Kemper County Storage Complex

Proposed Injection Wells MPC 19-2 and MPC 32-1

Mississippi Power Company

Post-Injection Site Care and Site Closure Plan

40 CFR 146.93

Facility Information

Facility Name:	Kemper County Storage Complex Well Names: MPC 19-2 and MPC 32-1
Facility Contact:	Mississippi Power Company Environmental Affairs P.O. Box 4079 Gulfport, MS 39502-4079
Well Locations:	Kemper County, Mississippi MPC 19-2 Latitude: 32.6130560, Longitude: -88.8061110 MPC 32-1 Latitude: 32.5908015, Longitude: -88.7792582

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List of Acronyms/Abbreviations

AoR	Area of Review
CCUS	Carbon capture, utilization, and storage
CO_2	Carbon dioxide
CMG	Computer Modelling Group
DOE	Department of Energy
ECO_2S	Establishing An Early Carbon Dioxide Storage
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response
ft	feet
mg/L	milligrams per liter
MMt	Millions of Metric tons
MPC	Mississippi Power Company
PCC	Porters Creek Clay
PISC	Post-Injection Site Care
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
RCA	Routine Core Analysis
SS	Sub- Sea
TMS	Tuscaloosa Marine Shale
Tonnes	Metric tons
TVD	True Vertical Depth
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water

A. Introduction

The *Post-Injection Site-Care and Site-Closure Plan (PISC-SC)* describes the activities that Mississippi Power Company (MPC) will perform to meet the requirements of 40 CFR 146.93. The PISC-SC plan provides an overview of the computational modeling, sensitivity analysis, post-injection monitoring, and site care and closure plans. The computational modeling overview will describe the method used to determine the areal extent of the CO_2 plume and pressure differential during the post-injection phase. The details of the computational modeling are discussed in the *Area of Review and Corrective Action Plan* and the *Conceptual Model* documents. The results of the modeling work determine the necessary monitoring, site care, and timeframe required to complete the post-injection phase. Upon injection completion, MPC will either submit an amended PISC-SC Plan or demonstrate to the UIC Program Director through monitoring data and modeling results that no amendment to the plan is needed.

The UIC Class VI Rule outlines that the demonstration of protection of USDWs throughout the Post-Injection Site-Care phase must be ensured and that they are not at risk of endangerment in order for MPC to request site closure. A rigorous sensitivity analysis has been performed to assess the impact of variations in reservoir properties to evaluate their effects on the extent of the CO_2 plume and pressure front. The post-injection monitoring and the site-closure plans are described in **Section D** and **Section E**, respectively. The PISC-SC Plan is based on *Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells*[1] and *Draft Underground Injection Control (UIC) Program Class VI Well Project Plan Development Guidance for Owners and Operators* [2].

Based on the results of the sensitivity analysis, MPC is proposing that the post-injection monitoring phase of the project will continue for 20 years after the cessation of

[1] EPA (U.S. Environmental Protection Agency). 2010. *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells Final Rule* (40 CFR 146.93). Washington, D.C.

[2] EPA (U.S. Environmental Protection Agency). 2011. *Draft Underground Injection Control (UIC) Program Class VI Well Project Plan Development Guidance for Owners and Operators*. EPA 816-D-10-012, Office of Water (4606M), Washington, D.C.

injection, at which time MPC plans to submit evidence to the EPA demonstrating that the plume is moving as predicted and no longer poses a risk to USDWs. MPC will then notify the EPA Region 4 UIC Branch with a Notice of Intent (NOI) for site closure at least 120 days before initiating site closure procedures. After authorization has been received from the UIC Program Director, MPC will plug all remaining monitoring wells, as described in the *Injection Well Plugging Plan,* and restore the site to pre-operational conditions.

B. Post-Injection Period Computation Modeling

Computational modeling of the Kemper County Storage Complex for the PISC-SC is reflected in the injection phase modeling efforts conducted for and described in the *Area of Review and Corrective Action Plan*. Modeling was conducted to represent 30 years of injection and 50 years of post-injection. All baseline and monitoring data will be incorporated into the model to track and update predictions of the plume and pressure front evolution with time. The model results show a plume migrating in the up-dip direction to the northeast, which follows the mapped geologic structure. Because of the continuity of the Paluxy Formation, including the lack of lateral confinement, and the favorable reservoir properties, the AoR extent is determined by the CO_2 plume. The model results indicate that the pressure buildup recedes to pre-injection levels once the injection period ends and further shows that the CO_2 plume is predictable in its movement following 20 years of post-injection monitoring (50 years after the start of injection). The modeling work is illustrated in the following sections that detail the difference between a 20- and 50-year post-injection monitoring period. The results indicate that at the end of the proposed post-injection modeling timeframe of 20 years the plume has migrated 2.5 miles from the injection site compared to 3 miles at the end of 50 years.

B.1 Pre- and Post-Injection Pressure Differential

Changes in pressure relative to the initial reservoir conditions were calculated from the simulation model to determine the project AoR. The predicted reservoir pressure prior to injection is considered the initial pressure. Reservoir pressure measurements taken prior to injection can be used to further refine the simulation model's initial pressure distribution. Numerical simulations were conducted for 30 years of CO_2 injection through two injection wells at a rate of 1.45 MMT/year per well. The simulations were continued for an additional 50 years after the cessation of injection to assess the CO_2 plume and pressure front evolution with time. During the post-injection period, the increased reservoir pressure across the storage complex is significantly lower than the 89-psi threshold pressure necessary to force fluids out of the injection zone and into the lowermost USDW (calculations provided in the *Area of Review and Corrective Action Plan*) due to the high permeability and large thickness of the proposed storage reservoir. Therefore, the AoR for the storage complex will be governed by the CO_2 plume extent. During injection, the maximum pressure buildup in the reservoir was observed in the uppermost portion of the Paluxy Formation. Therefore, the pressure buildup images presented through this document are shown for this horizon.

At the injection wells, a maximum pressure differentials of 96 psi and 98 psi were observed in the top perforation blocks of MPC 19-2 and MPC 32-1, respectively, early in the injection phase (**Figure 1**). This pressure is due to the increased saturation of the non-wetting phase which impacts the relative permeability and soon relaxes below the critical threshold pressure of 89 psi, which is necessary to lift fluids to the lowermost USDW. The differential pressure then stabilizes at approximately 80 psi for the remainder of the injection phase.

The fracture gradient is described in detail in the *Geological Site Characterization* section of the permit application. For modeling purposes, a value of 0.58 psi/ft, which is 90% of the maximum calculated fracture gradient, was used to represent the threshold for maximum allowable injection pressure within the Paluxy Formation. This represents a pressure of 2,900 psia. This is outlined in greater detail within the *Area of Review and Corrective Action Plan*.

The Paluxy Formation has been determined to fall within a normal pressure regime with a mean reservoir pressure gradient of 0.427 psi/ft. Samples taken from the MPC 10-4 characterization well indicate a reservoir pressure of 2,197 psia (see *Conceptual Modeling Plan* for more detail). This shows that even with a maximum differential pressure increase of 93 psi over initial conditions, the difference between reported fracture pressure and pressure during injection is approximately 700 psi and demonstrates that the injection process poses no threat to fracturing the Paluxy Formation. Careful monitoring of the injection well will be undertaken during the execution of this project, as described in the *Testing and Monitoring Plan*, and care will be taken to ensure wellbore integrity is maintained to mitigate pressure impacts upon fugitive movement of the CO_2 out of containment.

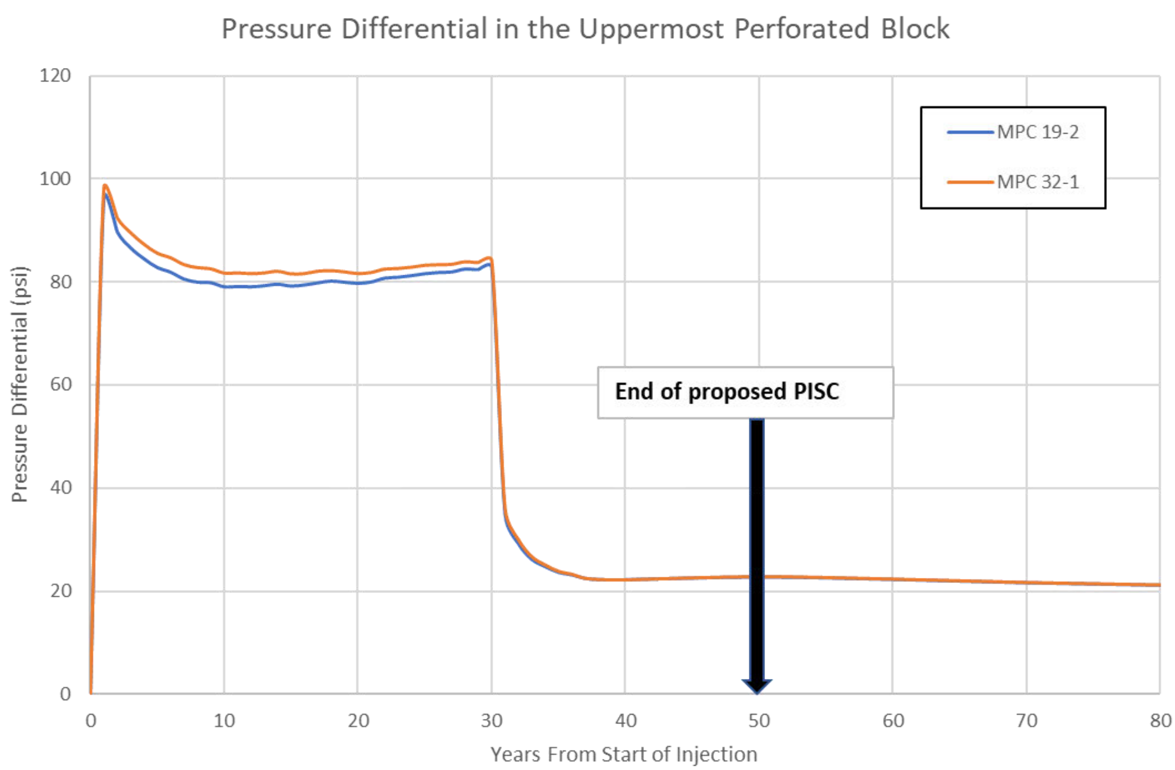

Figure 1: Pressure differentials around the MPC 19-2 and MPC 32-1 injection wells in the upper Paluxy Formation.

A calculated pressure threshold of 89 psi is used to define the extent of the pressure front for the purposes of determining the AoR. The pressure front is defined as "the minimum pressure within the injection zone necessary to cause fluid flow from the injection zone into the formation matrix of the USDW through a hypothetical conduit that is perforated in both intervals"[3]. The AoR is determined by the maximum extent covered

[3] United States Environmental Protection Agency, *Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*, May 2013

by the CO_2 plume and pressure front. Details of the pressure threshold calculations are provided in the *Area of Review and Corrective Action Plan*. The simulation model shows that dynamic reservoir pressures across the storage complex are less than the 89 psi critical pressure throughout the injection period as well as during the post-injection phase. After the cessation of injection, the pressure differential drops sharply and continues to decline with time during the post-injection phase.

To demonstrate this behavior, **Figure 2** and **Figure 3** show the pressure differential for the 30-year injection period and 50 years of post-injection monitoring at 5 locations in the upper Paluxy Formation at distances ranging from 400 ft to 2,000 ft northeast of the injection well. **Figure 4** shows the pressure differential throughout the injection area for the upper Paluxy Formation displayed both in map and cross-section view at the injection well. As these figures demonstrate, the highest pressures seen in the storage reservoir lie at the injection well and once the injection period concludes, the pressure rapidly declines.

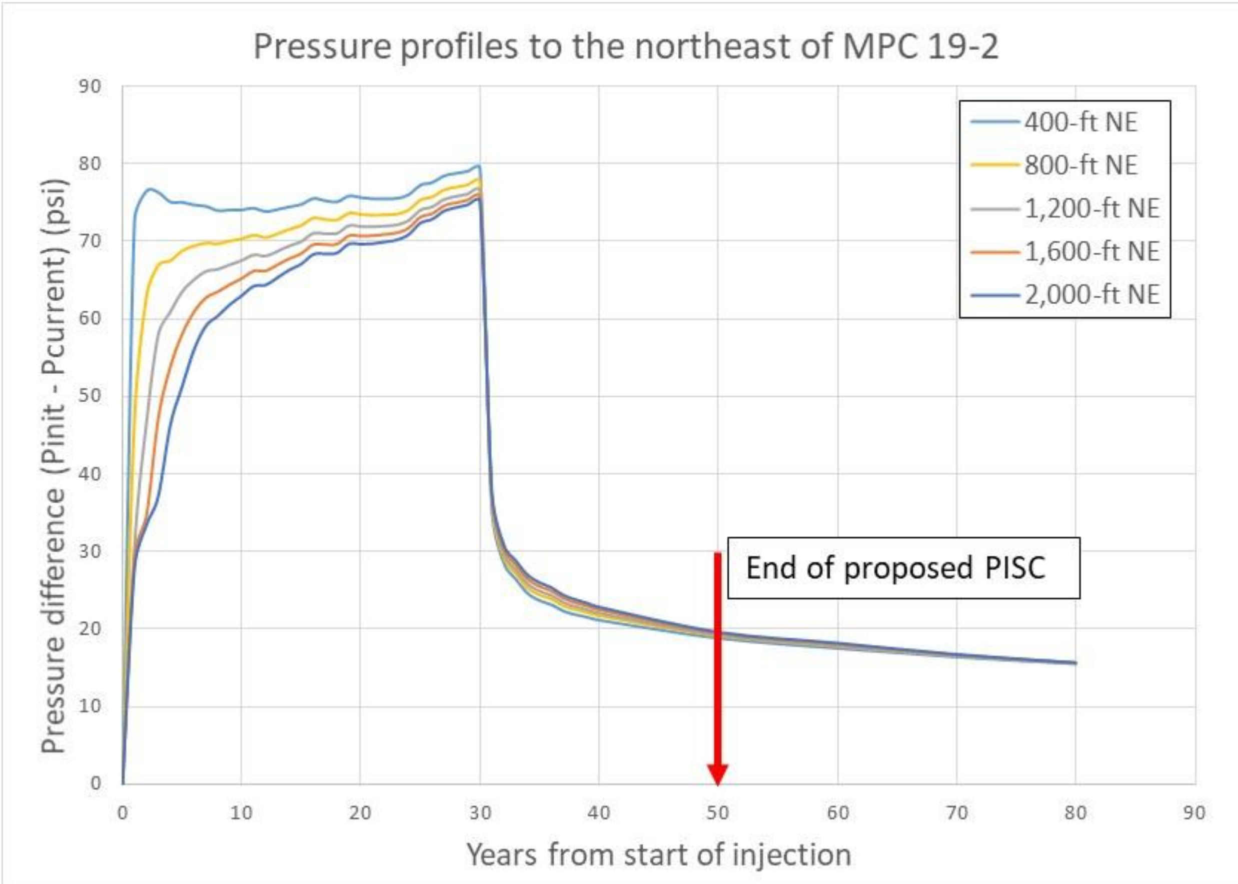

Figure 2: Simulated pressures at the top of Paluxy Formation from 400 ft to 2,000 ft northeast of the Injection Well.

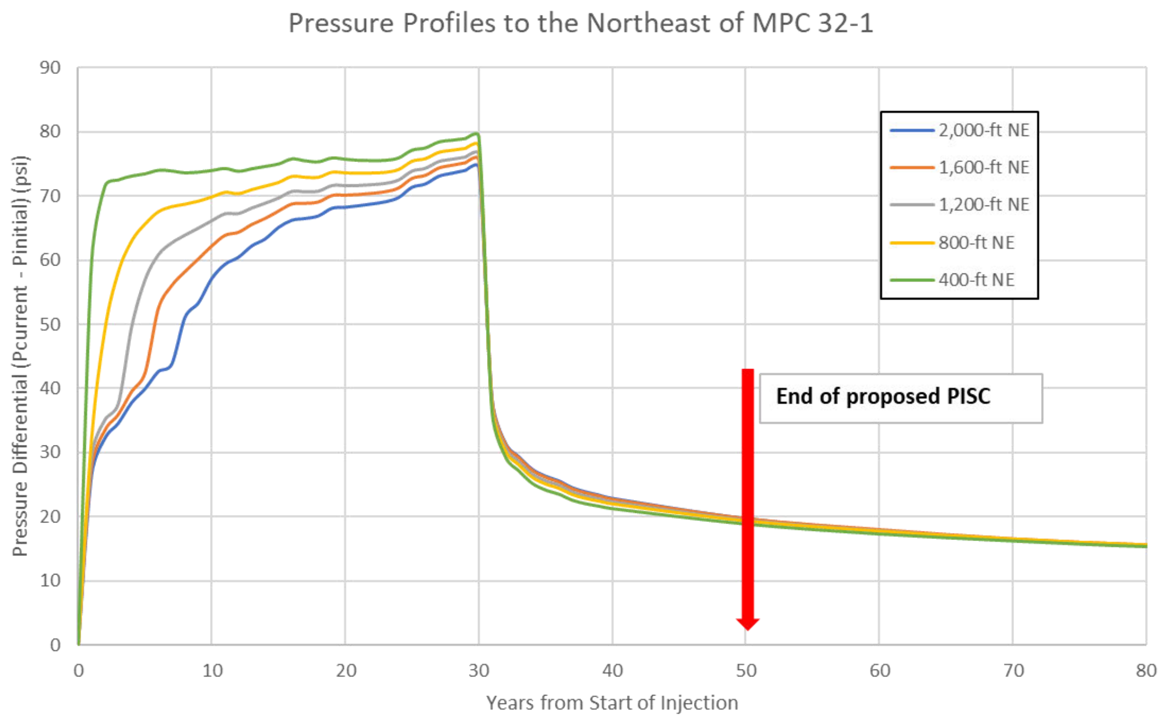

Figure 3: Simulated pressures at the top of Paluxy Formation from 400 ft to 2,000 ft northeast of the Injection Well.

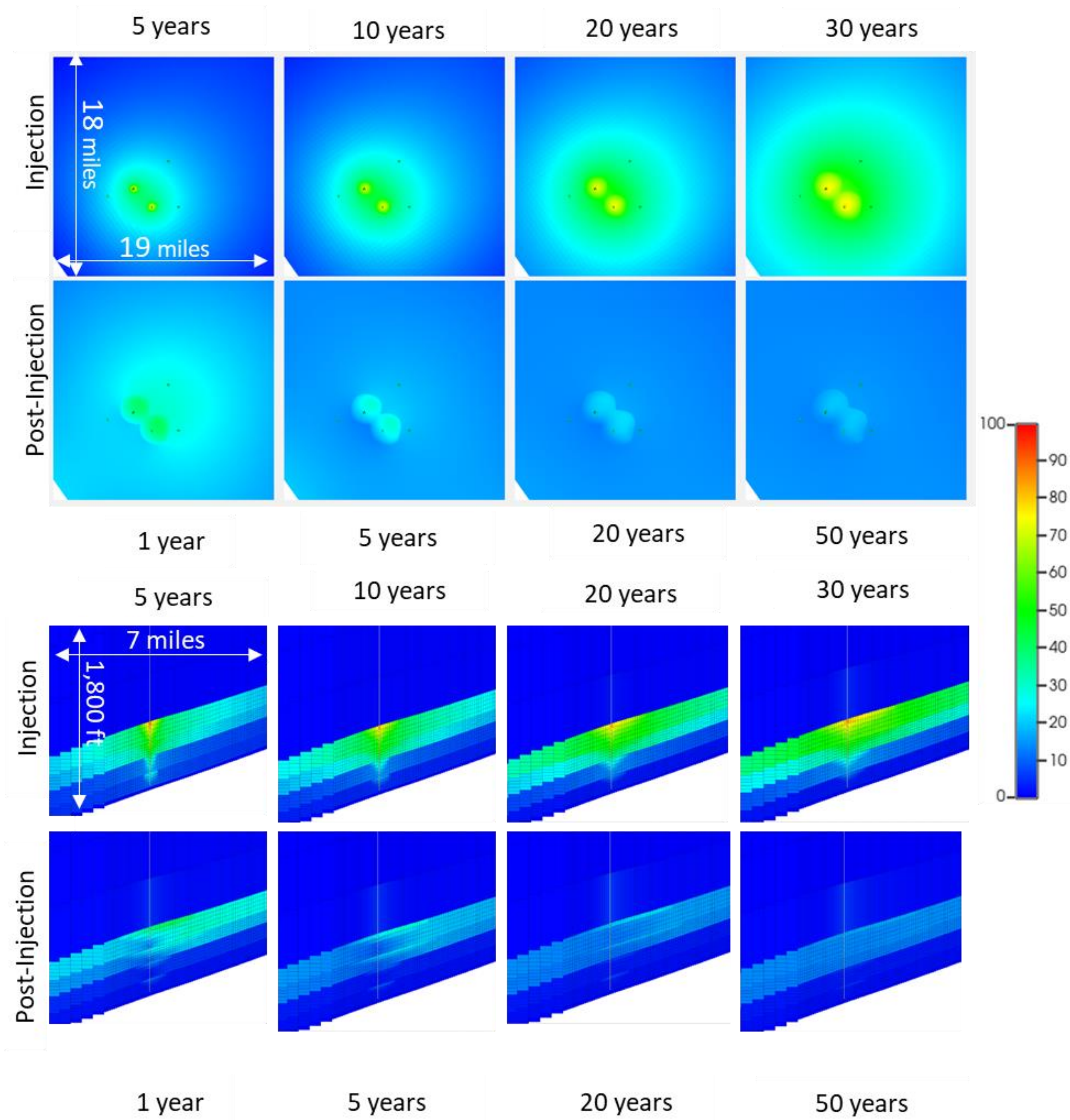

Figure 4: Pressure differential during the injection and post-injection phases. Top maps are the top-view of the upper Paluxy Formation while bottom maps are side-view maps at the injection wells. The scale displays the pressure differential from pre-injection in psi.

B.2 Predicted Three-Dimensional Extent of the Free-Phase CO_2 Plume and Associated Elevated Pressure Front at Site Closure

CO_2 migration during the post-injection period was modeled for a term of 50 years to evaluate CO_2 migration after injection had stopped. Migration was analyzed by mapping the CO_2 plume extent evolution over time. **Figure 5** shows the map and cross-section view for the migration of the CO_2 plume from the proposed MPC 19-2 and MPC 32-1 injection wells during the injection and post-injection period.

Additionally, the cross-sectional view of the plume evolution show that the CO_2 generally migrates upward to the top of the Paluxy Formation and then moves laterally to the northeast in the up-dip direction over time. As expected, the highest modeled CO_2 saturation is in the vicinity of the injection well, as indicated by the color palette in **Figure** 5**.**

The upward CO_2 migration within each Paluxy Formation zone is partially controlled by vertical permeability and gas trapping due to hysteresis. The vertical permeability in the base model is assumed to be 10% of the horizontal permeability. The critical gas saturation in hysteresis is assumed to be 30%, which is a conservative value found in the literature [4]. The impact of this parameter on the plume size is evaluated in the sensitivity analysis described later in this document. The geologic characterization of the Paluxy Formation indicates low permeability shale baffles vertically separating the reservoir into four zones. These baffles are implicitly modeled as zero vertical transmissibility boundaries.

[4] Bachu, S., 2013, *Drainage and imbibition CO_2/brine relative permeability curves at in situ conditions for sandstone formations in western Canada*, Energy Procedia, 37, 4428-4436

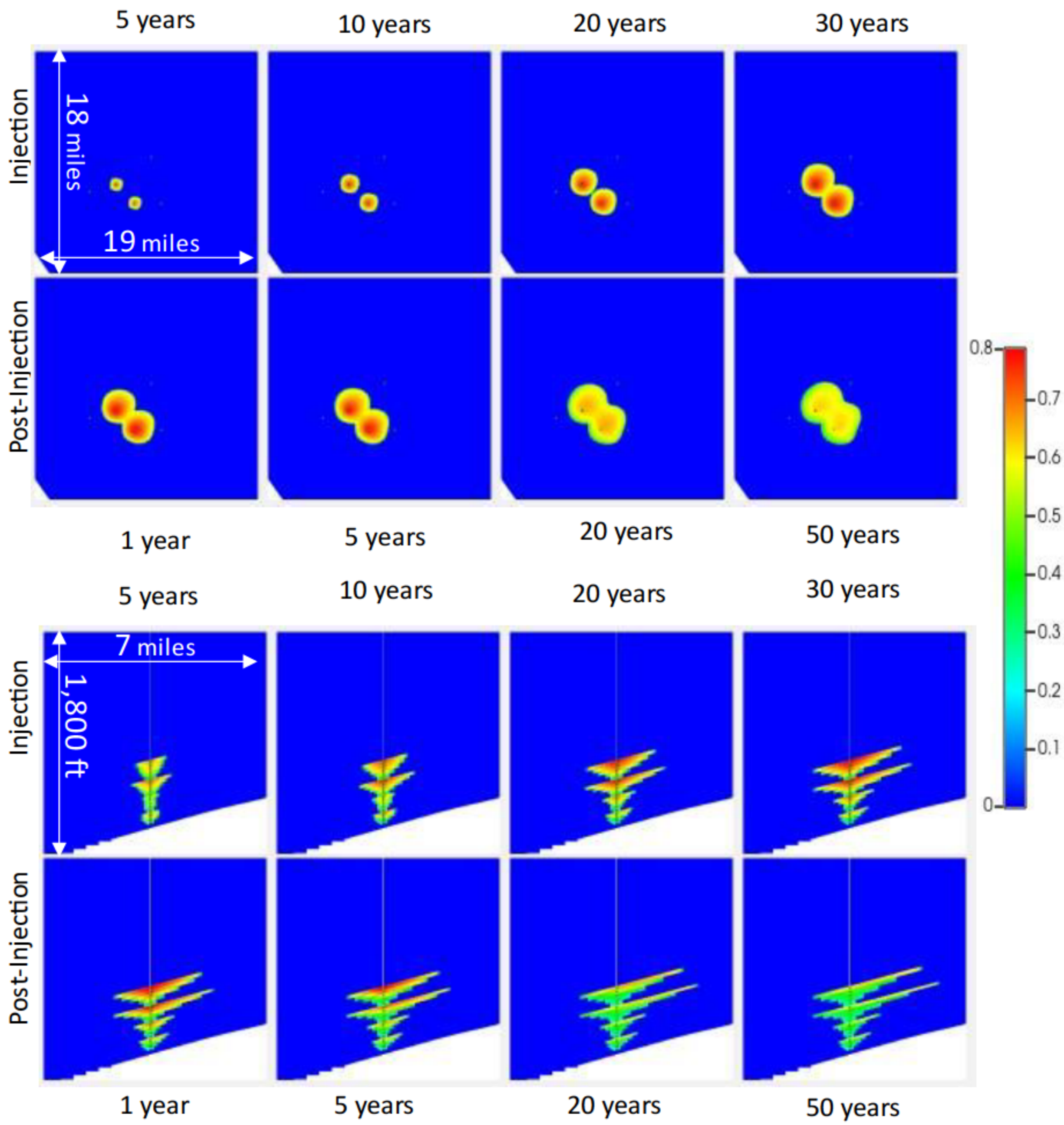

Figure 5: Gas saturation in map and cross-section view at MPC 19-2 and MPC 32-1 locations. The scale describes the CO_2 saturation from 0% to 80%.

B.3. Alternative Timeframe Proposal

The default monitoring timeframe provided by the Class VI guidance documents is 50 years. However, MPC is proposing an alternative timeframe of 20 years for the Post-Injection Site-Care and Site Closure phase of the Kemper County Storage Complex project. The details of this alternative timeline will be demonstrated to prove that, at the end of the 20-year post injection timeframe, the project will no longer pose a risk of endangerment to the overlying USDWs per regulation 40 CFR 146.93(c).

It is recognized that in order to accurately demonstrate that the proposed alternative timeframe is appropriate, several analyses are required. All available site-specific data has been incorporated in the AoR delineation modeling that is outlined in detail in the *Area of Review and Corrective Action Plan*. This data includes reservoir properties from the petrophysical logs and core data obtained from the geologic site characterization phase as well as information relative to the occurrence of geologic formations and their associated structural features. A result of this work, described in detail in the *Geological Site Characterization*, is that the area representing the extent of the Kemper County Storage Complex is structurally benign with no significant fault or fold features that would contribute to the presence of natural fractures potentially acting as conduits for fugitive fluid flow out of the targeted injection reservoir.

Detailed in the following sections is evidence that will demonstrate the proposed 20-year alternative timeframe for Post-Injection Site-Care and Site Closure is appropriate for the reservoir conditions present at the Kemper County Storage Complex. Each of the sensitivity analysis cases indicate a predictable CO_2 plume behavior and absence of a pressure front during the post-injection period. **Figure 6** shows the rate of CO_2 plume migration in the up-dip direction from the injection well. The rate of the CO_2 plume migration slows over time during the post-injection phase. At the end of the 20-year proposed PISC timeframe, the plume is projected to have migrated 2.45 miles away from the injection location which represents approximately 84% of the total plume migration of 2.9 miles modeled through 100 years post-injection. When compared to the migration modeled at 50 years post-injection, the plume has reached roughly 95% of the total migration at a distance of approximately 2.75 miles from injection site. Further, this analysis has also demonstrated that the growth evolution of the plume is similar under a variety of cases due to the regional dip and exceptional geologic storage qualities of the storage complex.

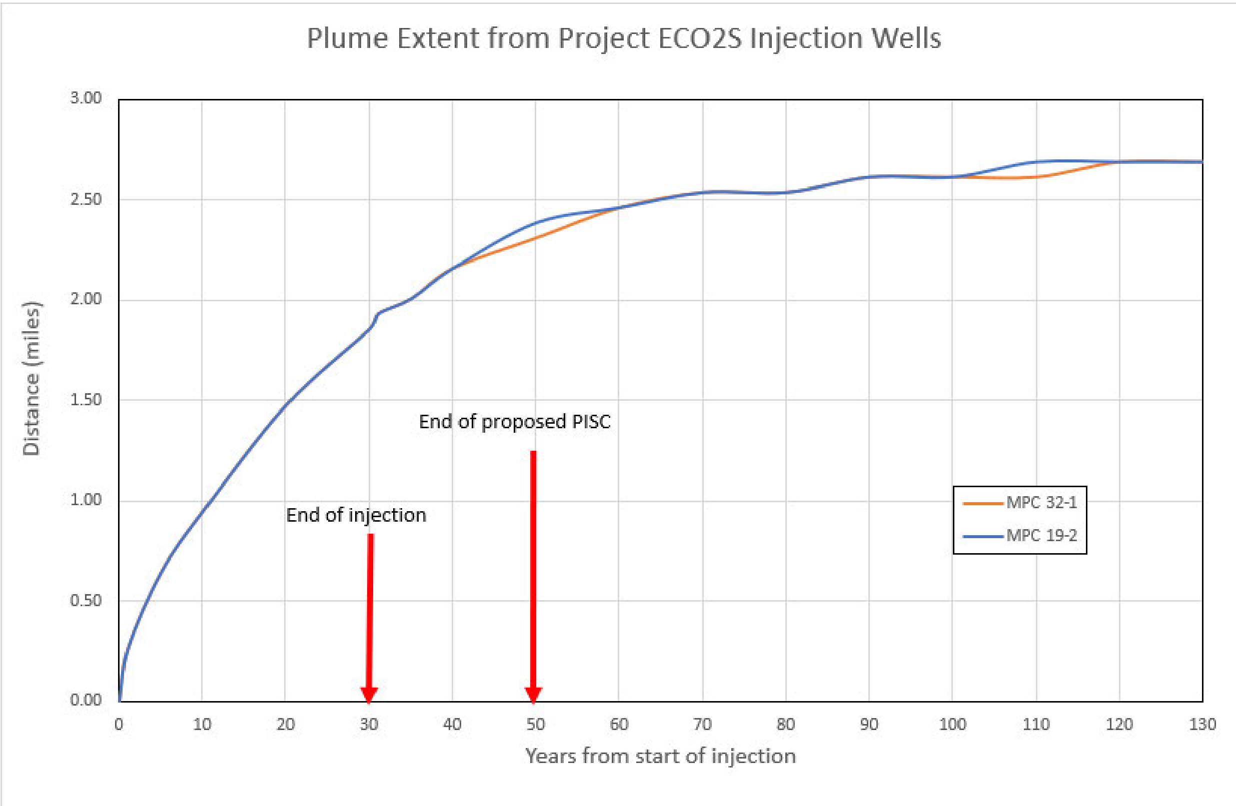

Figure 6: Rate of CO_2 plume migration from MPC 19-2 and MPC 32-1.

The model was run over a period of 500 years, with time-zero represented by January 1, 2021, to evaluate the long-term development of the CO_2 plume and identify a timeframe in which the plume ceases further expansion. At a period of 140 years post-injection the model indicates that the plume has reached its maximum size, shown in **Figure 7** in year 2161. **Figure 8** through **Figure 10** show 10-year time slices at 2171, 2181, and 2191 which show no further growth of the CO_2 plume.

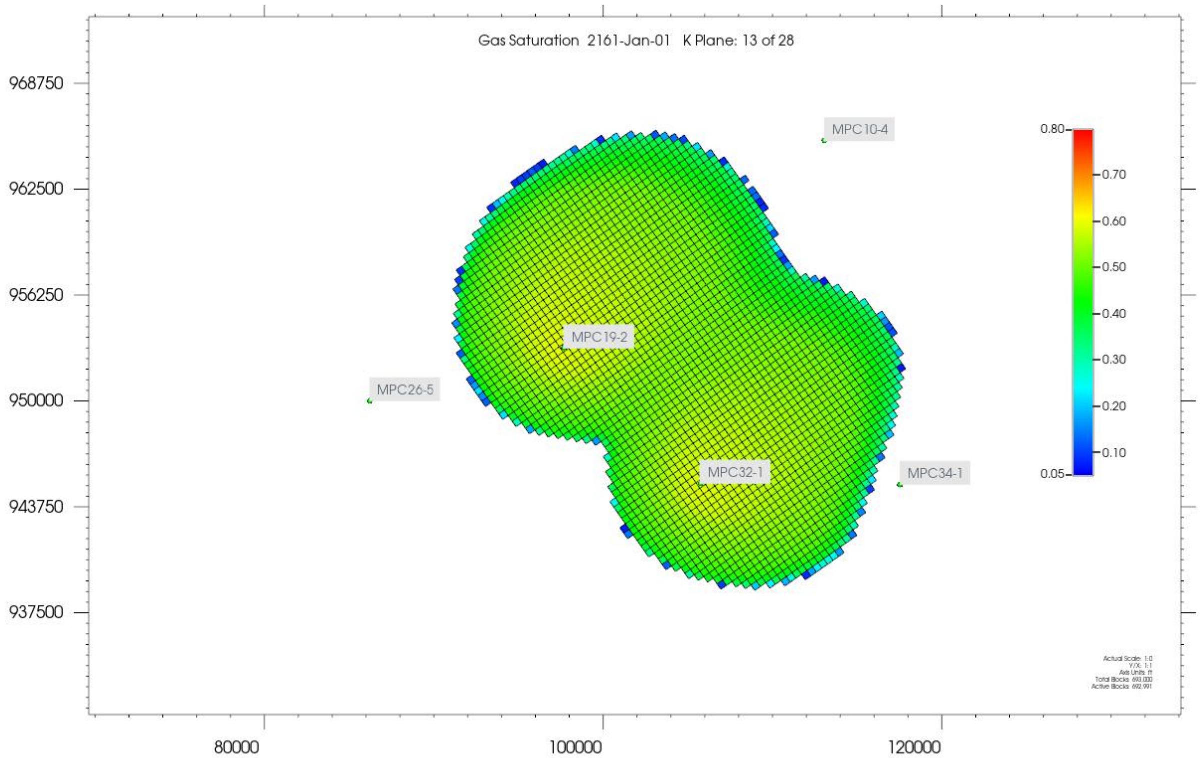

Figure 7: Aerial extent of the CO_2 plume development 140 years post-injection.

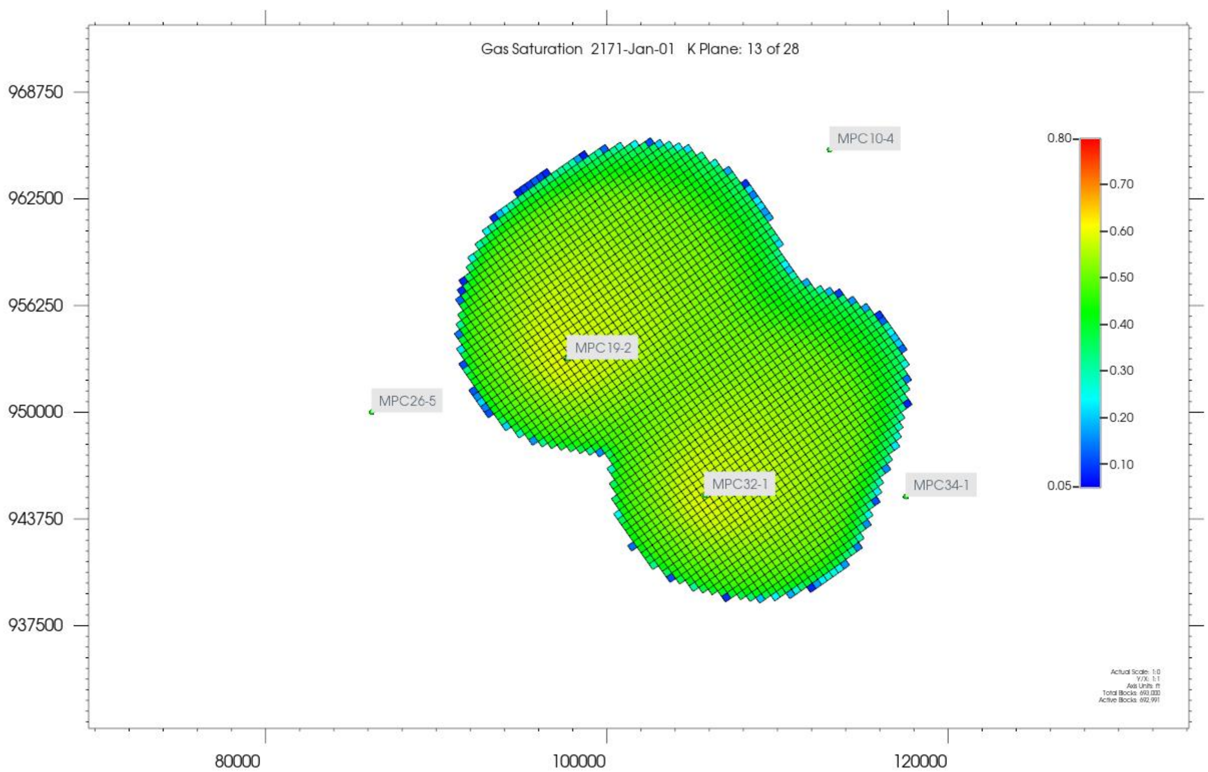

Figure 8: Aerial extent of the CO_2 plume development 150 years post-injection.

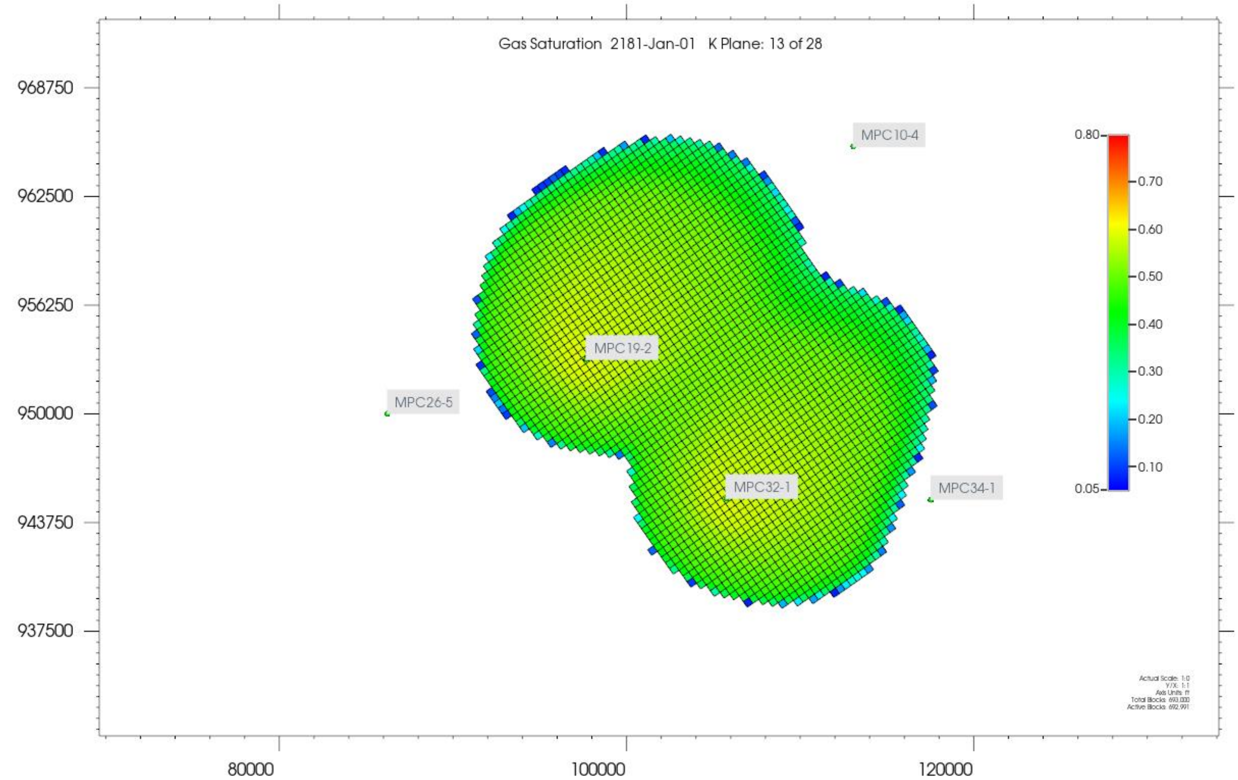

Figure 9: Aerial extent of the CO_2 plume development 160 years post-injection.

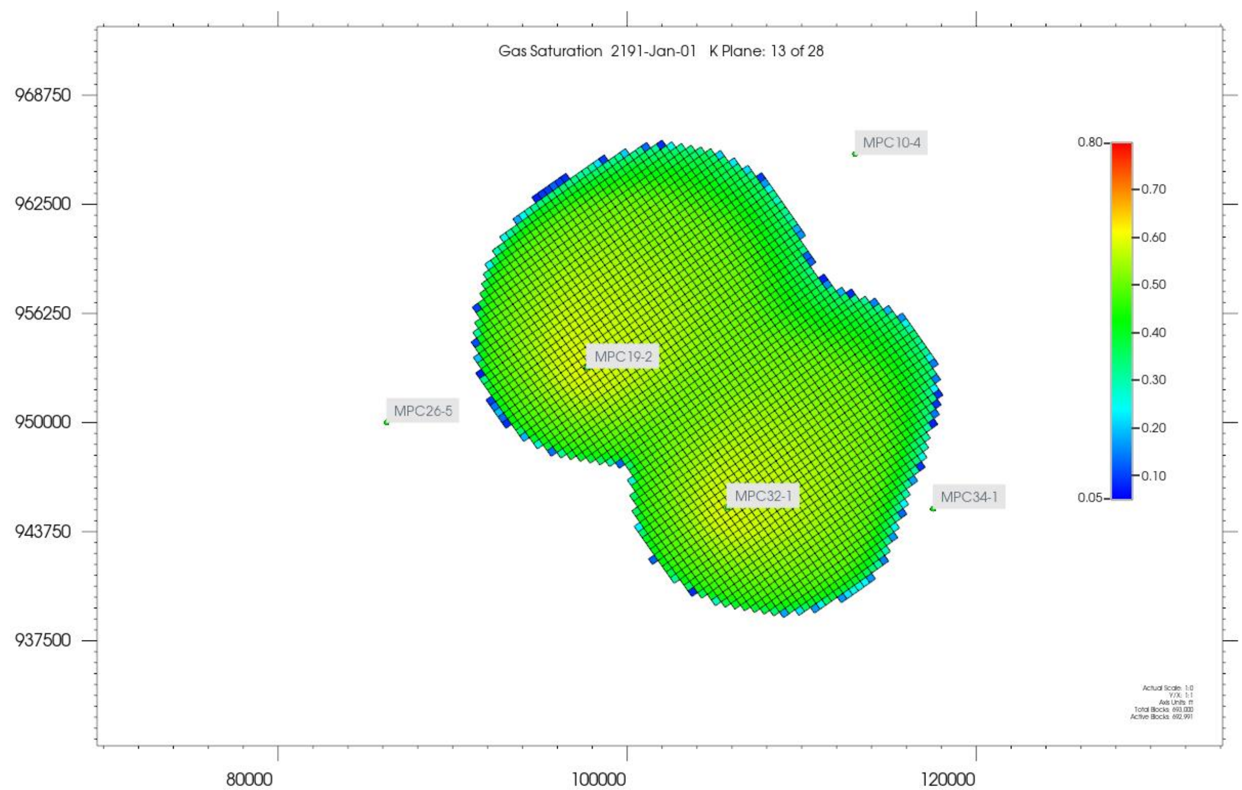

Figure 10: Aerial extent of the CO_2 plume development 170 years post-injection.

B.4. CO_2 Trapping Under Different Mechanisms

As detailed in the *Area of Review and Corrective Action Plan*, the trapping mechanisms tracked in the Kemper County Storage Complex model are structural, residual, and dissolution trapping. **Figure 11** shows the evolution of CO_2 trapping with time. Most of the CO_2, in the super-critical phase is structurally trapped. The structurally trapped CO_2 continues to be residually trapped after the injection has stopped.

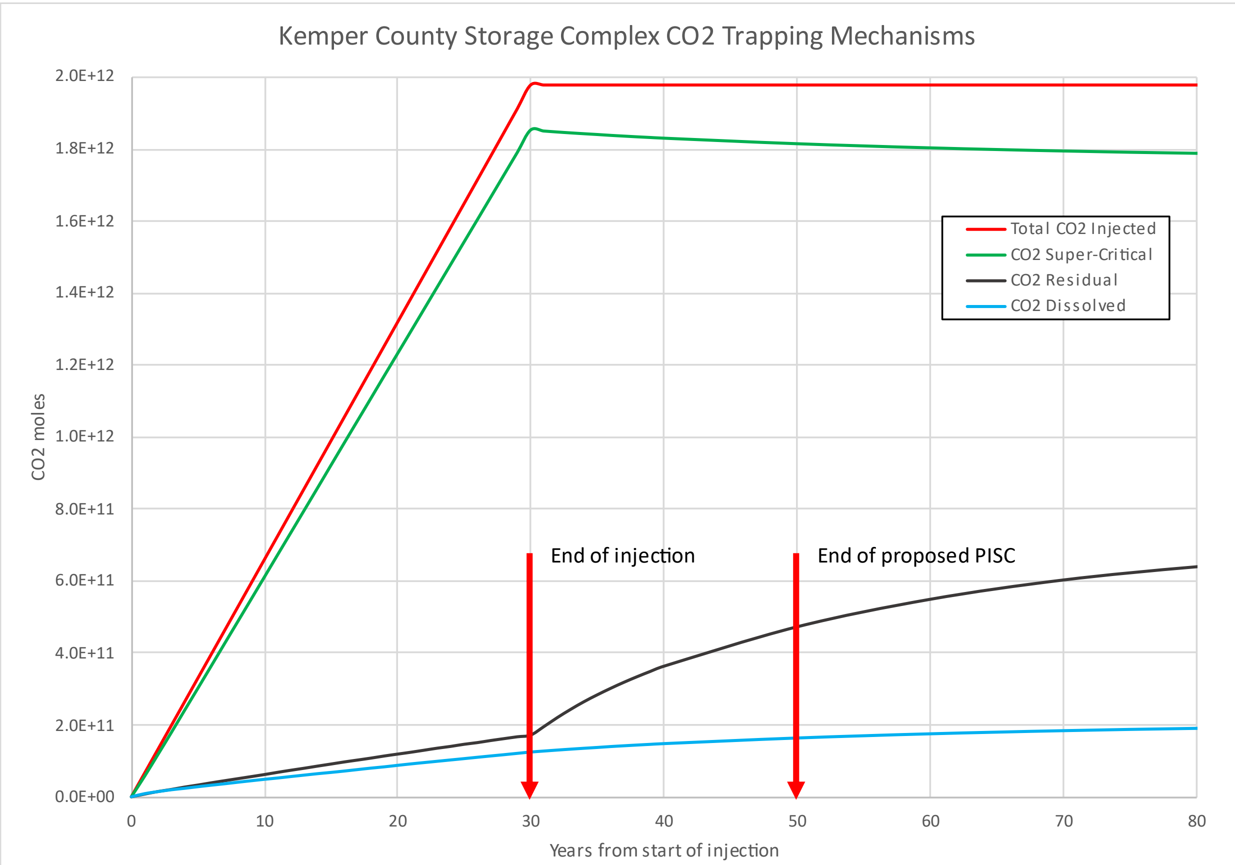

Figure 11: CO_2 storage under different trapping mechanisms. The super-critical CO_2 is structurally trapped.

C. Sensitivity Analysis

Key reservoir parameters that may impact plume movement were selected to assess their impact upon plume dimension estimates and, thus, upon the AoR. **Table 1** summarizes the description of each parameter and its impact on the CO_2 plume size. In all sensitivity cases, much like the base case laid out in the previous pages, the pressure front did not expand beyond that of the CO_2 plume. Therefore, the AoR was determined by the CO_2 plume extent.

The sensitivity values selected represent the optimistic and pessimistic cases for the key reservoir parameters given our knowledge of the storage complex. Described previously in the *Geological Site Characterization*, extensive data collection was conducted from the six stratigraphic test wells including well logs, core samples, fluid samples, and well tests. No values were observed beyond the extent of the ranges described in the table below.

Table 1: List of sensitivity cases for the Kemper County Storage Complex model with resulting CO_2 plume size 20 years after the end of injection. Base case plume is 16 square miles.

Sensitivity Case	Base value	Sensitivity value(s)	CO_2 plume (miles²)
Horizontal permeability anisotropy	1:1	3:1	15
Vertical to horizontal permeability ratio	0.1	0.01, 0.25	13, 16
Net to Gross multiplier	1	0.9, 1.1	15, 17
Porosity multiplier	1	0.9, 1.1	18, 15
Permeability-porosity transform function (exponent in the Power Law function)	4.6363	4.4, 4.9	12, 23
Shale baffle transmissibility multiplier between the Paluxy Formation zones	0	0.1	19
Gas relative permeability endpoint	0.65	0.4, 0.8	14, 17
Confining zone permeability	50 nD	500 nD	16

CO_2 plumes were modeled for each of the sensitivity cases presented in **Table 1** over a timeframe of 20 years and 50 years following injection. The aerial extent of these plumes over these 20- and 50-year timeframes are shown in **Figure 12** and **Figure 13**, respectively. When the modeled CO_2 plume maps for each sensitivity case are overlain, the similarity of the modeled plumes at 20 and 50 years, post-injection, become readily apparent. Further, most (85%) of the plume movement within the 50-year PISC timeframe occurs during to the proposed alternative 20-year PISC timeframe and the modeled plume lays within the monitoring field, as set forth in the *Testing and Monitoring Plan*. These modeled outcomes demonstrate confidence in the baseline assessment and firmly indicates that the proposed alternative timeframe of 20 years for the Post Injection Site Care and Site-Closure is sufficient to demonstrate a lack of fugitive CO_2 movement and non-endangerment of USDWs. The following sections discuss the outcomes of each sensitivity assessment.

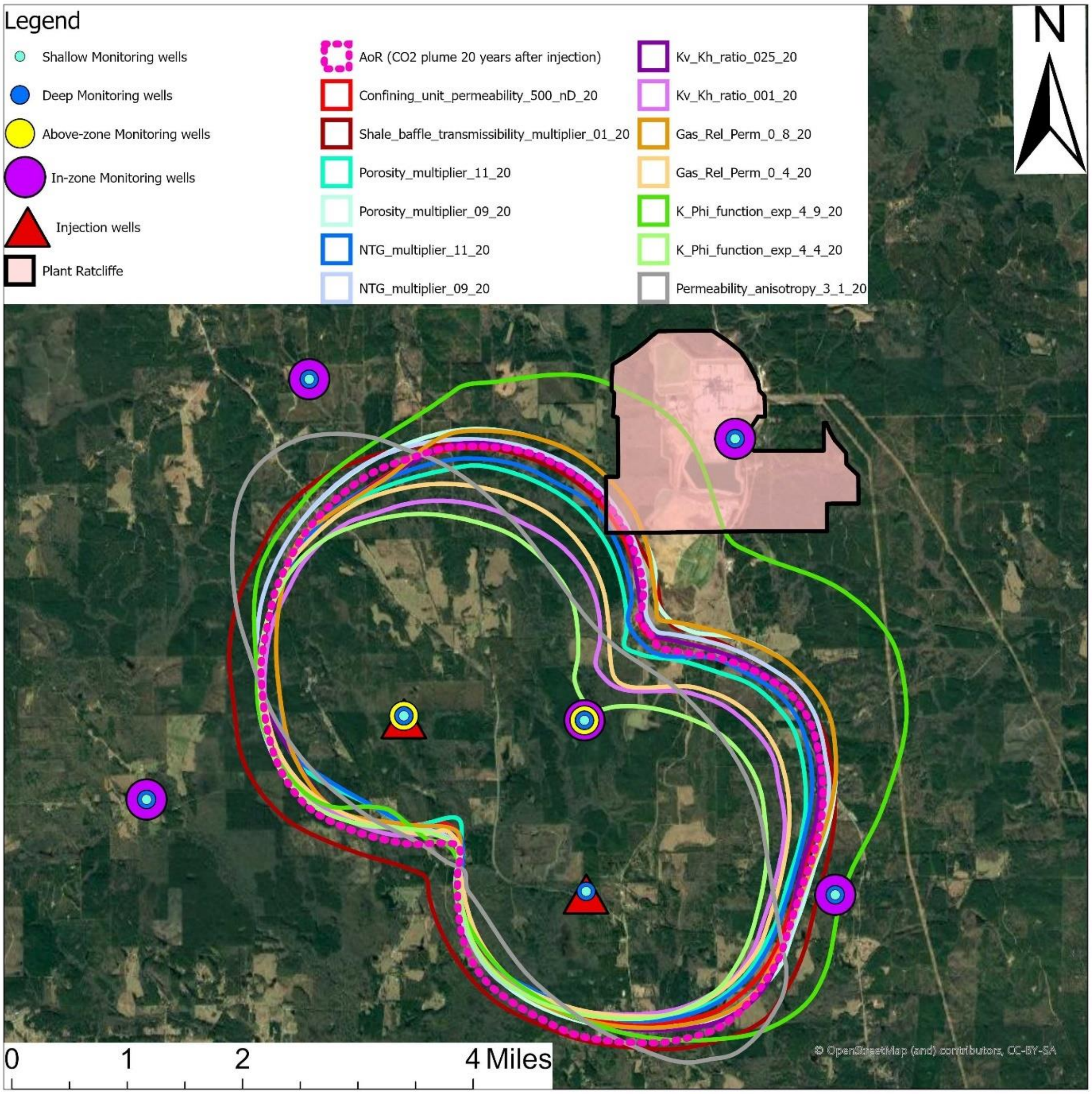

Figure 12: Aerial extent of modeled CO_2 plumes for sensitivity cases presented in Table 1 over a timeframe of 20 years post-injection.

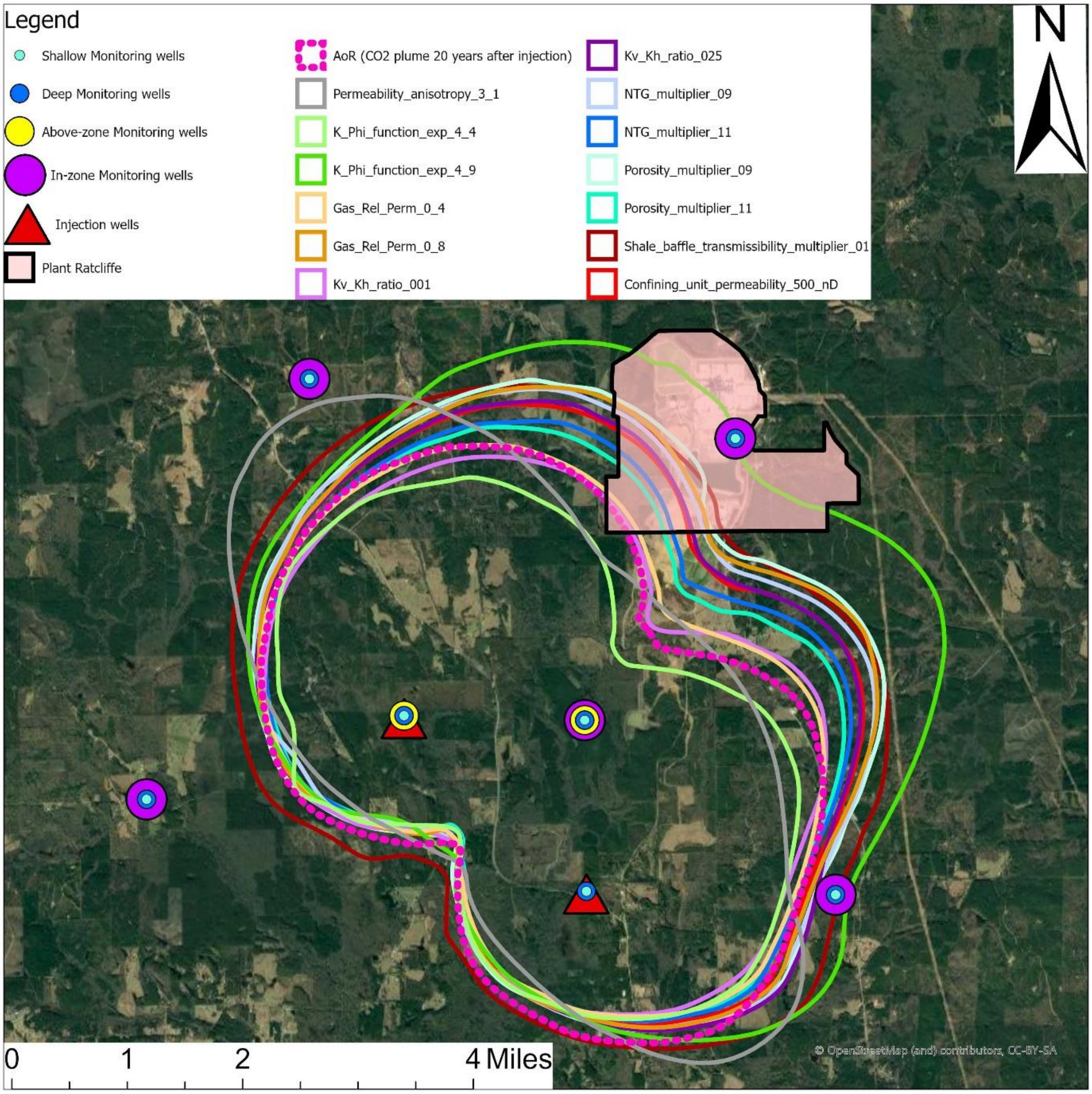

Figure 13: Aerial extent of modeled CO_2 plumes for sensitivity cases presented in Table 1 over a timeframe of 50 years post-injection.

C.1. Effect of Horizontal Permeability Anisotropy on CO_2 Plume Migration

Isotropic horizontal permeability is assumed in the base model. However, the possibility of horizontal permeability anisotropy exists. In a previous CO_2 storage project in the Paluxy Formation[5], a horizontal permeability anisotropy of 3 to 1 was observed through history matching of the injection and monitoring results.

In this sensitivity scenario, both horizontal permeability values, i.e., along the structure (k_i) and perpendicular to it (k_j), are adjusted so their geometric average is the same as the isotropic case and k_i is three times higher than k_j.

The modeling results of this case show that the 20-year post injection CO_2 plume is slightly smaller than the base case. The CO_2 plume tends to become wider (expands in the k_i direction) but does not migrate up-dip as much when compared to the base case. This uncertainty in horizontal permeability anisotropy can be validated by calibrating the simulation model to replicate the CO_2 breakthrough time in the in-zone monitoring wells that are placed around the injection site.

C.2. Effect of Vertical Permeability on CO_2 Plume Migration

The base model's vertical permeability (k_v) is assumed to be 10% of the horizontal permeability (k_h). Multiple shale layers are observed in the Paluxy Formation. These shale layers restrict the vertical movement of fluids and therefore, a k_v/k_h of 0.1 was deemed appropriate to model these restrictions. However, in the case that the ratio is different than 0.1, two sensitivity cases were run assuming k_v/k_h of 0.01 and 0.25 on the lower and higher ends respectively.

As expected, the lower k_v/k_h further restricts the upward CO_2 migration when compared to the base case. As a result, the developed CO_2 plume at the top of each Paluxy Formation zone covers a smaller area compared to the base case. In both cases,

[5] Advanced Resources International, 2016, *Southeast Carbon Sequestration Partnership (SECARB) Phase III Anthropogenic Test at Citronelle Field, Mobile Col., AL*, Report submitted to Alabama Department of Environmental Management

the developed CO_2 plume at the end of the proposed post injection site care time frame has not changed significantly.

C.3. Effect of Net Pay on CO_2 Plume Migration

Net-to-gross ratios are assigned to the Paluxy Formation zones based on the total amount of sandstone thickness in the gross interval observed in well logs. The uncertainty in these ratios is that they may not be representative of the entire Paluxy Formation since the calculations are based on a limited number of logs. Two sensitivity cases were generated to address the uncertainty in the net pay amount. These two cases considered a 10% variation in the values assumed in the base model. The modeling results show that a 10% change in the net pay amounts does not cause significant change to the CO_2 plume size.

C.4. Effect of Porosity on CO_2 Plume Migration

Porosity in the base case was obtained from available well log and core data. To capture uncertainty in the interpreted porosity values, two sensitivity cases were generated to understand the impact of a 10% deviation in the employed porosity values in the base case. The impact of porosity was similar to the impact in net pay variation since they both contribute to the amount of pore space available for storage. A reduction in porosity causes the CO_2 plume to expand to a bigger area. However, a 10% change in porosity does not significantly change the plume size.

C.5. Effect of Permeability-Porosity Transform Function on CO_2 Plume Migration

The process of generating the permeability-porosity functions and the data used are described in the *Area of Review and Corrective Action Plan*. The resulting power-law function has a low coefficient of determination (R^2 of 0.28) indicating a relatively high uncertainty in the accuracy of the calculated permeability values. To address this uncertainty, the exponent of the power-law function is modified to study the impact of the transform function on the CO_2 plume behavior. **Figure 14** shows the permeability-porosity functions generated from the two extreme exponent values superimposed on the core data. Notice that these functions generate permeability values that are at the extreme ends of core values.

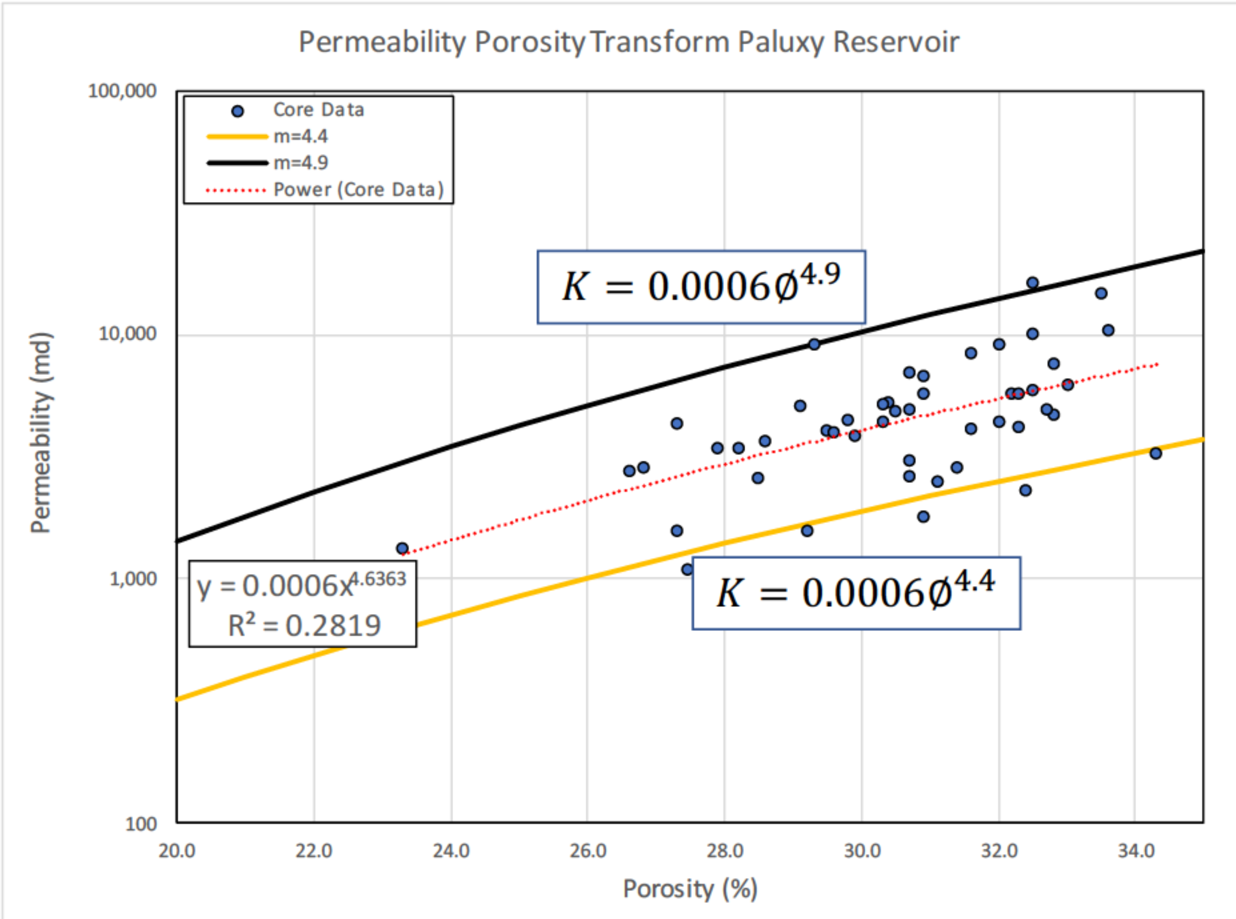

Figure 14: Sensitivity analysis in the Paluxy Formation permeability-porosity transform function.

The sensitivity results of this parameter show the largest effect on the CO_2 plume size compared to the other parameters considered in this sensitivity analysis. It is unlikely that the two extremes considered for the exponent apply to the entire Paluxy Formation since these trends are reflective of the upper and lower bands of the calculated permeability values resulting from these functions. In both cases, the CO_2 plume behavior remains the same and its movement is predictable. The appropriate magnitude of the permeability values in the Kemper County Storage Complex model will be verified by re-calibrating the model to injection data.

C.6. Effect of Shale Baffles Within the Paluxy Formation on CO_2 Plume Migration

The shale baffles separating the Paluxy Formation zones[6] have been implicitly modeled as zero vertical transmissibility boundaries. The shale baffle thicknesses observed in the available logs are sufficiently high to warrant their inclusion as no-flow zones in the base model. However, the possibility exists where these zones could produce limited vertical flow. To address this uncertainty, a sensitivity case that assumes 10% vertical transmissibility is created. This is implemented as a 0.1 vertical transmissibility multiplier applied to the shale baffles.

The modeling results show that if the shale baffles at the base of each Paluxy Formation zone allow limited vertical flow, the CO_2 plume at the end of the 20-year post injection period can expand to a larger area of 19 square miles compared to the base case scenario of 16 square miles. This scenario was included to demonstrate the impact on CO_2 plume development in the event vertical transmissivity were present at an equivalent level to that observed through the storage reservoir. However, due to the ultra-low baffle permeability observed in the Kemper County Storage Complex as compared to that of the sandstone reservoir, this case would be representative of the upper end member of vertical transmissivity potential through the shale baffles observed through the Paluxy Formation.

C.7. Effect of Gas Relative Permeability Endpoint on CO_2 Plume Migration

A 0.65 gas relative permeability at irreducible water saturation is assumed in the base model. Two sensitivity cases are run to test the sensitivity of the CO_2 plume and pressure front behavior to this parameter. The CO_2 plume size for the 0.4 and 0.8 gas relative permeability cases is 14 and 17 square miles respectively, which indicates an increasing relative permeability to gas will generate larger CO_2 plumes.

[6] *Wethington, C. L. R. (2020). Mudstone Characterization at a World-Class CO2 Storage Site: Kemper County Energy Facility, Kemper County, Mississippi. Stillwater, Oklahoma: Masters of Science Thesis, Oklahoma State University, 6–11.*

C.8. Effect of Confining Zone Permeability on CO_2 Plume Migration

A major factor in a secure CO_2 storage project is the existence of an impermeable confining layer overlaying the injection zone to block the upward migration of CO_2. The confining zone permeability can have a significant impact on the containment of the injected CO_2. At the storage site, there would be a large contrast between the very high Paluxy Formation permeability (hundreds to thousands of millidarcies) and a typical confining layer permeability (tens to hundreds of nanodarcies). As a result, CO_2 would preferentially move laterally within the Paluxy Formation rather than migrate vertically into the confining zone. To test the CO_2 containment, a sensitivity case was run where the permeability of the Undifferentiated Upper Washita-Fredericksburg Basal Shale, the confining layer immediately above the uppermost Paluxy Formation, was changed from 50 nD to 500 nD. The modeling results show that the CO_2 plume stays within the Paluxy Formation (**Figure 15** and **Figure 16**) and does not migrate upward.

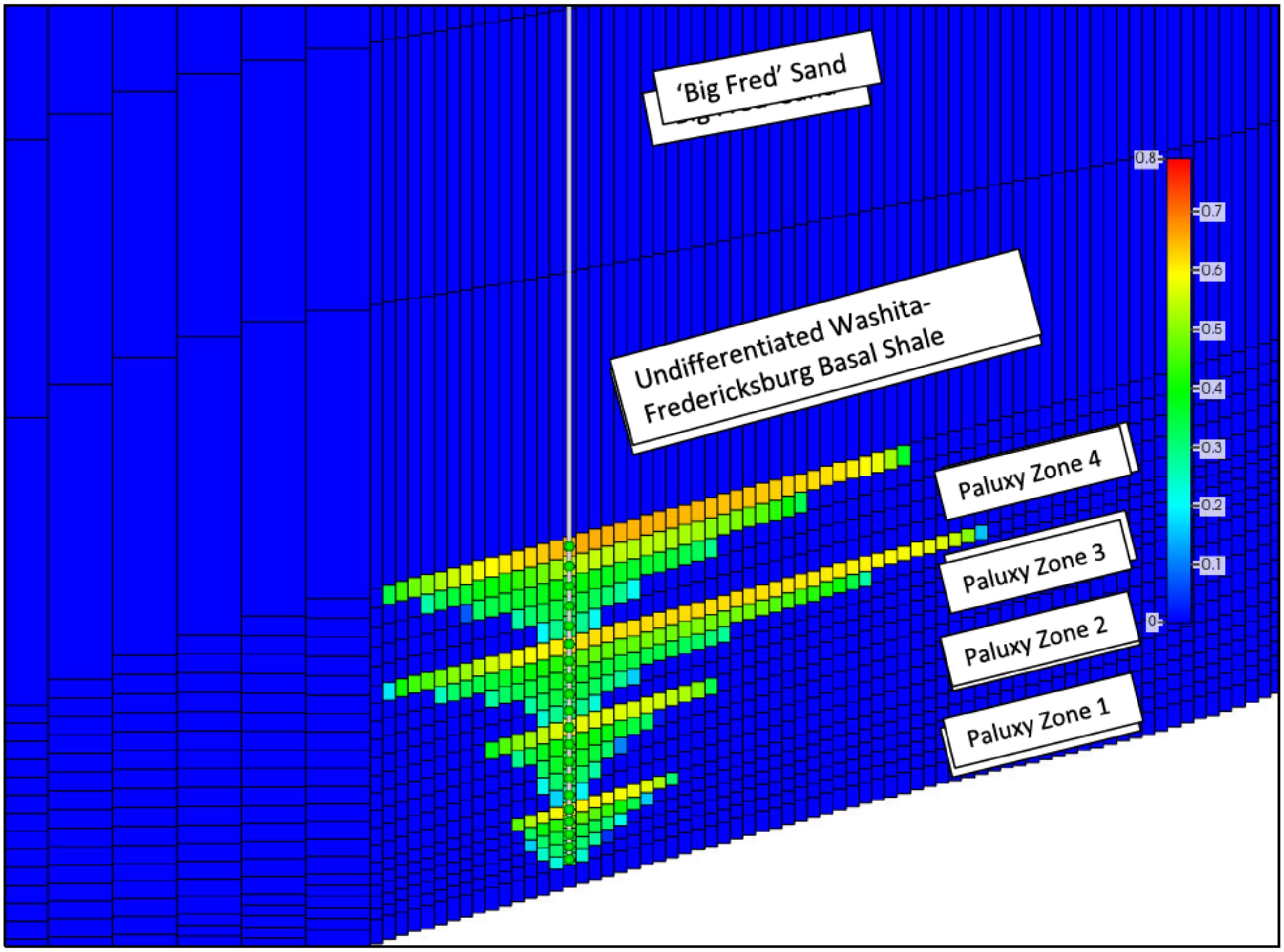

Figure 15: Cross-section view of CO_2 distribution at MPC 19-2 injector 20 years post-injection, with confining layer permeability of 500 nD.

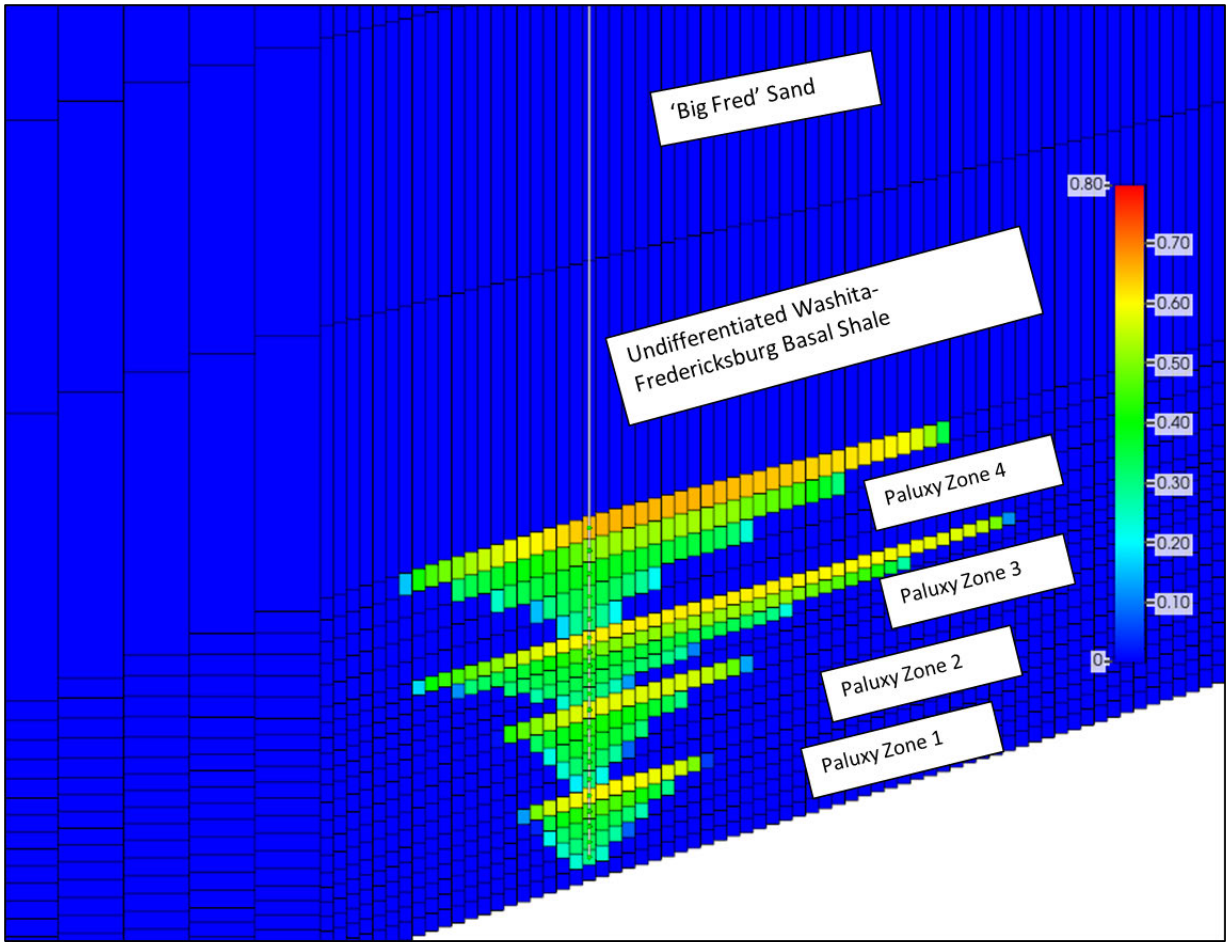

Figure 16: Cross-section view of CO_2 distribution at MPC 32-1 injector 20 years post-injection, with confining layer permeability of 500 nD.

D. Post-Injection Monitoring Plan

Post-injection monitoring will include a combination of groundwater monitoring and storage zone pressure monitoring at Kemper County Storage Complex The monitoring locations (**Figure 12**), methods, and schedule are designed to show the position of the CO_2 plume and potential pressure front and demonstrate that USDWs are not being endangered pursuant with Class VI Rule 40 CFR 146.93(b).

- **CO_2 Injection Wells (MPC 19-2 and MPC 32-1)**. Two CO_2 injection wells located in the southern portion of the project area will be drilled and completed in the Paluxy Formation and spaced roughly two miles apart. The placement of these two CO_2 injection wells is based on the regional geologic study that has been completed as part of the characterization phase of this project. MPC expects the CO_2 plume to partially migrate up-dip in the northeast direction given the gentle southwest trending dip that is observed in the subsurface across the modeled area.

- **In-Zone Monitoring Wells (MPC 01-1, MPC 10-4, MPC 26-5, MPC 20-1, and MPC 34-1)**. Five in-zone monitoring wells are located at various distances from the two CO_2 injection wells. Some of these monitoring wells were drilled during the site characterization phase of the project to UIC Class VI standards. They are equipped with tubing, packers, and pressure gauges and are perforated in the Paluxy Formation.

- **Above-Zone Monitoring Wells (MPC 19-1 and MPC 20-2).** Two above-zone Monitoring wells will be completed in the Upper Tuscaloosa Sand, that directly overlies the Tuscaloosa Marine Shale which is the primary confining zone. The two above-zone monitoring wells will continuously monitor pressure via surface gauges and will also conduct annual fluid sampling during the PISC phase of the project. MPC 19-1 has already been drilled and completed to UIC Class VI standards. The proposed MPC 19-2 injection well is planned to be drilled on the same pad as a direct offset to the MPC 19-1 well which will serve as the primary source of site-specific geologic data for the project.

- **Deep USDW Monitoring Wells (DP-1, DP-2, DP-3, DP-4, DP-5, DP-6 and DP-7).** Seven deep USDW Monitoring wells will be completed in the Upper Cretaceous Eutaw Formation, where potential USDW aquifers with reported Total-dissolved-solids (TDS) concentrations of ~3,000 mg/L are observed. In addition to baseline sample collection and analysis prior to the start of injection, fluid samples will be collected annually from each monitoring well during the PISC phase.

- **Shallow Ground Water Monitoring Wells (SH-1, SH-2, SH-3, SH-4, SH-5, SH-6, and SH-7).** Seven shallow groundwater wells will be completed in the local shallow USDW, within the Eocene-Aged formations, including the Middle/Lower Wilcox group. In addition to baseline sample collection and analysis prior to the start of injection, fluid samples will be collected annually from each of these wells during the PISC phase of the project.

Table 2 details monitoring methods and frequency for monitoring strategies. For more detailed information on the testing and monitoring technologies, please refer to the *Testing and Monitoring Plan*. The monitoring strategy utilizes a fixed frequency schedule to collect data. A *Quality Assurance and Surveillance Plan (QASP)* for all testing and monitoring activities is provided in the appendix to the *Testing and Monitoring Plan*.

Table 2: Monitoring methods and frequencies proposed for Kemper County Storage Complex.

Monitoring Category	Monitoring Method	Baseline Frequency	Injection Phase Frequency (30 years)	Post-Injection Frequency (20 years)
Monitoring Plan Update	N/A	As required	As required	As required
CO_2 Injection Stream Monitoring	Grab Sampling and Analysis	Quarterly, beginning at least 6 months prior to injection	Quarterly	N/A
CO_2 Injection Process Monitoring	Continuous monitoring of injection process (Injection rate, pressure, and temperature; annulus pressure and volume)	N/A	Continuous	N/A
Mechanical Integrity Testing	Injection well pressure fall-off testing	Once after well completion	Once every 3 years minimum	N/A
	PNC logging, temperature logging	Once after well completion	Annually	N/A
Corrosion Monitoring of Well Materials	Corrosion coupon testing	N/A	Quarterly	N/A
	Wireline monitoring of casing and/or tubing corrosion and cement	Once after well completion	Once every three years or during well workovers	N/A
Groundwater Quality and Geochemistry Monitoring (Above-Zone)	Early leak-detection in above-zone monitoring wells (fluid sampling)	3 events prior to injection	Annually	Annually
	Deep USDW monitoring and shallow groundwater monitoring (fluid sampling)	3 events prior to injection	Annually	Annually
Pressure Monitoring	Early leak-detection in above-zone monitoring wells	Once after well completion	Continuous	Continuous
	In-zone monitoring wells and injection wells	Once after well completion	Continuous	Continuous
Direct Plume Monitoring (In-zone)	Fluid sampling in the four in-zone monitoring wells	3 events prior to injection	Annually until CO_2 plume is confirmed	Annually until CO_2 plume is confirmed
Indirect Geophysical Monitoring Techniques (wireline logging)	PNC/RST logging, temperature logging in the two injection wells, four in-zone monitoring wells, and two above-zone monitoring wells	Once after well completion prior to injection	Annually	Every 2 years
	Flow profile surveys in the two injection wells	N/A	Annually	N/A

D.1. Groundwater Quality Monitoring

MPC will monitor ground water quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d). Monitoring groundwater in one or more zones between the confining zone(s) overlying the injection zone and the USDW aquifers is required by 40 CFR 146.90 (d). The purpose of such monitoring is to detect CO_2 migration out of the injection zone before it can result in any impacts on USDW aquifer water quality.

To meet the requirements of 40 CFR 146.95(f)(3)(i), MPC will also monitor groundwater quality, geochemical changes, and pressure variation in the first known potential USDW immediately above the primary confining zone, the Tuscaloosa Marine Shale, as well as shallower ground water drinking sources.

Direct monitoring of aqueous chemistry and related field parameters will be used to identify and quantify any potential impacts on USDW aquifers from a release of hypersaline waters and/or CO_2 from the injection zone. Monitoring locations will include immediately above the primary confining zone for early leak-detection (i.e., above-zone monitoring wells) and USDW aquifer monitoring.

The groundwater monitoring plan focuses on the following zones:

- Middle and Lower Wilcox (Eocene-aged) – shallowest USDW source.
- Eutaw-McShan Formation (Upper Cretaceous), including Eutaw-McShan aquifer with TDS reported at 1,670 ppm.
- Upper Tuscaloosa Sand – the zone directly above the main confining zone/seal (Tuscaloosa Marine Shale).

In addition to the extensive coverage that the deep USDW and shallow groundwater monitoring wells provide, MPC's *Testing and Monitoring Plan* satisfies the requirements of 40 CFR 146.90 (d). As such, groundwater samples will be collected and analyzed from the zone (i.e., Upper Tuscaloosa Sand) between the primary confining zone (Tuscaloosa Marine Shale) overlying the injection zone and the lowermost potential USDW aquifer (Upper Cretaceous).

Pressure and aqueous monitoring requirements for the In-Zone monitoring wells, including the general monitoring approach, the list of target analytes, and the analytical and quality assurance requirements, are discussed in the Sampling and Analysis Section below and detailed in **Table 3**.

D.2. Monitoring Location and Frequency

All monitoring locations are located on MPC property. Fluid samples will be collected and analyzed from each of the five In-Zone monitoring wells on an annual basis during injection or until CO_2 reaches the well. Details regarding in-zone fluid sampling are discussed in the *Testing and Monitoring Plan*. See **Table 2** for the specific monitoring activities and frequencies that will occur at each well.

D.3. Analytical Parameters

Table 3 identifies the parameters to be monitored and the analytical methods MPC will employ when collecting and analyzing groundwater sampling results.

Table 3: Summary of analytical and field parameters for ground water samples.

Parameters	Analytical Methods
Middle and Lower Wilcox (Eocene)	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0
Dissolved **CO_2** Total Dissolved Solids Alkalinity pH (field) Specific conductance (field) Temperature (field)	Coulometric titration, ASTM D513-11 Gravimetry, APHA 2540C APHA 2320B EPA 150.1 APHA 2510 Thermocouple
Eutaw-McShan (Upper Cretaceous) (Deep USDWs) and Upper Tuscaloosa Sand (Above-Zone)	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO_3 and SO_4 Dissolved **CO_2**	Ion Chromatography, EPA Method 300.0 Coulometric titration, ASTM D513-11
Isotopes: S13C of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids Water Density Alkalinity pH (field) Specific conductance (field) Temperature (field)	Gravimetry, APHA 2540C Oscillating body method APHA 2320B EPA 150.1 APHA 2510 Thermocouple

D.4. Carbon Dioxide Plume and Pressure Front Tracking

Pressure monitoring at the Kemper County Storage Complex during the post-injection site-care period will be accomplished with a combination of in-zone wells that monitor the Paluxy Formation and above-zone wells that monitor the Upper Tuscaloosa Sand. The objective of this monitoring is to collect storage zone pressure data to corroborate numerical models and to detect anomalous above-zone pressure increases that may indicate the potential for upward migration of CO_2 into USDWs. Well installations within the targeted storage zone will consist of two injection wells and an array of 5 In-Zone and 2 Above-Zone monitoring wells.

During the 30-year injection phase, continuous (i.e., uninterrupted) monitoring of pressure will be conducted in the two above-zone and five in-zone monitoring wells in addition to the two CO_2 injection wells. The pressure gauges will be removed from the monitoring wells only when they require maintenance or when necessitated by other activities (e.g., well maintenance). In addition, each of the five in-zone and two above-zone monitoring wells will be sampled (i.e., fluid sampling) on an annual basis during injection operations to quantify CO_2 arrival times and transport processes. Baseline pressurized fluid samples will be collected prior to the start of injection operations.

The two CO_2 injection wells will not be sampled during the operational phase so as not to interfere with injection operations. However, the CO_2 injection stream will be monitored/sampled during this phase and the injection wells will be sampled after the conclusion of the injection period. Aqueous samples will be analyzed for the same parameters that are measured during the baseline monitoring period. For more details on the well positioning, please refer to the *Testing and Monitoring Plan*.

Following the 30-year period of injection, the CO_2 plume and pressure front will be continuously monitored for 20 years. Groundwater quality and geochemistry monitoring in the Above-Zone monitoring wells will continue annually over the PISC period, while direct plume monitoring in the In-Zone monitoring wells will continue annually until the CO_2 plume ceases to advance. Early leak detection in each of the In-Zone, Above-Zone, and injection wells will be continuously monitored, and wireline logging in each of the monitoring and injection wells will take place every two years.

D.5. Schedule for Submitting Post-Injection Monitoring Results

The Post-injection monitoring methods and frequencies are summarized in **Table 2**. Groundwater quality monitoring will be performed through a network of shallow groundwater wells within the AoR. MPC will use indirect monitoring techniques, including Pulsed Neutron Capture (PNC) and temperature logs, in the two Above-Zone monitoring wells to compliment the direct fluid sampling analysis discussed previously. These indirect monitoring techniques will provide additional data to compare against fluid sampling results in the event that abnormal or unexpected results are detected during geochemical monitoring above the confining zone. PNC and temperature logs will be run on an annual basis during the injection phase. For a detailed description of proposed monitoring methods, please refer to the *Testing and Monitoring Plan*.

E. Site Closure Plan

Site closure will occur at the end of the PISC period. Site closure activities will include decommissioning surface equipment, plugging monitoring wells, restoring the site, and preparing and submitting site closure reports. The EPA Region 4 UIC Branch will be notified at least 120 days in advance with a Notice of Intent (NOI) for site closure. A revised site closure plan will be submitted should any changes be made to the original site closure plan. After authorization is received, site closure field activities will be carried out. At this point, the UIC Program Director will be issued a site closure report within 90 days of site closure which will be retained as designated by the UIC Program Director for 10 years.

E.1. Equipment Decommissioning

Surface equipment decommissioning will occur in two phases: the first phase will occur after the active injection phase, and the second phase will occur at the end of the PISC phase. At the end of the active injection period, plume monitoring will continue but there will be no further need for much of the pumping and other control equipment. All unnecessary equipment and temporary facilities will be broken down and removed from the location. This will work toward clearing space on location as well as enable surface site reclamation processes to begin in areas no longer utilized by operations associated with injection.

Equipment and facilities that are to be utilized throughout the PISC period will remain. This will include all equipment associated with the collection of data from monitoring wells and other monitoring stations. This data will be electronically disseminated for review offsite throughout the proposed 20-year post injection monitoring period.

Once the end of the post injection monitoring period has been reached, all remaining equipment and facilities located at the well site will be decommissioned and removed. This includes the removal of any fencing and electrical wiring installed as part of the site construction phase. The site will be restored to its pre-development condition once everything has been removed from location.

E.2. Site Closure Well Plugging Program

The well plugging program will be designed to prevent communication between the injection reservoir and overlying USDWs. Because the injection wells and in-zone monitoring wells have a direct connection between the injection formation and ground surface, they will be plugged and abandoned using industry best practices to prevent any upward migration of the CO_2 or other formation fluids to USDWs upon site closure.

Before the wells are plugged, the internal and external integrity of the wells will be confirmed by operating cement-bond, temperature, and noise logs on each of the wells. In addition, a pressure test will be performed above the perforated intervals (when present) to confirm well integrity. The results of the logging and testing will be approved prior to plugging the wells.

E.3. Site Restoration

After the active injection phase, all disturbed acreage during the active injection period will be reclaimed and returned as close as possible to pre-development condition. All gravel pads, access roads, and surface facilities will be removed, and the land will be reclaimed for agricultural or other pre-development uses.

E.4. Site Closure Reporting

A site-closure report will be submitted to the EPA Region 4 UIC Branch within 90 days of site closure. The site-closure report will include the following information:

- Documentation of appropriate well plugging, including survey plat of the injection well locations.
- Documentation of well-plugging report to Mississippi and local agencies that have authority over drilling activities at the facility site.
- Records reflecting the nature, composition, and volume of the CO_2 injected into MPC 19-2 and MPC 32-1.

In association with site closure, a record of notation on the facility property deed will be added to provide any potential purchaser of the property information the following information:

- Notification that the land was used for Geologic Sequestration.
- The name of the Mississippi and local agencies and the EPA Region 4 Office to which the survey plat was submitted.
- The volume of fluid injected, the injection zone, and the period over which injection occurred.

Post-injection site-care and site-closure records will be retained for 10 years after site closure. At the conclusion of this 10-year period, these records will be delivered to the EPA Region 4 UIC Branch for further storage.