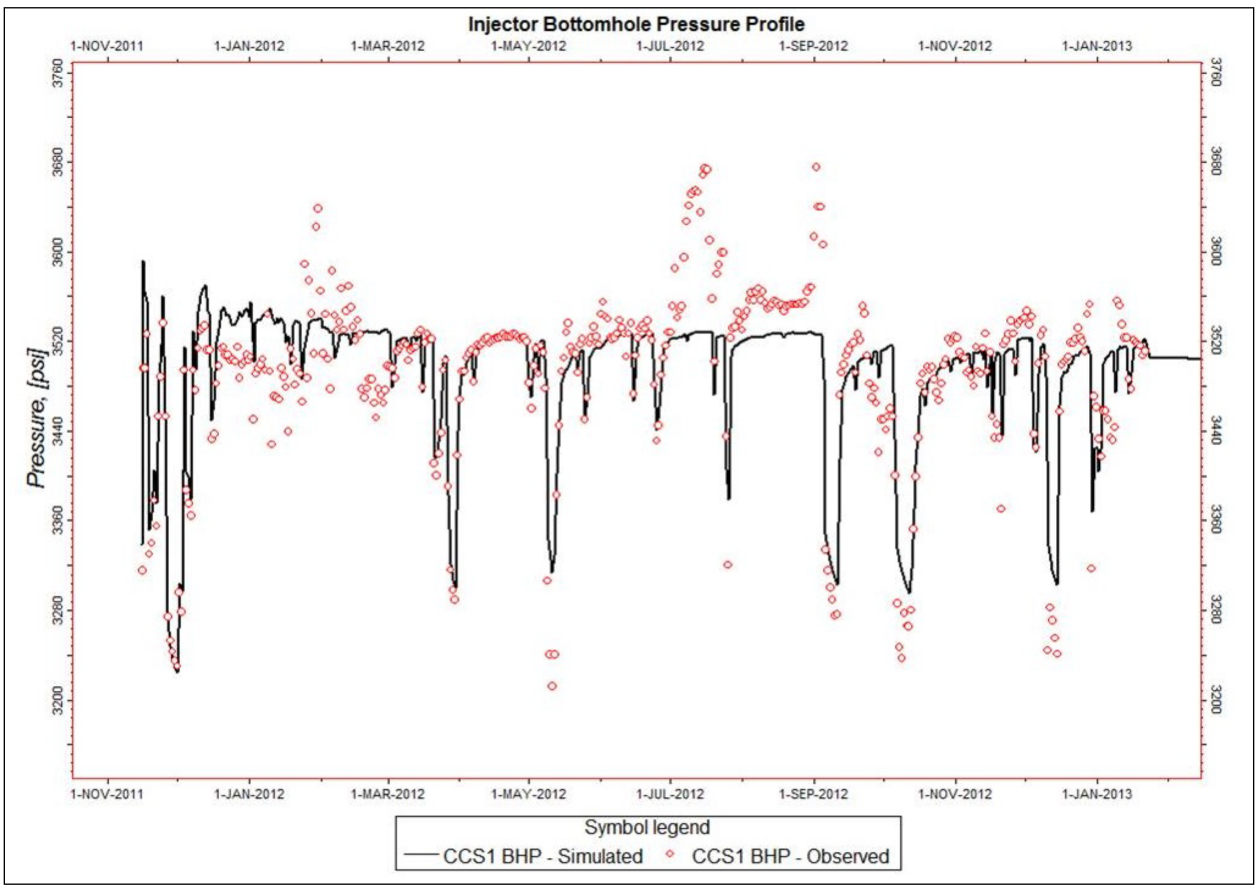


**Figure 3. History Matched Injection Bottom Hole Pressure (BHP) for CCS#1, submitted February 2014.**

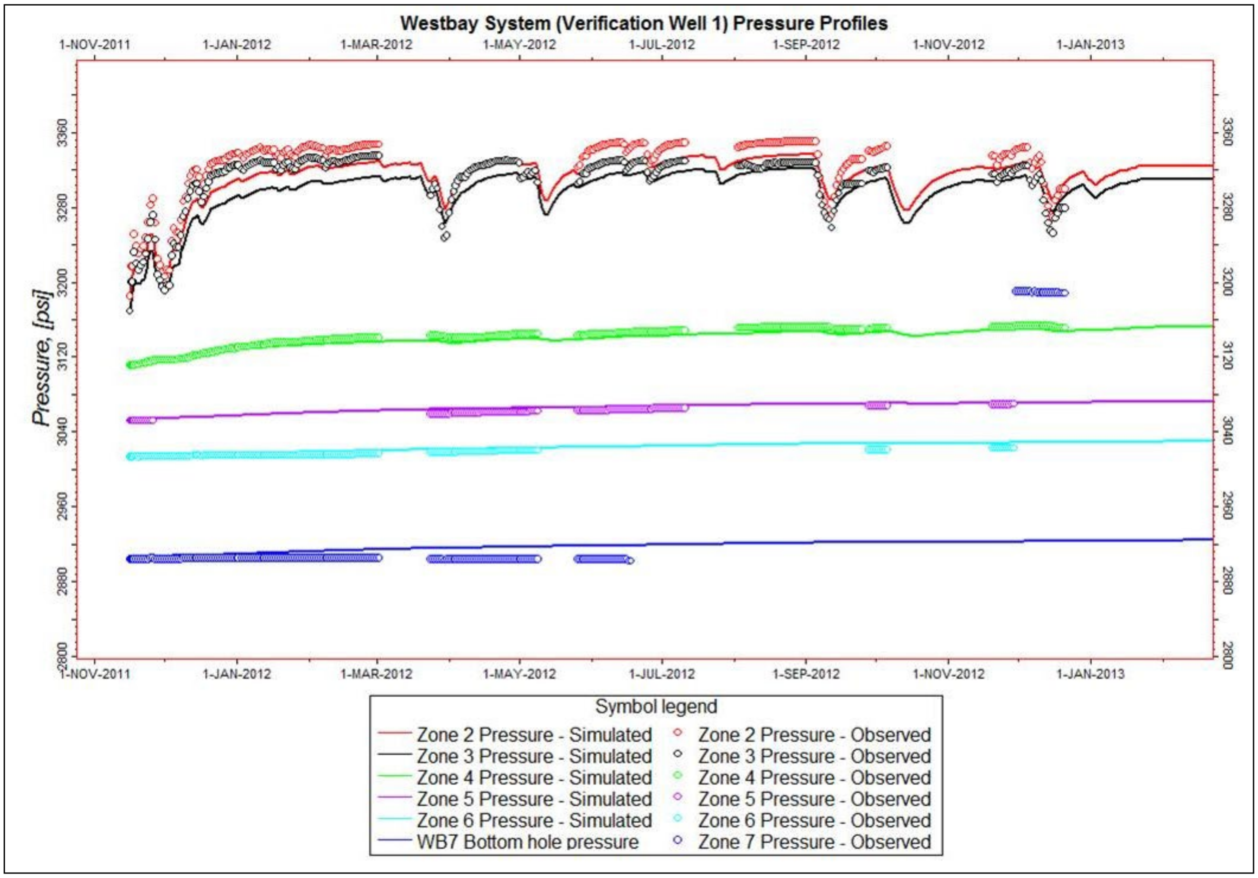


**Figure 4. History Matched Pressures at VW#1 for CCS#1, submitted February 2014.**

RST well logs helped estimate the location, saturation, and thickness of the $CO_2$ column around the injection and verification wells. This information helped fine tune the end points of relative permeability curves which dominate the $CO_2$ and brine flow in the reservoir. Figure 5 and Figure 6 show the relative permeability curves and the constitutive relationships for the reservoir rock types used to characterize the lower and middle Mt. Simon storage units. Figure 5 shows the relative permeability with respect to brine saturation ($S_w$), for the $CO_2$-brine system during drainage and imbibition. Where: brine drainage (krw) represents the relative permeability of brine during drainage, brine imbibition (krw) represents the relative permeability of brine during imbibition, $CO_2$ drainage (krg) represents the relative permeability of $CO_2$ during drainage, and $CO_2$ imbibition (krg) represents the relative permeability of $CO_2$ during imbibition. Please note that drainage is defined as $CO_2$ replacing brine in the pores and imbibition is defined as brine replacing $CO_2$ in the pores.

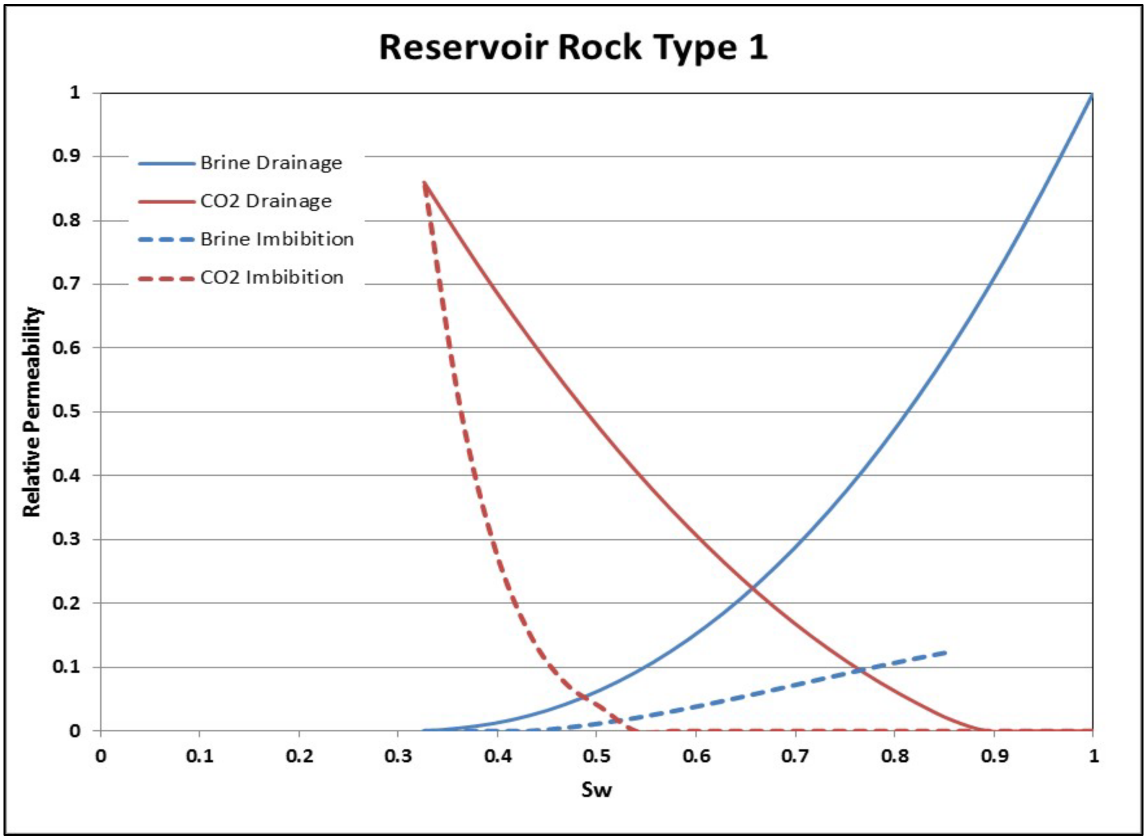


**Figure 5. Calibrated Relative Permeability Curves – Type 1 LL Mt. Simon, submitted March 2016.**

| Rock Type | | Rel. Perm | | Capillary Pressure ($P_c$) |
|---|---|---|---|---|
| | | CO2 | Brine | |
| 1 | Drainage | From lab data<br>See Figure 5 | From lab data<br>See Figure 5 | van Genuchten model (data from Battelle, 2011)<br>$S_e=(S_w-S_{w,ir})/(1-S_{w,ir})$<br>$P_c=\alpha^{-1}[(Se^{-1/m} - 1]^{1/n}$<br>$\alpha = 0.5$<br>$m=0.8$<br>$n=1/(1-m)$ |
| | Imbibition (hysteresis) | From lab data<br>See Figure 5 | From lab data<br>See Figure 5 | No Hysteresis |
| 2 | Drainage | Brooks-Corey (see Krevor et al. 2012)<br>$S_e=(S_w-S_{w,ir})/(1-S_{w,ir})$<br>$K_{rg}=k_{rg}(S_{w,ir})\ (1-S_e)^2\ (1-S_e^{N_{co2}})$<br>$N_{co2} = 4$ | Brooks-Corey (see Krevor et al. 2012)<br>$S_e=(S_w-S_{w,ir})/(1-S_{w,ir})$<br>$K_{rw} = S_e^{Nw}$<br>$N_w=9$ | Brooks-Corey (see Krevor et al. 2012)<br>$P_c=P_e*S_e^{-1/\lambda}$<br>$P_e=0.667$<br>$\lambda = 0.55$ |
| | Imbibition (hysteresis) | Land's model<br>$K_{rg}=k_{rg}(S_{w,ir})\ (1-S_e)^2\ (1-S_e^{N_{co2}})$<br>where<br>$S_e=(S_{w,bt}-S_{w,ir})/(1-S_{w,ir})$<br>$S_{w,bt} = 1- S_{co2,bt}$<br>$S_{co2,bt} = S^*_{co2,c}\ (1-S_{w,ir})$<br>$S^*_{co2,c} = 0.5\ \{(S^*_{co2}- S^*_{co2,r}) + [( S^*_{co2}- S^*_{co2,r})^2 + 4/C\ (S^*_{co2}- S^*_{co2,r})]^{0.5}\}$<br>$S^*_{co2} = S_{co2}/(1-S_{w,ir})$<br>$S^*_{co2,r} = S^*_{co2,i}/(1+C\ S^*_{co2,i})$<br>$S^*_{co2,i} = S_{co2,i}/(1-S_{w,ir})$<br>$C=2.1$<br>$N_{co2} = 4$ | No Hysteresis | Land's model<br>$P_c=P_e*S_e^{-1/\lambda}$<br>where<br>$P_e=0.667$<br>$\lambda = 0.55$<br>$S_e=(S_{w,bt}-S_{w,ir})/(1-S_{w,ir})$<br>$S_{w,bt} = 1- S_{co2,bt}$<br>$S_{co2,bt} = S^*_{co2,c}\ (1-S_{w,ir})$<br>$S^*_{co2,c} = 0.5\ \{(S^*_{co2}- S^*_{co2,r}) + [( S^*_{co2}- S^*_{co2,r})^2 + 4/C\ (S^*_{co2}- S^*_{co2,r})]^{0.5}\}$<br>$S^*_{co2} = S_{co2}/(1-S_{w,ir})$<br>$S^*_{co2,r} = S^*_{co2,i}/(1+C\ S^*_{co2,i})$<br>$S^*_{co2,i} = S_{co2,i}/(1-S_{w,ir})$<br>$C=2.1$ |
| 3 | Drainage | van Genuchten model<br>$S_e=(S_w-S_{w,ir})/(1-S_{w,ir})$<br>$K_{rg}=k_{rg}(S_{w,ir})\ (1-S_e)^{1/2}\ (1-S_e^{1/m})^{2m}$<br>$m=0.41$ | van Genuchten model<br>$S_e=(S_w-S_{w,ir})/(1-S_{w,ir})$<br>$K_{rw} = S_e^{1/2}[1-(1-S_e^{1/m})^m]^2$<br>$m=0.41$ | van Genuchten model (entry pressure obtained from Lahann et al. , 2014)<br>$P_c=\alpha^{-1}[(Se^{-1/m} - 1]^{1/n}$<br>$n=1/(1-m)$<br>$\alpha=6.495E-2$<br>$m=0.41$ |
| | Imbibition (hysteresis) | No Hysteresis | No Hysteresis | No Hysteresis |

**Figure 6. Constitutive relationships for rock types used in AoR modeling, submitted March 2016.**

Using the calibrated model, a predictive simulation was run to evaluate plume development and pressure perturbation during the course of injection.

### *Computational Modeling Results*

The map below presents the AoR based on the modeling results (the maximum extent of the plume and pressure front), along with wells identified within the AoR.

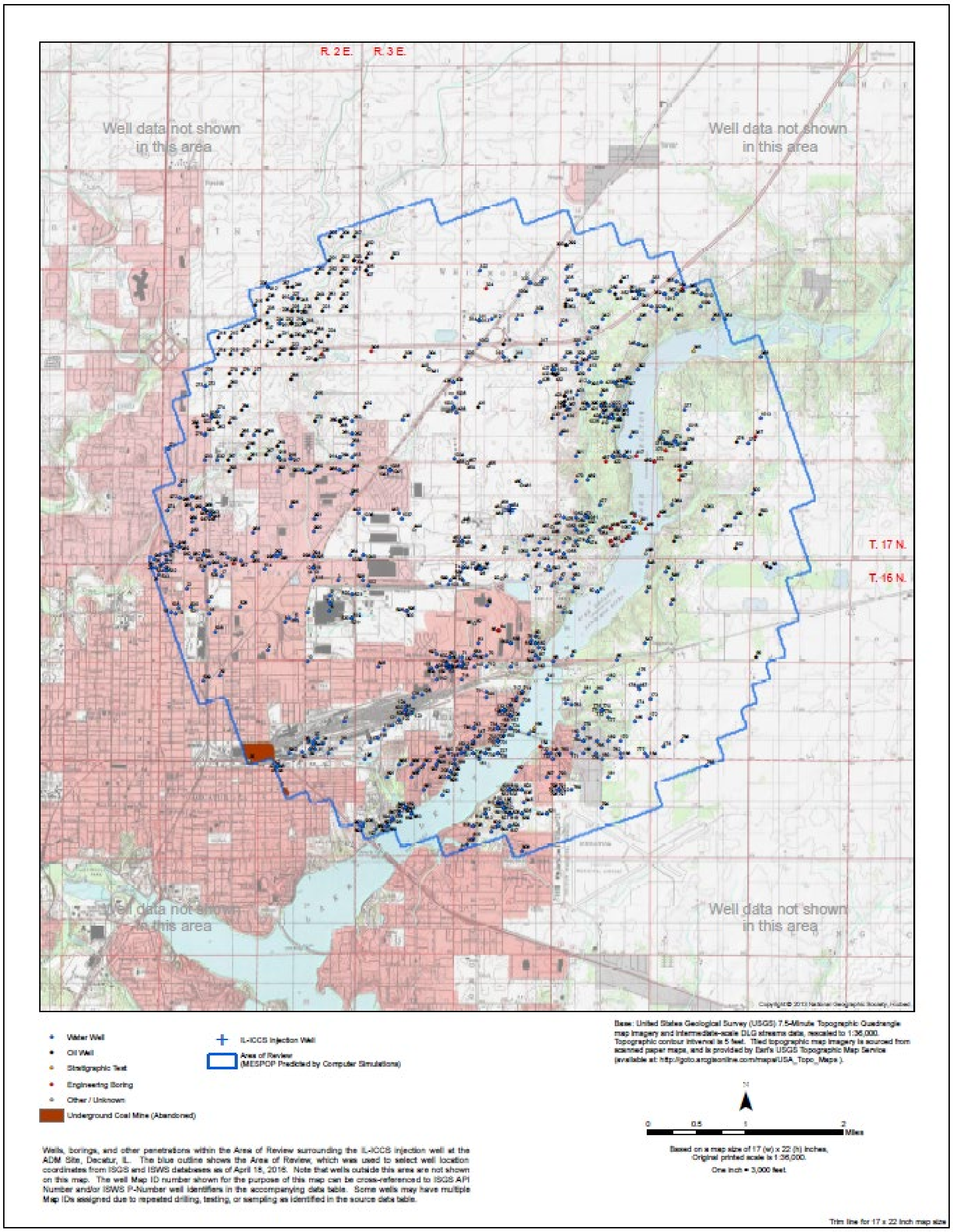


**Figure 7. Map of the AoR as delineated by the reservoir model simulation.**

The surface area of the AoR is 34.17 square miles. The predicted evolution of the plume and pressure front relative to monitoring locations is shown in the Testing and Monitoring Plan (Attachment C to this permit) and the Post-Injection Site Care (PISC) and Site Closure Plan (Attachment E to this permit).

## Corrective Action Plan and Schedule

Based on information from the Illinois State Geological Survey (ISGS) and the Illinois State Water Survey (ISWS) gathered in April 2016, ADM identified a total of 1,065 wells within the AoR. According to Illinois Department of Natural Resources (IDNR) drilling records (and confirmed by ISGS), no additional oil and gas wells were drilled in Macon County between April and September 2016. Except for the wells associated with the IBDP and IL-ICCS projects (as described below), no wells were identified that penetrate the confining zone within the AoR.

### *Tabulation of Wells within the AoR*

#### *Wells within the AoR*

The only existing wells within the AoR which currently penetrate the caprock (Eau Claire Formation) are wells associated with the IBDP and IL-ICCS projects:

- The IBDP injection well, CCS#1 (which is currently permitted as a Class VI well in its post-injection phase and will be used as a monitoring well during the IL-ICCS project).
- The IBDP verification well, VW#1 (which will continue to be used as a monitoring well during the IL-ICCS project).
- The IL-ICCS injection well, CCS#2.
- The IL-ICCS verification well, VW#2.

The latest estimate shows that a total of 1,065 wells are located within the AoR. Water wells (725 of 1,065 wells) are the most common well type. The domestic water wells generally have depths of less than 60 m (200 ft). Other wells include stratigraphic test holes, non-domestic water wells, and oil and gas wells. As part of the original permit application, all wells within the 4 townships-area of the injection well site were also identified (total of 3,761 wells at that time). Information regarding these wells was provided as a supplement to the permit application (available in an electronic format).

Ten oil and gas wells are located within approximately 2.4 km (1.5 miles) of the injection well location. The closest well is located in the northeast quarter of Section 5, T16N, R3E. This well (API number 121150061800) was drilled as a gas well in 1933 and was -27 m (-88 ft KB) deep. There is no record of this well being plugged. This well was likely collecting naturally occurring methane from the Quaternary sediments. The other 9 wells are located in Section 5, T16N, R3E or Section 28 and Section 29, T17N, R3E. The deepest of these oil wells is API number 121152369400, located in the northeast quarter of Section 34. This well was drilled into the Ordovician and was -905 m KB (-2,970 ft KB) deep.

*Wells Penetrating the Confining Zone*

With the exception of the injection and verification wells previously detailed, there are no known wells within the area of review that penetrate deeper than -905 m KB (-2,970 ft KB). The depth to the top of the injection zone (Mt. Simon Sandstone) is -1,690 m KB (-5,545 ft KB). Therefore, there are only four known wells that penetrate into the uppermost injection zone: the IBDP wells CCS#1 and VW#1, and the IL-ICCS wells CCS#2 and VW#2.

If any of these wells are taken out of service during the life of the project, ADM will provide information to EPA to confirm that they have been properly plugged to ensure USDW protection pursuant to requirements at 40 CFR Part 146. If any additional wells that penetrate the confining zone are identified (e.g., if the AoR is re-delineated to cover a larger area as the result of an AoR reevaluation), ADM will complete corrective action as needed pursuant to 40 CFR 146.84(d).

*Wells Requiring Corrective Action*

Based on information about the wells in existence at the time of permit issuance, no corrective action is required prior to initiation of injection.

***Plan for Site Access***

This is not applicable because no corrective action is required at this time.

***Justification of Phased Corrective Action***

This is not applicable because no corrective action is required at this time.

## Area of Review Reevaluation Plan and Schedule

ADM 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. ADM will:

- Review available monitoring data and compare it to the model predictions. ADM will analyze monitoring and operational data from the injection well (CCS#2), the monitoring and geophysical wells, other surrounding wells, 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 (Attachment C to this permit) and the PISC and Closure Plan (Attachment E to this permit). 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 RST saturation and seismic survey data). Specific activities will include:
    - Correlating data from time-lapse RST logs, time-lapse VSP surveys, and other seismic methods (e.g., 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. Also, 2D and 3D seismic surveys will be employed to determine the plume location as described in the Testing and Monitoring Plan and/or the PISC and Site Closure Plan (as applicable).

        - 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 Quaternary and/or Pennsylvanian strata) monitoring wells, the St. Peter, and the Ironton-Galesville to verifying that there is no evidence of excursion of carbon dioxide 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. ADM 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 represent 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 plume and pressure front movement, ADM 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, ADM 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 the Computational Modeling Section of this 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's type, construction, date drilled, location, depth, record of plugging and/or completion.
  - Determining which abandoned wells in the newly delineated AoR have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs.
  - Performing corrective action on all deficient wells in the AoR using methods designed to prevent the movement of fluid into or between USDWs, including the use of materials compatible with carbon dioxide.
- 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 will be submitted to EPA within one year of the reevaluation. The report will include maps that highlight 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***

ADM will reevaluate the above described AoR every five years during the injection and post-injection phases.

In addition, monitoring and operational data will be reviewed periodically (likely annually) by ADM during the injection and post-injection phases. Given inconclusive results in the CCS#2 step-rate test, ADM will modify their monitoring and reporting schedule to collect and review data more regularly during the first six months of the injection phase. Specifically, pressure and seismic results will be reviewed on a monthly basis to identify any deviations from expected conditions (see Attachment A of this permit for more detail). The reservoir flow model will be history matched against the observed parameters measured at the monitoring wells. Pressure will be monitored as described in the Testing and Monitoring Plan. The time lapse pressure monitoring data will be compared to the model predicted time lapse pressure profiles. ADM will provide a brief report of this review to the UIC Program Director and discuss the findings.

If data suggest that a significant change in the size or shape of the actual $CO_2$ plume as compared to the predicted $CO_2$ plume and/or pressure front is occurring or there are deviations from modeled predictions such that the actual plume or pressure front may extend vertically or horizontally beyond the modeled plume and pressure front, ADM will initiate an AoR reevaluation prior to the next scheduled reevaluation. Such deviations may be evidenced by the results of direct or indirect monitoring activities including MIT failures or loss of MI; observed pressure and saturation profiles; changes in the physical or chemical characteristics of the $CO_2$; any detection of $CO_2$ above the confining zone (e.g., based on hydrochemical/physical parameters); microseismic data indicating slippage in or near the confining zone or microseismic data within the injection zone that indicates slippage and propagation into the confining zone; or arrival of the $CO_2$ plume and/or pressure front at certain monitoring locations that diverges from expectations, as described below.

### *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 the deep ground water (> 3,000 ft below KB) 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 $CO_2$ saturation that indicate the movement of $CO_2$ 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 $CO_2$ 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 measurement. This would be a violation of the permit conditions. The Testing and Monitoring Plan (Attachment C to this permit) and the operating procedures in Attachment A to this permit provides discussion of pressure monitoring and specific procedures that will be completed during the injection start-up period.
- ***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 (Attachment C to this permit) 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.
- ***Seismic Monitoring Identification of Subsurface Structural Features:*** Seismic monitoring data that indicates the presence of a fault or fracture in or near the confining zone or a fault or fracture within the injection zone that indicates propagation into the confining zone. The Testing and Monitoring Plan provides extended information about the microseismic monitoring network.

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 the injection well;
- If there is an exceedance of any Class VI operating permit condition (e.g., exceeding the permitted volumes of carbon dioxide injected); or
- If new site characterization data changes the computational model to such an extent that the predicted plume or pressure front extends vertically or horizontally beyond the predicted AoR.

ADM will discuss any such events with the UIC Program Director to determine if an AoR reevaluation is required.

If an unscheduled reevaluation is triggered, ADM will perform the steps described at the beginning of this section of this Plan.