Establishing an Early CO_2 Storage Complex in Kemper County, Mississippi: Project ECO_2S (Phase III)

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Abstract

"Establishing an Early CO_2 Storage Complex in Kemper County, Mississippi (Project ECO_2S)" is an *early mover* project within the U.S. Department of Energy (DOE) and National Energy Technology Laboratory's Carbon Storage Assurance Facility Enterprise, or CarbonSAFE, initiative. Phase III of Project ECO_2S advanced the foundational work of Phase II, which confirmed the potential for safely, permanently, and economically storing commercial volumes of carbon dioxide (CO_2) in the regionally significant saline reservoir system near Mississippi Power Company's (MPC) Kemper County Energy Facility. The primary objective of Phase III was to complete detailed site characterization necessary to obtain an Underground Injection Control (UIC) Class VI Permit to Construct from the U.S. Environmental Protection Agency. This involved transitioning from regional geologic assessments to high-resolution site-specific analyses.

Key technical activities included the drilling of three additional characterization and monitoring wells, completion of a 92-mile, two-dimensional seismic survey, and the characterization and baseline monitoring of underground sources of drinking water. The project identified and assessed three primary storage formations: the Massive Sand/Dantzler, Washita-Fredericksburg, and Paluxy intervals. Collected data was integrated into geologic and numerical models to support risk assessments and define the Area of Review (AoR). These results informed the development of key Class VI UIC permit components, such as monitoring, AoR and corrective action, remedial response, and post-injection site care and closure plans.

In parallel, CO_2 capture pre-feasibility assessments were conducted at Plant Miller (coal) and Plant Ratcliffe (natural gas) to evaluate capture technologies, volumes, purity, and delivery conditions. Additional work in 2023 responded to updated National Energy Technology Laboratory Phase IV requirements, including completion of a pipeline front end engineering design study.

Despite technical progress, the MPC formally withdrew its UIC permit applications in March 2024. Subsequent efforts to explore alternative project pathways, including the identification of new permit holders and negotiation of well access, were not acceptable to MPC. A final decision to close the project was made in March 2025. ECO_2S yielded critical subsurface, regulatory, and infrastructure insights that contribute significantly to the advancement of commercial-scale CO_2 storage in the southeastern United States.

The Southern States Energy Board was the recipient and provided technical and financial oversight and direction. The Project ECO_2S team of technical experts included Advanced Resources International, Inc., Battelle Memorial Institute, Christiansen CCS Consult, The International Carbon Capture Knowledge Centre, Crescent Resource Innovation, Geological Survey of Alabama, IOM Law, Oklahoma State University, SAS Institute, Inc., Southern Company Services, Trimeric Corporation, U.S. Geological Survey, University of Alabama at Birmingham, and University of Wyoming's Enhanced Oil Recovery Institute. Schlumberger also supported the project as a cost-share partner.

Table of Contents

Executive Summary

"Establishing an Early CO_2 Storage Complex in Kemper County, Mississippi (Project ECO_2S)" is an "early mover" project within the U.S. Department of Energy (DOE) and National Energy Technology Laboratory's Carbon Storage Assurance Facility Enterprise, or CarbonSAFE, initiative. Phase III of Project ECO_2S advanced the foundational work of Phase II, which successfully demonstrated that the subsurface adjacent to the Mississippi Power Company's (MPC) Kemper County Energy Facility has the potential to store commercial volumes of carbon dioxide (CO_2) safely, permanently, and economically within a regionally significant saline reservoir system. The Phase III program's primary goal was completing the site characterization to obtain an Underground Injection Control (UIC) Class VI Permit to Construct from the U.S. Environmental Protection Agency (EPA). To meet this goal, the Partners completed a geologic storage characterization and a detailed injection site characterization.

Data collected from the characterization efforts was synthesized and incorporated into geologic and numerical flow models to assess the Area of Review (AoR) for a variety of business models and as a basis for the UIC Class VI Permit Application. Results from risk analysis workshops and National Risk Assessment Program (NRAP) tool modeling efforts were leveraged to develop key operational plans, such as the monitoring plan, AoR and corrective action plan, remedial response plan, and post-injection site care and site closure plans, in support of the UIC Class VI Permit to Construct application.

In parallel, pre-feasibility studies for CO_2 capture from two power plant sources were completed to identify suitable technologies as well as potential CO_2 capture volumes, achievable CO_2 purity, and delivery pressures. Tying it all together and feeding back into the UIC Class VI Permit to Construct application, injection simulation studies were carried out to define the project's potential AoR for the development scenario.

During Phase III of the project, significant progress was made in advancing CO_2 storage characterization, regulatory preparedness, and infrastructure planning:

- Well Drilling and Reservoir Characterization: Six characterization wells were successfully drilled (three in each project phase) supporting the identification and evaluation of three key storage formations: the Massive Sand/Dantzler, Washita-Fredericksburg, and Paluxy reservoirs.
- Geophysical and Environmental Data Collection: A 92-mile two-dimensional (2D) seismic survey was completed in July 2021, enhancing subsurface imaging. To enable comprehensive baseline monitoring of underground sources of drinking water (USDW), a USDW characterization well also was completed.
- Regulatory and Environmental Compliance: The National Environmental Policy Act (NEPA) Environmental Information Volume was submitted to the National Energy Technology Laboratory (NETL) in July 2021. Two UIC Class VI Permit to Construct applications were submitted in August 2022, marking a key regulatory milestone.
- Risk Management and Planning: A Phase III Risk Registry was developed within 45 days of award to guide an early-stage risk assessment, with a follow-up evaluation conducted in the summer of 2022.

- CO_2 Capture and Transport Readiness: Preliminary modeling of CO_2 transport scenarios was conducted, and capture assessments were completed for two key facilities: Plant Miller (coal) and Plant Ratcliffe (natural gas).

In 2022, NETL announced additional requirements for Phase III to Phase IV readiness. The Southern States Energy Board (SSEB) and NETL negotiated the terms of the additional requirements and costs. Work began on these requirements in 2023. The requested new deliverables included a pipeline front end engineering design study, storage development plan, and a community benefits plan.

In 2022, the team received the project's NEPA determination that required the completion of an Environmental Assessment (EA). This work was ongoing throughout 2023.

On March 27, 2024, MPC's Management Council decided to withdraw their UIC Class VI Permit to Construct applications that supported Project ECO$_2$S. EPA acknowledged their request, and the application is no longer under EPA review.

Multiple scenarios were proposed and explored to determine a way to continue the project without the involvement of MPC. Several options were analyzed, such as establishing alternate permit holders, securing well access agreements, identifying MPC pore space availability, and closing out the project in its entirety. In March 2025, a decision was made to close the project.

SSEB was the recipient and provided technical and financial oversight and direction. The Project ECO$_2$S team of technical experts included Advanced Resources International, Inc., Battelle Memorial Institute, Christiansen CCS Consult, The International Carbon Capture Knowledge Centre, Crescent Resource Innovation, Geological Survey of Alabama, IOM Law, Oklahoma State University, SAS Institute, Inc., Southern Company Services, Trimeric Corporation, U.S. Geological Survey, University of Alabama at Birmingham, and University of Wyoming's Enhanced Oil Recovery Institute. Schlumberger also supported the project as a cost-share partner.

Results and Discussion

Task 1.0 – Project Management and Planning

Subtask 1.1 – Project Management Plan

Cooperative Agreement: Base Award, Continuation Applications, and Modifications

Base Award 00, Effective September 1, 2020

The U.S. DOE's NETL initially awarded Project ECO_2S through a Cooperative Agreement to the SSEB with an effective date of September 1, 2020. Budget Period 1 (BP1) was initially partially funded, with $13,049,148 of $17,470,436 of the federal portion obligated. The award also set NEPA compliance conditions for activation of Subtasks 4.4, 5.1, and 5.2.

Award Modification 01, Effective May 20, 2021

The first award modification was effective on May 20, 2021, and obligated an additional $2,471,947 of federal funding. This addition increased the obligated budget to $15,521,095, which fully funded BP1. The award revised the NEPA compliance conditions for Subtasks 4.4, 5.1, and 5.2 following receipt of a Categorical Exclusion (CX), which satisfied all NEPA compliance requirements for the award and activated those subtasks. The modification also replaced the Statement of Project Objectives (SOPO) to reflect the use of a 2D seismic survey in lieu of a three dimensional (3D) seismic survey and corrected minor typos.

Budget Period 1:	9/1/2020	to	8/31/2022
Budget Period 2:	9/1/2022	To	8/31/2023
Project Period:	9/1/2020	to	8/31/2023

Award Modification 02, Effective July 27, 2021

Modification 02 became effective on July 27, 2021, and fully obligated the remaining federal funds for the project's period of performance. However, approval to use the Budget Period 2 (BP2) funding was not yet issued and would be contingent upon (1) availability of funds appropriated by Congress for the purpose of this program; (2) the availability of future-year budget authority; (3) substantial progress toward meeting the objectives of the approved application; (4) submittal of required reports; (5) compliance with the terms and conditions of the award; (6) the submission by the Recipient of a Continuation Application; and (7) written approval of the Continuation Application by the DOE Contracting Officer.

Award Modification 03, Effective November 29, 2021

On November 29, 2021, Modification 03 became effective and changed the sponsoring office code and federal Program Manager from Mary Sullivan to Andrea McNemar.

Award Modification 04, Effective August 15, 2022

Modification 03, effective August 15, 2022, (1) approved the Continuation Application submitted in July 2022; (2) authorized the project to continue into BP2; (3) provided an updated SOPO; and (4) replaced the System Management and Universal Identifier Requirements term with updated requirements.

Award Modification 05, Effective September 1, 2023

Award Modification 05 was received on September 1, 2023, and extended the Period of Performance by 18 months. The updated schedule is provided below. The modification also replaced the Reporting Subawards and Executive Compensation term with new language and replaced the Federal Assistance Reporting Checklist (FARC) with new requirements.

Budget Period 1:	9/1/2020	to	8/31/2022
Budget Period 2:	9/1/2022	To	2/28/2025
Project Period:	9/1/2020	to	2/28/2025

Award Modification 06, Effective March 8, 2024

On March 8, 2024, SSEB received award Modification 06 that incorporated several changes. The federal share of project funding was increased by $838,176 from $17,479,436 to $18,317,612, cost share was increased by $3,826,885 from $6,094,725 to $9,921,610, and the total project cost was increased by $4,665,061 from $23,574,161 to $28,239,222. The SOPO and budget attachments were updated. The following terms also were added to or updated in the award:

- Transparency of Foreign Connections;
- Participants and Other Collaborating Organizations;
- Potentially Duplicative Funding Notice;
- Affirmative Action and Pay Transparency Requirements (March 2023); and
- Reporting Subaward and Executive Compensation (September 2023).

Federal Assistance Reporting Checklist

The FARC is an Award attachment that outlines the frequency of periodic reporting, the final reporting required to close out the project, and related guidance. The FARC was provided as Attachment 3 to the Base Award and changed in Modification 05. As of June 28, 2025, all FARC reporting has been completed as indicated in **Table 1** and in accordance with the September 1, 2023, version (Modification 05). A final Federal Financial Report (SF425) will be completed and sent for closeout upon completion of final invoice and payment from DOE.

***Table 1** Federal Assistance Reporting Checklist and Completion Timeline by Project Quarter*

		9/30/20	12/31/20	3/31/21	6/30/21	9/30/21	12/31/21	3/31/22	6/30/22	9/30/22	12/31/22	3/31/23	6/30/23	9/30/23	12/31/23	3/31/24	6/30/24	9/30/24	12/31/24	3/31/25	6/28/25
Reporting	**Frequency**	**M1**	**Q1**	**Q2**	**Q3**	**Q4**	**Q5**	**Q6**	**Q7**	**Q8**	**Q9**	**Q10**	**Q11**	**Q12**	**Q13**	**Q14**	**Q15**	**Q16**	**Q17**	**Q18**	**Final**
Management Reporting																					
Research Performance Progress Report (RPPR)	Quarterly (30 Days After End of Reporting Period)	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	
Special Status Report	Within 5 calendar days after the event or as																				
Scientific/Technical Reporting																					
Scientific and Technical Reporting Products	Within 5 calendar days after the event or as																				
Journal Article-Accepted Manuscript	*Within 5 calendar days after the event or as*																				
Scientific/Technical Conference Paper/Presentation or Proceedings	*Within 5 calendar days after the event or as*																				
Final Scientific/Technical Report	Final (120 Days after POP																				☑
Financial Reporting																					
SF425	Quarterly, Final (30 Days After End of Reporting Period & 120 Days After POP End)	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑
Closeout Reporting																					
Invention Certification (Patent Certification-DOE F2050.11)	Final (120 Days after POP End)																				☑
SF-428 & 428B Final Property Report	Final (120 Days after POP																				☑
Other Reporting																					
Annual Incurred Cost Proposal	Yearly (180 After End of Recipient's FY)		☑				☑				☑				☑				☑		
SF-428 Tangible Personal Property Report Forms Family	Within 5 calendar days after the event or as																				☑
Subject Invention Reporting	Within 5 calendar days after the event or as																				
Intellectual Property Reporting	Post-Project (after the POP); Within 5 calendar days after the event or as																				
Invention Utilization Report	Post-Project (after the POP); Within 5 calendar days after the event or as																				
Federal Subaward Reporting System	Within 5 calendar days after the event or as	☑								☑									☑		
Uniform Commercial Code (UCC) Financing Statements	Other - see instructions.																				
Other	Within 5 calendar days after the event or as																				

Project Management Plan

SSEB managed and directed the project in accordance with a Project Management Plan (PMP) to meet all technical, schedule and budget objectives and requirements. SSEB coordinated activities in order to effectively accomplish the work. SSEB also ensured that project plans, results, and decisions were appropriately documented and project reporting, and briefing requirements were satisfied.

Management of project risks occurred in accordance with the risk management methodology delineated in the PMP in order to identify, assess, monitor, and mitigate technical uncertainties as well as schedule, budgetary, and environmental risks associated with all aspects of the project. The results and status of the risk management process were presented during project reviews and in quarterly progress reports with emphasis placed on the medium- and high-risk items.

In accordance with the awarded SOPO, the PMP was due and delivered within 30 days after the definitized award with additional revisions submitted as requested by the NETL Project Manager.

PMP 01 - September 30, 2020

The proposed PMP was adjusted to reflect the Award Modification 01 documentation. The PMP was finalized and submitted to NETL on September 30, 2020. The PMP is Deliverable 1.1 and also satisfies Milestone 1.1. Based on comments from the Federal Project Manager, additional edits were incorporated into the PMP on October 14, 2020. The final version includes updates to staffing, the contractual organization chart, the milestones table, the Gantt chart, budget tables, and decision points.

PMP 02 - February 19, 2021

The PMP was updated to reflect an adjusted workflow of the Environmental Information Volume (EIV) development schedule, which required updates to the Milestone Log and the Gantt, and a modified schedule for UIC permitting.

PMP 03 - February 9, 2024

Modifications to the PMP were necessary to align with changes in Partners, personnel, and costing funding profiles. The Milestone Log and Gantt also were adjusted. The PMP is available for review as Appendix 01.

Subrecipient Awards

Once the Award was fully executed, SSEB staff worked with legal counsel to ensure that the Subrecipient agreements were in compliance with the Prime Award and with all applicable laws and regulations. The appropriate flow-down language was included in the agreements as an attachment, along with a copy of all Recipient Award documents. Reporting requirements, invoice expectations, and an approved invoice template were also provided with the agreements.

The Federal Funding Accountability and Transparency Act (FFACTA) reports are updated when new obligations are made to agreements through the Federal Subaward Reporting System (FSRS) website.

The final contractual organizational chart is provided in **Figure 1**.

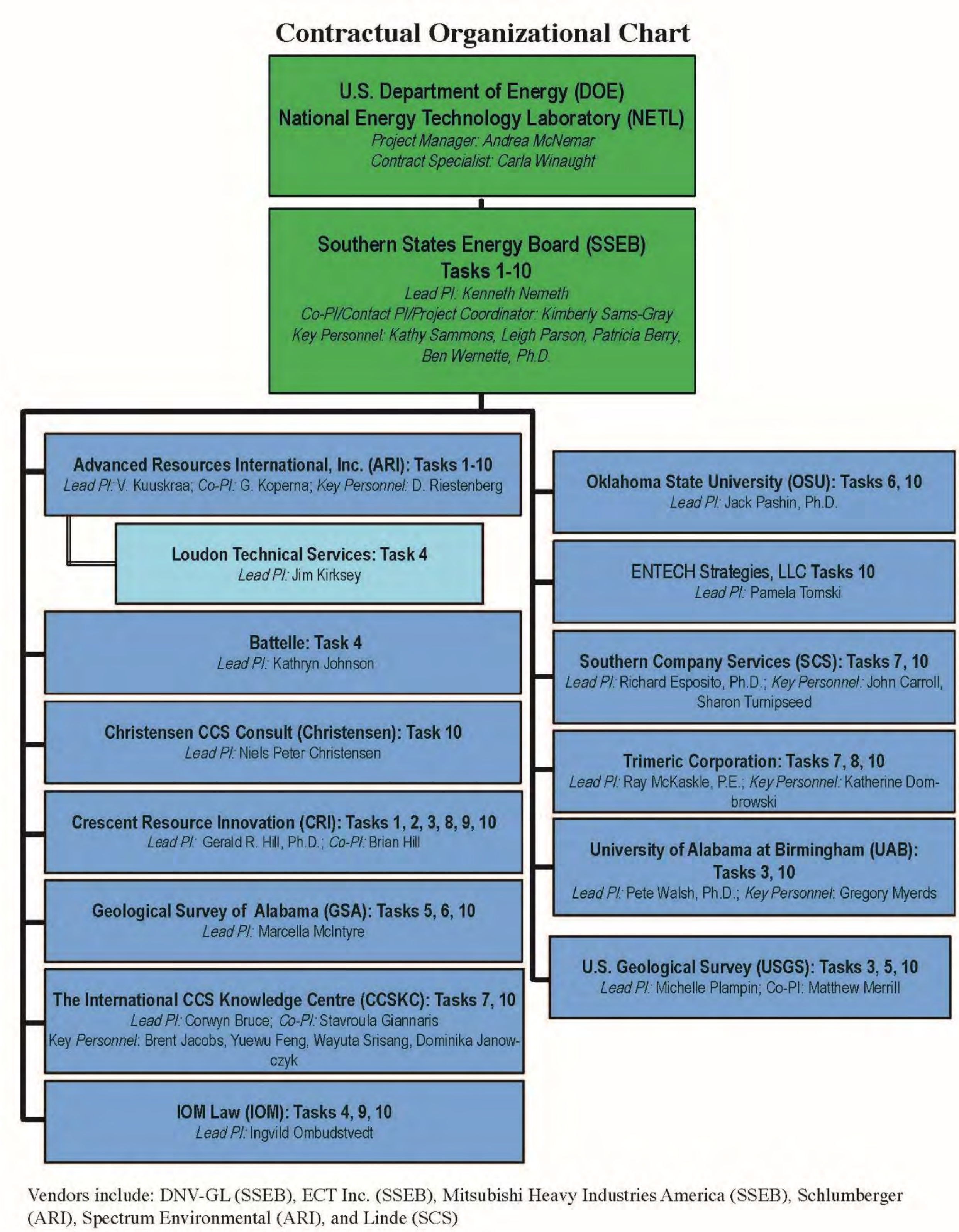


Figure 1 *Project ECO_2S Contractual Organizational Chart (final)*

Subrecipient Monitoring

Project Oversight, Management, and Recurring Reporting

Subrecipient monitoring of the technical and financial status is critical to the project's success. Throughout the Period of Performance, SSEB and Crescent Resource Innovation (CRI) frequently met with the Project Team to discuss project management-related items, with an emphasis on tracking and monitoring technical progress, budget and spend rate, project risks, reporting status, and schedule. During these risk reviews, SSEB continued to determine if additional information may be necessary from the entity. We implemented further consideration of the entity/team member procedures through on-site or in-house reviews. SSEB's technical and financial teams conducted a comprehensive review of the subrecipients' invoices and backup documentation to verify that work performed was within the approved scope and budget and all costs (federal and non-federal) were allowable, allocable, and reasonable. Each invoice submitted through the Vendor Invoicing Portal & Electronic Reporting System (VIPERS) contained detailed cost information per cost element and subrecipient backup documentation for the billing period that was also tracked in accordance with the budget and tasks. Through a three-way tracking system (SSEB generated invoices, accounts payable system and separate subrecipient tracking worksheets), SSEB maintained consistent monitoring of all financial documentation for both federal costs as well as reporting of cost share received by team members.

There were many technical and financial team discussions throughout the course of this project, as SSEB recognizes the fluidity of collaborative management for subrecipients. Financial discussions by SSEB and subrecipient's consisted of reconciliation of cumulative balances, budget task assignment deviations (when applicable), spend plan requests, terms and conditions compliance with 2 CFR 200 and many other actions. SSEB hosted calls with the full team or individuals to discuss invoicing procedures, internal control policies, as well as any conflicts or concerns that could cause schedule issues to our deliverables or delays related to modifications or payment approvals. Further monitoring occurred during regular overall budget planning technical and financial team discussions with the Federal Contract Specialist when deemed appropriate. Through these reviews occasional follow-up meetings were necessary with the subaward representatives as well to discuss appropriate budget, billing or reporting concerns or necessary corrections to budgets or invoices.

In accordance with the FARC, the Research Performance Progress Reports (RPPR) and form SF425 were submitted quarterly. The RPPR summarizes activities and accomplishments by task and reports on products developed as part of the project, participants and other collaborating organizations, the impact of the project, changes and problems encountered, any special reporting to document per the FARC, and budgetary information, including the baseline cost plan, the actual incurred costs, and the variances. The SF425 summarizes: (1) Transactions in the categories of Federal Cash, Federal Expenditures and Unobligated Balance, Recipient Share, and Program Income; and (2) Indirect Expenses.

SSEB undergoes an independent annual financial audit and a single audit required by the Office of Management and Budget for non-federal entities receiving $750,000 or more in federal funds. The final audit report and required communications were shared with SSEB members and DOE/NETL, as required by the Cooperative Agreement. Once a year, audit information was requested from all Subrecipients and included an electronic Subrecipient Audit Certification form that was completed and returned by the Subrecipients. The form provides detailed information pertaining to the Subrecipient's most recent audit or upcoming audit. The subrecipient must answer questions pertinent to audit deficiencies or audit findings and may provide a link to the audit report. SSEB is tasked with reviewing these and reevaluating risk related to audit findings and follow-up measures.

SSEB also completes an indirect incurred cost and request for provisional overhead rate each year. This is submitted after the independent audit is completed and this rate is used for billing throughout the year. At the end of the fiscal year, a "true up" process is completed to reconcile indirect cost billing with the actual approved rate. These are submitted to our cognizant agency, NETL for approval each year and are uploaded to FITS upon completion. This also is part of the FARC requirements.

Management and Oversight Meetings and Field Trips

The Project Team encountered a unique challenge with regard to COVID-19 protocols limiting the number of people allowed on site. Virtual field trips were developed to provide live streaming of site operations. On December 3, 2020, a first-ever, live virtual project management field trip to the site was coordinated and hosted by SSEB in collaboration with Advanced Resources International, Inc. (ARI) and Southern Company. Mary Sullivan of NETL, Kenneth Nemeth, Kimberly Gray, Patti Berry of SSEB, Richard Esposito of Southern Company, George Koperna and Dave Riestenberg of ARI, and Brian Hill of CRI attended the virtual site tour. The field trip was recorded.

Figure 2 *COVID-19 protocol sign at the ECO_2S project site, Kemper County, Mississippi*

Patti Berry (SSEB), Ben Wernette (SSEB), George Koperna (ARI), Dave Riestenberg (ARI), and Jack Pashin (Oklahoma State University, OSU) met at Stratum Reservoir in Houston, Texas, on July 29, 2021. After brief introductions with Stratum personnel, the team examined the MPC 10-4, MPC 19-1, and MPC 34-1 core. Following lunch, the team discussed data required to support the ECO_2S UIC Class VI permit application and toured the Stratum Reservoir labs. Laboratories toured included (1) the routine core analysis (RCA), (2) porosity and permeability, (3) x-ray fluorescence, (4) x-ray diffraction, (5) petrography, and (6) rock mechanics.

Figure 3 *Brittany Hollon, Senior Project Manager for Stratum Reservoir, discussing routine core analyses with the team. From left to right: Richie Ness (ARI), Brittany Hollon (Stratum), Jack Pashin (OSU), Patti Berry (SSEB), Dave Riestenberg (ARI), and George Koperna (ARI). Not pictured: Ben Wernette (SSEB).*

Michelle Plampin, U.S. Geological Survey (USGS), and Patti Berry, SSEB, met with Holly Evans, ARI, on October 27, 2022, at the ECO_2S field site to observe the MPC 10-4 well testing. They also visited the MPC 19-1 site, which contains the USDW well drilled in 2021 and was the site of the potential Injection Well MPC 19-2 for which the Class VI permit application was submitted.

Figure 4 *Patti Berry, SSEB, and Holly Evans, ARI, review well pressure testing data*

Foreign National Participation

Foreign National participation was requested and processed pursuant to the Terms and Conditions of the Award. During the Period of Performance, four individuals were approved.

- Valluri, Manoj (approved 9/20/2021-10/31/2022)
- Ostgaard, Lena, Wammer (submitted August 2022 and approved by 12/2/22 with revised terms)
- Nyberget, Jorgen (submitted August 2022 and approved by 12/2/22 with revised terms)
- Ademilola, Joshua, Adeyemi (approved 12/1/2021-8/31/2023)

Project Schedule

The Gantt chart provided in **Figure 5** represents the final schedule for Project ECO_2S Phase III.

Tasks	Start	Due Date
TASK 1.0: PROJECT MANAGEMENT AND PLANNING	**09/01/20**	**02/28/25**
Subtask 1.1: Project Management Plan	09/01/20	02/28/25
Milestone: Implement Project Management Plan	09/30/20	09/30/20
Decision Point 1: Negotiation/Implementation of PMP	09/30/20	09/30/20
Decision Point 3: Negotiation /Implementation of Phase II/BP2	08/31/22	08/31/22
Subtask 1.2: Data Management Plan	09/01/20	08/31/23
Subtask 1.3: Technology Maturation Plan	09/01/20	08/31/22
Subtask 1.4: Contractual	09/01/20	12/01/20
Subtask 1.5: Project Coordination	09/01/20	02/28/25
TASK 2.0: NATIONAL ENVIROMENTAL POLICY ACT (NEPA)	**09/01/20**	**08/31/23**
Subtask 2.1: Preparation and Submission of NEPA Documentation for Site Characterization and CO2 Capture Assessment	09/01/20	12/31/20
Milestone: Complete Environmental Information Volume	03/03/21	03/03/21
Subtask 2.2: Preparation and Submission of an EIV for Potential Future Construction and Operation	09/01/20	03/03/21
Subtask 2.3: Preparation and Submission of NEPA Documentation for Potential Future Construction and Operation	03/04/21	08/31/23
TASK 3.0: RISK MANAGEMENT	**09/01/20**	**08/31/23**
Decision Point 2: Complete Initial Risk Register	09/01/20	09/01/20
Subtask 3.1: Commercial Scale Integrated Risk Assessment	09/01/20	08/31/23
Subtask 3.2: Risk Assessment Tools	09/01/20	08/31/23
TASK 4.0: SITE SELECTION AND WELL DRILLING	**09/01/20**	**12/30/22**
Subtask 4.1: Well Site Selection	09/01/20	12/01/20
Subtask 4.2: Permitting and Site Surveys	09/01/20	03/03/21
Subtask 4.3: Well Design	09/01/20	12/01/20
Subtask 4.4: Well Drilling and Geologic Data Collection	11/01/20	12/30/22
TASK 5.0: COMPLETE GEOLOGIC CHARACTERIZATION	**09/01/20**	**12/01/22**
Subtask 5.1: Underground Sources of Drinking Water	09/01/20	12/01/22
Subtask 5.2: 3D Seismic Survey	03/04/21	03/03/22
Subtask 5.3: Surface Characterization for UIC Injection Well Drilling	12/02/21	12/01/22
TASK 6.0: GEOLOGIC DATA ANALYSIS	**03/04/21**	**02/28/25**
Subtask 6.1: Core and Fluid Analysis	03/04/21	03/03/22
Subtask 6.2: Refined Geologic Model	09/01/21	03/03/22
Subtask 6.3: Reservoir Modeling	12/02/21	08/31/22
Subtask 6.4: Seismic Processing and Interpretation	09/01/21	03/03/23
Milestone: Complete Geologic Characterization	02/28/25	02/28/25
Subtask 6.5: DeepLook STUDY	03/04/21	02/28/25

Tasks	Start	Due Date
TASK 7.0: CO2 CAPTURE ASSESSMENT	**09/01/20**	**08/31/22**
Subtask 7.1: Potential CO2 Source Screening and Selection	09/01/20	03/03/21
Subtask 7.2: Selecting Engineering Contractor for Engineering Services	09/01/20	12/01/21
Subtask 7.3: Establish Basis of Design	12/02/20	12/01/21
Subtask 7.4: Permitting Considerations	12/02/20	04/29/22
Subtask 7.5: Flue Gas Supply System	03/04/21	08/31/22
Subtask 7.6: Flue Gas Pre-Treatment Process	03/04/21	08/31/22
Subtask 7.7: Regeneration Energy Source Evaluation	03/04/21	08/31/22
Subtask 7.8. Additional Cooling Capacity	03/04/21	08/31/22
Subtask 7.9. CO2 Compression and Dehydration	03/04/21	08/31/22
Subtask 7.10. CO2 Pipeline Infrastructure	03/04/21	08/31/22
Subtask 7.11. Balance of Plant	09/01/21	08/31/22
Milestone: Complete CO2 Capture Pre-Feasibility Studies	08/31/22	08/31/22
TASK 8.0: PROJECT INTEGRATION	**03/04/21**	**03/03/23**
Subtask 8.1: CO2 Delivery and Well Infrastructure Needs	03/04/21	03/03/23
Subtask 8.2: Pore/Surface Rights and Right of Way Requirements	03/04/21	03/03/23
Subtask 8.3: Financial and Contractual Model(s)	09/01/21	08/31/22
TASK 9.0: UIC PERMITTING	**09/01/21**	**02/28/25**
Subtask 9.1: Project Description and Site Characterization	09/01/21	08/31/22
Subtask 9.2: Construction and Operational Plans	09/01/21	08/31/22
Subtask 9.3: Site Closure Demonstration	09/01/21	08/31/22
Milestone: Submit UIC Class VI Permit to Construct Application	08/31/22	08/31/22
Subtask 9.4: Public Outreach and Engagement	03/04/22	03/03/23
Subtask 9.5: Address U.S. EPA Comments on Class VI Permit Application	09/01/22	02/28/25
Milestone: Receive Permission to Construct UIC Class VI Well	02/28/25	02/28/25
TASK 10.0: KNOWLEDGE DISSEMINATION AND TECHNOLOGY TRANSFER	**09/01/20**	**02/28/25**
Subtask 10.1: Community Outreach and Education	09/01/20	02/28/25
Subtask 10.2: Regulatory Outreach	09/01/20	02/28/25
Subtask 10.3. Knowledge Sharing through Conferences, Workshop & Tech Papers	09/01/20	02/28/25
Milestone: Participate in Project Kickoff Meeting	11/30/20	11/30/20
Subtask 10.4. International Collaboration	09/01/20	02/28/25

Figure 5 *Project ECO₂S Schedule, final*

Project Deliverables – Statement of Project Objectives

In addition to the periodic and final reports required by the FARC, the SOPO presented a table of task-specific project deliverables that documented progress toward, and completion of, the Scope of Work (SOW) outlined in the SOPO. As of February 28, 2025, all project deliverables were completed and submitted in accordance with the prevailing version of the SOPO as noted in **Table 2**.

Table 2 *Deliverables listed in chronological order of completion*

Task/Subtask	Description	Due Date	Actual Completion Date
1.1	Project Management Plan	9/30/2020	9/30/2020
1.2	Data Management Plan	9/30/2020	9/30/2020
3	Initial Project Risk Register	10/16/2020	10/11/2020
1.3	Carbon Capture Technology(ies) Maturation Plan (TMP)	12/1/2020	12/18/2020
4.2	Well Drilling Permits	12/1/2020	11/17/2020
2.2	Environmental Information Volume	3/3/2021 - revised 9/30/21	7/8/2021
4.4	Geologic Catalog of Materials	8/31/2021	11/29/2021
4.4	As Built Well Construction	8/31/2021	11/29/2021
7.3	Basis of Design	4/30/2022	9/21/2022
3.3	NRAP Tools Report	8/31/2022	8/31/2022
4.4	Geologic Catalog of Materials	8/31/2022	8/31/2022
5	Summary of Geologic Characterization Information	8/31/2022	8/31/2022
9	Application for Underground Injection Control Class VI Permit to Construct	8/31/2022	8/31/2022
7	CO2 Capture Feasibility Assessment (Refer to FOA-1999 Appendix H for requirements)	8/31/2022	8/31/2022
8	Integrated Project Plan	2/28/2023 - revised 8/31/23 - NCTE Revised 02/28/2025	NA
3	Comprehensive Risk Assessment	8/31/2023 - NCTE Revised 2/28/2025	3/17/2025
2.3	Final NEPA document with a Record of Decision or Finding of No Significant Impact	8/31/23 - NCTE Revised 2/28/2025	NA
6	Final Geologic Characterization	8/31/2023 - NCTE Revised 2/28/2025	2/28/2025
4.4	Geologic Catalog of Materials	8/31/23 - NCTE Revised 2/28/2025	2/28/2025
9	Final UIC Class VI Permit to Construct Application	See comment	Requested to be removed in the next modification.

Project Milestones – Project Management Plan

In addition to the periodic and final reports required by the FARC and SOPO, the PMP sets a list of project milestones. Some milestones were task-based, while others were quantitative, and indicated progress toward accomplishing the project goals. Progress also was reported as part of the required RPPR. As of February 28, 2025, all project milestones were achieved and verification documentation submitted in accordance with the prevailing version of the PMP as reflected in **Table 3**.

Table 3 *Milestones listed in chronological order of completion*

Task/Subtask	Description	Due Date	Actual Completion Date
2.1	Complete Environmental Info. Volume	Y1 – 03/03/21 - revised 9/30/2021	7/8/2021
1.1	Implement Project Management Plan	Y1 – 09/30/20	9/30/2020
10.3	Participate in Project Kickoff Meeting	Y1 – 11/30/20	10/21/2020
9	Submit UIC Class VI Permit to Construct Application	Y2 – 08/31/22	8/31/2022
7	Complete CO2 Capture Pre-Feasibility Studies	Y2 – 08/31/22	8/31/2022
6	Complete Geologic Characterization	Y3 - 08/31/23 - NCTE Revised 02/28/2025	2/28/2025
9	Receive Permission to Construct UIC Class VI Well	Y3 - 08/31/23 - NCTE Revised 02/28/2025	NA

NETL's Project Landing Page, ECO_2S Phase III

NETL maintains a Project Landing Page for all of its funded projects. The ECO_2S Phase III site can be found here: https://www.netl.doe.gov/project-information?k=FE0031888. The site includes a project description, project benefits, contact information, and a section on presentations, papers, and publications.

Subtask 1.2 – Data Management Plan

During the execution of this project, the Partners collected and generated large volumes of data, designs, and cost information from the field, the laboratory, and the desktop. The Data Management Plan (DMP) explains how data generated during the work performed will be shared and preserved or, when justified, explains why data sharing or preservation is not possible or scientifically appropriate. Intellectual Property provisions in the Prime Award and the DMP attachment were included in the Subrecipient agreements and modifications. SSEB prepared and submitted the project DMP to DOE/NETL in September 2020 prior to receiving the award, and again on September 30, 2020. The most recent version of the DMP is available as Appendix 02.

Subtask 1.3 – Technology Maturation Plan

The Technology Maturation Plan (TMP) was developed and completed during the second quarter of BP1. CRI and Southern Company coordinated the development of two TMP documents. The LindeBASF TMP document provided information on the capture technology for gas-fired power facilities at Plant Daniel and Plant Ratcliffe, and the Mitsubishi Heavy Industries (MHIA) TMP provided information on the capture technology for coal-fueled power facilities at Plant Miller. Input on the TMPs was provided by Linde, BASF, MHIA, Southern Company, Alabama Power Company, and MPC. The two TMPs describe the current technology readiness level (TRL) of the proposed capture technologies, relate the proposed project work to maturation of the proposed technology, and describe known post-project work necessary to further increase the TRL of capture systems.

The LindeBASF TMP and the MHIA TMPs are included as Appendix 03.

Subtask 1.4 – Contractual

The Project ECO_2S Phase II site access and use agreement between MPC and ARI was renegotiated and fully executed to authorize the Phase III project on October 26, 2020. The agreement provides ARI and other Partners with access to the selected well locations near the Plant Ratcliffe facility for drilling and data collection activities. ARI contracted with the surface preparation and drilling service providers (including site construction, drilling, cementing, and geophysical logging, etc.) and finalized the timeline of field activities. All service providers were required to meet site access contractual stipulations for performing services on MPC properties. An electronic version of this agreement was emailed to the Federal Project Manager.

Subtask 1.5 – Project Coordination

On December 16, 2020, Kimberly Gray of SSEB, Richard Esposito of Southern Company, and George Koperna and Dave Riestenberg of ARI participated in a pre-meeting with DOE and other CarbonSAFE project leads regarding information exchange with EPA. The meeting facilitated briefings on the CarbonSAFE projects and EPA guidance regarding the permitting process and the Geologic Sequestration Data Tool (GSDT).

On March 27, 2024, MPC formally withdrew its UIC Class VI Permit to Construct application, a key component supporting Project ECO_2S. The EPA acknowledged the withdrawal, and the application is no longer under review. In response, a meeting was convened by Patricia Berry (SSEB) with representatives from NETL, DOE-FECM, and MPC to review the rationale behind MPC's decision and to evaluate the implications for the future of Project ECO_2S. The following statement was provided by MPC to share with DOE-FECM/NETL and the public:

"Mississippi Power's participation in the CarbonSAFE Project has provided valuable information for both the company and for Mississippi by identifying a world-class geological resource in the southeastern portion of the state. Our partnership with the Department of Energy, the Southern States Energy Board and Southern Company Services R&D has helped many recognize the potential for future economic development opportunities regarding CO_2 storage. ***In March 2024, Mississippi Power withdrew its permit application for two Class VI wells at EPA Region 4 due primarily to regulatory uncertainty."***

Following this briefing, SSEB, NETL, and DOE-FECM met separately to assess the situation and outline tentative next steps. SSEB was tasked with compiling a comprehensive inventory of completed and outstanding project activities, along with proposed future actions, including high-level descriptions and associated budget estimates for NETL's consideration.

In consultation with NETL, SSEB immediately directed the Project Team to pause all work related to the NEPA process, UIC Class VI permitting, and Community Benefits Plan (CBP) efforts. Throughout the remainder of 2024 and into the first quarter of 2025, the Project Team conducted internal discussions and meetings with DOE/NETL to evaluate potential paths forward. After careful deliberation, the team reached a consensus to formally close out the project in March 2025.

Task 2.0 – National Environmental Policy Act (NEPA)

Subtask 2.1 – Preparation and Submission of NEPA Documentation for Site Characterization and CO_2 Capture Assessment

The NEPA Environmental Questionnaires (EQ) that were submitted with the proposal covered "Group A" activities for all Partners and their respective locations. A CX for Tasks 1, 2, 3, 6-10, 4.1-4.3, and 5.3 was issued on August 28, 2020.

SSEB and ARI assembled NEPA data for three prospective drilling sites for characterization wells that were selected in October of 2020. An additional EQ for Subtask 4.4 was completed and submitted for the three characterization well sites, as illustrated in **Figure 6**. A CX for Subtask 4.4 (well drilling) was issued on October 26, 2020.

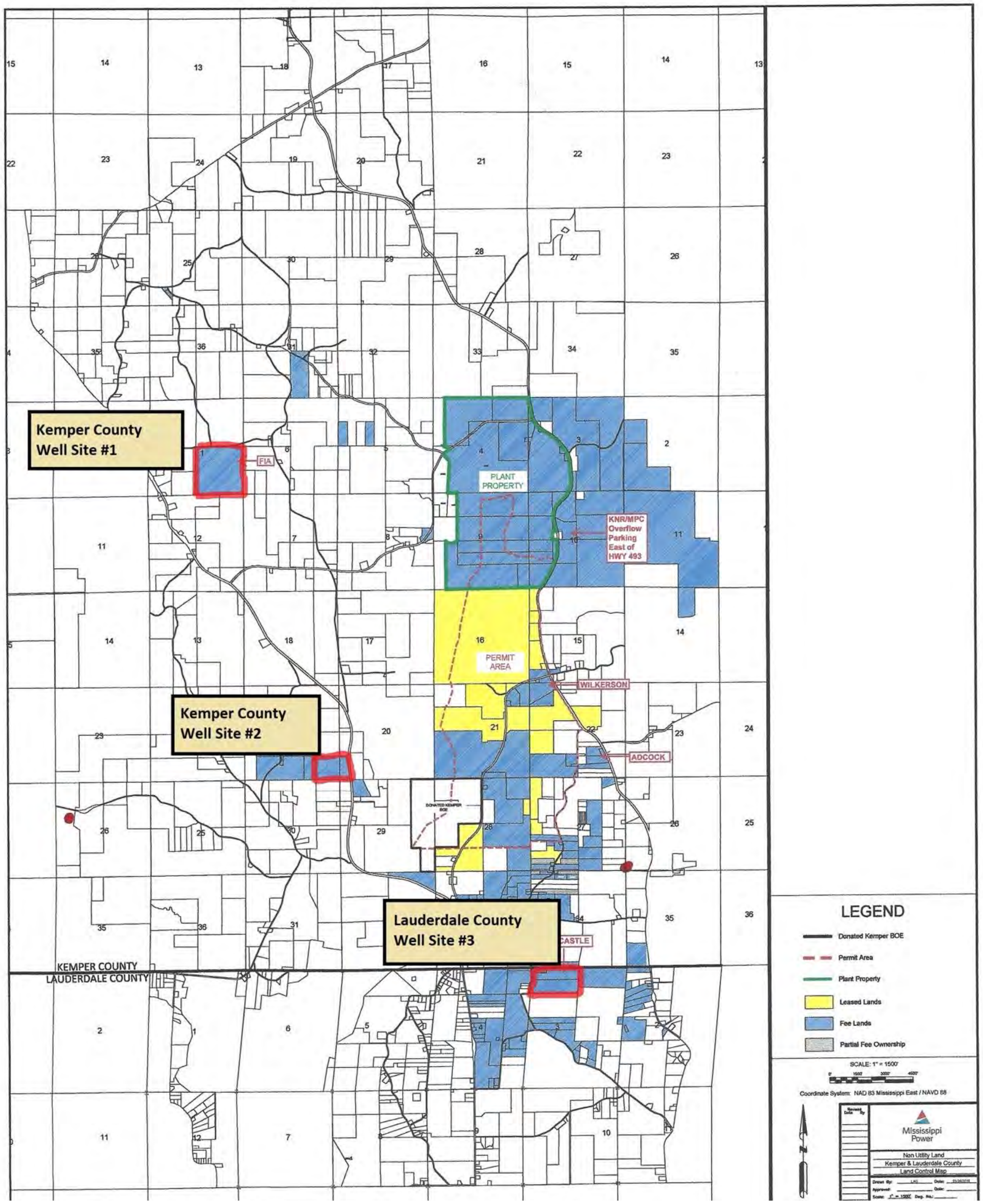


Figure 6 *Map of initial Well locations from CX*

Figure 7 *Map of Well Site #1 from CX*

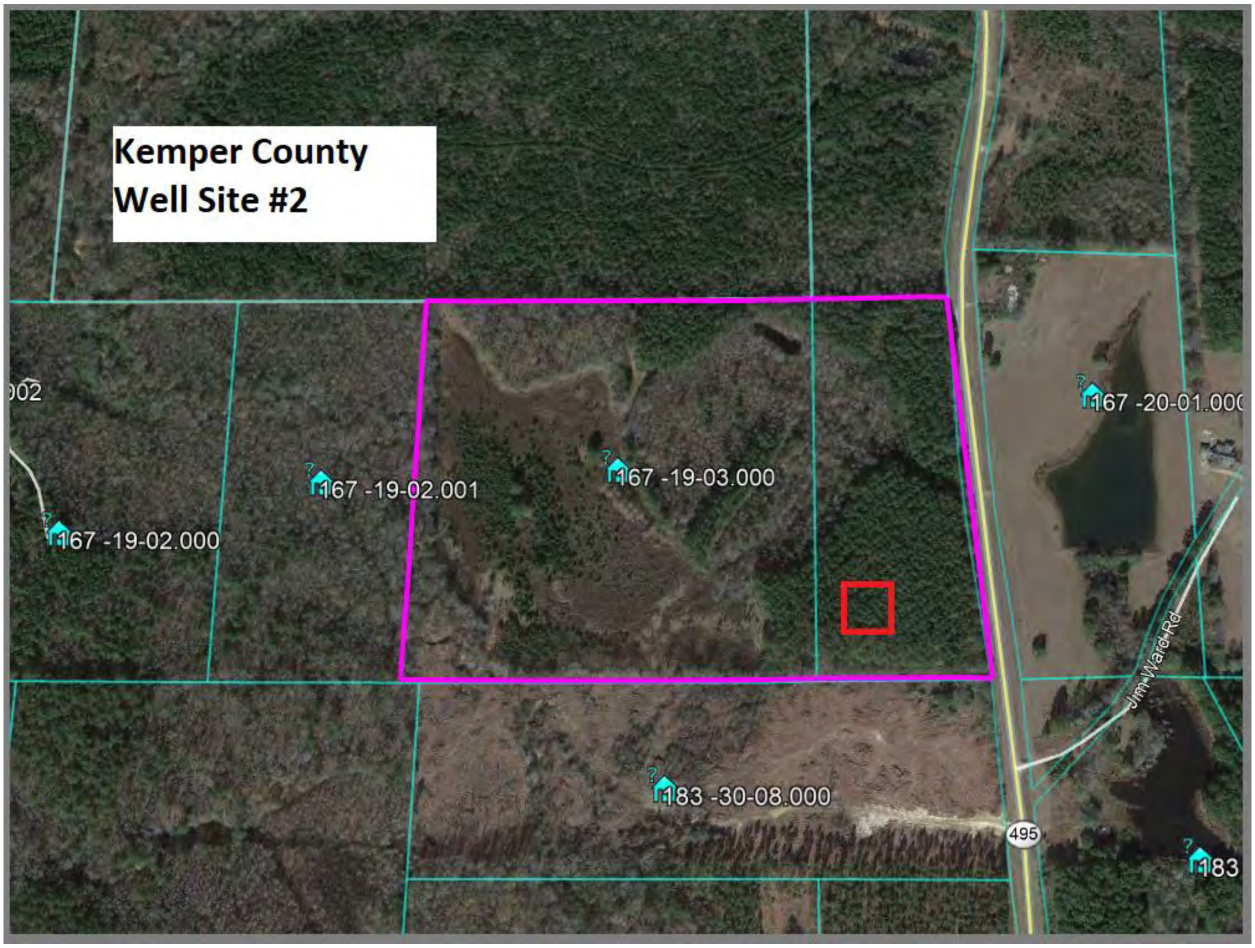


Figure 8 *Map of Well Site #2 from CX (later replaced with the map in Figure 10)*

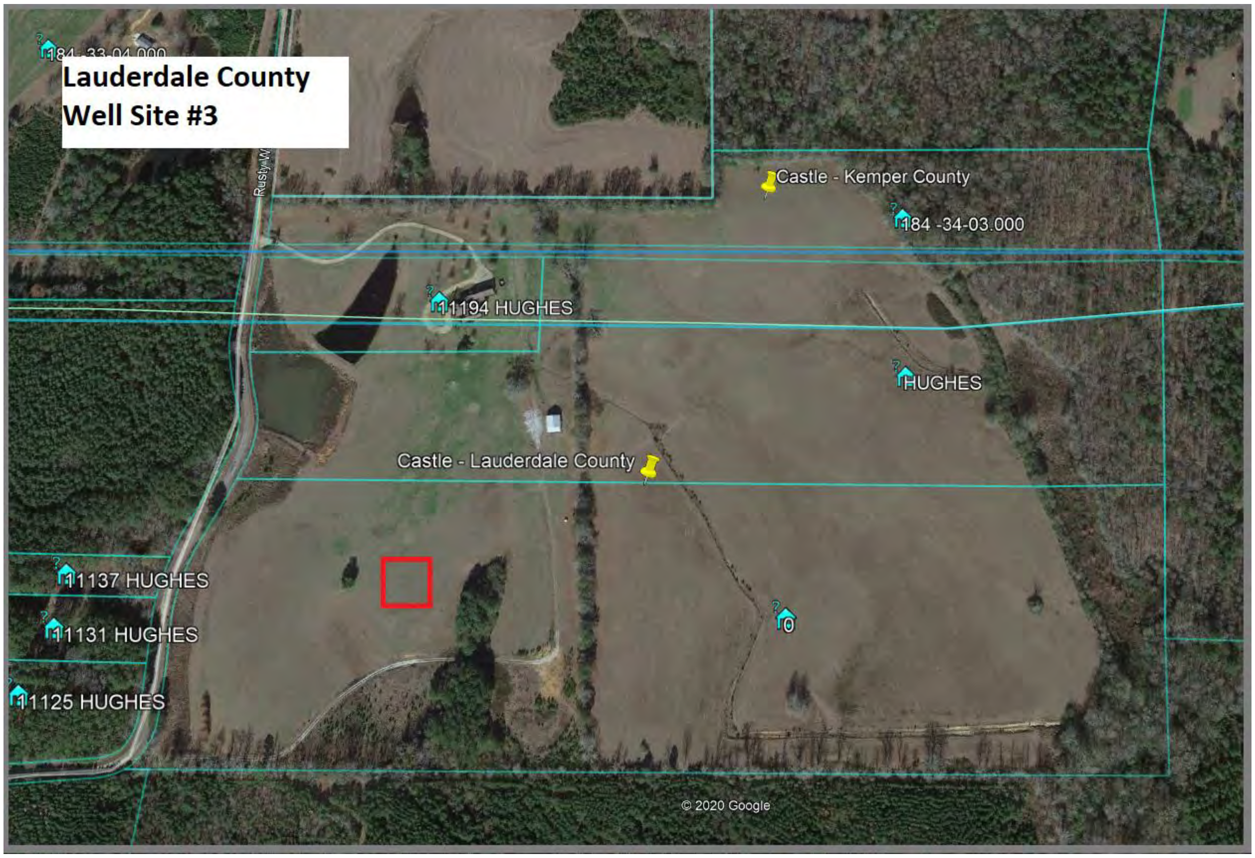


Figure 9 *Map of Well Site #3 from CX*

In February 2021, the site of the characterization well previously identified as MPC 20-1 was relocated for non-technical reasons. The Partners confirmed that the descriptions contained in the previously submitted EQ for the three wells were accurate for the new site. A new site map was provided to NETL on February 17, 2021. On February 19, 2021, SSEB was notified that the map was replaced, and the new site is covered by the existing CX.

The EQs for Subtask 5.1, USDW, and Subtask 5.2, Seismic Survey, were submitted on April 12, 2021. The CX was issued on May 20, 2021.

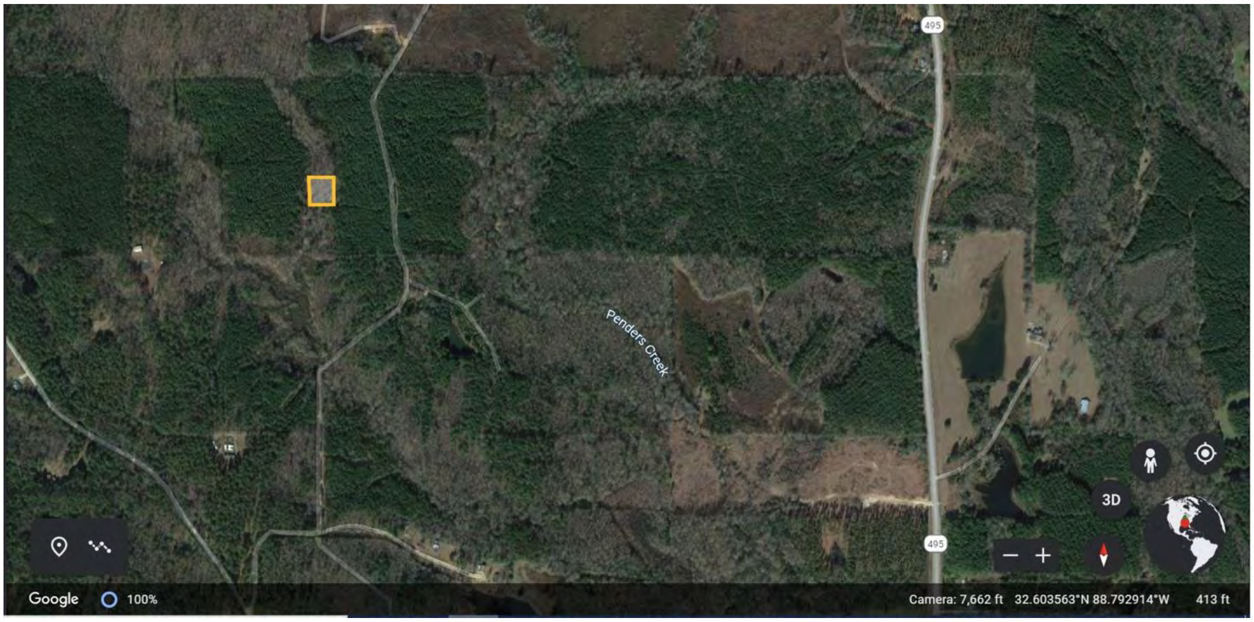


Figure 10 *New Map with relocated MPC 20-1 (Well Site #2) from CX*

Subtask 2.2 – Preparation and Submission of an Environmental Information Volume for Potential Future Construction and Operation

SSEB hosted an initial planning meeting on December 3, 2020, with Environmental Consulting & Technology, Inc. (ECT), the consulting company preparing the EIV. The purpose of the call was to identify the types of existing and new data ECT would need to obtain from the Project Team to begin assembling the EIV.

On December 11, 2020, SSEB hosted a NEPA-focused virtual meeting to facilitate introductions among all Partners and vendors involved in the Task 2 effort and to establish a schedule for deliverable and milestone completion. On December 21, 2020, SSEB hosted a NEPA Partners virtual meeting to further define the area of prospective environmental impacts related to construction and operation of the future capture units at Plants Miller, Ratcliffe, and Daniel, pipeline routes, and the Storage Complex. Participants included ARI, CRI, ECT and Trimeric.

With information received from the team, ECT continued to develop the EIV through March of 2021. Interaction during this time included calls and emails with team members to identify additional details necessary to complete the EIV. A team call was held during May 2021 to discuss the initial Draft EIV prepared by ECT. Comments from the NEPA team were compiled by ECT, and the revised EIV was submitted to SSEB on June 28, 2021, for dissemination to DOE. Following review by SSEB, the EIV was sent to NETL on July 8, 2021.

SSEB received comments to the EIV from NETL in December of 2021, and the team immediately began addressing the observations. NETL's guidance was to reduce the document length by making the content more concise. NETL also noted that there were two significant pipeline segments (from Plant Miller and Plant Daniel) and the resulting impacts of the proposed project would require full consultation with the U.S. Fish and Wildlife Service (FWS) and U.S. Army Corps of Engineers (USACE) due to potential wetland impacts. The extensive area under consideration necessitated a review by the State Historical Preservation Office (SHPO). The area within Alabama and Mississippi has significant tribal presence and would require review by the U. S. Department of Interior's (DOI) Bureau of Indian Affairs (BIA) and consultation with affiliated Tribes. It also was noted that a cumulative impact section would need to be added.

On January 7, 2022, CRI, SSEB, ECT, and ARI participated in a conference call to review initial comments to the EIV, discuss responses, and assign teams to address remaining action items. A follow up meeting with DOE's NEPA office was scheduled and held on February 23, 2023. CRI, SSEB, ECT, and DOE's NEPA office participated in the discussion to address outstanding comments and requests. Subsequently, ECT delivered the final EIV to SSEB on February 27, 2022, and it was revised and resubmitted to NETL on April 26, 2022.

In June 2022, managing partners decided to limit the scope of the project's AoR by removing two of the three potential sources of CO_2, namely Plants Miller and Daniel, and the related CO_2 transport infrastructure. **Figure 11** identifies the locations of the three and the initial proposed pipeline routing. The decision to remove Plants Miller and Daniel significantly reduced the potential impact of the project.

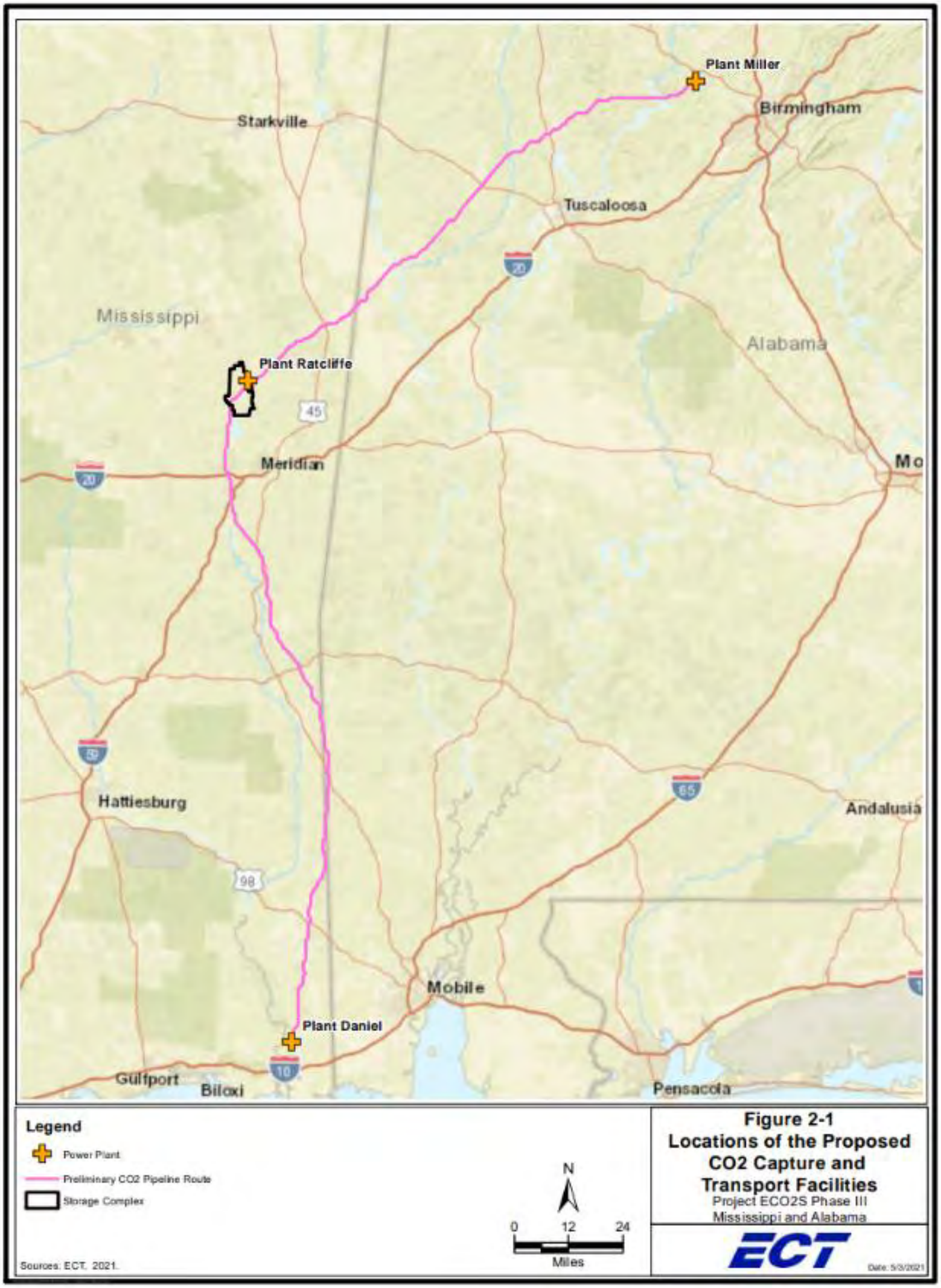


***Figure 1** Initial locations of the proposed CO_2 capture and transport facilities*

The approximately 180-mile pipeline from Plant Daniel to the injection sites would have traversed many surface waterbodies within the Pascagoula Watershed. A majority of these water bodies drain from northeast to southwest through the generally medium grade Southeastern Plains region to the lower grade Coastal Plains region. The most notable major rivers in this area include the Pascagoula, Chickasawhay, and a few head waters of the Tombigbee, along with their smaller tributaries. In the pipeline Region of Influence (ROI) there were approximately 440 waterbody crossings.

The approximately 150-mile pipeline from Plant Miller to the injection sites would have traversed many waterbodies within the Mobile River Watershed (surface) and the ROI of the injection site. Moving southwest from the plant, the pipeline followed most drainage directions of rivers in the steeper graded Southwestern Appalachian region. The pipeline route then continued southwest to the injection sites through the generally medium grade Southeastern Plains region, where rivers mainly drain from northwest to south. The most notable major rivers in this area Include Bankhead lake on the Black Warrior River, North River, Sipsey River, and Tombigbee River, along with their smaller tributaries. The proposed pipeline ROI crossed about 250 streams and creeks, along with 33 larger named water bodies.

The pipelines would create a temporary loss of upland and wetland habitats and a permanent loss of some forested areas as a result of construction and operation. A preliminary estimate of the acreage of forested habitat that would be permanently converted to herbaceous habitat in each pipeline corridor is provided in **Table 4**.

Table 4 *Estimate of the Acreage of Permanent Habitat Conversion on each Pipeline Route*

Type of Habitat	Ratcliffe-Daniel Pipeline	Ratcliffe-Miller Pipeline
Deciduous forest	91.8	203.6
Evergreen forest	246.9	165.3
Mixed forest	127.1	87.4
Forested wetland	111.7	62.3
Totals	**577.5**	**518.6**

Subtask 2.3 – Preparation and Submission of NEPA Documentation for Potential Future Construction and Operation

Development of the NEPA EA began in the third quarter of 2022. Prior to beginning the EA, the project's AoR was modified to remove the two CO_2 sources, Plants Miller and Daniel and related pipeline infrastructure (see Subtask 2.2). Based on emissions rates over the past few years, Plant Ratcliffe alone satisfies the CarbonSAFE requirement of 50 million metric tons (MMT) CO_2 over a 30-year period.

DOE and SSEB began searching for a third-party contractor for the EA in the fourth quarter of 2022. As part of the search, ECT provided a Statement of Qualifications in December 2022. ECT prepared and submitted a revised EA scope and schedule on January 20, 2023. After receiving additional feedback from DOE and SSEB, the scope and schedule was further refined and submitted on February 17, 2023.

Based on the scope and schedule agreed upon by ECT, SSEB, and DOE, CRI began working with DOE's Pieri Fayish and ECT to establish a workflow and multi-party agreement for completing the project's EA. The multi-party Memorandum of Understanding (MOU) was executed on March of 2023 establishing ECT as the third-party contractor for the preparation of the EA.

Upon receipt of the executed MOU, CRI worked with ECT to refine the workflow and schedule, and it was approved by DOE. CRI facilitated a virtual EA kickoff meeting with DOE, SSEB, and ECT on March 14, 2023. At this meeting, it was decided that ECT would initiate and host a SharePoint site where all parties could work collaboratively on EA documents and where files would be stored. The parties convened for a second meeting on March 28, 2023, during which ECT provided access to the SharePoint project folder.

SSEB and CRI led multiple calls to advance work on the EA. Team calls were held on April 11 and 25, May 9 and 24, and June 20, 2023. SSEB and CRI coordinated efforts between the EA team and the Pipeline Front-End Engineering and Design (FEED) team given their dependencies (e.g., sensitive areas to be avoided that are identified in the EA will necessitate changes in pipeline routing and impact the Pipeline FEED).

During the second quarter of 2023, ECT requested additional information regarding the proposed pipeline route and the project narrative with a description of the sequestration facility and methods. Upon receipt of the requested information from Southern Company and DOE, the project schedule was revised to accommodate pipeline route information and the ongoing Pipeline FEED study.

At this time, ECT provided SSEB and Trimeric with a first order review of the proposed pipeline route with regard to known historical, cultural, and archaeologically significant features and protected wildlife and habitat per available database information, including the National Wetlands Inventory, National Hydrography Dataset, National Register of Historic Places, and Mississippi Department of Archives and History (MDAH).

On June 27, 2023, ECT provided SSEB and DOE with initial drafts of consultation letters from the State and Tribal Historic Preservation Officers, FWS, and Mississippi Department of Wildlife, Fisheries, and Parks (MDWFP), as well as a draft Inadvertent Discovery Plan (IDP).

With this information, the team continued to hold regular calls to advance the EA's completion. The calls occurred on July 5, July 18, August 1, August 15, September 12, and September 26, 2023.

ECT received comments from DOE regarding the draft consultation letters to agencies and Tribes. ECT then finalized the letters and drafted an IDP. ECT researched Tribes in response to the BIA comments for additional correspondence.

On August 7, 2023, ECT submitted the first draft of the EA to DOE. ECT participated in a call with DOE and EPA regarding Section 106, a review process that is part of the National Historic Preservation Act (NHPA) and requires federal agencies to consider environmental impacts on historic properties. As part of the MDAH request for a cultural resources survey, ECT prepared a scope and fee proposal and submitted the proposal to SSEB and DOE, which would require an Award modification to pursue. Work on the EA during the 4th quarter of 2023 slowed down substantially as the team awaited DOE's approval of the Award modification request, but team calls were hosted on October 10, October 24, November 21, December 5, and December 19 to discuss other necessary refinements of the EA.

A call with DOE and EPA was held on December 11, 2023. The purpose of the call was to discuss a new development regarding EPA's planned community outreach related to the EA and UIC Class VI Permit to Construct applications. SSEB, CRI, EPA, Southern Company, and MPC personnel participated in the call with DOE and EPA.

Award modification 06 was issued on March 8, 2024, and an EA "restart" call was held on March 12, 2024, to gather the EA team to start finalizing the EA.

On March 18, 2024, upon receipt of notice from MPC that they were withdrawing the two UIC permit applications, SSEB stopped work on the EA across all Partners. In response, SSEB communicated with MPC to understand their decision and requested that they reconsider this action and continue the project.

On March 27, 2024, MPC's Management Council rendered a second decision to withdraw their two UIC permit applications. EPA acknowledged their request, and the application was no longer under EPA's review. On the same day, SSEB hosted a remote meeting with NETL, DOE Office of Fossil Energy and Carbon Management (FECM), and MPC to allow MPC to explain what led to their decision and to discuss the fate of Project ECO_2S in light of these developments. Please refer to Subtask 1.5 for additional information regarding the MPC decision.

Following this briefing, SSEB, NETL, and DOE FECM personnel met separately to tentatively plan next steps, which were for SSEB to develop a list of what has been completed and outstanding and propose future actions with a high-level description and budget for NETL's review. As a result, SSEB notified the Project Team to cease working on the NEPA, UIC Class VI permitting, and community outreach tasks until further notice.

NETL requested that ECT consolidate all work completed to date on the EA. ECT provided the requested data to SSEB on March 10, 2025, as the final steps in the EA process. The final work was submitted to NETL on June 26, 2025.

Task 3.0 – Risk Management

Subtask 3.1 – Project Risk Evaluation

SSEB and CRI worked with the Federal Project Manager to assemble a draft of the Project Risk Register for the team's review. On October 7, 2020, the Project Team assembled in Charleston, West Virginia, and virtually to review the draft risk register as part of a well drilling planning meeting.

The Partners completed the Initial Project Risk Register, Deliverable 3.1, within 45 days after award and submitted it to NETL on October 11, 2020. Deliverable 3.1 is provided as Appendix 04.

On October 19, 2020, Jeffrey S. Kooser, Contracting Officer/Contract Specialist, DOE/NETL, contacted SSEB's Kimberly Gray stating that, "*In accordance with the Decision Point language contained in the Statement of Project Objectives, the NETL project team has reviewed the initial risk registered submitted by SSEB and finds it to be acceptable*." Approval by the Contracting Officer satisfied the requirements of Go/No-Go Decision Point 2, which allowed work to commence under Subtask 4.4, Well Drilling and Geologic Data Collection.

Subtask 3.2 – Commercial Scale Integrated Risk Assessment

Initial Risk Register Development

On June 14, 2021, Det Norske Veritas (DNV) and SSEB convened a focused workshop to initiate an update to the project's risk register previously submitted to NETL in October 2020 (Subtask 3.1, Go/No-Go Decision Point 2). The objectives were twofold: (1) to refresh and expand the risk register content and (2) to migrate the register into a digital format using DNV's EasyRisk Manager, a centralized tool designed to track the evolution of risk scenarios, assigned responsibilities, and the implementation of mitigation strategies.

Workshop participants—including representatives from DNV, SSEB, CRI, and Trimeric—collaboratively defined risk evaluation criteria, assigned ownership of individual risk scenarios, assessed initial risk statuses, and began identifying emerging risks. The designated risk owners were tasked with reviewing and updating their assigned risks moving forward.

Risk Register Expansion and Review

A planning call on August 11, 2021, laid the groundwork for a broader risk workshop. Subsequently, on September 14, 2021, a virtual meeting involving ARI, CRI, DNV, Southern Company, SSEB, and Trimeric reviewed the working draft of the risk register. The group confirmed that the document was ready for deeper engagement during an in-person workshop, which was originally planned for October 2021. However, due to COVID-related travel constraints, the session was rescheduled for Q2 2022. Meanwhile, DNV finalized the initial digital risk register and published it to the broader team on October 21, 2021.

Risk Assessment Workshop and Documentation

From January through March 2022, DNV continued to collect updates from risk owners and refine entries within the EasyRisk Manager system. This effort culminated in a comprehensive in-person Risk Assessment Workshop held on May 3–4, 2022, at Southern Company's offices in Wilsonville, Alabama. During the workshop, stakeholders reviewed existing risks, validated or revised their status, and discussed emerging risks relevant to future project phases.

Following the workshop, DNV submitted a draft report documenting the risk assessment process. After incorporating feedback from SSEB and CRI, the final version of the Risk Assessment Report was submitted on August 31, 2022.

Post-Permit Withdrawal Risk Evaluation

In July 2024, in response to MPC's decision to withdraw the UIC Class VI permit application, CRI and DNV initiated a final review of the 2022 risk assessment. The goal of this retrospective analysis was to compare the risks previously identified with actual project outcomes, evaluate the effectiveness of risk mitigation strategies, and document lessons learned. This activity represented a critical closure step for the project and served to enhance future risk planning efforts in similar large-scale carbon storage projects.

The final review of the risk assessment identified several instances where risks anticipated in the initial risk register were realized during the execution of the ECO_2S Phase III CarbonSAFE project. This retrospective analysis confirmed that many of the project's actual challenges had been correctly forecasted during earlier risk planning efforts. Notably, issues related to the availability and reliability of CO_2 sources, as well as uncertainties in pipeline routing and infrastructure development, were among the key risks that materialized. These topics were analyzed in detail and documented in the final risk review report submitted to NETL. Below are two examples included in the final report:

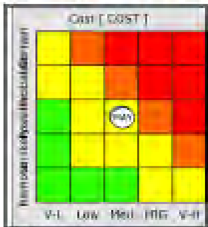
Risk Associated with Changes to Pipeline Routing

To proactively address potential environmental and routing risks, the Project Team incorporated a 1,000-foot-wide preliminary pipeline corridor during the development of the EIV. This corridor was designed to provide flexibility for adjusting the final CO_2 pipeline route between Plant Ratcliffe and the injection wells based on future engineering, environmental, and permitting considerations.

The pipeline FEED study, conducted in parallel with the NEPA EA, utilized this corridor framework to evaluate multiple routing options. As part of the risk mitigation strategy, sensitive environmental areas identified through the EIV and EA processes were provided to the pipeline FEED team to inform route selection.

Ultimately, the final pipeline alignment deviated from the initial conceptual path to avoid sensitive areas and minimize construction and operational impacts. Because the changes remained within the designated corridor, they did not significantly affect the EA's scope or conclusions. This flexible corridor approach effectively mitigated routing-related risks by allowing for adaptive planning without triggering major environmental or regulatory setbacks.

Risk: Change in Pipeline construction routing



ID	R-0056
Name/Description	Change in Pipeline construction routing
Cause	Alternative routing needed to avoid Seasonally wet areas, unstable ground - other issues that may be discovered during construction (e.g. Endangered animals)
Consequence	Potential Delay in timing to reroute pipeline. Potential financial cost due to time lost or increase in pipeline costs due to rerouting
Uncertainty	
Notes	
Status	Closed
Risk responsible	Brian Hill
Organisation	CRI
Next Review Date	
Category	Business Risks/Integrated Operations
ProjectPhase	
Stakeholder	

Current risk

Target	*Probability*	*Consequence*	*Criticality*	*Description*
Cost [COST]	Medium	Medium	Medium	Consequence: Project should be able to reroute to avoid small areas with minimal cost relative to overall pipeline cost Probability: Pipeline distances increase the likelihood that there may be some areas initially identified that will need to be avoided

Related Actions

ID	*Name*	*Status*	*Action responsible*	*Start Date*	*Planned finish*	*Stop Date*
A-0036	EIV provides for 1000 foot corridor for Pipeline that should allow for minor adjustments in routing if needed.	Proposed	Brian Hill			

Residual risk

Related Incidents:
List is empty

Related Risks:
List is empty

Relations to Linked document:
List is empty

Source	
Originator	Furtado, Sonia

Related Emerging Risks:
List is empty

EasyRisk, Risk reporting tool Server time for generating document: 2022-06-01 15:56:45 UTC +2

Figure 12 *Risk evaluation ranking for "Change in Pipeline construction routing"*

Risks Associated with Project Viability

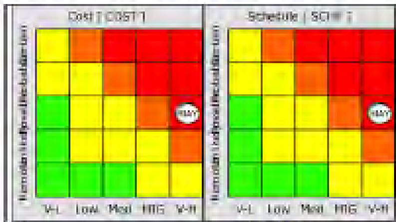
In March 2024, MPC withdrew its permit application for two Class VI wells at EPA Region 4. The withdrawal of the permit was the result of a determination by MPC on the future of carbon capture at Plant Ratcliffe. The decision was, in part, based on the following:

- MS Power currently does not have a federal requirement to capture and store CO_2 at its Plant Ratcliffe facility; and
- EPA's Section 111 Greenhouse Gas Rule did not include existing natural gas-fired units.

As such, there are no sources of CO_2 to store. While the removal of Plant Ratcliffe as a CO_2 source presented a significant challenge to the project, the subsurface storage site remains well-suited to accommodate substantial volumes of CO_2. The Project Team actively pursued alternative sources to maintain the site's potential as a regional carbon storage hub. However, on August 7, 2024, MPC communicated to SSEB that it would not participate in efforts involving third-party CO_2 sources or lease pore space on its property.

This decision ultimately precludes continuation of the project in its current form. The Project Team has since shifted its risk focus toward responsibly closing out the project, including the plugging and abandonment (P&A) of existing wellbores. Despite this outcome, the technical groundwork laid by the project provides valuable insights for future regional carbon storage initiatives.

Risk: Not able to convince the authorities that the project is economically viable.



ID	R-0054
Name/Description	Not able to convince the authorities that the project is economically viable.
Cause	Costs of CCUS technologies are higher than the potential revenues associated with the 45Q tax credits
Consequence	Business case for implementing CCUS cannot be made, especially for regulated companies.
Uncertainty	
Notes	
Status	Closed
Risk responsible	John Carroll
Organisation	Southern Company
Next Review Date	
Category	Commercial Readiness
ProjectPhase	
Stakeholder	

Current risk

Target	Probability	Consequence	Criticality	Description
Cost [COST]	Medium	Very High	High	Consequence: CCUS operating at a negative would have a massive negative financial impact for implementers. Probability: Most public information at this time has costs being near, but often slightly above, current 45Q tax credits.
Schedule [SCHE]	Medium	Very High	High	Consequence: Negative business case would indefinitely delay commercial implementation until conditions changed. Probability: Most public information at this time has costs being near, but often slightly above, current 45Q tax credits.

Related Actions

ID	Name	Status	Action responsible	Start Date	Planned finish	Stop Date
A-0035	Project partners are engaged with policy makers to achieve mutually beneficial regulatory environment and continue to identify potential options to reduce CCUS costs.	Proposed	John Carroll			

Residual risk

Related Incidents:
List is empty

Related Risks:
List is empty

Relations to Linked document:
List is empty

Source	
Originator	Furtado, Sonia

Related Emerging Risks:
List is empty

EasyRisk, Risk reporting tool Server time for generating document: 2022-06-01 15:56:45 UTC +2

***Figure 13** Risk evaluation ranking for "Not able to convince authorities that the project is economically viable"*

Throughout the duration of the ECO_2S Phase III project, the Project Team systematically identified, assessed, and developed mitigation strategies for a broad range of potential risks. These risks were documented in the project's risk register and regularly reviewed through structured workshops. In several instances, anticipated risks materialized during project execution. The team successfully implemented mitigation measures that allowed the project to advance through key milestones despite those challenges.

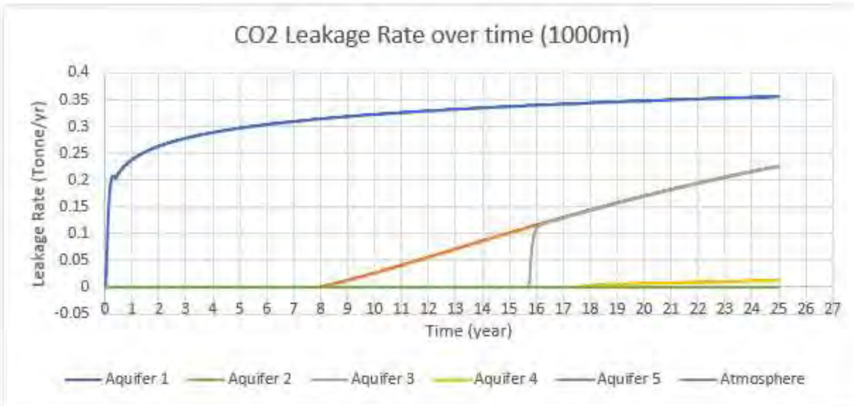
However, one critical risk—the loss of a committed CO_2 source—ultimately could not be mitigated. The decision by MPC to cease pursuit of carbon capture at Plant Ratcliffe, and subsequently withdraw its UIC Class VI permit application, resulted in the removal of the project's primary CO_2 source. While the Project Team had previously identified this risk and navigated earlier disruptions in CO_2 supply planning, the loss of Plant Ratcliffe proved terminal to the ECO_2S project. No viable alternatives could be secured, and MPC further confirmed that it would not support the use of its pore space or participate in third-party CO_2 storage arrangements.

The comprehensive risk identification and tracking process provided valuable insights into the types of risks that can fundamentally affect the viability of commercial-scale carbon storage initiatives. The Project Team remains confident that the methodologies, tools, and lessons captured through the risk management process will inform and strengthen future CarbonSAFE and regional carbon storage efforts.

The final Comprehensive Risk Assessment, Deliverable 3.2, was submitted to NETL on March 17, 2025, and is attached as Appendix 05.

Subtask 3.3 – Risk Assessment Tools

Work with NRAP Tools, associated with Project ECO_2S, began in 2018 at ARI. Shannon Szymusiak, working as a Research Assistant Intern with David Riestenberg at ARI in Knoxville, TN, during May to August 2018, conducted a thorough study of the properties and performance of Well MPC 34-1 #1 using the NRAP *Well Leakage Analysis Tool*, including its Cemented Wellbore, Multisegmented Wellbore, Brine Leakage, and Open Wellbore Models (Szymusiak, 2018). Ms. Szymusiak's calculations evaluated CO_2 and brine leakage rates into a thief zone, five aquifers, and the atmosphere as functions of time, depth, saturation history, permeabilities, pressure history, wellbore diameter, and distance from the injector. An example of Shannon Szymusiak's work is shown in **Figure 14**.



	Aquifer 1	Aquifer 2	Aquifer 3	Aquifer 4	Aquifer 5	Atmosphere	Total leakage out of Reservoir
Total Leakage (Tonne)	2912	738	577	21	0	0	4247
Total Percentage of Reservoir Leakage	0.06%	0.014%	0.011%	0.00041%	0%	0%	0.083%

Figure 14 *CO_2 leakage rate over time and total leakage when the distance from well to injector is 1000 m. (Well MPC 34-1 #1, Szymusiak, 2018)*

The NRAP Tool chosen for application during Project ECO_2S Phase II was the Seal Barrier Reduced-Order Model, (*NSealR)*, developed by Ernest Lindner, Research Leader with the Battelle / Leidos Research Support Team at NETL (Lindner, 2016, 2019). The principal storage reservoirs under consideration were included in the analysis: *Massive and Dantzler Sands, Washita-Fredericksburg Interval, and Paluxy Formation*. The properties of the three reservoirs are summarized in **Table 5**.

Run-to-run variation in the simulation results and nonlinearity in the dependence of CO_2 loss on seal permeability were encountered during the initial trials with *NSealR*. Both problems were most pronounced in the results for the Washita-Fredericksburg reservoir. They were eliminated by assignment of smaller standard deviations to the thickness of the seals and allowance for specification of maximum and minimum thicknesses for the seals, to better represent the actual distributions of seal thickness. The number of realizations, during execution of the model, was also increased, contributing to the virtual elimination of run-to-run variation in the results for all three reservoirs, including the Washita-Fredericksburg.

Table 5 *Reference elevation, mean, standard deviation, and range of seal thickness, and mass of CO_2 injected, for the simulations of CO_2 loss from the three storage reservoirs using the modified version of NSealR prepared by Ernest Lindner (Lindner, 2019). The elevations, means and ranges of heights, and storage capacities were obtained from the detailed discussion of the characteristics of the reservoirs by Riestenberg et al. (2018).*

Reservoir	Reference Elevation* (m)	Mean Thickness of the Seal (m)	Std. Dev. of Thickness (m)	Range of Thick-ness of the Seal (m)	CO_2 Injected† (Mtonne)
Massive and Dantzler Sands	-1035	125	25	100 to 150	120
Washita-Fredericksburg	-1130	100	20	50 to 150	540
Paluxy	-1585	65	15‡	50 to 80	310

* Top of seal. † During 40 years. ‡ Rough estimate.

Simulations, using the modified version of *NSealR* (Lindner, 2019), of the dependence of CO_2 loss from the Massive/Dantzler, Washita-Fredericksburg, and Paluxy reservoirs on the permeability of their seals, during 40 years of CO_2 injection, are shown in **Figure 15**. The dependence of CO_2 loss from the Washita-Fredericksburg reservoir on permeability is now linear, and the scatter present in the early results for CO_2 loss from the reservoir is now absent.

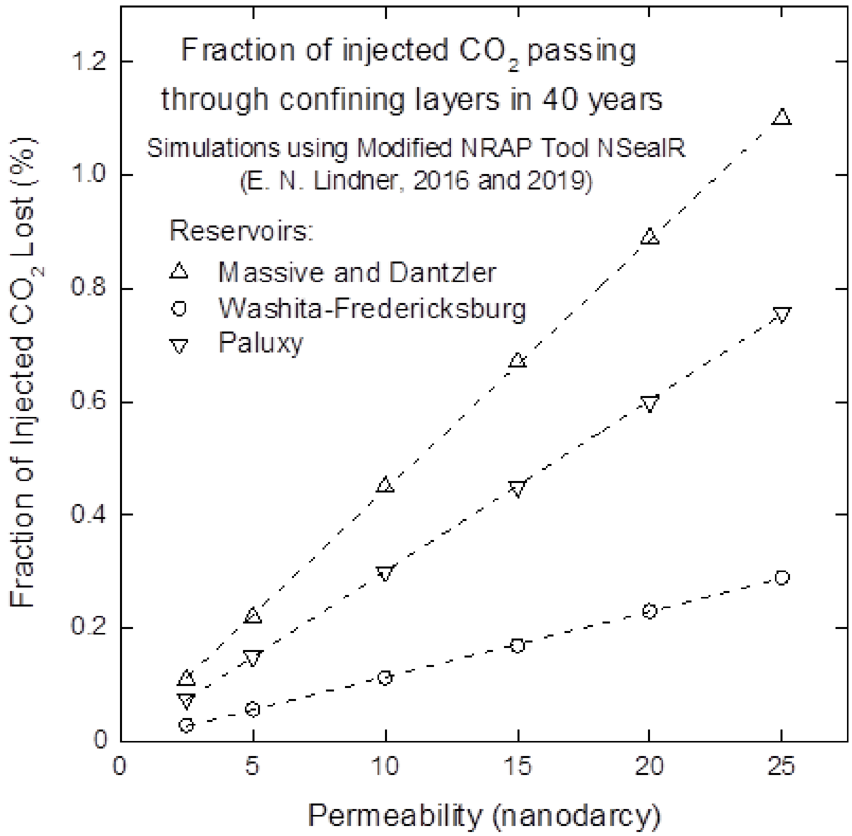


Figure 15 *Simulations using the modified version of NSealR prepared by Ernest Lindner, of the dependence of CO_2 loss from the Massive/Dantzler, Washita-Fredericksburg, and Paluxy reservoirs on the permeability of their seals, during 40 years of CO_2 injection. The large run-to-run variation in the simulation results and unexpected nonlinearity in the dependence of CO_2 loss on seal permeability, especially for the Washita-Fredericksburg reservoir, were eliminated by assignment of a smaller standard deviation to the thickness of its seal and allowance for specification of maximum and minimum thicknesses for the seal to better represent the actual distribution of seal thickness. The number of realizations during execution of the model was also increased, contributing to the virtual elimination of run-to-run variation in the results.*

Between the end of Project ECO$_2$S Phase II and the start of Phase III, Ernest Lindner constructed an approximate estimate of leakage from a storage reservoir, which he named *Seal_Flux: A Seal Barrier Reduced-Order Model* (Lindner, 2020). Simulation of CO_2 leakage from the Storage Complex using this new NRAP *Seal_Flux* Tool was the first task undertaken by the University of Alabama at Birmingham (UAB) team during Project ECO$_2$S Phase III. Following the investigation of storage reservoir performance using *Seal_Flux*, work was begun on the evaluation of properties of the Storage Complex using the NRAP Open-Source Integrated Assessment Model, *NRAP-Open-IAM*.

Seal_Flux: A Seal Barrier Reduced-Order Model

The reduced-order *Seal_Flux* model evolved from the *NSealR* code developed in 2013-2015 under the GoldSim framework (Lindner, 2016). During ECO$_2$S Phase II, UAB applied the NRAP Tool, *NSealR*, to the estimation of CO_2 leakage from the Washita-Fredericksburg storage reservoir in the Storage

Complex. Work during Project ECO_2S Phase II using *NSealR* was presented in Deliverable 4.6 – Risk Assessment Tool Report (Walsh, 2020) and briefly summarized in Section 1 of the present report.

During the period between the end of Phase II and the beginning of Phase III, Ernest Lindner, the developer of the *NSealR* Tool and author of its User's Guides (Lindner, 2016, 2019) constructed an interesting and very useful approximate estimate of leakage from a reservoir, which he named *Seal_Flux* (Lindner, 2020). During ECO_2S Phase III, estimates of CO_2 leakage using Dr. Lindner's *Seal_Flux* approximation were found to be in excellent agreement with results from the more detailed calculations using *NSealR*. Based upon calculations using both models, loss of stored CO_2 from the Washita-Fredericksburg storage reservoir during 40 years of CO_2 injection is expected to be negligible.

Seal_Flux is a *Python*-based computer code simulating the flow of CO_2 through a seal layer above an injection horizon for CO_2 sequestration (Lindner, 2020). It is written in *Python 3.7* using the functions of the Anaconda Distribution. The code is constructed as a simplified program to run Monte Carlo simulations involving thousands of simulations and therefore does not include a comprehensive flow logic. Rather, it simulates the general aspects of the problem using standard statistical methods to characterize the two-phase flow through a layer, which is essentially impervious but contains fracture systems allowing vertical flow.

Examples of the time dependence of cumulative CO_2 leakage through a representative area of the seal layer above the Washita-Fredericksburg storage reservoir, calculated using the *Seal_Flux* code, assuming a permeability of 15 ± 3 nanodarcy (nD), are shown in **Figure 16**. During the first 40 years of CO_2 injection, the P_{50} capacity (Goodman et al., 2011; Esposito and Riestenberg, 2017; Riestenberg et al., 2018) of the formation is reached. At 40 years, the CO_2 leakage through a seal layer having a permeability of 15 ± 3 nD, taking the average of the data shown in the figure, is 145,700 tonnes. The area considered in the simulation is 1.8×10^7 m^2, or 15% of the actual plan area of 1.2×10^8 m^2 for the reservoir and seal (Esposito and Riestenberg, 2017; Riestenberg et al., 2018). The spatial distribution of seepage shown in **Figure 17** was calculated for a distribution of permeability having a mean and standard deviation of 15 ± 3 nD, near the middle of the range of permeability over which the seepage was simulated. Additional heterogeneity of permeability was also included in the simulation, with an hFactor of 0.5. The generation of contour plots is included in the *Seal_Flux* program.

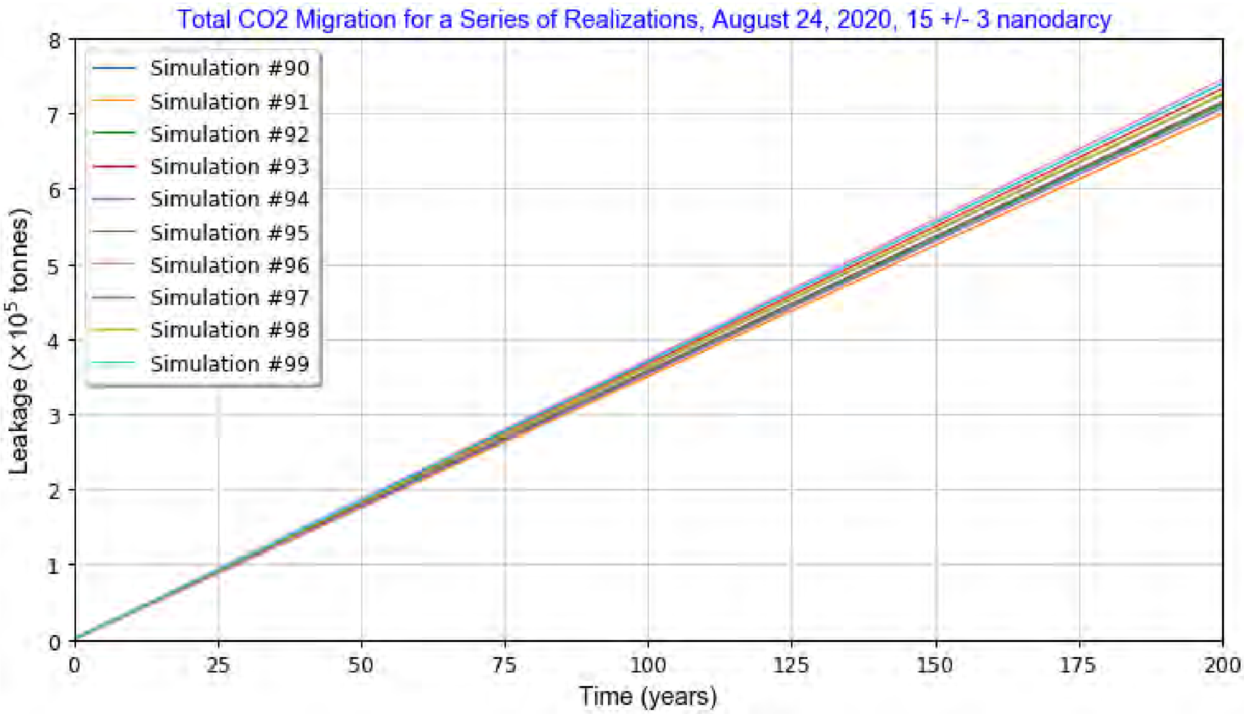


Figure 16 *Examples of the time dependence of cumulative CO_2 leakage through a representative area of the seal layer above the Washita-Fredericksburg storage reservoir, from a subset of 100 realizations of CO_2 migration calculated using the Seal_Flux code, assuming a permeability of 15 ± 3 nanodarcy.*

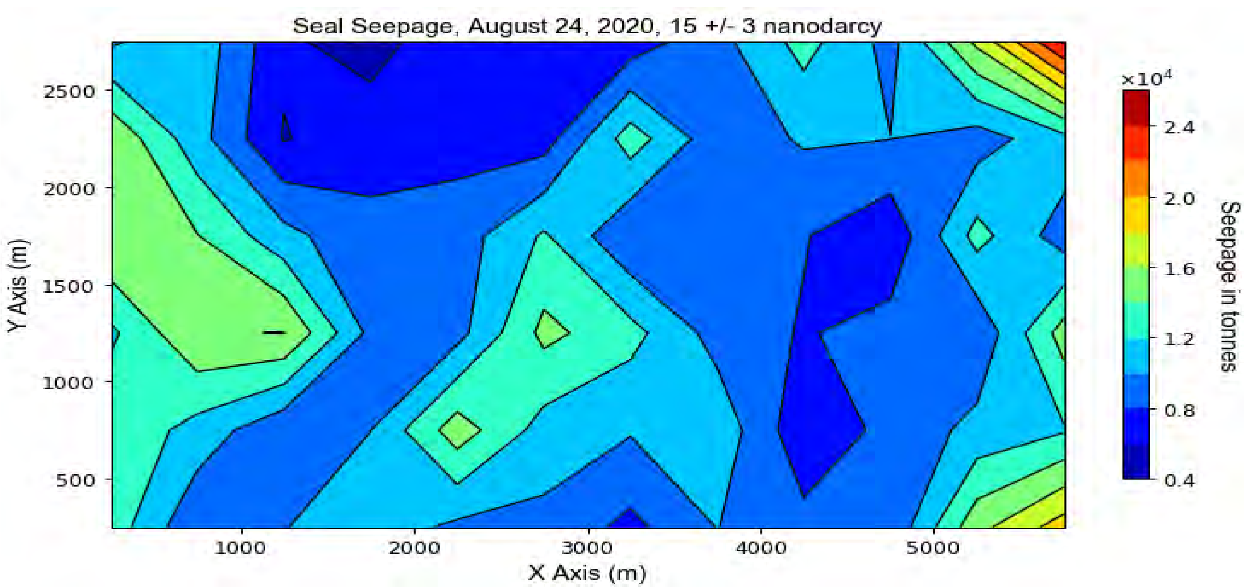


Figure 17 *Spatial distribution of CO_2 seepage from Seal_Flux. Contour plot of CO_2 seepage through a representative area, 6000 m x 3000 m, of the seal layer above the Washita-Fredericksburg Formation at the Kemper County, Mississippi, Storage Complex. The area covered by the figure represents 15% of the total plan area of the formation and seal.*

The calculated fractions of CO_2 lost, from simulations of CO_2 leakage through the seal layer above the Washita-Fredericksburg formation in the Kemper County, Mississippi, Storage Complex using the two NRAP Seal Barrier Reduced-Order Models, *NSealR* (Lindner, 2019) and *Seal_Flux* (Lindner, 2020), are compared in **Figure 18**. The fraction of stored CO_2 lost was determined as a function of the mean permeability of the seal during injection of a total of 540 MMT of CO_2 at the rate of 36,961 tons per day for 40 years. The standard deviation of the permeability distribution was 20% of the mean. The total amount of CO_2 stored corresponds to the P_{50} estimate of the capacity of the formation (Goodman et al., 2011; Esposito and Riestenberg, 2017; Riestenberg et al., 2018). There is excellent agreement between the leakage calculations using the two codes.

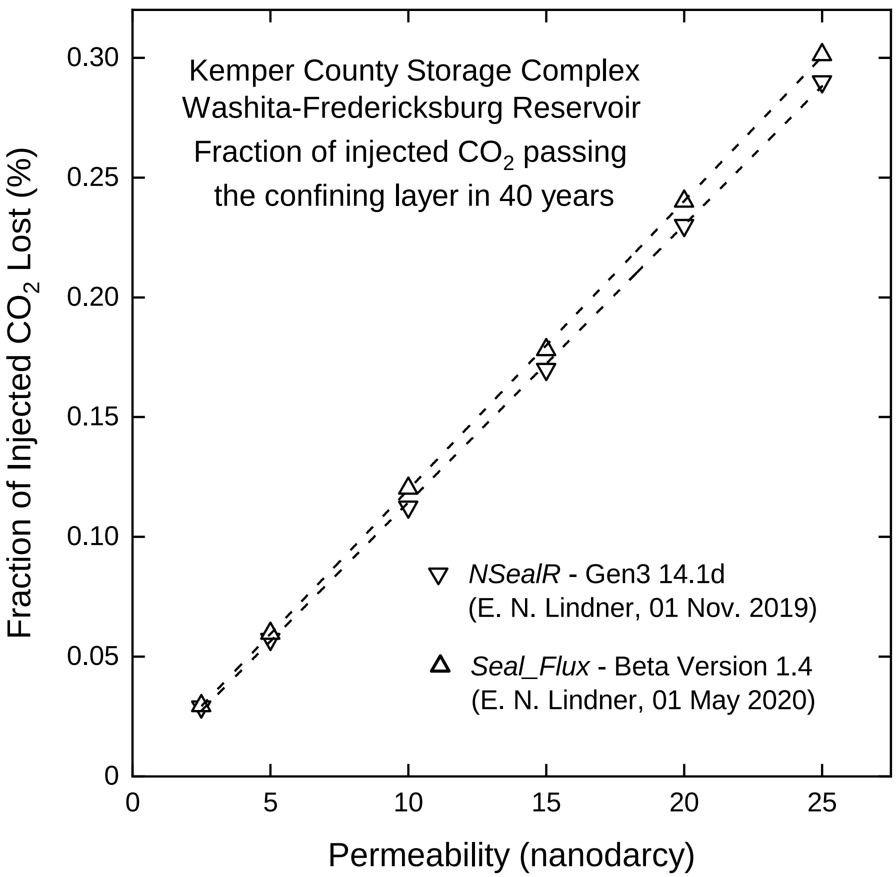


Figure 18 *Comparison of the calculated fractions of CO_2 lost, from simulations of CO_2 loss through the seal layer above the Washita-Fredericksburg formation in the Kemper County, Mississippi, Storage Complex, using the two NRAP Seal Barrier Reduced-Order Models, NSealR (Lindner, 2019) and Seal_Flux (Lindner, 2020).*

NSealR and *Seal_Flux* are both straightforward and useful software packages for the simulation of CO_2 leakage from geologic formations. The simulations of leakage for the cases tested were in excellent agreement. *NSealR* has some features that are not present in *Seal_Flux*.

NRAP Open-Source Integrated Assessment Model (IAM)

Initial Trials

Following the work with *NSealR* and *Seal_Flux*, the UAB team began application of the National Risk Assessment Partnership's Integrated Assessment Model, *NRAP-Open-IAM* (Vasylkivska et al., 2021 and 2022; Vasylkivska, 2021), to the evaluation of CO_2 leakage from the Kemper County storage reservoir to the atmosphere. The simulation of leakage using *NRAP-Open-IAM* was first attempted by adaptation of the "01_Forward_SR_CW.OpenIAM" Graphical User Interface (GUI) File included with the *NRAP-Open-IAM* Tool. That treatment is described as a forward simulation in which the saturation and pressure output calculated using a simple reservoir model are used as input for a cemented wellbore model.

The cemented wellbore model was thought to serve as a useful introduction to the application of *NRAP-Open-IAM* to the Storage Complex, though David Riestenberg had recommended using a multisegmented wellbore model and had directed a student's study of the application of a multisegmented wellbore model, the *Well Leakage Analysis Tool* (*WLAT*), to the Storage Complex (Szymusiak, 2018) mentioned in the Introduction to the present report. David Riestenberg's intuition and advice turned out to be correct, as described below.

A monotonic increase in the leakage rate with increasing well permeability was expected. Instead, the cemented wellbore simulation exhibited a complicated dependence of the leakage rate on permeability, even including negative values for the leakage (implying that the well was extracting CO_2 from the atmosphere). These results were shared with Dr. Vasylkivska, with a request for advice on how to proceed. Upon reviewing the data, Dr. Vasylkivska pointed out that the stratigraphy of the reservoir, aquifers, and shales at the Kemper County Storage Complex did not meet the requirements of the cemented wellbore simulation. She recommended using the more robust multisegmented wellbore model instead.

Based upon the recommendations of David Riestenberg and Veronika Vasylkivska, the focus of the work was shifted entirely to a multisegmented wellbore model. The simulation was adapted from the "02_LHS_SR_MSW.Open IAM" GUI File included with the *NRAP-Open-IAM Tool*. That treatment is described as using Latin hypercube sampling with 30 realizations in which the saturation and pressure output calculated using a simple reservoir model are used as input for a multisegmented wellbore model.

The parameters characterizing the components of the chosen multisegmented wellbore model are specified in the *NRAP-Open-IAM* User's Guide (Vasylkivska et al., 2022) as follows: stratigraphy component on pp. 17-18, simple reservoir component on pp. 18-19, and multisegmented wellbore component on pp. 21-22. CO_2 injection was specified at a fixed rate of 1.5 m^3/s (718.5 kilograms per second, or kg/s) for 30 years, corresponding to a total of 680 MMT, meeting the project's storage target of 675 MMT (Koperna, 2020). Kemper County stratigraphy (Riestenberg et al., 2018, **Figure 20**) was incorporated, approximately, using a single reservoir, two aquifers, and two shale layers. The CO_2 leakage pathway is through the wellbore cement to the aquifers and the atmosphere. All of the Simple Reservoir Component properties were left just as in the original file, except for the CO_2 injection rate. The permeability of the single CO_2 injection well and the four characterization wells (MPC 26-5, MPC 34-1, MPC 10-4, and MPC 01-1) in the Multisegmented Wellbore Components were all assumed to be the same and were varied over the range from 10^{-14} to 10^{-9} m^2 with the well diameters and aquifer permeability fixed at 0.14 m and 10^{-11} m^2, respectively. The instantaneous rate of CO_2 leakage to the atmosphere (kg/s) at 30 years was expressed as a fraction (%) of the injection rate. The calculated dependence of CO_2 leakage on wellbore permeability for each of the four characterization wells, the CO_2 injection well, and the total leakage from all five wells is shown in **Figure 19**, with logarithmic scales on both axes. The factor of 10^5 variation in wellbore permeability results in a range of a factor of 10^7 in the leakage rates. The leakages from the injection well and from a single characterization well are similar, under the present assumption that their diameters and wellbore permeabilities are the same. Under the assumed conditions, the total rate of CO_2 loss to the atmosphere is less than 0.1% of the injection rate for wellbore permeability less than about 2.5×10^{-11} m^2.

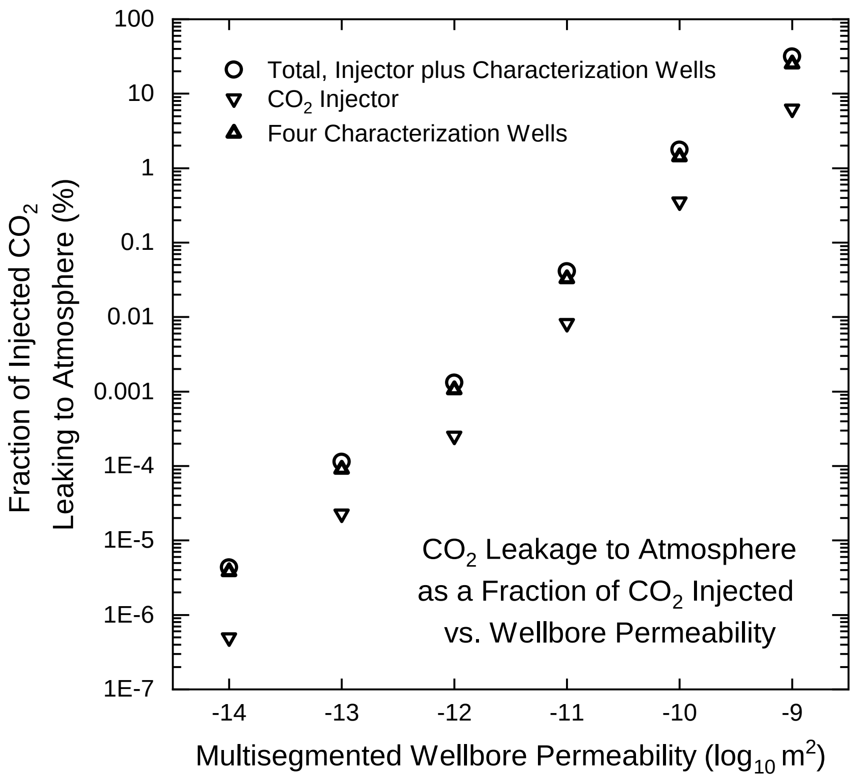


Figure 19 *Estimates of the fraction of CO_2 injected into the storage reservoir at the Storage Complex leaking to the atmosphere from an injection well and four characterization wells, versus the permeability of the wells, on completing the injection of 680 million metric tons of CO_2 over 30 years. For purposes of this initial trial using NRAP-Open-IAM, all five of the wells were assumed to have the same diameter (0.14 m, 5.5") and permeability.*

CO_2 Leakage to the Atmosphere and Aquifers

Application of the National Risk Assessment Partnership Integrated Assessment Model, *NRAP-Open-IAM* (Vasylkivska et al., 2021 and 2022; Vasylkivska, 2021) to wells in the Kemper County Storage Complex continued with the assessment of CO_2 leakage to the atmosphere from wells having different diameters and extension of the simulation to include specification of leakage from the wells to aquifers. Based upon the recommendations of David Riestenberg and Veronika Vasylkivska, the simulations were executed using a multisegmented wellbore model, adapted from the "02_LHS_SR_MSW.Open IAM" GUI File included with the *NRAP-Open-IAM Tool*. That treatment is described as using Latin hypercube sampling, with 30 realizations in which the saturation and pressure output calculated using a simple reservoir model are used as input for the multisegmented wellbore model.

The stratigraphy of the Storage Complex is described, approximately, as shown on the right in **Figure 20**, derived from the stratigraphic chart presented by Pashin et al. (2008) on the left. The approximate description includes the storage reservoir, two shale layers, and two aquifers. The thicknesses of the layers are derived from the stratigraphic column presented by Riestenberg et al. (2018).

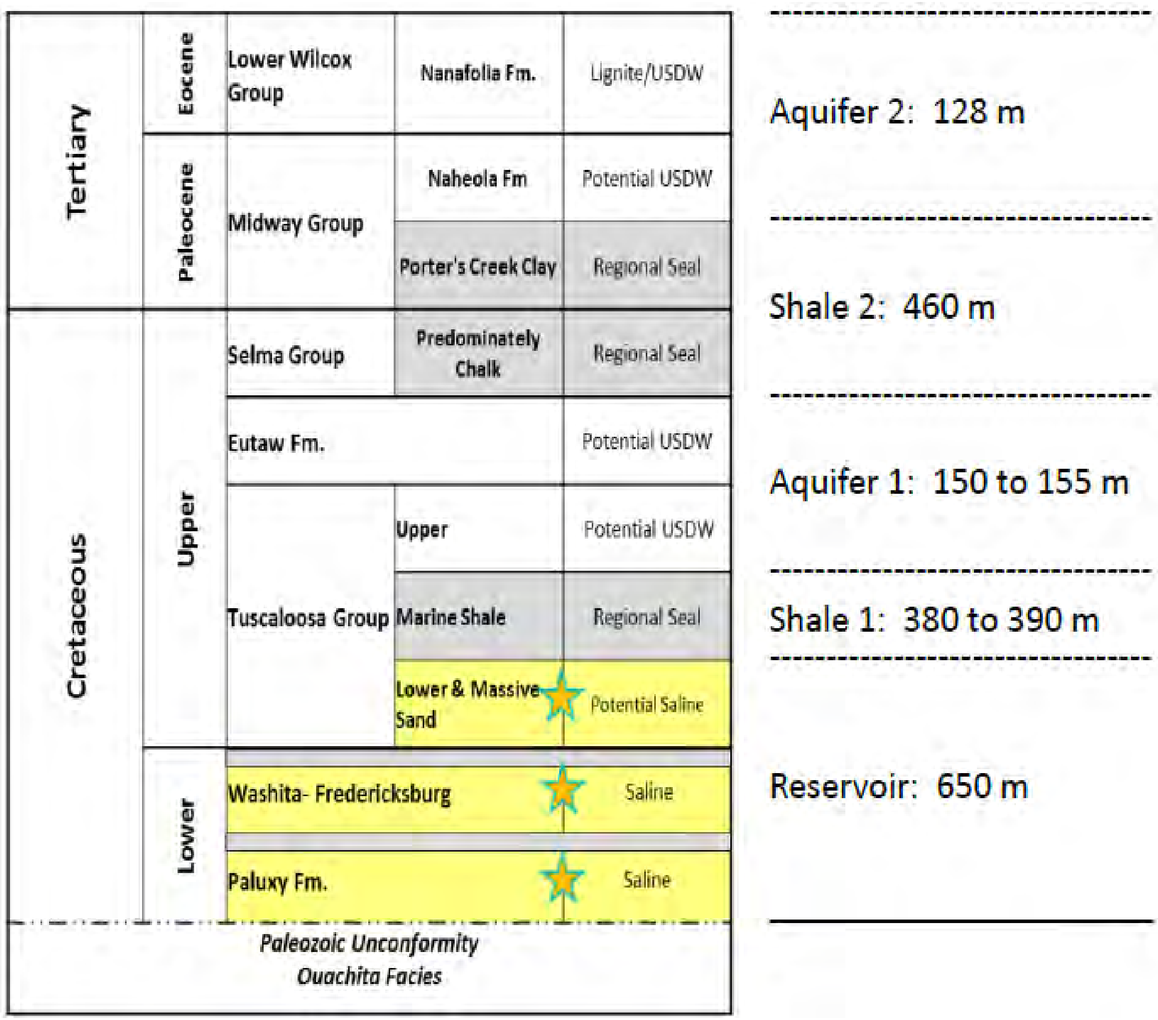


Figure 20 *Stratigraphic chart showing the geologic CO_2 storage formations (yellow stars). Geologic seals overlay each reservoir (gray). Geologic formations containing Potential USDW are noted. The original stratigraphic chart, on the left, is from J. C. Pashin, D. J. Hills, D. C. Kopaska-Merkel, and M. R. McIntyre, 2008. The layers incorporated in the NRAP-Open-IAM Multisegmented Wellbore Model are listed on the right.*

The CO_2 leakage under consideration was assumed to occur from the storage reservoir to atmosphere, at a rate limited by passage through the cement in the annulus between the long-string casing and the wellbore. For the leakage estimates shown in **Figure 19**, the simulation assumed that the outside diameter of the long-string casing in all of the wells under consideration was 5.5" (0.14

m). Later, we learned that the diameter of the long-string casing in Well 10-4 is 7" (0.178 m). A new simulation was performed for the larger well and the results are included in the revised **Figure 21**.

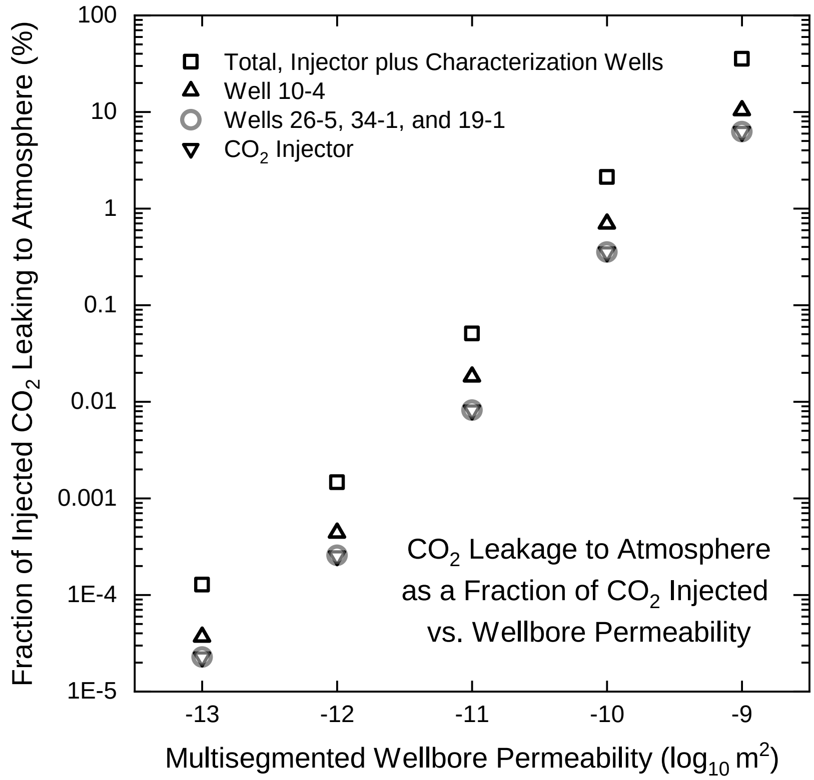


Figure 21 *Estimates of the fraction of CO_2 being injected into the storage reservoir at the Storage Complex leaking to the atmosphere from an injection well and four characterization wells, versus the permeability of the wells, on completing the injection of 680 million metric tons of CO_2 over 30 years. All of the wells were assumed to have the same permeability. The diameter of a well was set equal to the diameter of its long-string casing: 5.5" (0.14 m) for the injector (not yet drilled) and Wells 26-5, 34-1, and 19-1, and 7" (0.178 m) for Well 10-4.*

CO_2 injection was specified at a fixed rate of 1.5 m^3/s (718.5 kg/s) for 30 years, corresponding to a total of 680 MMT, meeting the project's storage target of 675 MMT (Koperna, 2020). All of the Simple Reservoir Component properties were left just as in the original file, except for the CO_2 injection rate. The permeability of the single CO_2 injection well and the four characterization wells (MPC 26-5, MPC 34-1, MPC 10-4, and MPC 01-1) in the Multisegmented Wellbore Components were all assumed to be the same and were varied over the range from 10^{-13} to 10^{-9} m^2, with the aquifer permeability fixed at 10^{-11} m^2. The instantaneous rate of CO_2 leakage to the atmosphere (kg/s) at 30 years was expressed as a fraction (%) of the injection rate. The calculated dependence of CO_2 leakage on wellbore permeability for each of the four characterization wells, the CO_2 injection well, and the total leakage from all five wells is shown in **Figure 21**, with logarithmic scales on both axes. The factor of 10^4 variation in wellbore permeability results in a range of a factor of almost 10^6 in the leakage rates. The leakages from the injection well and from a single characterization well having the same diameter are similar, under the present assumption that their permeabilities are the same. Under the assumed conditions, the total rate of CO_2 loss to the atmosphere from the five wells is less than approximately 0.05% of the injection rate from wells having wellbore permeability less than 10^{-11} m^2.

As shown in **Figure 20**, there are several actual or potential USDW on the path for CO_2 from the storage reservoir to atmosphere. These aquifers are combined and identified as Aquifers 1 and 2 for estimation of their uptake of CO_2. The multisegmented wellbore model includes calculation of the CO_2 losses from wellbores to aquifers, as shown in **Figure 22**. Comparison of **Figures 21 and 22** indicates that leakage of CO_2 from the wells to aquifers is less sensitive to wellbore permeability than leakage from the wells to the atmosphere. The total leakage to the atmosphere and aquifers, as a fraction of the injection rate from wells having permeability of 10^{-11} m^2, is 0.05102% to atmosphere plus 0.0311% to Aquifer 1, plus 0.0079% to Aquifer 2, for a total of 0.090%, just below 0.1% of the CO_2 injection rate. Sensitivity of CO_2 leakage to the permeability of the aquifers themselves is also of interest. This will be examined in the following Section of the report.

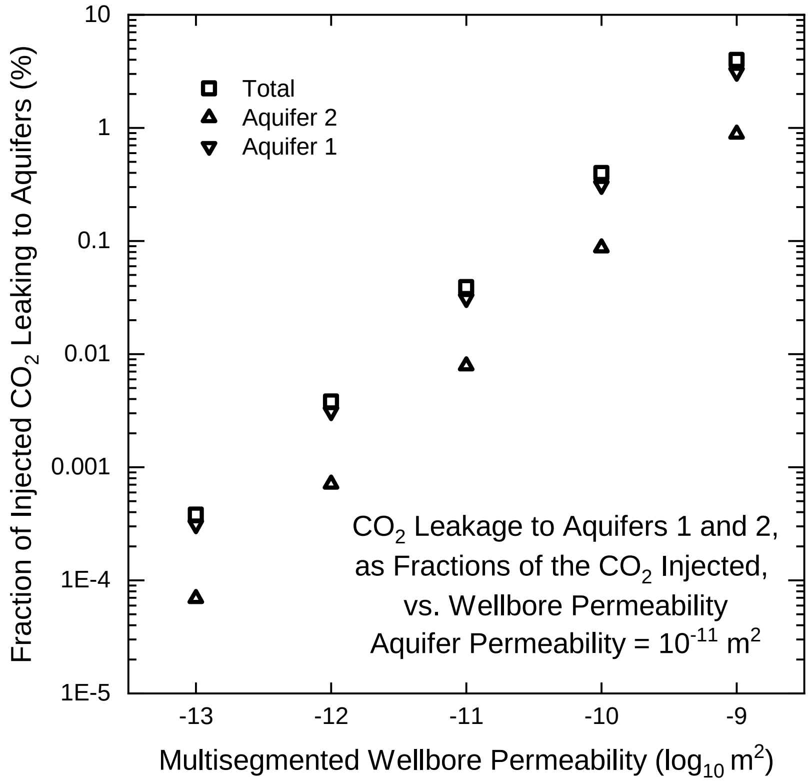


Figure 22 *Estimates of the fraction of CO_2 injected into the storage reservoir at the Storage Complex leaking to Aquifers 1 and 2 from the injection well and four characterization wells, versus the permeability of the wells, on completing the injection of 680 million metric tons of CO_2 over 30 years. As for the wellbore leakage to atmosphere, the wells were assumed to have uniform permeability, but different diameters. The permeability of both aquifers was fixed at 10^{11} m^2.*

Dependence of CO_2 Leakage on Aquifer Permeability

Comparison of the fractions of stored CO_2 leaking to the atmosphere and to aquifers indicates that leakage from the wells to aquifers is less sensitive to wellbore permeability than leakage from the wells to the atmosphere. Sensitivity of CO_2 leakage to the permeability of the aquifers was examined, with the results shown in **Figure 23**. For these calculations the wellbore permeability was fixed at 10^{-11} m^2, and the permeability of Aquifers 1 and 2 varied over the range from 10^{-13} to 10^{-9} m^2. As shown in the figure, no significant variation in leakage of CO_2 from the wellbores to either Aquifer 1, Aquifer 2, or the atmosphere, with change in aquifer permeability over the range investigated, is indicated.

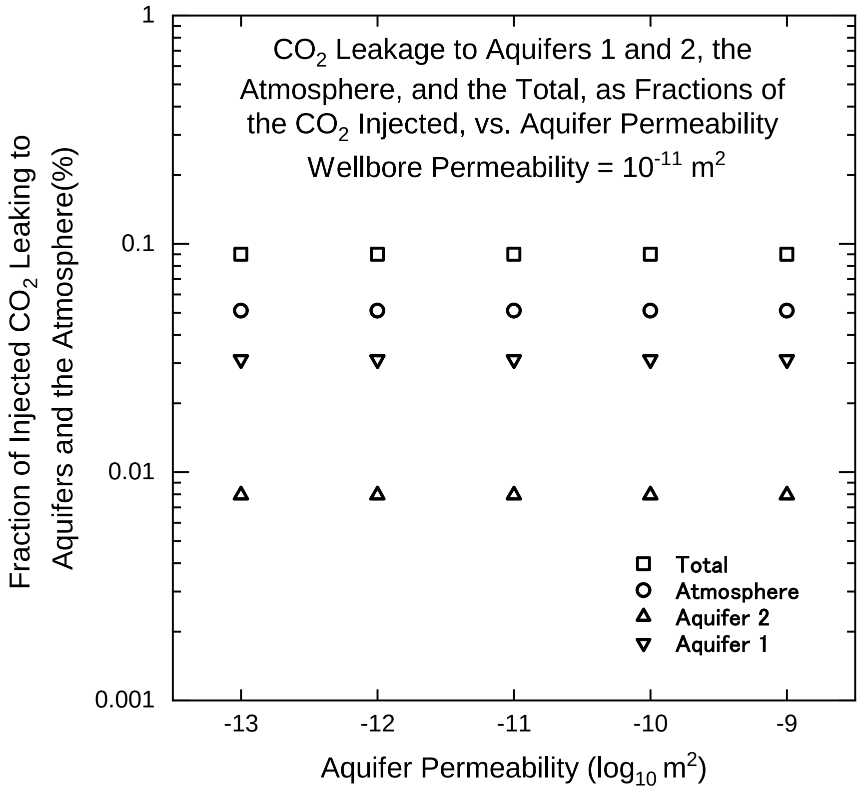


Figure 23 *Estimates of the fraction of CO_2 injected into the storage reservoir at the Storage Complex leaking to the atmosphere and aquifers from the injection well and four characterization wells, versus the permeability of the aquifers, on completing the injection of 680 million metric tons of CO_2 over 30 years. All of the wellbores were assigned a permeability of 10^{-11} m^2. The diameter of a well was set equal to the diameter of its long-string casing: 5.5" (0.14 m) for the injector (not yet drilled) and Wells 26-5, 34-1, and 19-1, and 7" (0.178 m) for Well 10-4.*

Although aquifers may make a significant contribution to the destinations of CO_2 leaking from the storage reservoir, the simulation results shown in **Figure 23** indicate that the permeability of aquifers has negligible influence on the rate of leakage of CO_2 through wellbores into the aquifers and to the atmosphere.

Thickness of the Marine Shale Regional Seal

The fractions of injected CO_2 leaking from the injection well and four characterization wells to the aquifers and atmosphere were examined as a function of the mean thickness assigned to the Marine Shale. The Marine Shale is the primary regional seal, designated as Shale 1 in the stratigraphic chart shown in **Figure 20**, on the right. The range of the thickness was $\pm$ 5 m in each case and all of the wellbores were assigned a permeability of 10^{-11} m^2. The diameter of a well was set equal to the diameter of its long-string casing: 7" (0.178 m) for Well 10-4 and 5.5" (0.14 m) for the injector (not yet drilled) and Wells 26-5, 34-1, and 19-1. The leakage, as before, is through the cement in the annulus between the long-string casing and the wellbore. Using the wellbore diagram for Well MPC 26-5 as our example (Koperna, 2020), the cement surrounding the long string casing is in direct contact with the geologic formations at depths greater than 758.6 m (2489 ft), which is the maximum depth of the surface casing, and is about 176.5 m (579 ft) above the top of the Marine Shale. Where the cement is surrounded by shale, or by surface casing, the route for CO_2 leakage is upward through the cement. Where the cement is surrounded by an aquifer, the leakage is also radial—outward through the cement to the aquifer.

As shown in **Figure 24**, influence of the mean thickness of the Marine Shale (Shale 1 in **Figure 20**) on CO_2 leakage to the upper aquifer (Aquifer 2) and to the atmosphere is negligible. The effect of variation in the thickness of the Marine Shale is to change the length of the path from the Reservoir to Aquifer 1 through the wellbore cement in the Marine Shale. The large range in mean thickness of the Marine Shale shown in **Figure 24**, from 285 to 485 m, is associated with a change of only 0.015% in the fraction of injected CO_2 leaking to Aquifer 1.

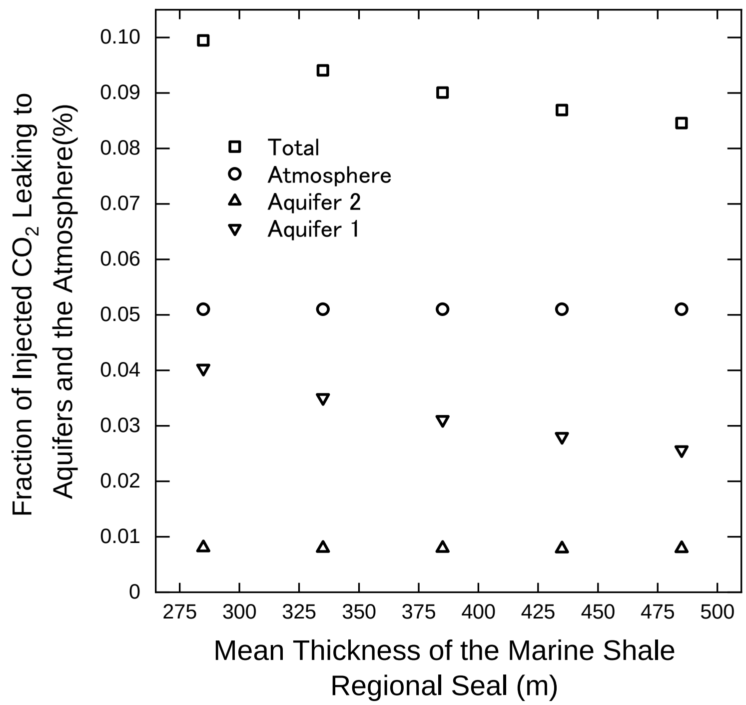


***Figure 24** CO_2 leakage to the Atmosphere, to Aquifers 1 and 2, and the total CO_2 leakage, as fractions of the CO_2 injected, vs. the mean thickness assigned to the Marine Shale regional seal. The range of the thickness in each case is ± 5 m. All wellbores were assigned a permeability of 10^{-11} m^2.*

Time Required to Accomplish the CO_2 Storage

It is also important to assess the potential for CO_2 leakage into aquifers and the atmosphere if maintaining a consistent injection rate of 1.5 m^3/s (718.5 kg/s) over a 30-year period proves to be unfeasible or undesirable. The total amount of CO_2 to be stored is fixed by the properties of the storage reservoir, but the time available in which to complete the injection might change. The time could be shorter if, for example, an opportunity arose to accept CO_2 from an additional source or sources or if the power generation and CO_2 production from the power plants under consideration were increased. Similarly, the rate of CO_2 storage might decrease if one or more of the plants under consideration were derated or retired. The effects of changes in the time during which 680 MMT of CO_2 are injected into the formation on the fraction of the stored CO_2 leaking to the aquifers and the atmosphere were examined, with the results shown in **Figure 25**. The wellbore permeability for this example was fixed at 10^{-11} m^2. The base case considered in all of the examples presented here is for the injection to be completed in 30 years (slightly to the left of center in **Figure 25**) where the total fraction of CO_2 leaking to the aquifers and atmosphere is 0.09% of the 680 MMT of CO_2 stored.

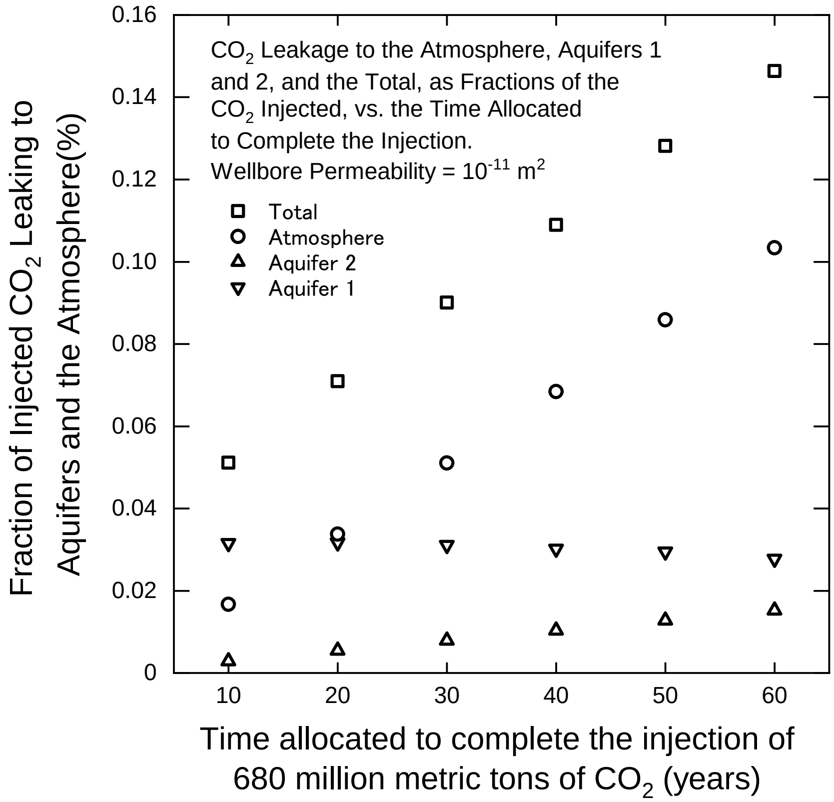


***Figure 25** Estimates of the fraction of CO_2 injected into the storage reservoir at the Storage Complex leaking to the aquifers and atmosphere from the injection well and four characterization wells, versus the time allocated to complete the injection of 680 million metric tons of CO_2. All of the wellbores were assigned a permeability of 10^{-11} m^2. The diameter of a well was set equal to the diameter of its long-string casing: 7" (0.178 m) for Well 10-4 and 5.5" (0.14 m) for the injector (not yet drilled) and Wells 26-5, 34-1, and 19-1.*

Increasing the CO_2 injection rate by a factor of 3 and completing the injection of 680 MMT in only 10 years decreases the loss of CO_2 during its injection by roughly a factor of 2, to just 0.05% of the CO_2 stored. The total CO_2 loss has close to linear dependence on the storage time. Slowing the injection rate and increasing the time to complete storage of 680 MMT to 60 years increases the fraction of CO_2 leaking to the aquifers and the atmosphere to approximately 0.15% of the CO_2 stored. The CO_2 loss is sufficiently insensitive to the rate of CO_2 injection that an increase, even by a factor of two, in the time required to complete the project would not be expected to undermine its viability. Provision for this might be included in the permit application. It must be said, however, that such large changes as factors of 2 or 3 in the CO_2 injection rate are unlikely to be possible for other reasons. Very high injection rates, for example, might be above the capacity of the original CO_2 storage and handling equipment. Very low rates might lead to an unacceptable increase in the cost of maintaining the project for an extended period.

An interesting feature of the dependence of CO_2 leakages on the injection time, shown in **Figure 25**, is the slight negative slope of the dependence of CO_2 leakage on injection time for Aquifer 1 (the deeper of the two aquifers) as shown in **Figure 25**. Evidently, leakage from the storage reservoir to Aquifer 1 through the wellbore cement in Shale 1 is more rapid than loss of CO_2 from Aquifer 1 to Aquifer 2 through the wellbore cement in the thicker Shale 2.

Summary of Results from *NRAP-Open-IAM*

NRAP-Open-IAM is a powerful new tool, currently under active development, for the detailed simulation of CO_2 storage scenarios (Vasylkivska et al., 2022).

Using the *NRAP-Open-IAM* multisegmented wellbore model, the total CO_2 leakage to the atmosphere and aquifers during 30 years of CO_2 injection at the Kemper County Storage Complex was estimated to be less than 0.1% of the CO_2 stored for wellbore permeability less than approximately 10^{-11} m^2.

No dependence of CO_2 leakage to the atmosphere and aquifers on aquifer permeability is expected over the range of aquifer permeability from 10^{-13} to 10^{-9} m^2.

Influence of the mean thickness of the Marine Shale on CO_2 leakage to the upper aquifer, Aquifer 2, and to the atmosphere is small, because the effect of variation in the thickness of the Marine Shale (Shale 1 in the stratigraphic chart, **Figure 20**) is only to change the length of the path from the Reservoir to Aquifer 1 through the wellbore cement in the Marine Shale. A large range in mean thickness of the Marine Shale, from 285 to 485 m, is associated with a change of only 0.015% in the total fraction of stored CO_2 leaking to the aquifers and the atmosphere.

If the rate of CO_2 storage should change, due to increase or decrease in the availability of CO_2, *NRAP-Open-IAM* predicted a change in the total leakage to aquifers and the atmosphere from 0.05 to 0.15% of the CO_2 stored, with increase in the time required for injection of 680 MMT of CO_2 from 10 to 60 years.

Task 4.0 - Site Selection and Well Drilling

Subtask 4.1 – Well Site Selection

The Project Team identified three prospective Phase III well sites near the Kemper County Energy Facility (Plant Ratcliffe). ARI coordinated and hosted a well drilling planning meeting on October 7, 2020, in Charleston, West Virginia, to discuss the prospective well sites, drilling operations, data acquisition, and conduct an initial risk register (see Subtask 3.1). The three wells drilled in Phase III were the MPC 03-1 (to test the southern part of the Storage Complex), the MPC 01-1 (to test the northern part of the Storage Complex), and the MPC 19-1 (to test the location of one of the proposed Class VI UIC wells). **Figure 26** shows the stratigraphic test wells drilled during Phase II and Phase III and the proposed Class VI injection well locations (MPC 19-2 and MPC 32-1). **Table 6** provides an outline of the six wells that were drilled during both phases of the project and provides details on when drilling commenced as well as their intended use to achieve project objectives.

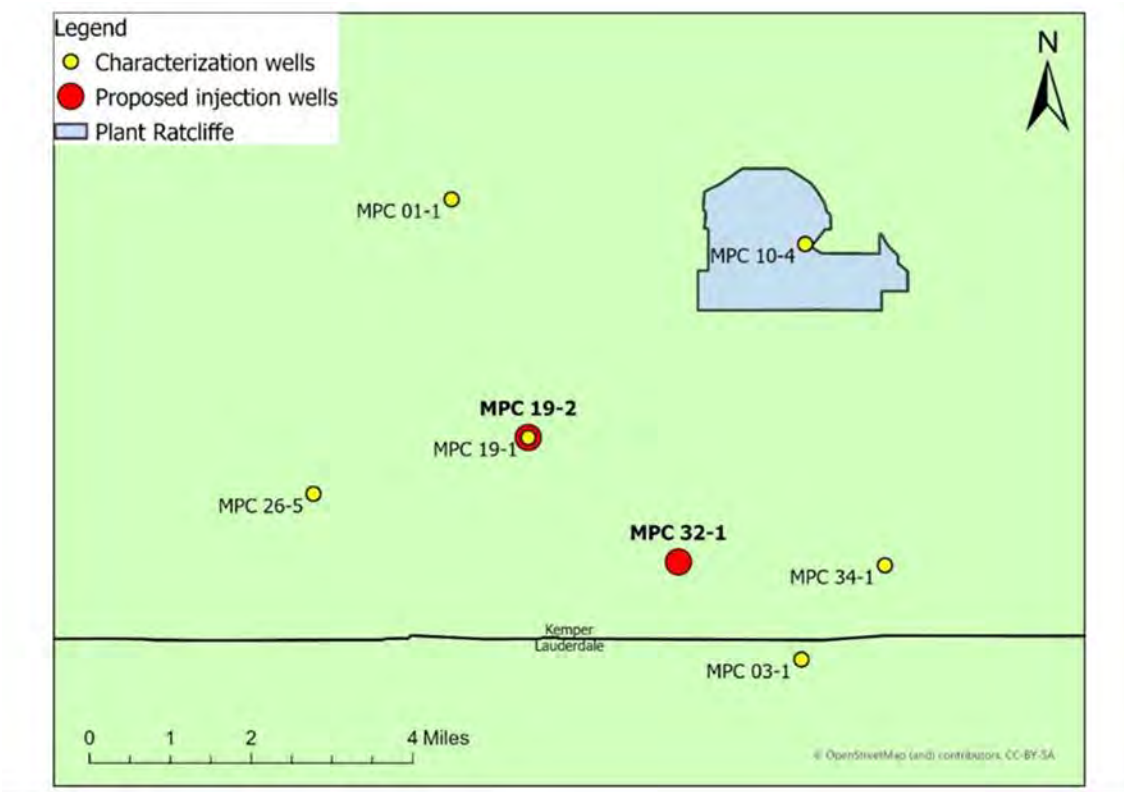


Figure 26 *Well locations for stratigraphic test wells drilled during Phase II and Phase III and the proposed Class VI well locations (MPC 19-2 and MPC 32-1).*

Table 6 *List of stratigraphic test wells drilled during both CarbonSAFE phases of the project along with their intended use.*

Well	Phase	Spud	Purpose	P&A Date
MPC 10-4	II	Aug-17	Injector	N/A
MPC 26-5	II	May-17	In-Zone Monitor	May-25
MPC 34-1	II	Jun-17	In-Zone Monitor	May-25
MPC 01-1	III	Nov-20	Stratigraphic	Dec-20
MPC 03-1	III	Mar-21	Stratigraphic	Mar-21
MPC 19-1	III	Apr-21	Above-Zone Monitor	May-25
USDW	III	May-21	USDW Monitor	May-25

Subtask 4.2 – Permitting and Site Surveys

Applications for permits to drill were submitted to the Mississippi State Oil and Gas Board (MSOGB). The MPC 01-1 and MPC 20-1 (later to be 19-1) applications were submitted on October 27, 2020, and approved on November 17, 2020. The MPC 03-1 application was submitted on October 29, 2020, and approved on November 17, 2020. MPC 20-1 well was relocated from Kemper County Section 20 to Section 19 and renamed MPC 19-1. The MSOGB was notified and agreed to the change.

Deliverable 4.2, Well Drilling Permits, contains the applications and permit documents and was submitted to NETL on November 17, 2020. The deliverable is provided as Appendix 06.

Subtask 4.3 – Well Design

As noted in Subtask 4.1, a well planning meeting occurred in Charleston, West Virginia, on October 7, 2020. Details regarding the drilling, coring, openhole logs, casing design, and P&A of the wells were discussed. During the meeting, the Project Team coordinated health, safety, and environmental (HSE) requirements at the well sites, particularly in light of the COVID-19 pandemic, to include screening at the well pad entrance, social distancing, masks, more housing than is typically available for personnel, and special personal protection equipment (PPE) to reduce direct contact with other individuals on site. Planning related to workforce management, NEPA and permitting, and the initial risk register was discussed as well. Additional well design and drilling meetings were conducted prior to site clearing and drilling activities for each of the wells. Detailed descriptions of the three wells' design, locations, and scope are included in Deliverable 4.4, As Built Well Construction.

Subtask 4.4 – Well Drilling and Geologic Data Collection

The first of three new wells for Project ECO_2S Phase III was drilled in November and December 2020. The well (MPC 01-1) was categorized as a "stratigraphic" well, meaning that its sole purpose was to gather geologic and stratigraphic data for the field. The total depth of the well was 5,650 ft, with surface casing cemented in place from 1,500 ft to surface. The remainder of the well was left open hole. After geologic data was gathered from MPC 01-1 via whole core retrieval and open hole logging, the well was P&A beyond state requirements.

The second of three new wells was drilled in March 2021. Again, the well (MPC 03-1) was categorized as "stratigraphic." The total depth of the well was 5,760 ft, with surface casing cemented in place from 1,480 ft to surface. The remainder of the well was left open hole. After geologic data was gathered from MPC 03-1 via open hole logging, the well was P&A beyond state requirements. **Figure 27** is a representative diagram of the final state of MPC 01-1 and MPC 03-1.

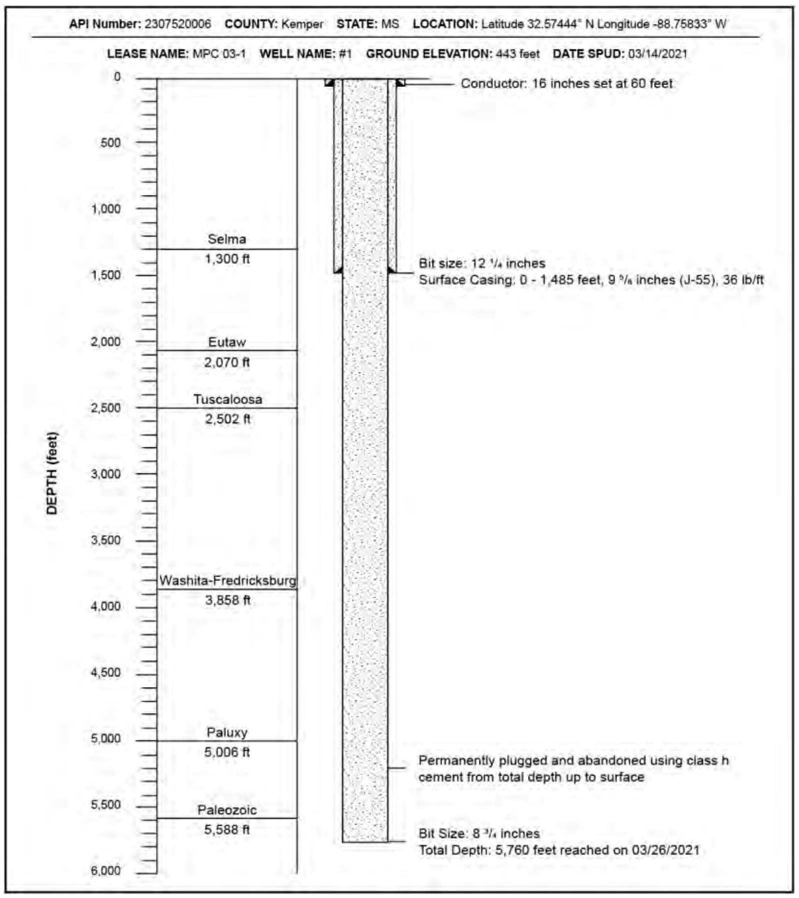


Figure 27 *MPC 03-1 As-completed wellbore diagram.*

The third and final well, MPC 19-1, was drilled in April and May 2021. The purpose of the well was to test the storage reservoir and confining units, and to remain as an above-zone monitoring well. The total depth of the well was 5,740 feet (ft). Surface casing was cemented in place from 1,488 ft to surface, and long string casing was cemented from 3,052 ft to surface. Whole core was pulled from the ECO_2S primary confining unit (Tuscaloosa Marine shale), a secondary confining unit (lower Washita-Fredericksburg interval), and a potential injection interval (Paluxy formation).

Geologic data was collected through open hole geophysical logs (triple combo, dipole sonic, CMR, and FMI). A standard "triple combo" includes GR, SP, Caliper, Resistivity, Density, and compensated neutron. A dipole sonic tool was also included within the logging string. After geological data was gathered from MPC 19-1 via whole core and open hole logging, the well was plugged back with cement from TD to a depth of 2,942 ft, covering the open hole section and long string casing shoe. The as-completed wellbore diagram of MPC 19-1 is shown in **Figure 28**.

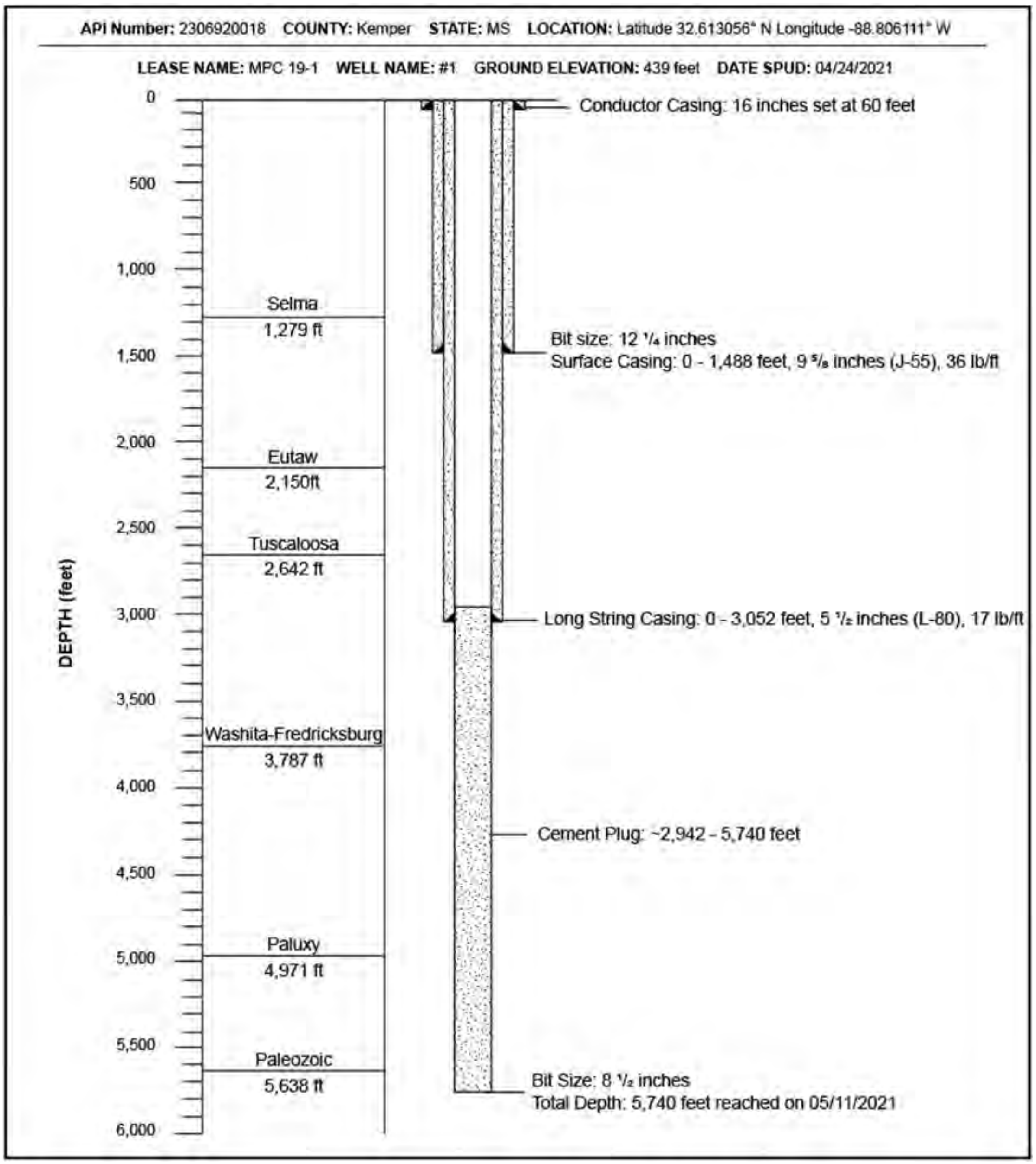


***Figure 28** MPC 19-1 As-completed wellbore diagram.*

The following deliverables were submitted for Subtask 4.4:

- Deliverable 4.4, Geologic Catalog of Materials (Appendix 07), was submitted on November 29, 2021, August 31, 2022, and February 28, 2025; and
- Deliverable 4.4, As Built Well Construction (Appendix 08), was submitted on November 29, 2021.

Subtask 4.5 - Plug and Abandonment

As mentioned above, both the MPC 01-1 and MPC 03-1 were plugged immediately after data collection, and all remaining wells were plugged at the conclusion of the project.

The MPC 19-1 well, originally designed as an above-zone monitoring well, was P&A (**Figure 29**) using wireline as per state requirements. Cast-iron bridge plugs (CIBP) were set at 2,850 ft and 30 ft below the surface, with 100 ft and 25 ft of class H cement on top of each respective CIBP. Once cement plugs were cured, the wellhead was cut 5 ft below ground surface and a permanent cap was welded on top with the well's American Petroleum Institute (API) number. On the same pad as the MPC 19-1 well, a deep USDW well, originally designed as a deep water monitoring well, was P&A using a cement-bentonite mix from total depth up to 25 ft below ground surface and then filled with enviro-plug chips from 25 ft up to the surface per the Mississippi Department of Environmental Quality (MSDEQ) regulations. Once plugged, the casing was cut 4 ft below the ground surface, a 2 ft cement cap was poured inside the casing, and then covered with a 2 ft thick cement slab. and covered with class h cement. The MPC 19-1 and Deep USDW wells were deemed permanently P&A on May 6, 2025.

The MPC 10-4, MPC 26-5, and MPC 34-1 well were drilled and completed during ECO$_2$S Phase II. MPC 10-4 is located within the fence of MPC Plant Ratcliffe and remains under the ownership and supervision of MPC. The MPC 26-5 well and MPC 34-1 were P&A at the close of Phase III.

The MPC 26-5 well, originally designed as an in-zone monitoring well, was P&A (**Figure 30**) using wireline as per state requirements. Prior to P&A, a workover rig was used to mill out the initial CIBP set at 562 ft. Once milled out, the workover rig demobilized and the wireline truck mobilized for P&A operations. Cast-iron bridge plugs were set at 2,850 ft and 30 ft below the surface, with 100 ft and 25 ft of Class H cement on top of each respective CIBP. Once cement plugs were cured, the wellhead was cut 5 ft below ground surface and a permanent cap was welded on top with the well's API number. The MPC 26-5 well was deemed permanently P&A on May 16, 2025.

The MPC 34-1 well, originally designed as an in-zone monitoring well, was P&A (**Figure 31**) using wireline as per state requirements. A CIBP was initially set at 4,480 ft. Class H cement plugs of 10 ft, 100 ft, and 25 ft were set on top of the respective CIBP's at 4,480 ft, 2,850 ft, and 30 ft. Once cement plugs were cured, the wellhead was cut 5 ft below ground surface and a permanent cap was welded on top with the well's API number. The MPC 34-1 well was deemed permanently P&A on May 7, 2025.

Once all four wells (MPC 19-1, 26-5, 34-1, and Deep USDW) were P&A, all locations were restored in accordance with their respective landowners. Naturally Occurring Radioactive Material (NORM) surveys were completed at all locations. All P&A operations were completed as per the state requirements. P&A forms and NORM survey records were submitted to the MSOGB and can be found in Appendix 09.

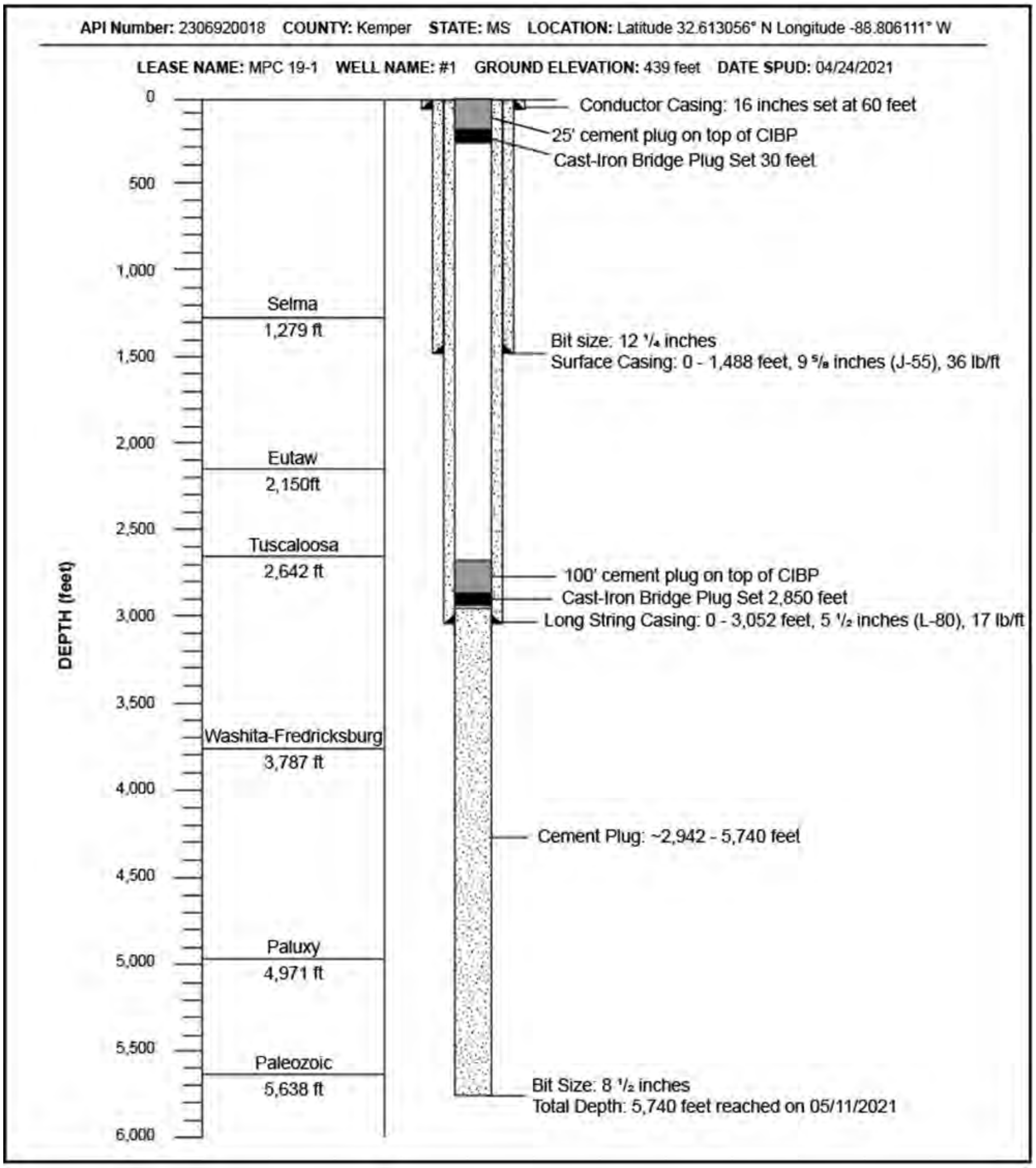


Figure 29 *MPC 19-1 wellbore plugging design (not to scale, for illustration purposes only).*

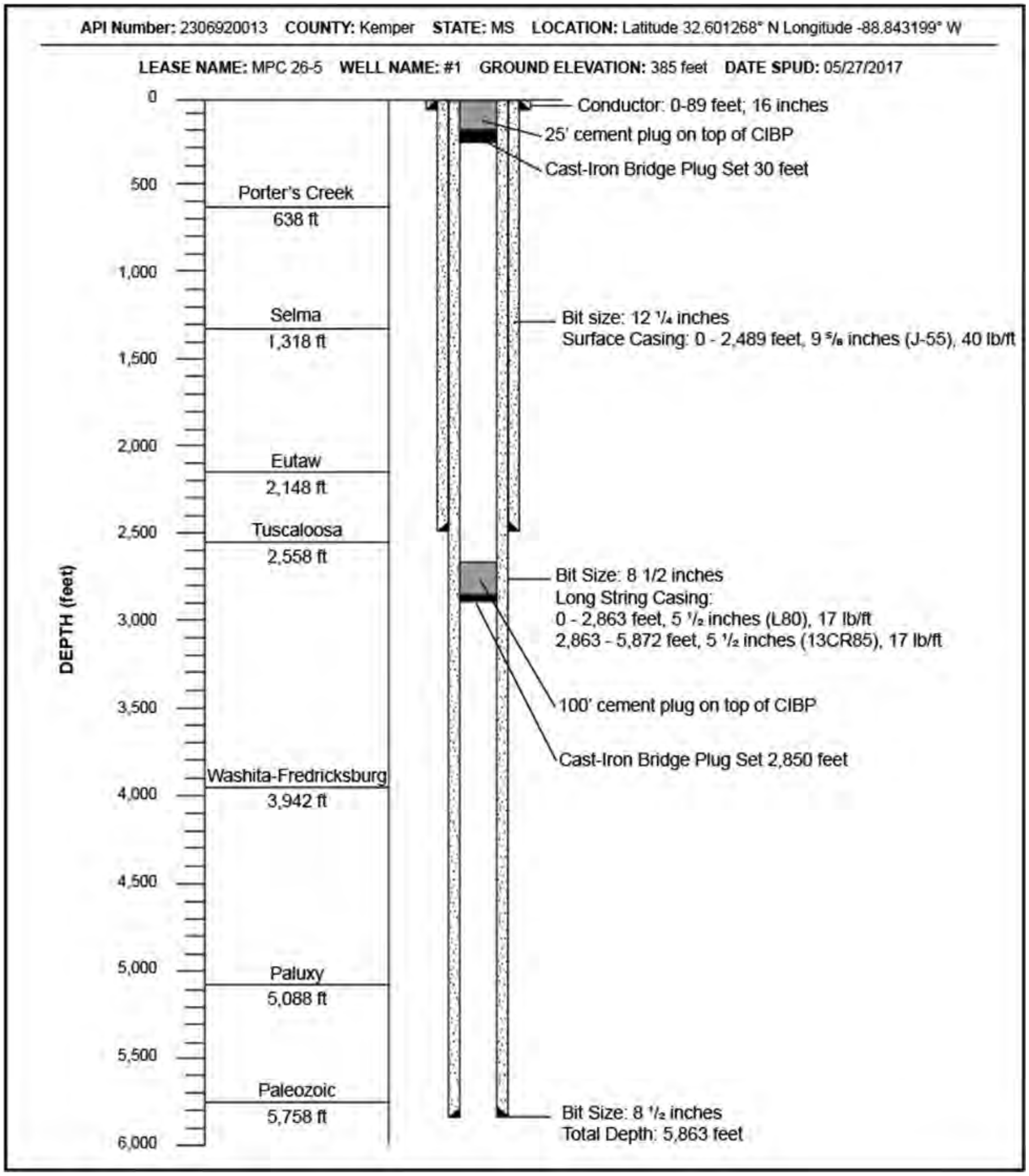


Figure 30 *MPC 26-5 wellbore plugging design (not to scale, for illustration purposes only).*

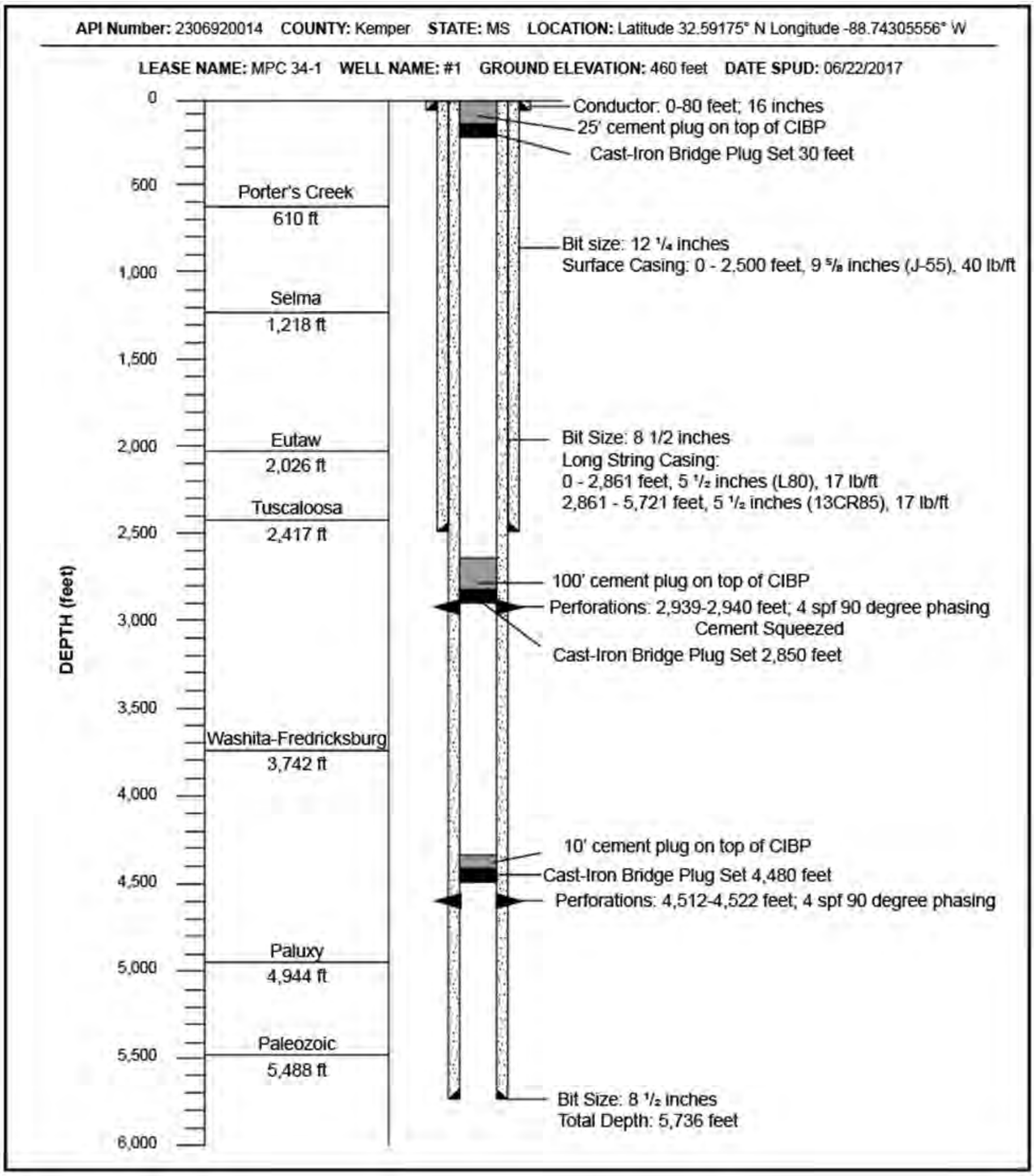


Figure 31 *MPC 34-1 wellbore plugging design (not to scale, for illustration purposes only).*

Task 5.0 – Complete Geologic Characterization

The subsurface geological characterization conducted for the Kemper County Storage Complex is summarized below for Task 5 activities. A total of six stratigraphic test wells were drilled during Project ECO$_2$S Phase II and Phase III to characterize and test the geologic properties of the underlying reservoirs. The purpose of this work was to evaluate the viability of implementation of commercial-scale CO_2 storage.

The MPC 10-4, MPC 26-5, and MPC 34-1 wells were drilled during Phase II and the MPC 01-1, MPC 03-1 and MPC 19-1 were drilled during Phase III. For each of the characterization wells, a suite of geophysical logs was run and approximately 290 ft of core was obtained. The obtained core covered intervals of the identified saline reservoir formations as well as the regional primary and secondary confining units. In Phase III, the Project Team also implemented a 2D seismic program providing data coverage across the Kemper County Storage Complex. In total, 92 line-miles of seismic were acquired across 17 lines.

The Kemper County Storage Complex is located within Mississippi's North Central Hills physiographic region that overlies the predominately sandy units of the Eocene-aged Claiborne Group and the Eocene-Paleocene Wilcox Group. The Wilcox Group outcrops along the eastern boundary of the North Central Hills physiographic region and is the recharge area for Eocene and Paleocene aquifers. Kemper County, Mississippi is underlain by more than 26,000 ft of sedimentary rock that is Cambrian through Tertiary age that nonconformably overlies the Precambrian crystalline basement. Paleozoic strata range in age from Cambrian through Pennsylvanian and were deposited near the southern limit of the Black Warrior Basin at what is now the buried juncture of the Appalachian and Ouachita tectonic belts in central and southern Kemper County (**Figure 32**).

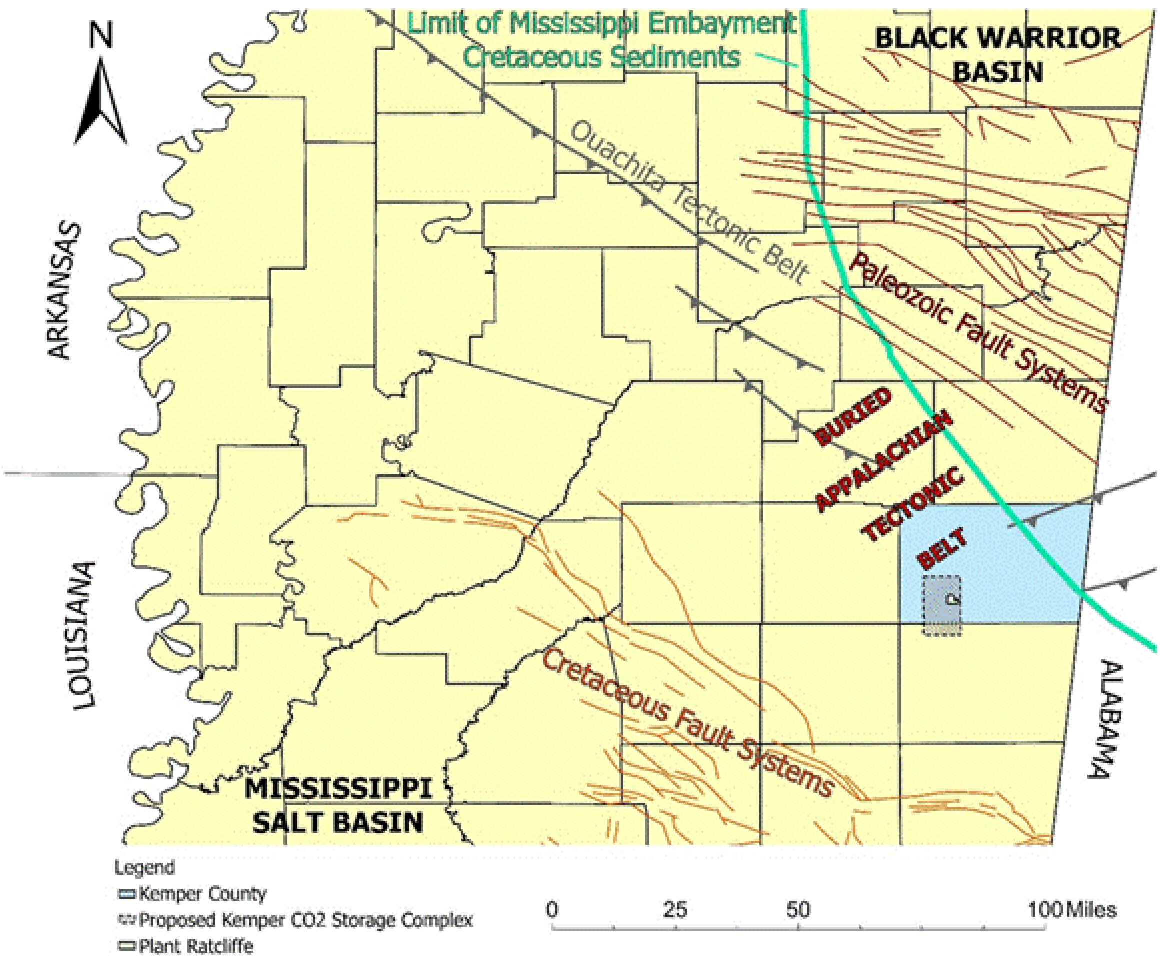


Figure 32 *Generalized Structural Setting of Kemper County Storage Complex in Central Mississippi.*

Thrust faults associated with the Appalachian and Ouachita orogenies penetrate the Paleozoic section below the injection zone in Kemper County (**Figure 33**). The transition from the Paleozoic to the Mesozoic is recorded in geophysical logs and seismic lines by an erosional surface marking the change in depositional environment from a synorogenic clastic wedge to fluvial deltaic deposits associated with the Gulf Coastal Plain. Above this unconformity the Mesozoic units are unfaulted and of lower structural complexity. The Mesozoic-Cenozoic strata were deposited in the Mississippi Embayment, a subsection of the larger Gulf Basin, forming a southwest-dipping wedge of sediment. Mesozoic structural features include the Cretaceous Fault System, located approximately 40 miles south of the Storage Complex, marking the closest surface expression of faults to the Kemper County Storage Complex. The limit of the Cretaceous sediments of the Mississippi Embayment in northeast Kemper County corresponds to the surface outcrop of the Upper Cretaceous age Selma Chalk.

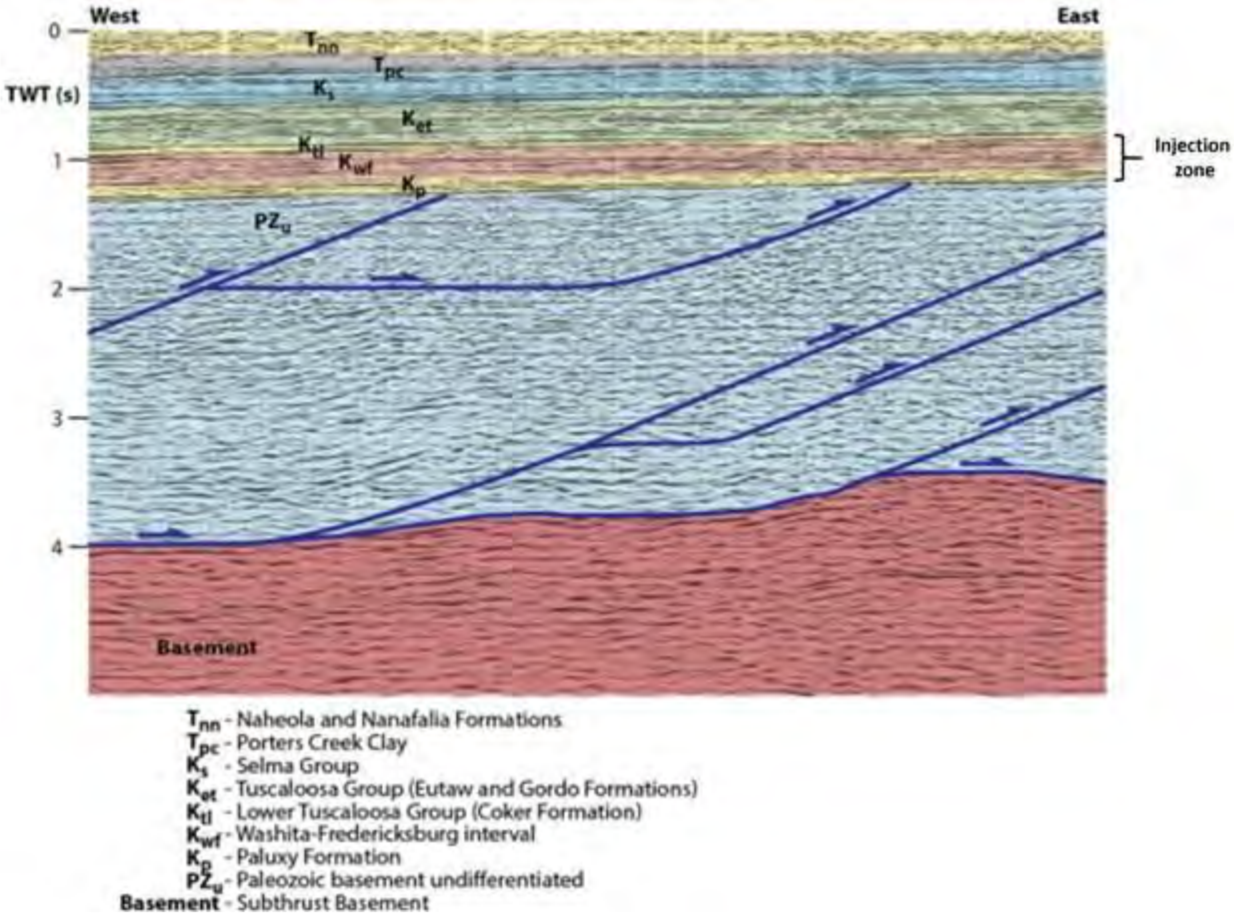


Figure 33 *Interpreted Seismic Profile Near the Kemper County Storage Complex, which shows the relationship between Paleozoic strata of the Appalachian-Ouachita Oregen and gently dipping deposits of the Mississippi Embayment (Seismic formation licensed to the Geological Survey of Alabama by Seismic Exchange, Inc.).*

The target storage and confining formations at the Kemper County Storage Complex are in the Lower Cretaceous section of Kemper County, from the top of the Tuscaloosa Marine Shale to the base of the Paluxy Formation (**Figure 34**). These zones are known to be regionally consistent throughout eastern Mississippi as well as other parts of the Gulf Coast. The primary confining zone is the Tuscaloosa Marine Shale and undifferentiated Lower Tuscaloosa shale. Locally, the Tuscaloosa Marine Shale isolates the deepest known USDW in the Eutaw Formation from saline aquifers in the Lower Tuscaloosa Massive sand and Dantzler sand. The Tuscaloosa Marine Shale is a proven confining unit in other parts of Mississippi and Alabama for hydrocarbons in the Lower Tuscaloosa. Below the confining zone is the injection zone, which consists of a series of sandstone saline storage intervals, confinement intervals, and the injection interval. The Paluxy Formation is the base of the injection zone and serves as the initial permitted injection interval for this Project. Overlying the Paluxy, the Lower Tuscaloosa Massive sand and the Dantzler and 'Big Fred' sands of the Washita Fredericksburg are alternate saline storage reservoirs in the injection zone, while the Upper and Basal Washita-Fredericksburg shales are secondary confinement intervals. The confinement intervals and alternate saline storage reservoirs form a containment system that will prevent vertical migration of fluids out of the injection interval, with the Tuscaloosa Marine Shale confining zone providing the ultimate closure for this system.

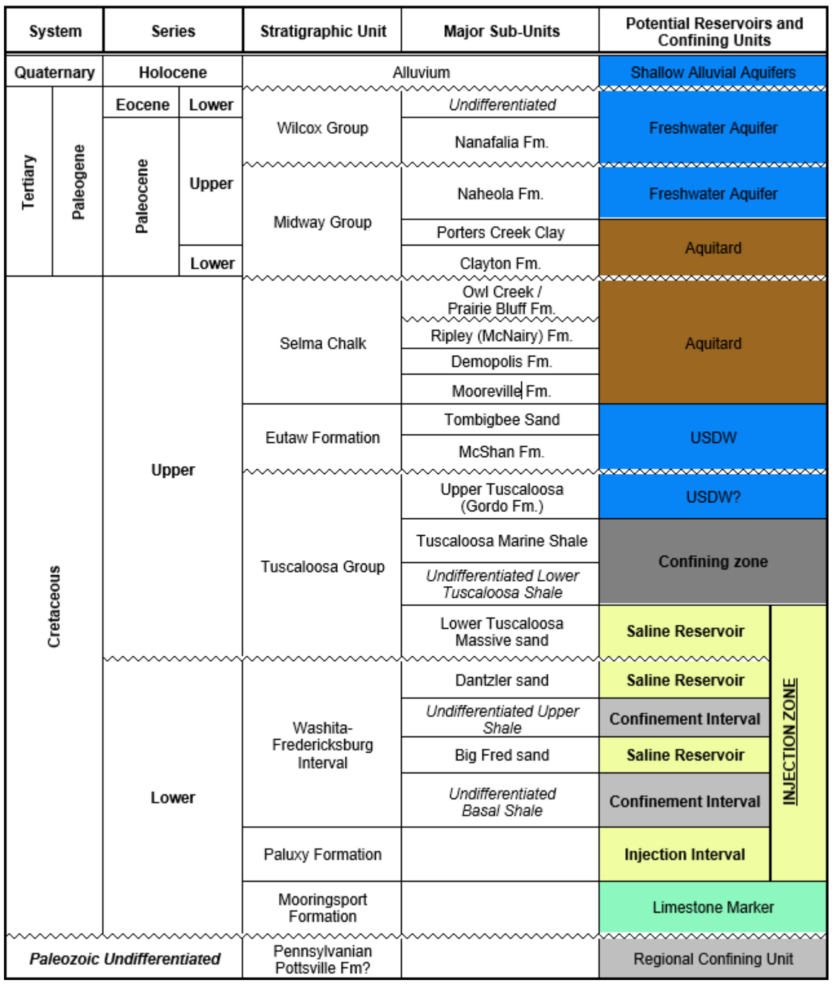


Figure 34 *Cenozoic and Mesozoic Stratigraphic Units at Proposed Kemper County Storage Complex.*

Subtask 5.1 – Underground Sources of Drinking Water

Major aquifers in the central portion of Mississippi are part of the southeastern Coastal Plain aquifer system that developed within the Mississippi Embayment during the Cretaceous through Tertiary period. USDWs are any aquifers that currently supply drinking water to a public water system or have the potential to do so in the future. These aquifers must contain less than 10,000 milligrams per liter (mg/L) total dissolved solids (TDS) and are required to be protected based on guidelines established within the UIC regulations established by EPA. USDW aquifers within Kemper County reside in both Tertiary- and Upper Cretaceous-age clastic reservoirs. The Tertiary formations include the Middle and Lower Wilcox, the Naheola, and the Nanafalia Formations (**Figure 35**). The Middle and Lower Wilcox USDW aquifers have TDS of < 200 mg/L.

The principal drinking water source for Kemper County comes from the Middle and Lower Wilcox Formation, and potable water at Plant Ratcliffe, provided by the Northwest Kemper Water Association, utilizes the Lower Wilcox as its source. The Naheola and Nanafalia Formations are shallower than 600 ft in the area around the Storage Complex, and these formations receive meteoric recharge at the surface in northeastern Kemper County. Therefore, all active and potential aquifers of Tertiary age can be expected to be USDW and must be protected.

The Porters Creek Clay and Selma Chalk are over 1,500 ft thick in Kemper County and together serve as an aquitard to separate the freshwater aquifers in the Tertiary from the Upper Cretaceous. The Upper Cretaceous contains the Eutaw-McShan, Gordo, and Coker aquifers having potential USDW considerations with TDS concentrations of 1,000 to 20,000 mg/L. A deep groundwater characterization well installed at the MPC 19-1 site collected water from the Eutaw Formation to determine the characteristics of the deepest USDW in the Kemper County Storage Complex. The Eutaw Formation sampling resulted in a TDS value of 1,670 mg/L and alkalinity measurements reported 272 mg/L, which is within the freshwater range of 30 to 400 mg/L. The Eutaw-McShan aquifer has been determined to be the deepest USDW in the Kemper County Storage Complex and is a candidate for deep USDW monitoring.

System	Series	Group	Formation	Principal Aquifer	Aquifer System
Tertiary	Eocene	Wilcox Group	Nanafalia Formation	Middle/Lower Wilcox Aquifer System	Lower Wilcox Aquifer
	Paleocene	Midway Group	Naheola Formation		
			Porters Creek Clay	Aquitard	
Cretaceous	Upper	Selma Group	Undifferentiated	Aquitard	
		Eutaw Group	Eutaw Formation	Eutaw-McShan Aquifer	
			McShan Formation		
		Tuscaloosa Group	Gordo Formation	Gordo Aquifer (Saline)	Tuscaloosa Aquifer System
			Coker Formation	Coker Aquifer (Saline)	
			Tuscaloosa Marine Shale	Aquitard (Primary Confining Zone)	
			Massive Sand	Massive Sand (Saline Reservoir)	

Figure 35 *Geologic Units and Principal Aquifers in Central Mississippi.*

To investigate potential CO_2 leakage pathways by which USDW may be contaminated, the USGS constructed a numerical model of a portion of the subsurface at the site (Plampin and Merrill 2025)[1]. The model represents a section of the Eutaw aquifer, which was determined by ARI to be the deepest USDW at the Storage Complex. After the geologic data were analyzed, the model was populated with hydrologic parameters representative of the Eutaw Formation and various scenarios of CO_2 leakage into the system were simulated to determine their potential impacts on the aquifer.

[1] Plampin, M.R., Merrill, M.D. Hypothetical CO_2 leakage into, and hydrological plume management within, an underground source of drinking water at a proposed CO_2 storage facility, Kemper County, Mississippi, USA. *Environ Earth Sci* **84**, 18 (2025). https://doi.org/10.1007/s12665-024-11973-9

The study outline in Plampin and Merrill (2025) evaluated the dissolved CO_2 behavior within a USDW under different leakage and water extraction scenarios. Because gas-phase CO_2 remained localized above the injection point in all simulations, the primary indicator for potential water quality degradation was the concentration of dissolved CO_2. Results showed that higher permeability and CO_2 inflow rates produced more extensive plumes, though maximum concentrations stayed at the solubility limit (approximately 50 grams per liter, or g/L) near the wellbore and declined downstream over time. Simulations with modest extraction rates (less than 21 kg/s) yielded relatively symmetric plume patterns. However, at higher extraction rates, plumes were diverted toward or captured by monitoring wells, impacting breakthrough patterns. Despite these dynamics, modeled increases in dissolved CO_2 concentrations at monitoring locations were minimal and likely undetectable with existing instruments. While dissolved CO_2 isn't inherently hazardous, concerns remain about its role in acidifying groundwater, potentially mobilizing other contaminants. The modeled conditions demonstrated that such risks appear negligible, though future geochemical modeling is recommended to validate these conclusions.

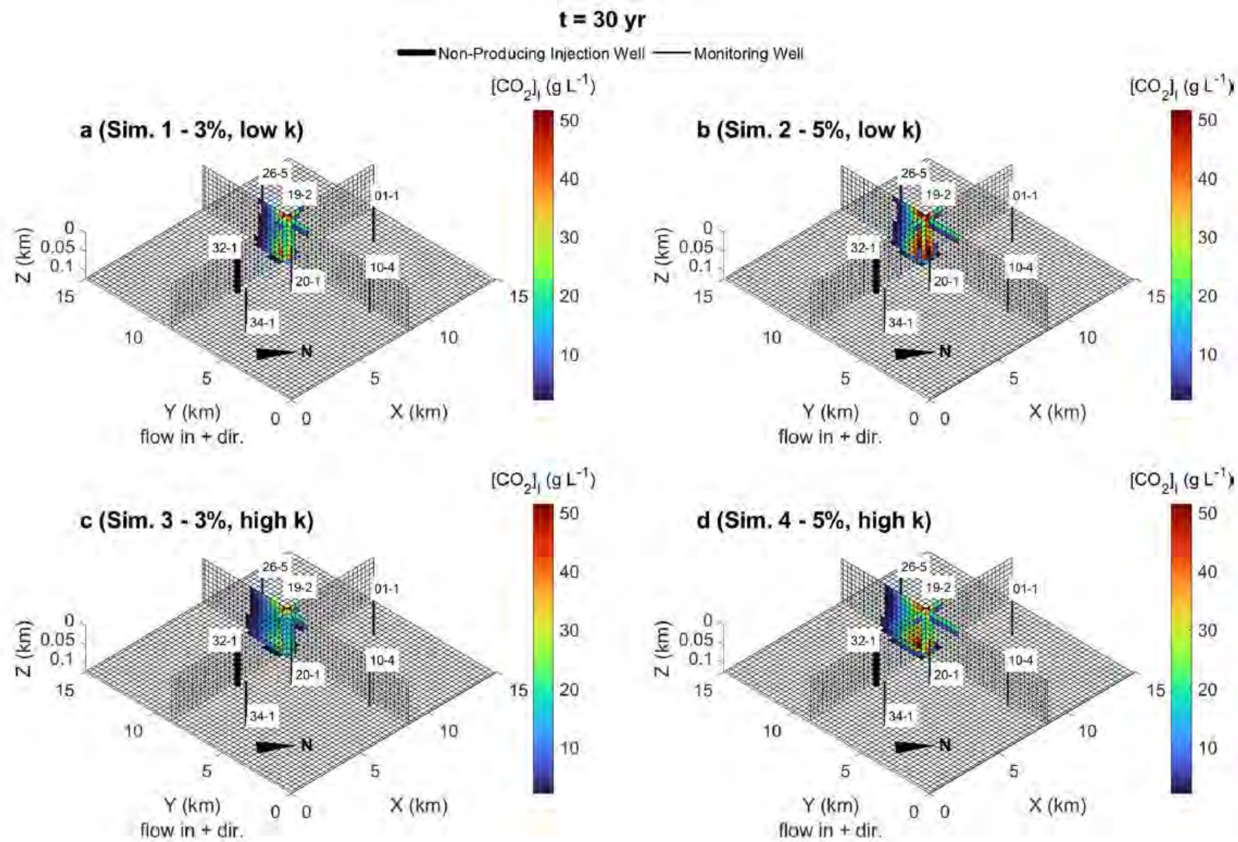


***Figure 36** At the 30-year mark (end of CO_2 injection), the modeled distributions of dissolved CO_2 concentration are shown for four scenarios varying by permeability and leakage rate. The visualizations are plotted on three orthogonal planes: one at the base of the Eutaw Group (Z-axis), and two intersecting at well MPC 19-2 (X- and Y-axes), which together pinpoint the simulated leakage source. In each case, ranging from low to high permeability and leakage rate, the contours illustrate how these variables affect plume development. Additional wells are marked as vertical black lines, with the non-leaking injector (MPC 32-1) highlighted in bold.*

Subtask 5.2 – 3D Seismic Survey

Seismic data acquisition was utilized to further characterize the subsurface within and surrounding the project area. The primary objectives for incorporating seismic data into the characterization efforts were to (1) confirm the presence and lateral continuity of targeted storage and sealing intervals and (2) derisk development of the Storage Complex by confirming that no sources of potential leakage pathways exist in the form of faults or other structures penetrating the storage and confining intervals. Initially, the Project Team planned to acquire a 3D seismic volume around the Storage Complex. However, the team decided that challenges with the geography would impact the layout of acquisition equipment resulting in lesser quality data at a relatively high cost to the project. Further, the size of the characterized area (over 30,000 acres) and relatively predictable geologic structure both indicated that a series of 2D lines would suffice for characterization purposes and for inputs to the geologic model. The decision was made to pursue the implementation of a 2D seismic program that provided the necessary information and areal coverage to accomplish the characterization objectives for the project.

Exoduas Inc. was contracted to perform a 2D seismic survey around Plant Ratcliffe in Kemper and Lauderdale counties, Mississippi. The data was collected from 17 individual lines that totaled 92 linear miles. The data was used to characterize the subsurface structure and reservoir characteristics around Plant Ratcliffe for potential CO_2 storage. The data acquisition was carried out in June 2021. Exoduas facilitated road permitting and private landowner permitting from June 1-7, as well as One-Call notifications that were carried out from June 12-17. Acquisition of 2D seismic data occurred from June 28-July 22. The data was recovered and processed through July 28. **Figure 37** shows the source-receiver array scheme (receiver every 110’ on blue & green lines, vibrator point every 55’ & 110’ on green lines).

Exoduas contracted Agile Seismic LLC in June 2021 to process pseudo-3D land seismic data in Kemper County through Post-Stack Time Migration (PoSTM – Multi-2D and pseudo-3D) and Pre-Stack Time Migration (PSTM – Multi-2D). Since all channels were kept alive for all shots, this created pseudo-3D data that allowed a Multi-2D survey to be processed, which is referred to as a Multi-2D and pseudo-3D seismic survey. The processing report was delivered to the Project Team in November 2021, and the processed data was sent to the Geological Survey of Alabama (GSA) for interpretation.

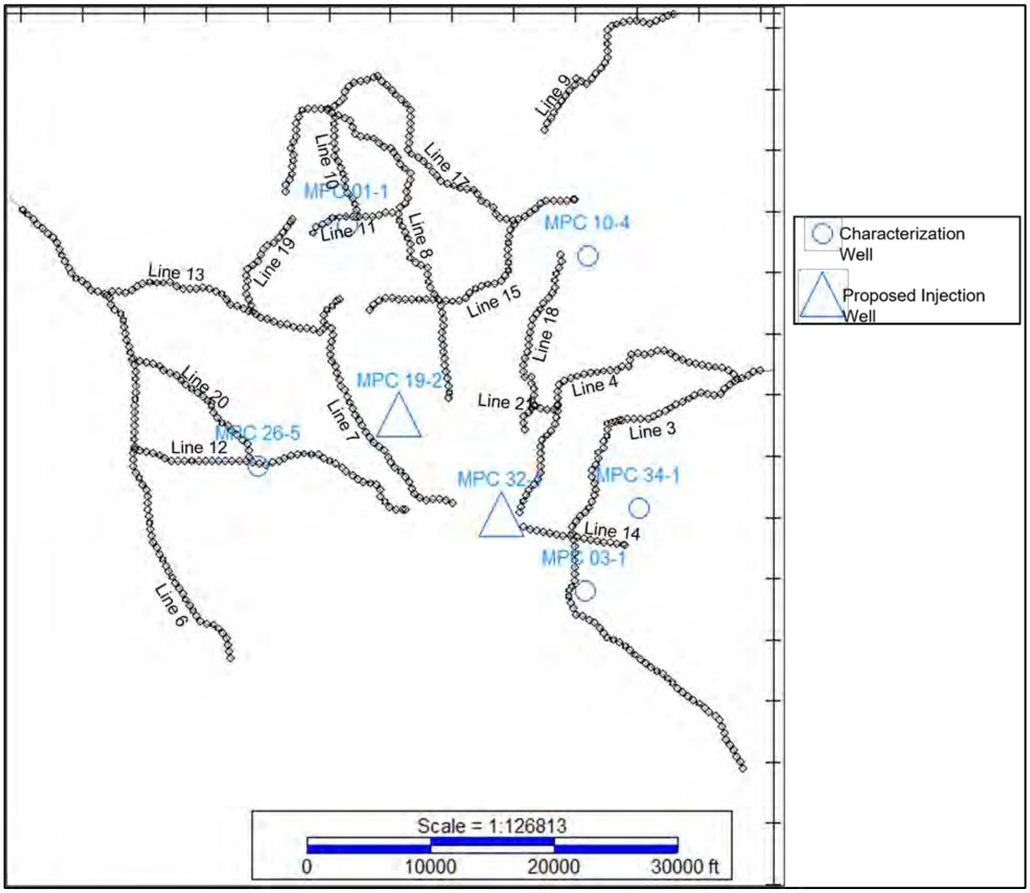


Figure 37 *Receiver array scheme*

Results from analysis of the 2D seismic lines and incorporation of the pseudo-3D seismic dataset provided confirmation that both the targeted reservoir interval and confining interval are regionally extensive throughout the project area. As further explained and documented in Subtask 6.4, no major structural features were identified (such as faults or folds) that could contain fracture networks, providing the Project Team with confidence that no natural leakage pathways exist within the project area.

Subtask 5.3 – Surface Characterization for UIC Injection Well Drilling

Potential UIC injection and monitoring well sites were surveyed to determine their suitability for: (1) drilling characterization/monitoring wells and, later, injection wells; (2) potential delivery points for CO_2 and well services; (3) locations for surface and subsurface monitoring equipment; and (4) useable rights-of-way. There is adequate space for all required equipment and rights-of-way as well as suitable pore/mineral access. **Figure 38** shows the locations of the injection and monitoring wells for the prospective UIC Class VI program.

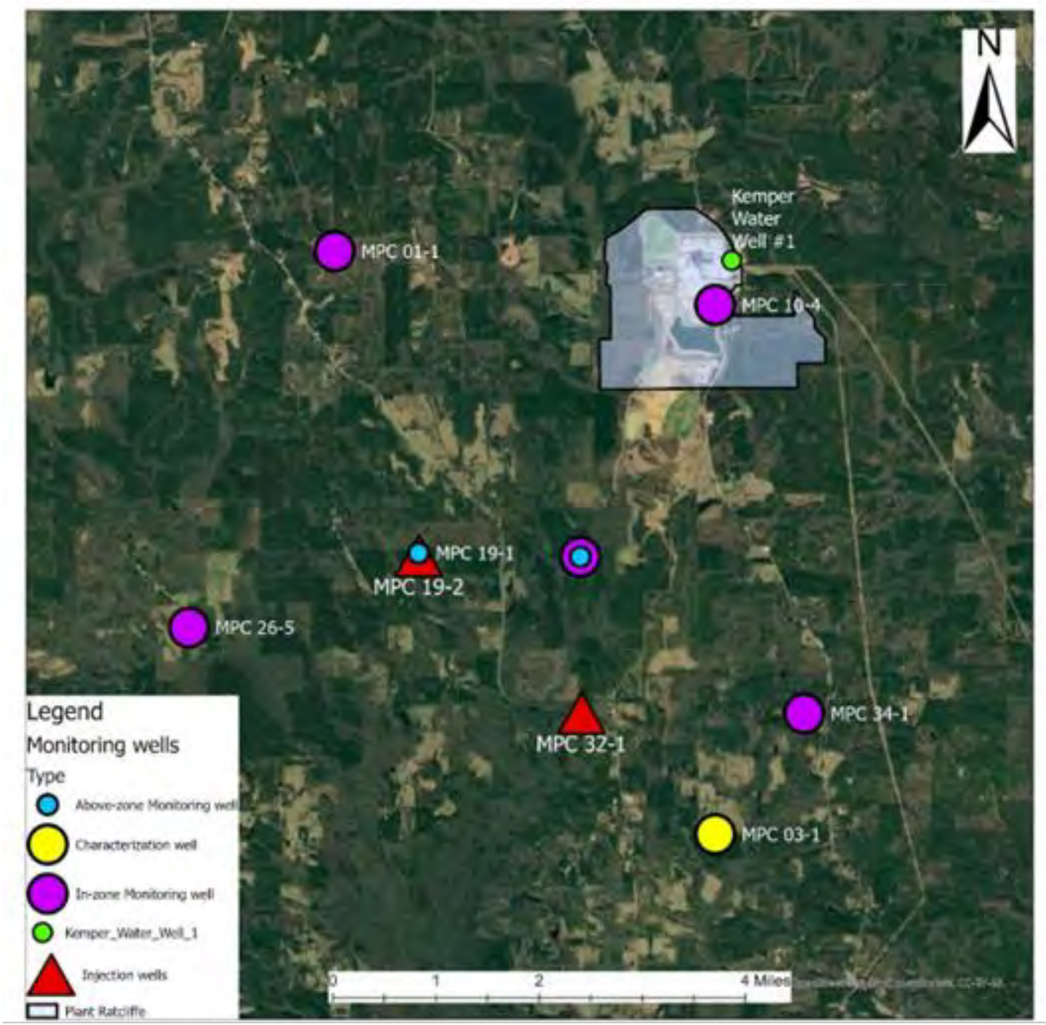


Figure 38 *The locations of the injection and monitoring wells for the prospective Class VI program*

Task 6.0 - Geologic Data Analysis

Characterization of the Kemper County Storage Complex was accomplished through the integrated analysis of data collected from the geophysical logs, routine and special core analysis, and the integration of the acquired 2D seismic. **Figure 39** presents the full stratigraphic cross section for the six characterization wells drilled during Project ECO_2S Phase II and Phase III. Gamma ray logs are measured in American Petroleum Institute (API) units that are used as a standard measure of radioactivity. Gamma ray values for the characterization wells shown in the figure are colored from left to right to relatively distinguish sandstone or limestone units corresponding to low API (beige) from shaly sequences corresponding to higher API (black). The Maximum Flooding Surface in the Tuscaloosa Marine Shale interval serves as the reference datum. Interpretation of the characterization wells shows a uniform stratigraphic package across the intervals of interest. Consistent with the interpretation of the 2D seismic, no significant changes in formation thickness have been observed and the primary confining interval shows no sign of diminishing across the project area. The storage interval (Lower Tuscaloosa Massive sand through base of the Paluxy Formation) represents a 2,000 – 2,200 ft thick package over the study area.

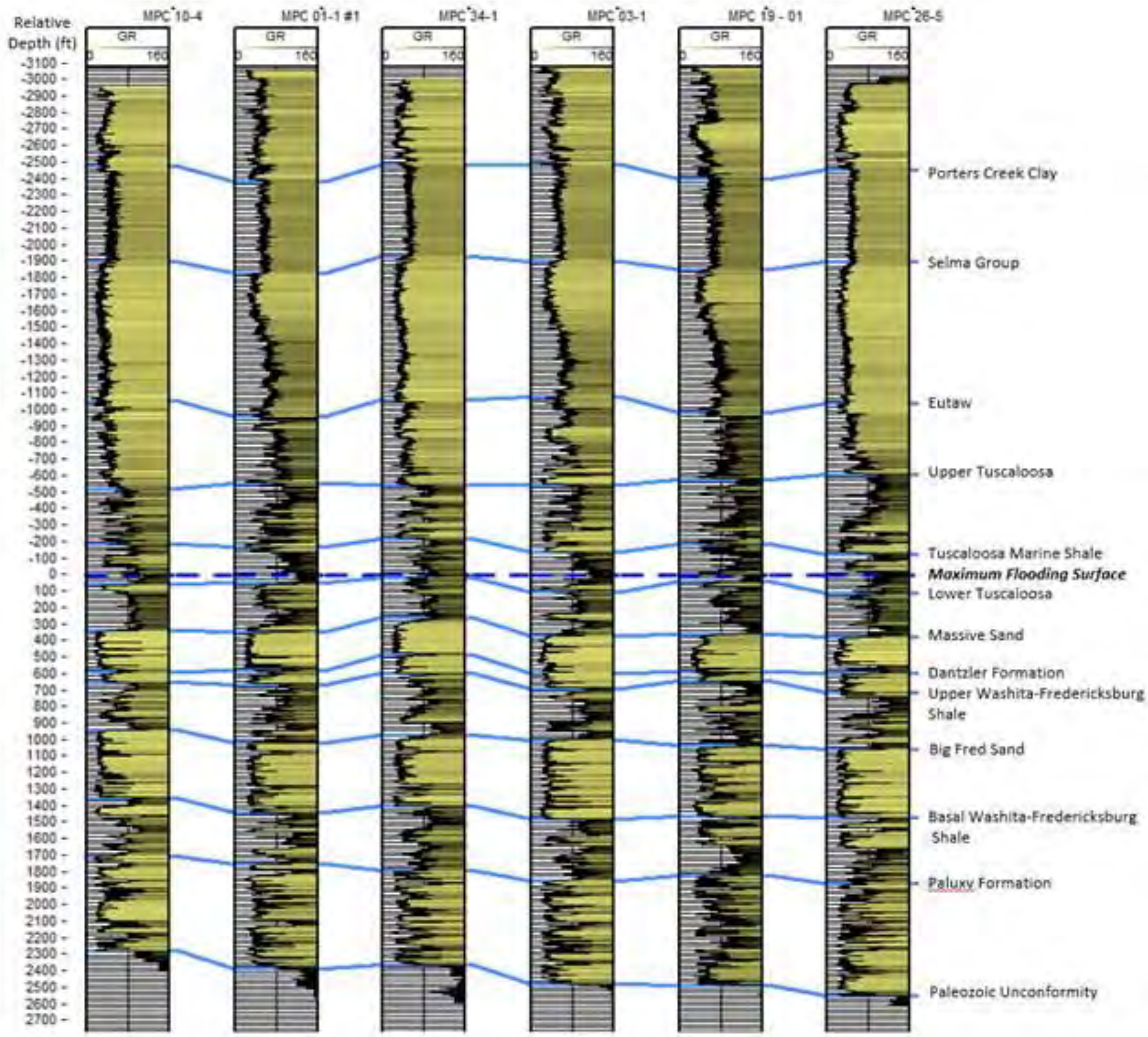


Figure 39 *Characterization Wells Full cross-section. The cross-section is flattened on the Maximum Flooding Surface in the Tuscaloosa Marine Shale interval.*

Figure 40 is an enhanced cross-section of the characterization wells, focused on the primary confining zone (Tuscaloosa Marine Shale) and storage intervals (top Lower Tuscaloosa Massive sand through the base of the Paluxy Formation), which includes the Upper and Basal shales of the Washita-Fredericksburg Interval as secondary confinement intervals. Log analysis of the characterization wells indicates that the geology of the proposed storage interval and confining interval is consistent across the AoR. Characterization of the Paluxy Formation has identified four zones as potential CO_2 storage reservoirs. These zones consist of sand bodies that are separated by thin interbedded shales that will impact the vertical movement of the CO_2 plume in the subsurface.

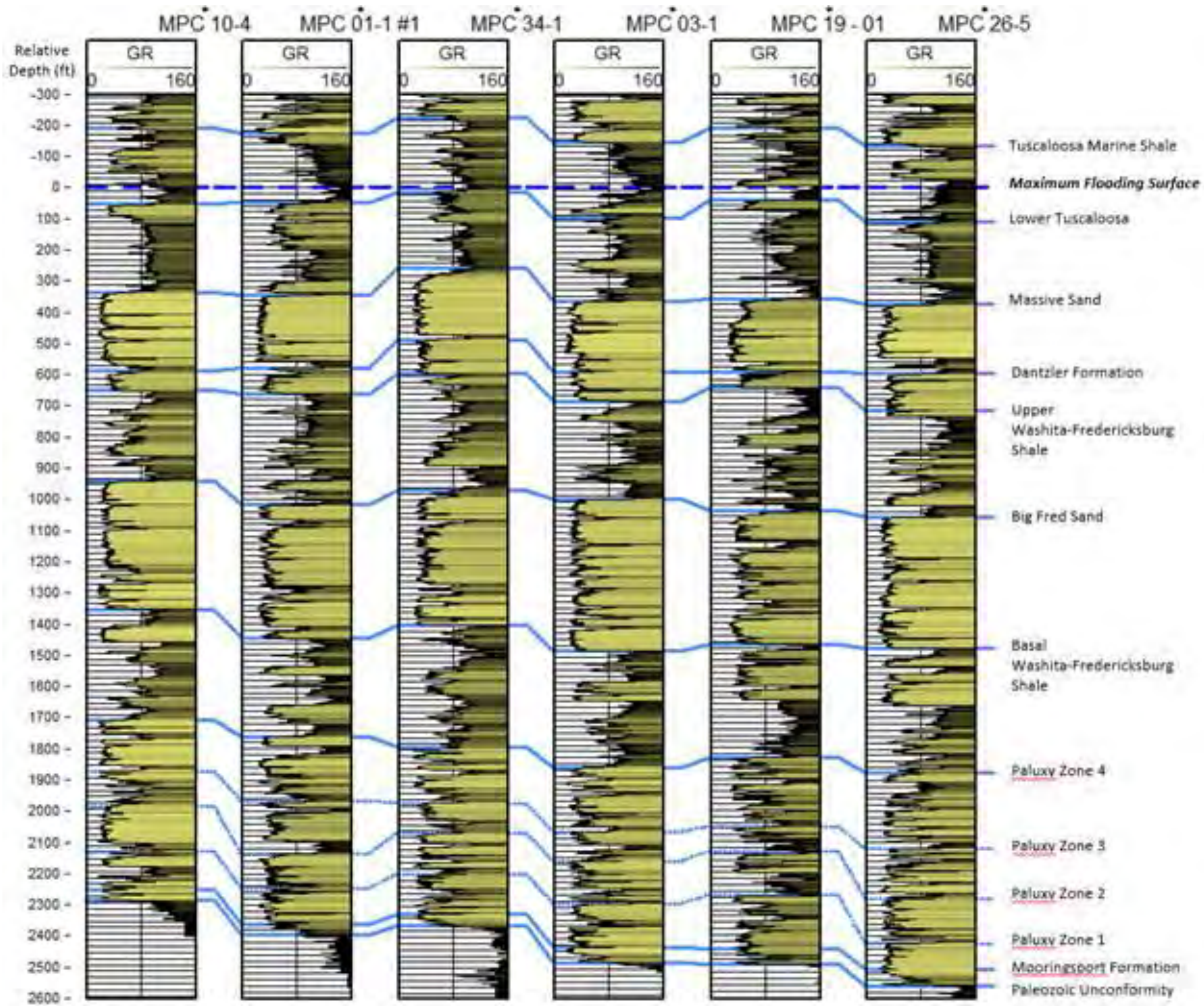


Figure 40 *Characterization Well Cross-Section of the Confining Zone (Tuscaloosa Marine Shale) and the Injection Interval. The cross-section is flattened on the Maximum Flooding Surface in the Tuscaloosa Marine Shale interval.*

The correlations established on the geophysical logs were used to generate a series of structure contour and isopach maps. These served the purpose of demonstrating the relative structure and thickness of the injection zone, storage interval, and primary and secondary confining zones. All depths are reported in sub-sea feet (SS). **Figure 41** shows the spatial extent of the contour maps, using the characterization wells as a point of reference, marking the approximate location of the injection wells. Each of the confinement intervals and storage zones are laterally continuous across this region. There are no major geologic structures (faults, domes, etc.) in the storage zone that would serve as trapping mechanisms or leakage pathways for stored CO_2 and/or brine to escape toward the ground surface. The red dashed line shown is the official AoR that was modelled for the Kemper County Storage Complex.

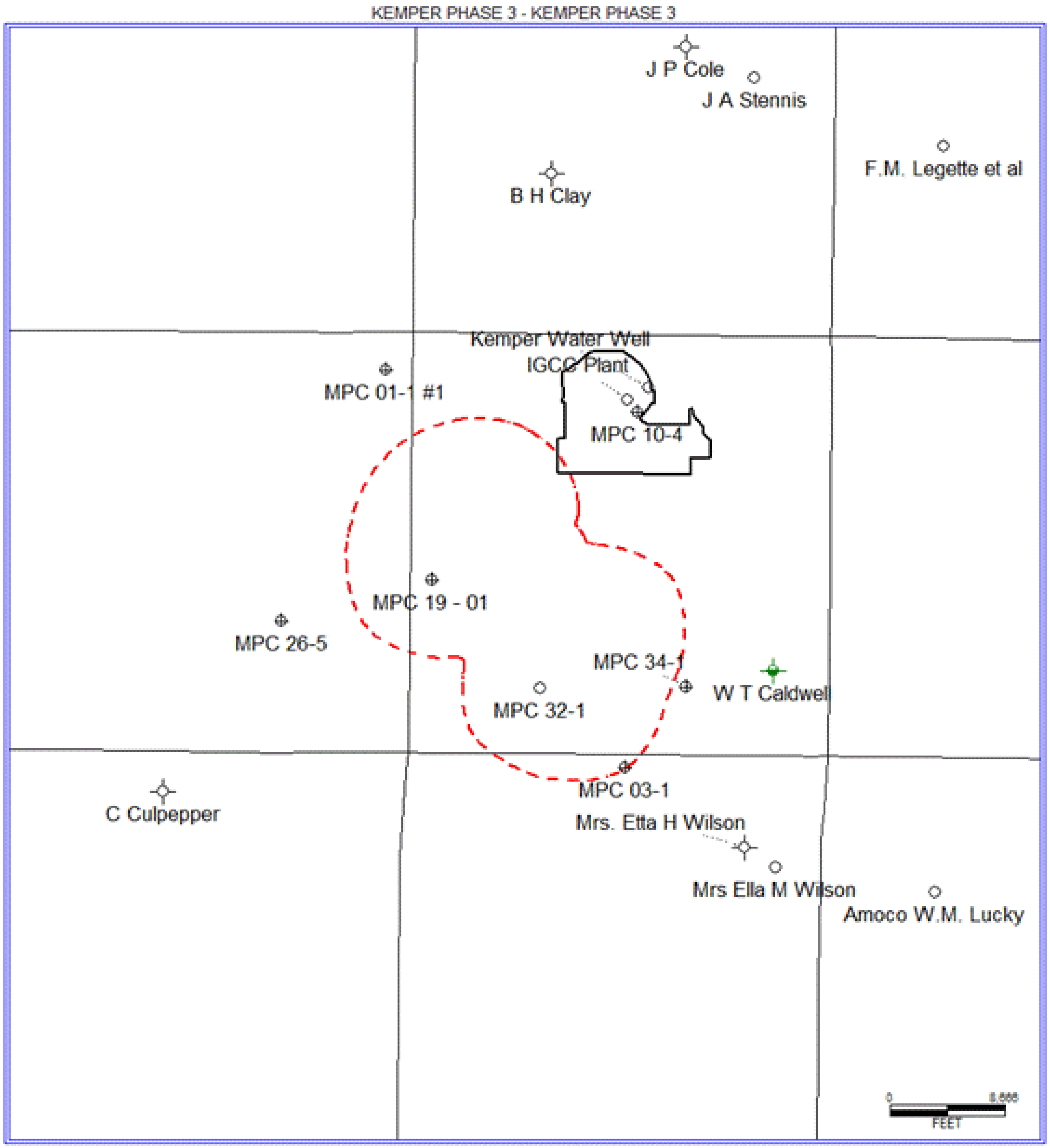


Figure 41 *Contour Map Data Limits, including well locations, well names, Plant Ratcliffe outline, and the Area of Review outline (red dashed line).*

The depth of the Tuscaloosa Marine Shale ranges from -2,692 to -2,380 ft SS around the characterization wells (**Figure 42**), and the thickness of the Tuscaloosa Marine Shale ranges from 221-245 ft (**Figure 43**). The Tuscaloosa Marine Shale dips to the southwest at 59.2 ft per mile and thickens toward the south of the characterization wells from 219-245 ft.

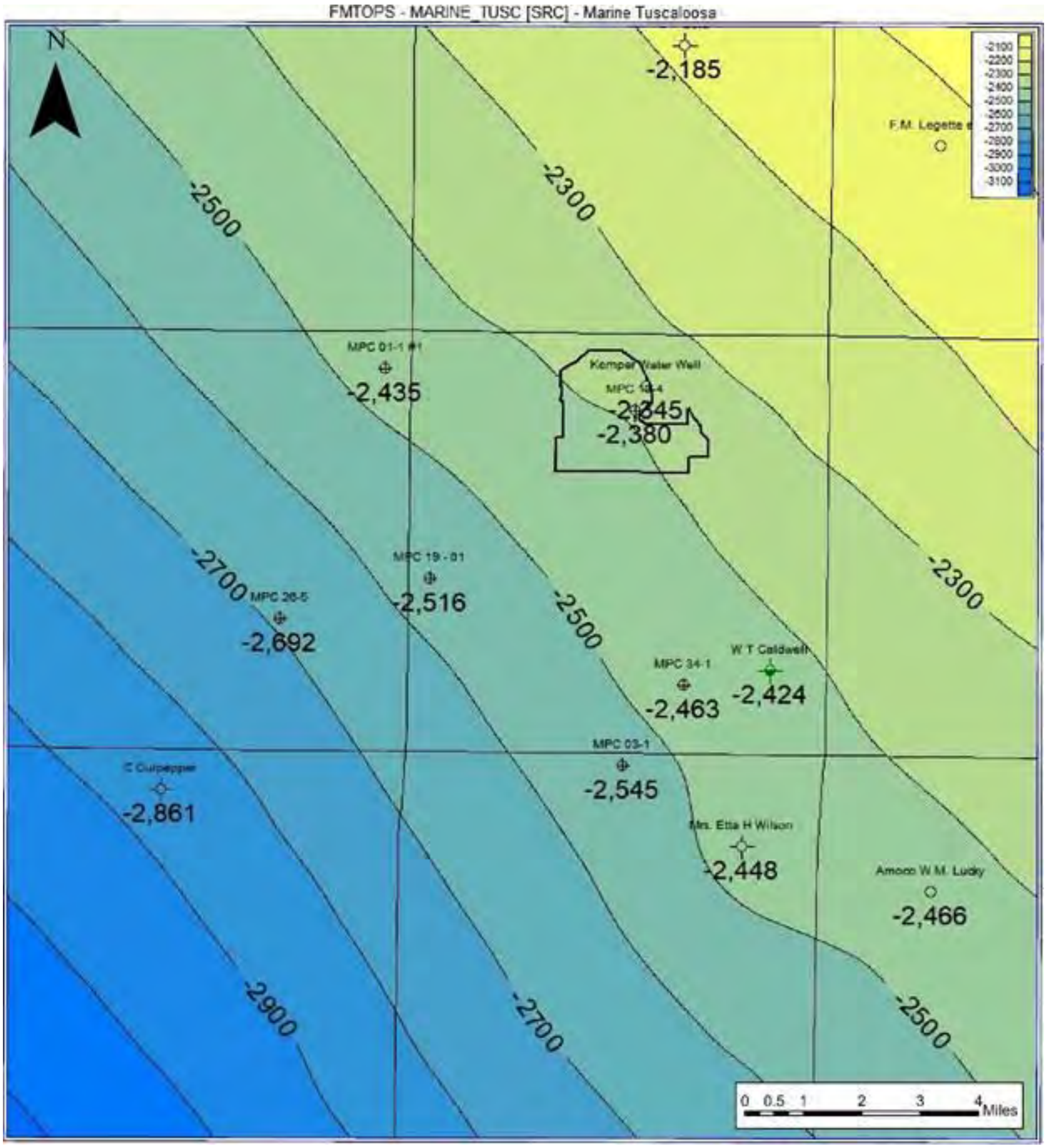


Figure 42 *Top of Tuscaloosa Marine Shale Structure Map*

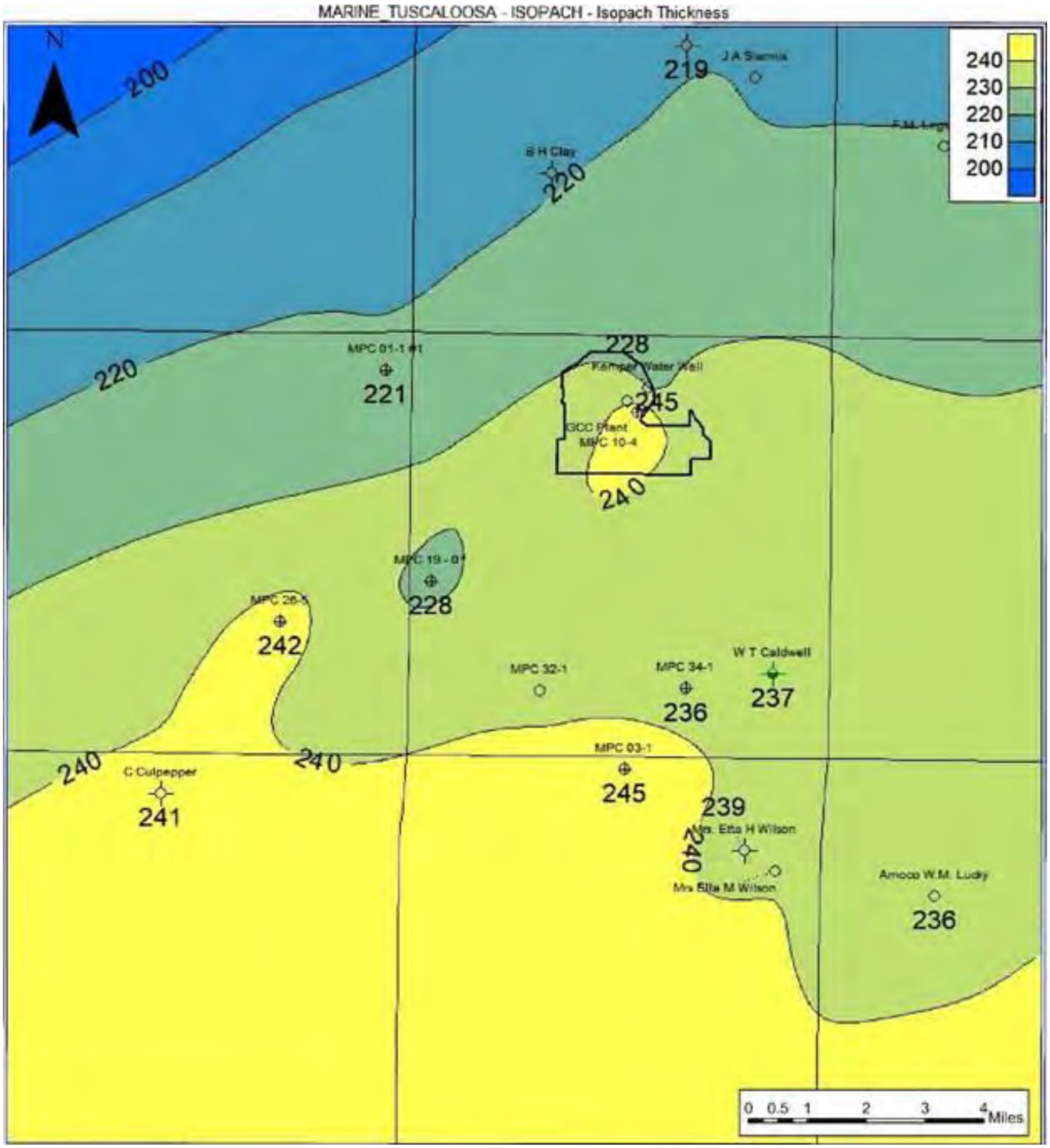


Figure 43 *Tuscaloosa Marine Shale Gross Isopach Map*

The depth of the Paluxy Formation ranges from -4698 to -4277 ft SS around the characterization wells (**Figure 44)**, and the thickness ranges from 534-630 ft (**Figure 45**). The Paluxy Formation dips to the southwest at 72.9 ft per mile and its thickness increases uniformly to the west from 484 to 676 ft. The net sand for the Paluxy Formation ranges from 350-496 ft for the characterization wells (**Figure 46**).

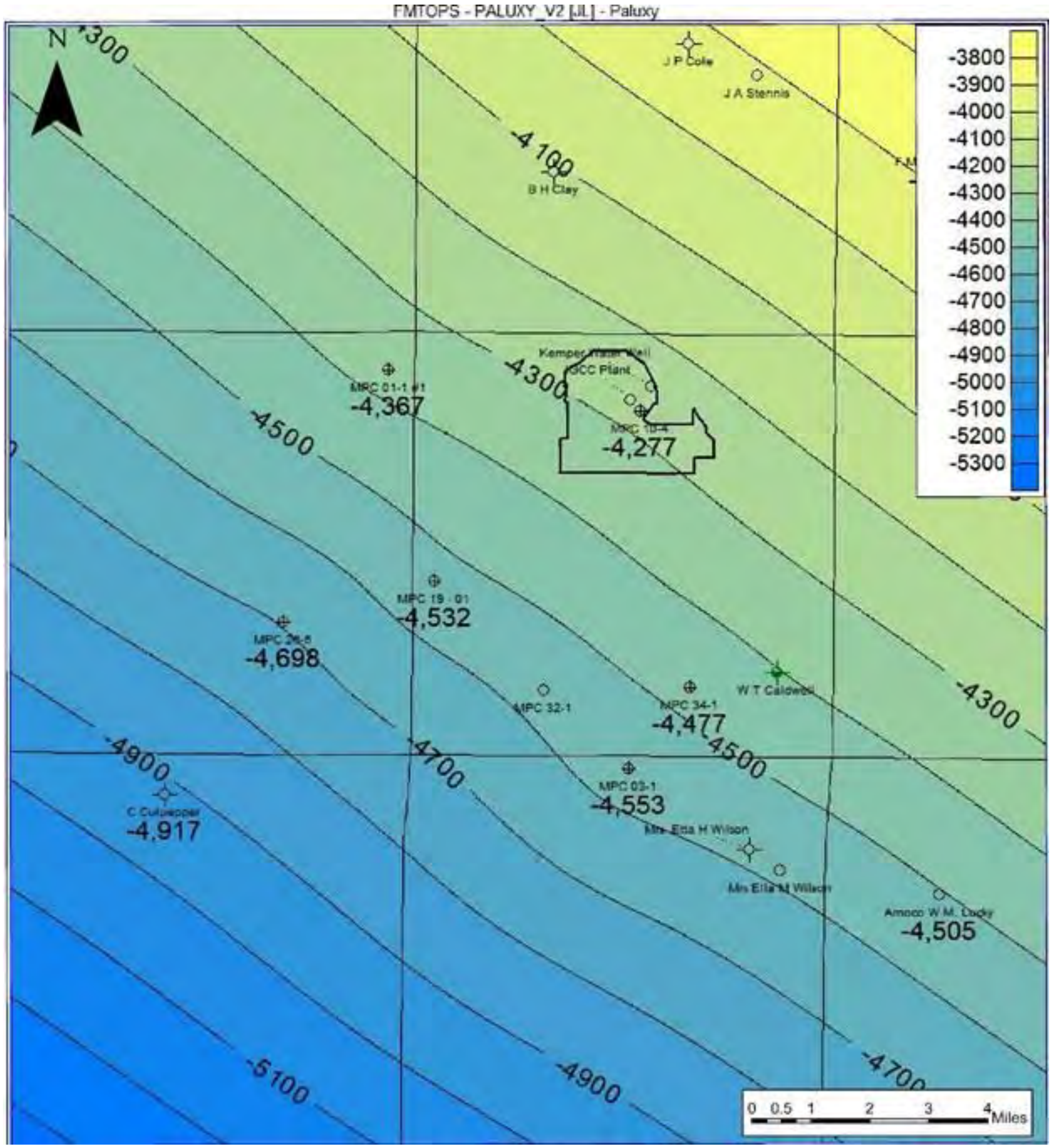


Figure 44 *Top of Paluxy Formation Structure Map*

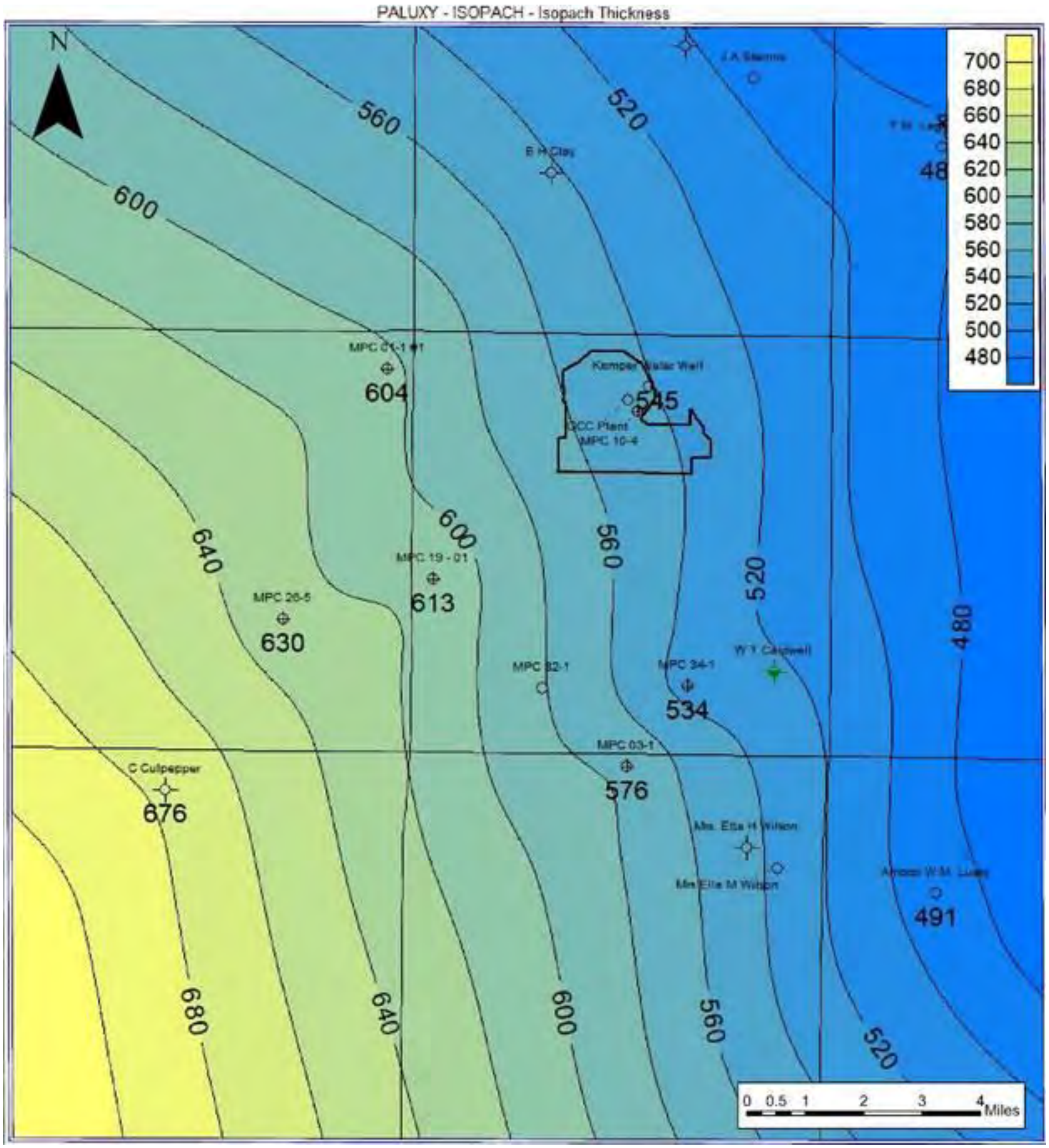


***Figure 45** Paluxy Formation Gross Isopach Map*

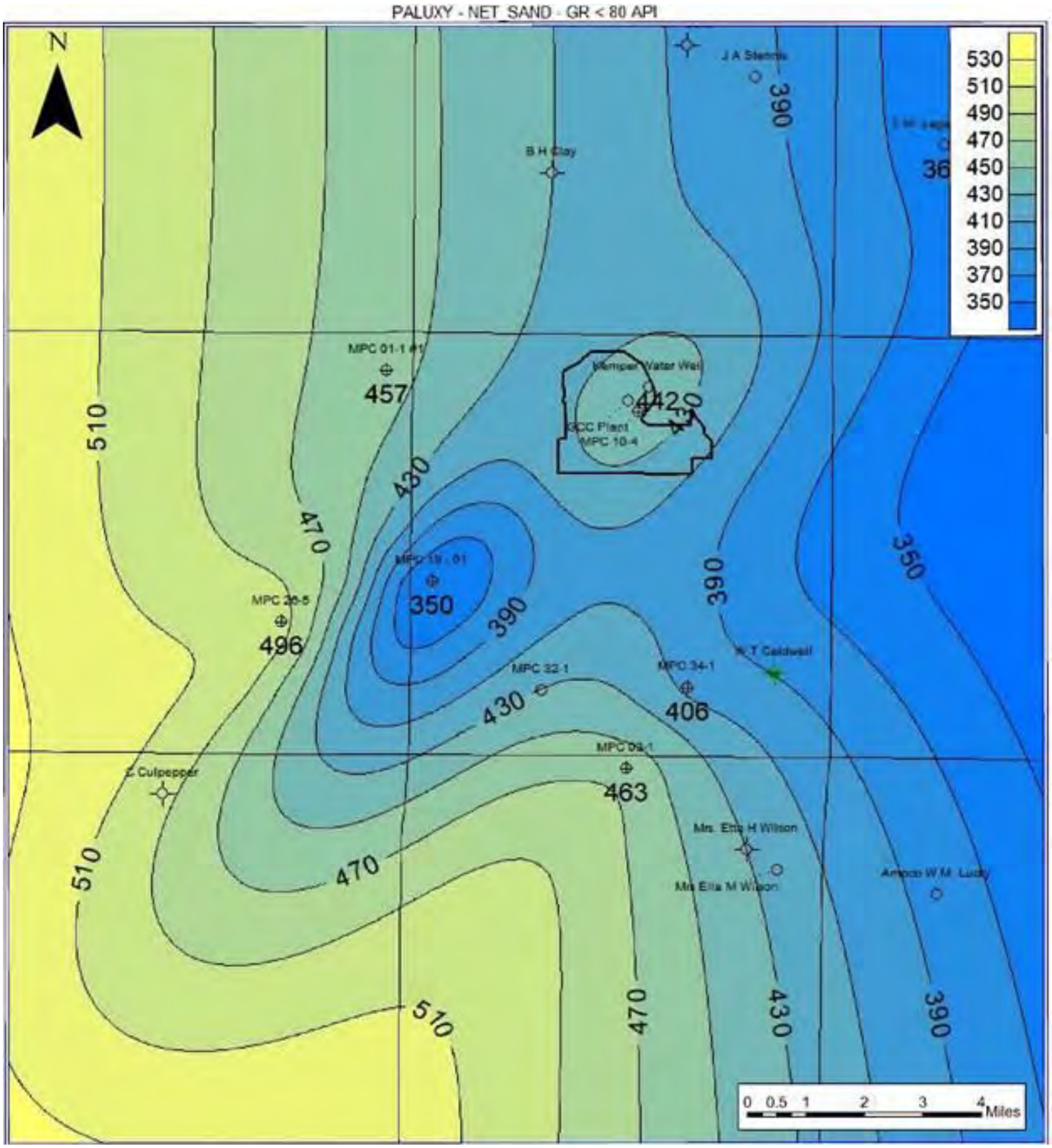


Figure 46 *Net Sand Map of the Paluxy Formation*

Subtask 6.1 - Core and Fluid Analysis

Reservoir characteristics of the injection and confining intervals were investigated using the whole core that was acquired during the stratigraphic test well drilling. Petrophysical properties were derived through routine and special core analysis and review of petrographic thin sections. The results of the petrophysical properties are shown in **Table 7**. Reservoir properties from each of the wells demonstrated a little variation in the reported values, which suggests a high degree of reservoir consistency across the Storage Complex.

RCA was used to determine porosity, Klinkenberg permeability, and fluid saturation. Density porosity logs were used to quantify sandstone porosity. Pressure decay permeability analysis was performed on mudrock samples from core and cuttings, and standard petrographic thin sections were developed from core samples to determine porosity and mineralogy. This reservoir data was then used to calculate the storage capacities of the three saline reservoirs in the injection zone (Lower Tuscaloosa Massive sand, Big Fred sand, and Paluxy Formation sands).

Standard saline storage efficiency factors (Goodman et al., 2011[2]) of 7.4%, 14%, and 24% were applied to capacity estimates to reflect the fraction of total pore volume that will be occupied by injected CO_2. These specific saline storage efficiencies are used when the area, net reservoir thickness, and core-derived (effective) porosities are known for the storage reservoirs.

Additionally, Lohr and Hackley (2018)[3] conducted Mercury Injection Capillary Pressure (MICP) analysis on Tuscaloosa Marine Shale core samples to determine CO_2 column height retention, porosity, and Swanson permeability. OSU analyzed thin sections to determine the composition and fabric of the Tuscaloosa Marine Shale, and porosity of the reservoir and confining units was determined using the Dean Stark Extraction method. Net storage reservoir thicknesses and porosity also were investigated using triple combo well logs. Porosity, permeability, and calculated storage capacity for sandstone and mudstone units are presented in **Table 8 and Table 9**, respectively.

Table 7 *Well Core Depths from the Characterization Wells.*

MPC 26-5			
Depth Range (ft)	**Cored (ft)**	**Recovered (ft)**	**Intervals Cored**
3,587 - 3,643	56	4	Lower Tuscaloosa Massive sand
3,645 - 3,622	17	10.5	Lower Tuscaloosa Massive sand
4,331 - 4,349	18	4.3	Washita-Fredericksburg Interval Big Fred sand
MPC 34-1			
Depth Range (ft)	**Cored (ft)**	**Recovered (ft)**	**Intervals Cored**
4,850 - 4,867	17	12.5	Washita-Fredericksburg Interval
5,307 - 5,340	33	30	Paluxy Formation

[2] Goodman, A., Hakala, A., Bromhal, G., Deel, D., Rodosta, T., Frailey, S., Small, M., Allen, D., Romanov, V., Fazio, J., Huerta, N., McIntyre, D., Kutchko, B., and Guthrie, G., 2011. U.S. DOE methodology for the development of geologic storage potential for carbon dioxide at the national and regional scale. International Journal of Greenhouse Gas Control. Vol. 5, Issue 4, p. 952-965.

[3] Lohr, C. D., & Hackley, P. C., 2018. Using mercury injection pressure analyses to estimate sealing capacity of the Tuscaloosa marine shale in Mississippi, USA: Implications for carbon dioxide sequestration. International Journal of Greenhouse Gas Control, 78, 375-387.

MPC 10-4			
Depth Range (ft)	**Cored (ft)**	**Recovered (ft)**	**Intervals Cored**
3,170 - 3,200	30	26	Tuscaloosa Marine Shale
3,200 - 3,210	10	7	Tuscaloosa Marine Shale
5,038 - 5,068	30	27.5	Paluxy Formation
5,068 - 5,098	30	30	Paluxy Formation
5,098 - 5,135	37	28	Paluxy Formation
MPC 01-1			
Depth Range (ft)	**Cored (ft)**	**Recovered (ft)**	**Intervals Cored**
3,850 – 3,881	31	31	Upper Washita-Fredericksburg shale
MPC 19-1			
Depth Range (ft)	**Cored (ft)**	**Recovered (ft)**	**Intervals Cored**
3,076 – 3,099	23	0	Tuscaloosa Marine Shale
3,099 – 3,125	26	6	Tuscaloosa Marine Shale
4,800 – 4,808	8	5	Basal Washita-Fredericksburg shale
4,808 – 4,832	24	20	Basal Washita-Fredericksburg shale
5,320 – 5,344	24	15	Paluxy Formation
5,344 – 5,369	25	25	Paluxy Formation

Table 8 *Tabulation of Mudstone Porosity and Permeability Data Measured from Core.*

Mudstone Characteristics			Tuscaloosa Marine Shale	Paluxy Formation
Porosity				
RCA Porosity (%) [28]	MPC 10-4		2 – 4	4.2 – 14.7
	MPC 19-1			7.9 and 13.6
MICP Porosity [29]			3.86 – 9.86	
Permeability				
RCA permeability (mD) [28]	MPC 10-4		0.54 - 38.1	0.2 - 0.37
	MPC 19-1		3.11 - 13	0.0058 and 0.032
MICP Permeability (mD) [29]			< 0.003	
Pressure decay permeability (nD) [28]	MPC 26-5	Hyperbolic	194.7	34.4
		Exponential	64.4	23.8
	MPC 10-4	Hyperbolic	79.9	
		Exponential	12.4	

***Table 9** Tabulation of Sandstone Porosity, Permeability, and Storage Capacity Estimates.*

Sandstone Characteristics		Lower Tuscaloosa Massive sand	Washita-Fredericksburg sand	Paluxy sands
Porosity				
RCA Porosity (%)		28.8	27.4	26.3
RCA Porosity (%)	MPC 10-4			30
	MPC 34-1		> 30.0	
	MPC 19-1			28

Mercury Injection Porosity (%)	**MPC 10-4**			28.3 – 32.6
Triple Combo Porosity (%)	**MPC 26-5**	30.0	28.0	28.0
	MPC 34-1	30.0	28.0	27.0
	MPC 10-4	31.0	27.0	28.0
Permeability				
RCA Permeability (mD)	**MPC 10-4**			1800
	MPC 34-1		600	
Pressure decay permeability MPC 26-5 (nD)	**Hyperbolic**			34.40
	Exponential			23.80
Capacity				
Storage capacity (Mt/mi^2)	**p10**	1.82	7.53	4.28
	p50	3.45	14.25	8.10
	p90	5.92	24.43	13.90

Tuscaloosa Marine Shale

The Tuscaloosa Marine Shale is a succession of interbedded shale, siltstone, and very fine- to fine-grained sandstone that serves as a regional confining unit in the eastern Gulf basin. The Tuscaloosa Marine Shale consists of medium to dark gray mudstone that forms laminae to medium beds. The siltstone and sandstone units are light to medium gray, forming laminae to very thick beds (**Figure 47)**. The basal portion of the Tuscaloosa Marine Shale contains graded bedding of shale, siltstone, and sandstone, and these beds have sharp bases and gradational to sharp tops. Other structures included soft-sediment deformation, current ripple cross laminae, and pinstripe, lenticular, and wavy bedding. Together, the Lower and Upper Tuscaloosa form a progradational succession of fluvial-deltaic deposits that grade upwards from the offshore facies associated with the Tuscaloosa Marine Shale to the coastal and terrestrial facies of the Upper Tuscaloosa. The Tuscaloosa Marine Shale is the top-seal for the hydrocarbons sourced in the lower Tuscaloosa Group, which is a major source of petroleum in Mississippi and Alabama, making it an adequate confining unit for CO_2 storage.

Table 8 details porosity and permeability data for the Tuscaloosa Marine Shale, including RCA and Pressure decay permeability and MICP data. Porosity measurements from fresh cuttings and core samples indicate that porosity of the mudrocks is on the order of 2-4%, although these values appear to reflect alteration of the mudrock during retrieval and preparation of the samples. Permeability values from RCA in the Tuscaloosa Marine Shale show a wide range of permeability from 0.54-38.1 millidarcy (mD). Curves fitted to the pressure decay analysis for wells MPC 25-5 and MPC 10-4 data yielded permeability values of 194.7 and 79.9 nD for the Hyperbolic segment and 64.4 and 12.4 nD for the Exponential segment, respectively. The MICP analysis conducted on core and cuttings from the Tuscaloosa Marine Shale yielded porosity values of 3.86-9.86% and Swanson permeability values less than 0.003 mD. Moreover, it was demonstrated that the Tuscaloosa Marine Shale can retain a CO_2 column height of 100 meters before any CO_2 intrusion, suggesting desirable sealing ability.

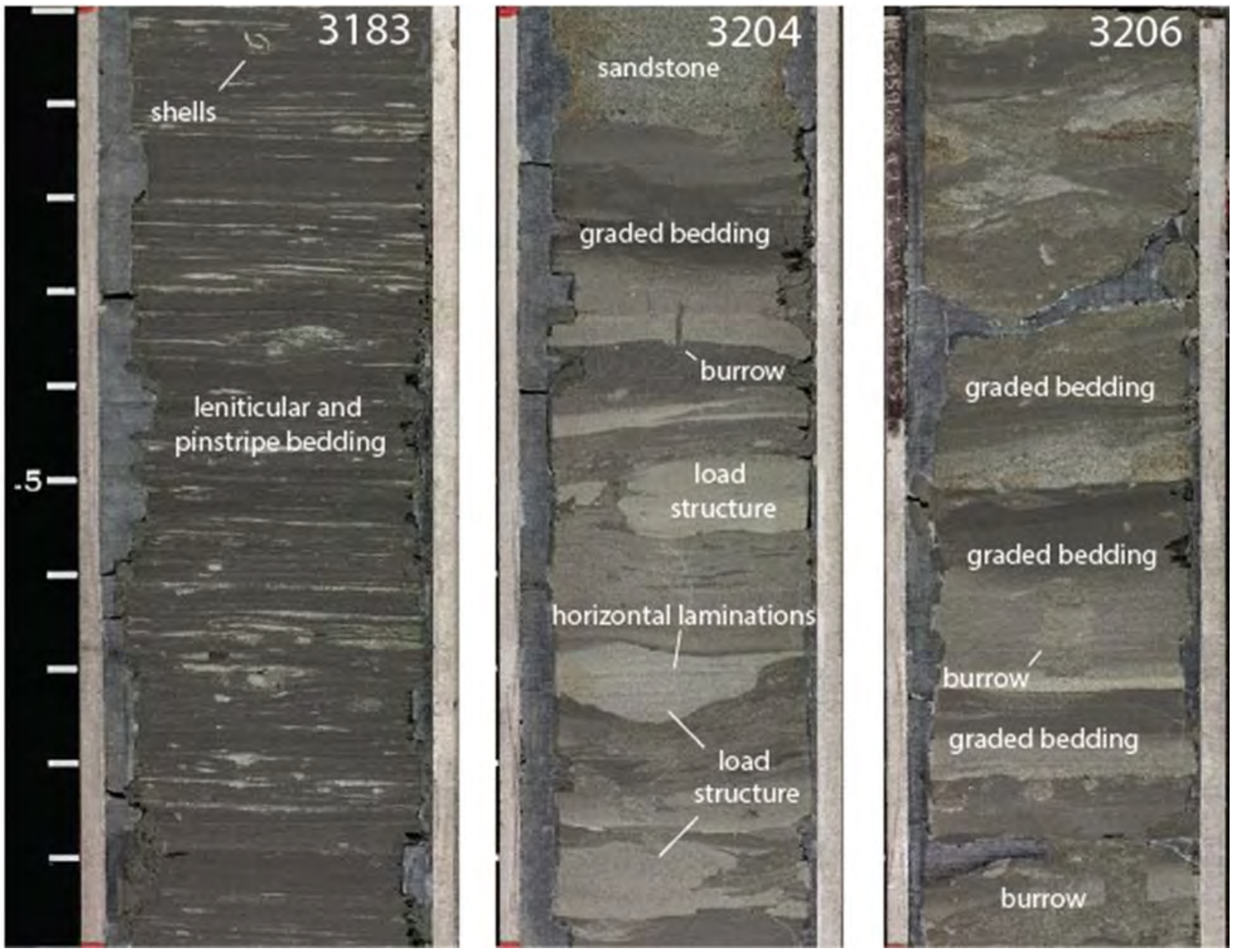


Figure 47 *Tuscaloosa Marine Shale Core from MPC 10-4*

Lower Tuscaloosa

The Lower Tuscaloosa Massive sand marks the top of the injection zone, directly underlying the Tuscaloosa Marine Shale confining zone, and is interpreted to have formed in a fluvial to coastal environment. This unit consists of an interval of thickly bedded, very poorly sorted, medium-grained consolidated sandstone while a basal conglomerate forms the lower portion of the Lower Tuscaloosa Massive sand. RCA of the Lower Tuscaloosa Massive sand shows a porosity value of 28.8%, while porosity derived from triple combo logs run on the characterization wells yielded porosity values of 30 and 31%. CO_2 storage capacity for the Lower Tuscaloosa Massive sand was calculated at 1.82, 3.45, and 5.92 Mt/mi^2 for estimates of p10, p50, and p90, respectively.

Upper Washita-Fredericksburg shale

In the upper part of the Washita-Fredericksburg interval, and overlying the Big Fred sand, is a mudstone assemblage that is proposed as one of the secondary confinement intervals for the Paluxy Formation. The interbedded sandstone and mudstone units resemble those of the Paluxy Formation and lower Washita-Fredericksburg interval. Mudstone X-ray diffraction mineralogy of mudstone from well MPC 26-5 in the Washita-Fredericksburg Interval shows 35.3% clay, 63.2% quartz, and 1.5% carbonate, with most of the clay being smectite. Correlation of mudstone units in the Washita-Fredericksburg Interval shows that individual mudstone layers have sufficient continuity to contain the migration of injected CO_2 in and around the Kemper County Energy Facility. Several Washita-Fredericksburg Interval sandstone units are known to produce hydrocarbons in Mississippi, demonstrating that relatively thin shale beds within the Washita-Fredericksburg Interval succession can form effective reservoir seals. This red mudstone succession likely represents the abandonment of the fluvial channel facies in the Big Fred sand.

Big Fred sand

The Big Fred sand makes up the central portion of the Washita-Fredericksburg Interval and consists of a succession of quartzose sandstone, pebble and cobble conglomerate, and red and gray mottled mudstone. RCA of the Washita – Fredericksburg Interval sands shows porosity values of 27.4% and 30%, while porosity derived from triple combo logs yielded porosity values of 27 and 28%. CO_2 storage capacity for the Washita-Fredericksburg Interval sands was calculated at 7.53, 14.25, and 24.43 metric tons per square mile (Mt/mi^2) for estimates of p10, p50, and p90, respectively. Grain size decreases upwards in section from conglomeritic sand to fine sand, silt, and mud. The Washita-Fredericksburg Interval is interpreted as fluvial conglomerate and interfluvial redbeds.

Washita-Fredericksburg Basal Shale

The basal shale of the Washita-Fredericksburg Interval contains mudstone with isolated sandy units which act as an overlying seal for CO_2 storage in sands of the Paluxy Formation. This gray, silty mudstone has a blocky appearance resulting from inclined fractures, interpreted as blocky peds produced during soil development. The bottom part of the Basal shale contains a network of sandstone-filled cracks, providing evidence for desiccation and sand infiltration through a soil profile. The gray appearance of the infiltrating sand may be a secondary feature resulting from the migration of reducing fluids through the sandstone during its initial burial and diagenesis. This unit is present throughout the east-central Gulf Basin, making it a suitable and regionally extensive seal. Renken et al. (1989)[4] and Pashin et al. (2008)[5] suggested that the Washita-Fredericksburg Interval contains fluvial and interfluvial redbeds similar to those in the underlying Paluxy Formation.

Paluxy Formation

The Paluxy Formation is a succession of sandstone and shale with three major lithofacies: (1) the conglomerate lithofacies; (2) the sandstone lithofacies; and (3) the mudstone lithofacies. The Paluxy Formation sands are composed of thick to very thick bedded sandstone packages with regular cross-bedding structures separated by thinner mudstone laminae (**Figure 48**). The sand is dominantly fine- to medium-grained, while some intraclastic and extraclastic granules and pebbles are locally

[4] Renken, R. A., Mahon, G. L., and Davis, M. E., 1989. Hydrology of clastic Tertiary and Cretaceous regional aquifers and confining units of the southeastern coastal plain aquifer system of the United States (No. 701).
[5] Pashin, J. C., Hills, D. J., Kopaska-Merkel, D. C., and McIntyre, M. R., 2008. Geological Evaluation of the Potential for CO_2 Sequestration in Kemper County. Mississippi: Birmingham, Final Report, Southern Company Research and Environmental Affairs.

present along cross-bed foresets. The Paluxy Formation has been interpreted to represent sandy braided fluvial (sandstone and conglomerate) and interfluvial deposits (mudstone).

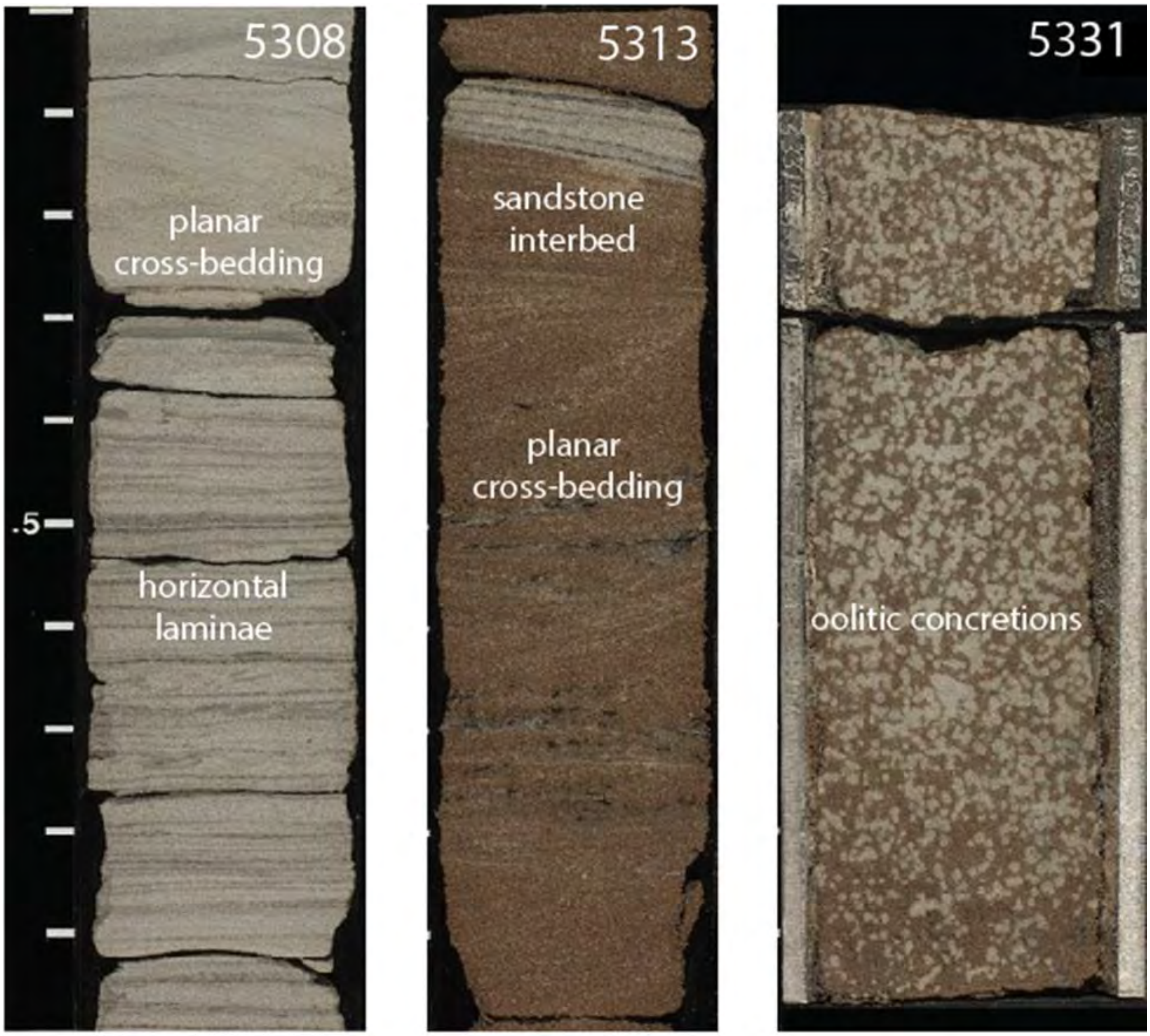


Figure 48 *Paluxy Formation Core from Well MPC 34-1*.

Sandstone lithologies of the Paluxy Formation are composed of quartz, feldspar, and lithic fragments and are classified as subarkose and feldspathic litharenite according to the Folk (1980) classification. Quartz grains are angular to subrounded and slightly elongate to spherical. Quartz content ranges from 65-95%, while feldspar and lithic fragments are present in relatively equal proportions in the Paluxy Formation sands. Orthoclase and plagioclase feldspar are both present and commonly partially dissolved or vacuolized and result in secondary porosity. Lithic rock fragments in the Paluxy Formation sands include metamorphic rocks, igneous rocks, and a few grains of oolitic chert. Common accessory minerals include biotite and muscovite, with minor amounts of zircon grains, calcite cement, and kaolinite in pore spaces. Like the Washita-Fredericksburg Interval, the anomalously high-water saturation (100%) in the cores from the clay-rich intervals in the Paluxy Formation was likely due to the shallow burial depths and resulting low thermal maturity and immature clay minerals. The RCA results for the Paluxy Formation sands show an average of 1.8 darcy (D) permeability and 28% porosity for the MPC 10-4 samples. Data derived from triple combo logs run on the three Phase II characterization wells suggests porosity of 27 and 28% in the Paluxy Formation sands. Additionally, Paluxy Formation sand core samples underwent steady-state CO_2/Brine Relative Permeability Measurements at the University of Wyoming, which resulted in a porosity and permeability of 30% and 1601 mD, respectively. Scanning electron microscopy of the Paluxy Formation sands thin sections reveal a predominance of quartz, and a porosity of 20-25% was determined from back-scattered electron detector images. Other minerals include feldspar, clay (kaolinite, smectite, and illite), and carbonates (calcite, dolomite, and siderite). Clay minerals are present as a coating on other mineral phases or bridges between grains. Cross-sectional slices extracted from 3D X-ray CT images were analyzed and yielded an average porosity of 26%. In reactive transport simulations, the carbonate minerals showed the greatest alterations. Clay and aluminosilicate minerals were altered to a lesser degree. The mineral dissolution resulted in a porosity increase from 25-32%. Calcite will dissolve more quickly in regions where brine saturation is higher, while other minerals' grains are left mostly unchanged. These reactive phases are anticipated to dissolve along all depths in the Paluxy Formation. Pore network modeling showed an increase in permeability from 1,555.4 mD to 8,000 mD. Curves fitted to the pressure decay analysis for mudstones in the Paluxy Formation from well MPC 26-5 data yielded permeability values of 34.4 and 23.8 nD for the Hyperbolic and Exponential segment, respectively. Capacity for the Paluxy Formation sands was calculated at 4.28, 8.10, and 13.9 Mt/mi^2 for estimates of p10, p50, and p90, respectively.

Subtask 6.2 - Refined Geologic Model

Results from Subtask 6.1 were integrated with Phase II stratigraphic, structural, geomechanical, and geochemical models. Local and regional geologic structure maps of potential storage and confining zones have been constructed, emphasizing the architecture of the storage reservoirs and continuity and thickness of the confining systems. Together these studies are utilized to refine the geologic framework for the Storage Complex. Results of the characterization focusing on the confining intervals are presented in Wethington, et. al, (2022)[6] and Wethington, et. al, (2024)[7]. Additionally, thesis work carried out by Oklahoma State University focused on detailed characterization of the Paluxy Formation and its suitability as a large-scale CO_2 storage opportunity (Urban, 2020)[8].

Cores from the MPC 01-1 and 19-1 wells were photographed and described, and samples were selected for analysis. The cores were retrieved from a variety of confining beds and reservoir units in the Paluxy Formation and Washita-Fredericksburg interval, as well as the upper Tuscaloosa Group. Findings are largely consistent with those from the earlier phase of this research. Confining beds are largely red mudstone with sedimentary features typical of paleosols. The major confining bed in the upper Washita-Fredericksburg interval is more strongly calcic and contains more desiccation structures than the other paleosols, which are dominated by burrow and root structures. Sandstone reservoir units resemble those in the other cores and are mainly medium grained sandstone with

[6] Wethington, C., Pashin, J., Wethington, J., Esposito, R., and Riestenberg, D., 2022. "Mudstone Baffles and Barriers in Lower Cretaceous Strata at a Proposed CO_2 Storage Hub in Kemper County, Mississippi, United States." Frontiers in Energy Research, Vol. 10, Article 904850.
[7] Wethington, C., Pashin, J., and Bynum, J., 2024. "Characterization of a marine mudstone confining unit at a proposed CO_2 storage hub: Kemper county energy facility, Mississippi, USA." International Journal of Greenhouse Gas Control, Vol. 133, Article 104093.
[8] Urban, S. 2020. Geologic Characterization of Cretaceous Sandstone at the Kemper County Energy Facility, Mississippi: A World-Class Site for CO_2 Storage. [Unpublished Master's Thesis]. Oklahoma State University.

abundant cross-bedding. These sandstone units are interpreted to have been deposited in sandy bedload-dominated fluvial systems.

Well logs from the three new exploratory wells have been interpreted and correlated with those from Project ECO_2S Phase II. A new stratigraphic cross section has been constructed that shows the stratigraphic architecture and facies heterogeneity in the reservoir units and confining strata. This has greatly increased knowledge of the thickness and continuity of candidate sinks and seals at the energy facility. RCA of sandstone from the MPC 19-1 well has been incorporated into the dataset developed during Phase II. These data confirm earlier findings that the mean sandstone porosity is 28.5% and geometric mean permeability is 3.58 D, indicating exceptional reservoir properties. Pulse decay permeability tests on mudrock samples from the Washita-Fredericksburg interval indicate that permeability ranges from 9 to 900 nD and that values between 20 and 30 nD are typical. Accordingly, the mudrock beds in the Storage Complex have exceptional confining properties.

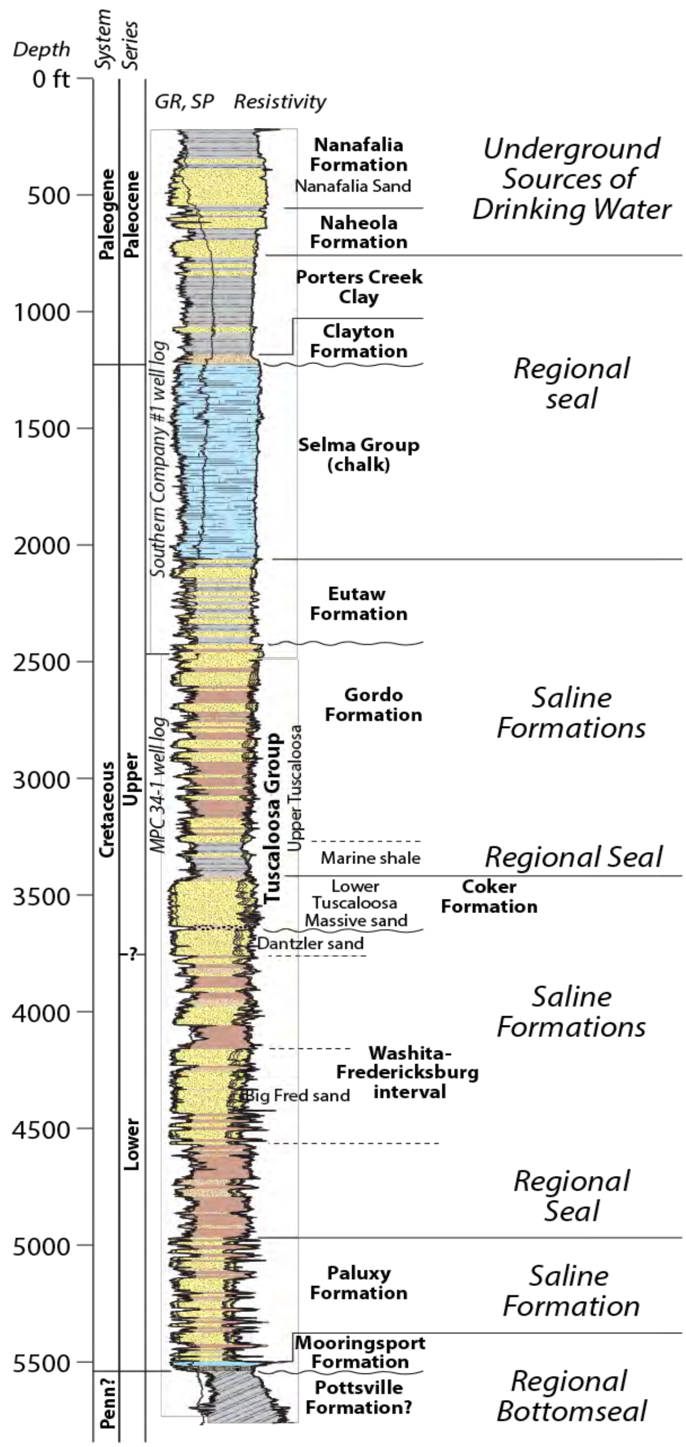


Figure 49 *Composite geophysical well logs showing distribution of reservoirs, seals, and USDWs at the Kemper County Energy Facility (after Pashin et al., 2020).*

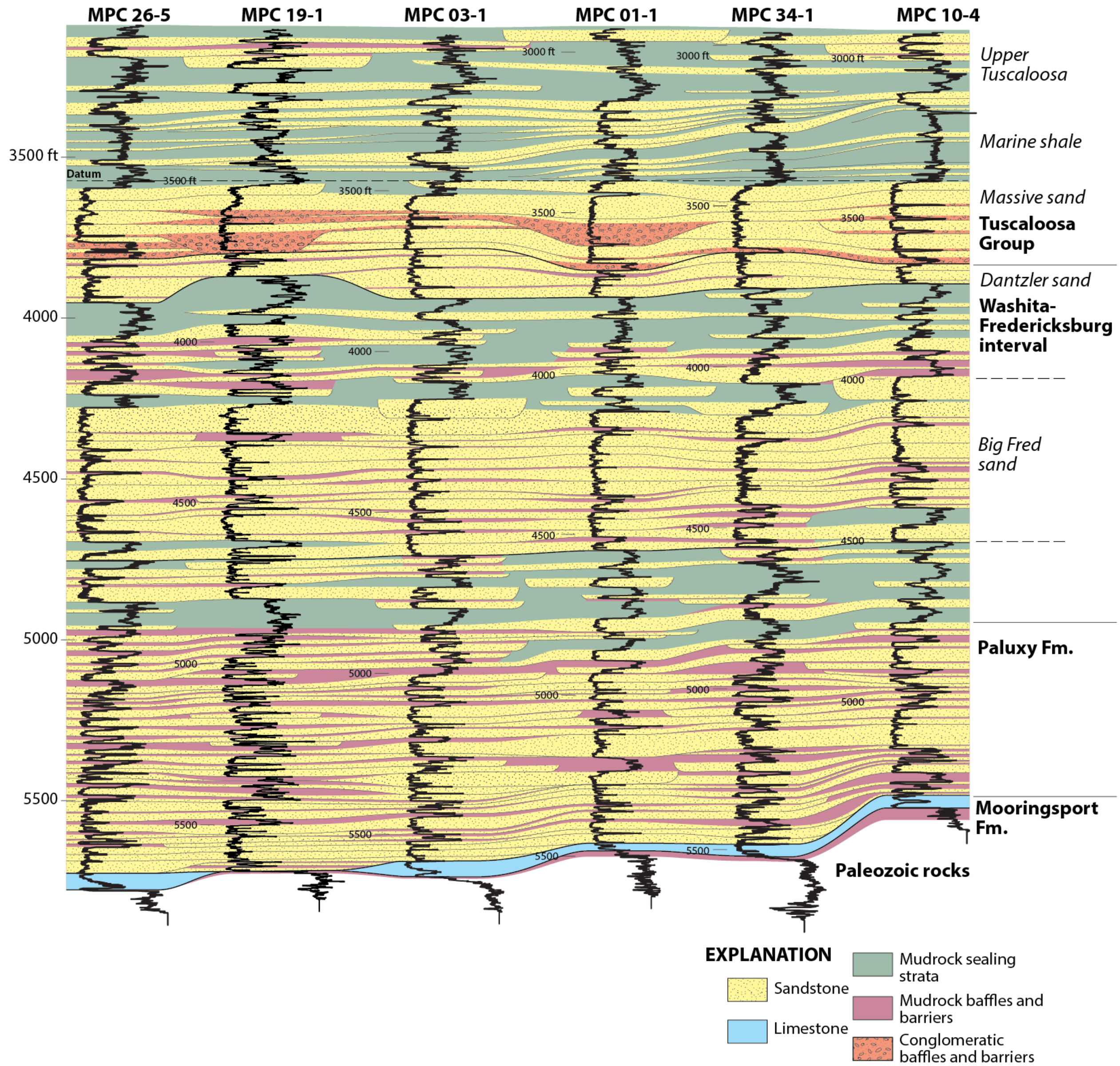


Figure 50 *Stratigraphic cross section showing correlation of well logs in Cretaceous strata at the Kemper County Energy Facility and the architecture of sandstone reservoirs and confining mudstone units (after Pashin et al., 2022).*

Analyses of reservoir stacking, facies patterns, and permeability indicate that the storage field contains a complex system of reservoirs, baffles, barriers, and seals. Individual sandstone units within the Paluxy Formation and Washita-Fredericksburg intervals are separated by baffles and barriers that will help confine CO_2 within the target reservoirs, and discontinuity of the baffles and barriers will result in areas where plumes may migrate into superjacent sandstone units. Barriers and sealing layers are abundant in the basal Washita-Fredericksburg and upper Washita-Fredericksburg intervals, and the widespread sealing layers are predicted to confine nearly all injected CO_2 within the Storage Complex. As illustrated in **Figure 51**, the Marine Tuscaloosa shale is a regionally extensive confining interval, and only minor amounts of fugitive CO_2 would be expected to reach the Marine Tuscaloosa. Any fugitive CO_2 would be absorbed by thin sandstone layers in the secondary confining intervals and, in the unlikely event that fugitive CO_2 would reach the top of the Marine Tuscaloosa, that CO_2 would be sealed by a regionally extensive mudstone unit that forms the base of the upper Tuscaloosa Group. Accordingly, it appears that commercial volumes of CO_2 can be injected into Paluxy and Washita-Fredericksburg strata with minimal risk to USDW in the Eutaw, Naheola, and Nanafalia Formations.

Subtask 6.3 – Reservoir Modeling

The refined geologic model developed in Subtask 6.2 was used to develop a series of CO_2 injection simulations to estimate the behavior and areal extent of the CO_2 plume and the extent of the associated pressure front during and after CO_2 injection. These computational reservoir models draw on existing subsurface data obtained from the stratigraphic test wells and analyses of extracted core, 2D seismic surveys, and the results of the injection tests conducted in the saline reservoir. The Computer Modeling Group's reservoir simulator, GEM™, was used for all the simulation work conducted in support of this permit application. GEM™ is an industry standard Equation of State reservoir simulator for compositional, chemical, and unconventional reservoir modeling that is fully capable of accurately modelling the long-term effects of CO_2 injection into saline reservoirs.

In Phase II, modeling scenarios were developed to understand how the AoR may change with target cumulative storage volumes increasing significantly over 50 MMT and up to 675 MMT. These simulations employed stochastic modeling techniques to ascertain key performance parameters that impact (positively and negatively) the storage volume and AoR and explore the efficacy of using up-dip water injection ("water curtain") to more rapidly immobilize and contain these ultra-large CO_2 plumes.

During Phase III, the Project Team modeled CO_2 injection volumes to support the generation of a UIC Class VI permit reservoir AoR simulation. The final reservoir model is 32.2 mi in the dip direction and 26.5 mi along strike, covering an area of more than 850 mi^2 (545,000 acres). The injection interval, the Paluxy Formation, is approximately 5,000 ft in depth at the proposed injection location. Total injection interval thickness is approximately 563 ft in thickness with porosity ranging from 15.3-29.8% and horizontal permeability ranging from 545-4,120 mD. Vertical heterogeneity is incorporated into the model by varying layer properties in accordance with the interpreted well log and core data. Shale baffles exist within the Paluxy Formation, which limit the vertical migration of CO_2. Geological characterization indicates the Paluxy Formation is regionally extensive, and thus an open boundary condition was utilized for all modeling scenarios. For more information on the reservoir parameters and model construction, including relative permeability curves, rock properties, and capillary pressure, refer to the Conceptual Model Plan submitted as part of the Class VI UIC Permit Application. The Conceptual Model Plan is available as Appendix 10.

The injection interval is considered to be normally pressured and uses an initial pressure gradient of 0.427 pounds per square inch (psi) per foot (psi/ft), based on seven metrics summarized in section 2.1.6 of the Conceptual Model Plan. Bottomhole injection pressure is limited to 2,900 psi, which is 90% of the 0.65 psi/ft fracture gradient at 5,000 ft. The threshold pressure was calculated in accordance with the approach described in section 3.4.1 of EPA's UIC Class VI Well Area of Review Evaluation and Corrective Action Guidance. The calculated value of 89 pounds per square inch absolute (psia), which is only reached at the beginning of injection, attributes to an increased saturation of the non-wetting phase and quickly relaxes as relative permeability conditions become more favorable near the wellbore. This increase in pressure is only observed near the injection wellbore and does not extend significantly into the reservoir or pose any threat to penetrating the regional confining zone. **Figure 51** illustrates the pressure differential change around the MPC 19-2 injection well, which stabilizes around 80 psia during injection.

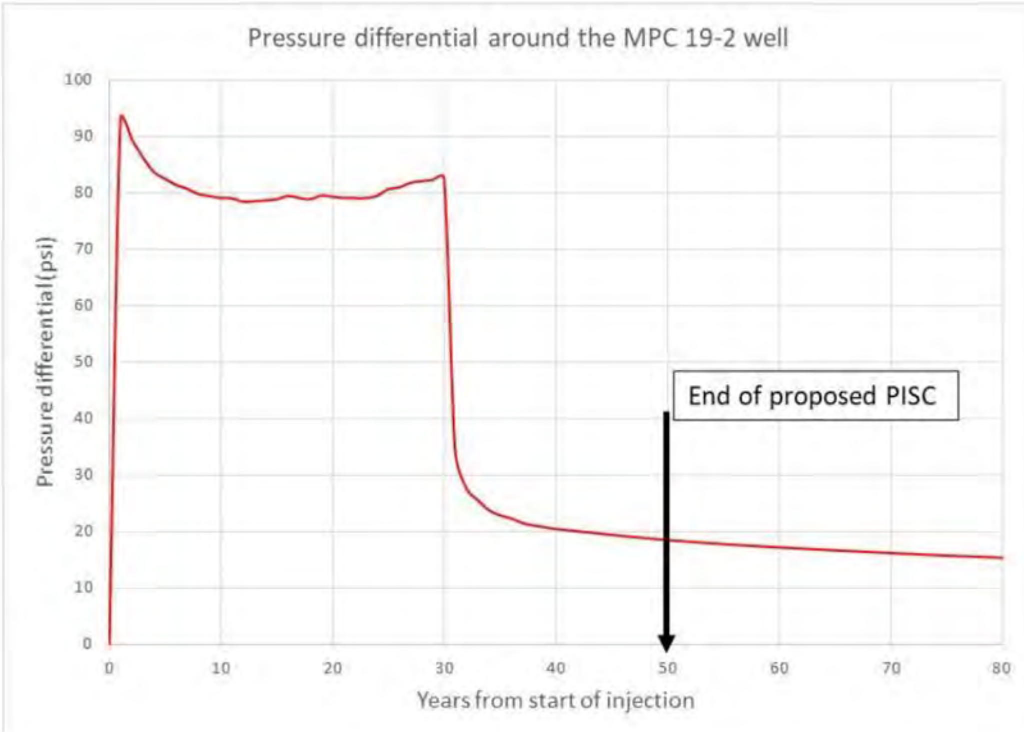


Figure 51 *Pressure differentials around the MPC 19-2 injection well in the upper Paluxy.*

To meet project goals, two injection wells (MPC 19-2 and MPC 32-1, **Figure 26**) were planned to inject 3,890 metric tons per day (approximately 75 million standard cubic feet per day, or MMscfd) per well of CO_2 for 30 years for a potential total of approximately 85 MMT of stored CO_2. The AoR is delineated by the free-phase CO_2 plume, as opposed to the critical pressure threshold, which is demonstrated by the lack of pressure build-up in the high permeability environment of the injection interval as demonstrated in **Figure 51**. The CO_2 plume migrates vertically upward and up-dip but is baffled by the interbedded shale layers as well as the regional confining unit at the top of the injection interval. An image showing a 3D view of CO_2 saturation at the end of the simulated 30-year injection period is shown in **Figure 52**, where the up-dip migration and separation of sand packages within the Paluxy Formation can be observed. Further imagery on the pressure plume and free-phase CO_2 plume are given in the AoR and Corrective Action Plan which is available as Appendix 11. Key reservoir parameters that may impact plume movement, such as horizontal permeability, porosity multipliers, and shale baffle transmissibility were investigated for Sensitivity Analysis detailed in Section C of the Post Injection Site Care and Site Closure Plan (PISC-SC) (Appendix 12). Plume area calculated from the Sensitivity Analysis varies from 13-23 m^2, compared to 16 mi^2 for the base case. Overall, simulations indicate that the CO_2 plume movement is well-defined given the substantial regional data collected, behaves in a predictable manner, and confining units demonstrate the ability to contain CO_2 within the injection interval, diminishing the risk to upward migration into overlying USDW.

A paper, *Building the Permit for the First Carbon Storage Hub in the United States*, written by Partners in support of the Project ECO_2S UIC permitting is provided in Appendix 13.

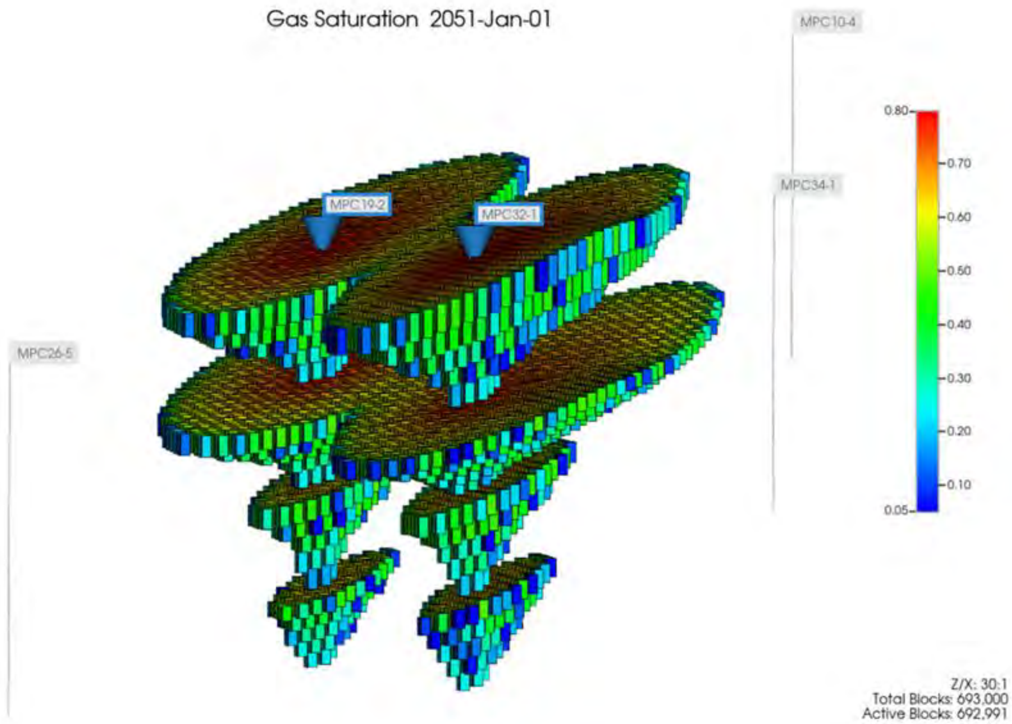


Figure 52 *3D View of CO_2 saturation at the end of the simulated 30-year injection period*

Subtask 6.4 – 3D Seismic Processing and Interpretation

Throughout BP1, the Project Team worked on the interpretation of the pseudo-3D seismic survey. Horizons for Paleozoic Unconformity, Paluxy Formation, Tuscaloosa Group, Eutaw Formation, Selma Chalk, and Porters Creek Clay have been picked and correlated on all 17 2D-seismic lines (**Figure 53**). True vertical depth (TVD) structure grids were created and further refined with the incorporation of data provided from formation correlations obtained from the stratigraphic test wells. The development of these structure grids provided the Project Team with a more detailed understanding of the subsurface geology present across the Kemper County Storage Complex. The development of accurate subsurface models provides the ability to produce more refined and accurate reservoir simulations.

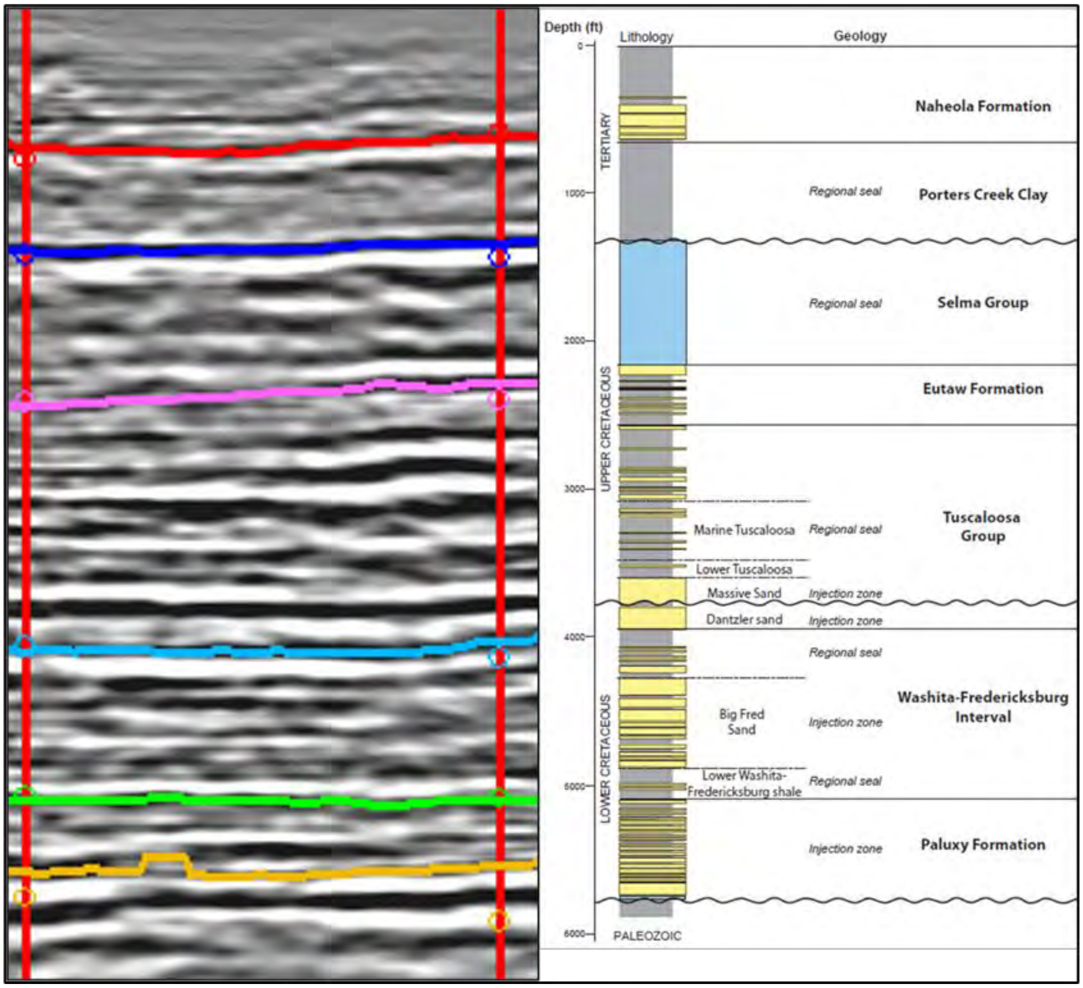


***Figure 53** Comparison of stratigraphic column with picked horizons from 2D seismic lines.*

Subsurface images were generated by the seismic survey to visualize the injection zones that will be used for CO_2 storage. GSA interpreted the 2D survey data. The processing results suggest that the Multi-2D data (see Subtask 5.2) was of high quality and there is no appearance of structural hazards beneath the Project ECO_2S storage site. **Figure 54** shows an interpretation of one 2D line that intersects the MPC 19-1 well location. The lack of structural interruption of any units above the Paleozoic unconformity is apparent.

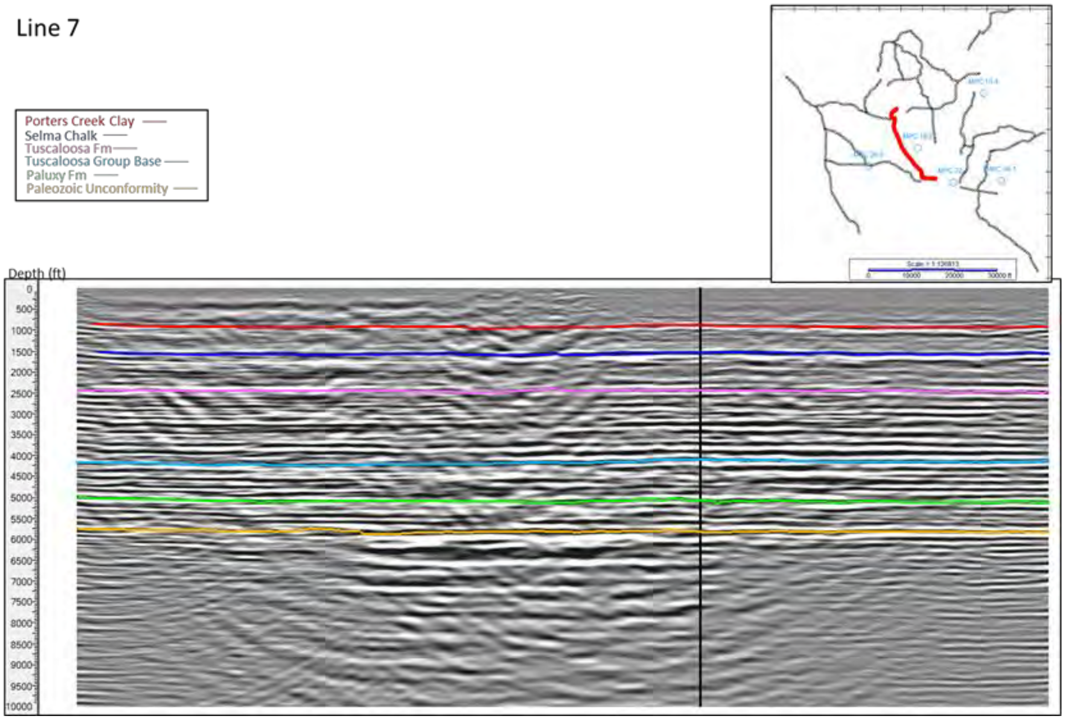


Figure 54 *An interpretation of one 2D line that intersects the MPC 19-1 well location*

Subtask 6.5 – *DeepLook* Study

The *DeepLook* Study was not conducted. The original Subrecipient who planned to perform the work withdrew from the project. Their replacement was prepared to sign a contract to perform the work, but MPC's decision to suspend work, as described in Subtask 1.5, prevented SSEB from executing the contract.

Task 7.0 – CO_2 Capture Assessment

Task 7 involved a detailed pre-feasibility assessment of CO_2 capture and transport infrastructure in support of commercial-scale storage associated with Project ECO$_2$S. The analysis focused on two power generation facilities identified as potential CO_2 sources:

- James H. Miller Jr. Electric Generating Plant (a coal-fired facility in Jefferson County, Alabama), and
- Plant Ratcliffe (Kemper County Energy Facility) (a natural gas-fired facility in Kemper County, Mississippi).

Together, these plants offered a representative cross-section of flue gas characteristics relevant to carbon capture technology design. The work included screening potential CO_2 sources, evaluating capture rates, and conducting conceptual designs for carbon capture systems capable of achieving at least 90% capture efficiency. A technical Basis of Design was established for both units, incorporating site-specific data such as flue gas flow, cooling capacity, and energy demand.

In addition, supporting systems and infrastructure were analyzed, including flue gas supply and pre-treatment, steam and cooling requirements, CO_2 compression and dehydration, and pipeline transport to proposed injection sites. Permitting considerations and environmental factors were also identified. The results of this task informed the overall feasibility, design, and planning for a scalable Carbon Capture and Storage (CCS) network integrated with these source facilities.

Furthermore, MPC's natural gas combined cycle (NGCC) facility at Plant Daniel in Moss Point, MS, was the subject of a separate DOE-funded (DE-FE0031847) FEED study led by Southern Company Services (SCS).

Facility locations are provided in **Figure 11**. The roles of contributing Partners to this task are outlined in **Table 10**.

***Table 10** Roles and responsibilities of Task 7 contributing Partners*

	Task Description	SSEB	CCS Knowledge Centre	MHIA	Stantec
1	**Reporting**				
1.1	Techno Economic Assessment / Cost of Capture	DR	P	IS	IS
1.2	Final Pre-Feasibility study report	DR	P	IS	IS
1.3	Quarterly Progress Reports	DR	P	IS	IS
2	**Project Management**				
2.1	Procurement of Services / Vendors	P	DR	DR	DR
2.2	Services / Vendor Contract Management	P	DR	DR	DR
2.3	Project Integrated Schedule	DR	P	IS	IS
2.4	Project Progress Measurement	DR	P	IS	IS
2.5	Action Items List	DR	P	P	P
2.6	Decision Log	DR	P	P	P
3	**Basis of Design Document**				
3.1	Site specific conditions	P	DR	DR	DR
3.2	Ambient Conditions		P	DR	DR
3.3	Current Flue Gas Composition	P	DR	DR	DR
3.4	Current fuel composition	P	DR	DR	DR
3.5	Current cooling capacity and availability of excess capacity	P	DR	DR	DR
3.6	Define Environmental Considerations related to carbon capture	DR	P	IS	IS
3.7	Define Current Environmental Requirements	P	DR	DR	DR
3.8	Construction Permitting Requirements	P	DR	DR	DR
3.9	Design Standards to be applied	P	DR	P	P
4	**CO_2 Capture Train**				
4.1	Flue Gas Pre-Treatment	IS	DR	P	DR
4.2	**CO_2 capture system**	DR	DR	P	DR
4.2.1	*Process area descriptions*		DR	P	DR
4.2.2	*Block flow diagrams*		DR	P	DR
4.2.3	*Process flow diagrams*		DR	P	DR
4.2.4	*Heat and material balances*		DR	P	DR
4.2.5	*Major Equipment List*		DR	P	DR
4.2.6	*Utility Consumption Summary*		DR	P	DR
4.3	*CO2 Compression*		DR	P	DR
5	**Balance of Plant**				
5.1	Flue Gas Supply, Gates, Dampers, Seal air	IS	DR		P

5.2	Heat Rejection Additional and Integration to existing unused capacity	IS	DR	IS	P
5.4	Heat Cycle Analysis		P	P	
5.5	Regeneration Steam Supply / Turbine Extraction	IS	P	IS	P
5.6	Reclaimer Steam Supply		DR	IS	P
5.7	Condensate Return		DR	IS	P
5.8	Flue Gas Heat Recovery Feasibility		DR	IS	P
5.9	Conceptual Site Arrangement		DR	IS	P
5.10	Civil Site Preparation and Grading		DR	IS	P
5.11	Demolition		DR	IS	P
5.12	Foundations, Structures and Buildings	IS	DR	IS	P
5.13	Water Treatment		DR	IS	P
5.14	Solid Waste Handling		DR	IS	P
5.15	Service and Instrument Air		DR	IS	P
5.16	Waste Water Treatment		DR	IS	P
5.17	Fire Protection		DR	IS	P
5,18	Electrical Supply and Distribution	IS	DR	IS	P
5.19	BOP Plant Control and Monitoring		DR	IS	P
6	**Deliverables**				
6.1	Prepare preliminary Process Flow Diagrams including Heat and Material Balances and BOP Electrical Single Line Diagrams		DR/P	P	P
6.2	Prepare Preliminary Conceptual General Arrangement Drawings		DR	P	P
6.3	Prepare BOP Major Equipment Data Sheets and Capture Equipment Lists		DR	P	P
6.4	Prepare Capital and OM&A Cost Estimates		DR	P	P
6.5	Techno-Economic Assessment / Cost of Capture	DR	P	IS	IS

Definitions	
P	*Performer*
DR	*Deliverable Recipient*
IS	*Information Source*

The CO_2 capture assessment reports for Plant Ratcliffe and Plant Miller were completed and submitted by Southern Company Services and the CCS Knowledge Center (CCSKC), respectively. SCS also compiled and submitted a summary report detailing findings from the separately funded FEED study at Plant Daniel from project DE-FE0031847. These reports outlined the basis of design for respective carbon capture technologies selected, outlined the necessary permitting considerations for a project of this scope and scale, described the major equipment required for the carbon capture system, and considered the balance of plant requirements as well. The Plant Daniel FEED considered the Linde-BASF post-combustion capture technology while Plant Ratcliffe and Plant Miller employed the MHIA KM-CDR process.

Given the confidential nature of the data related to Task 7 work and results, only summary information is provided in the Subtask descriptions below. Please reference Deliverable 7.0, CO_2 Capture Feasibility Assessment, for detailed findings of the CO_2 capture assessments. Deliverable 7.0 was submitted to NETL on August 31, 2022, and is provided as Appendix 14, which also satisfied Milestone 7.0, Complete CO_2 Capture Feasibility Assessment.

Subtask 7.1 – Potential CO_2 Source Screening and Selection

With a CO_2 storage goal of 675 MMT, the required CO_2 injection volumes are 20-30 MMT per annuum. Three power plants were initially identified as CO_2 sources: (1) gas units at Kemper County Energy Facility (Kemper, MS); (2) gas units at Plant Victor J. Daniel Electric Generating Plant (Moss Point, MS), which was awarded a DOE-NETL FOA-2058 FEED study for post combustion capture from the gas units; and (3) coal units at the James H. Miller Jr. Electric Generating Plant (Jefferson, Alabama).

A range of flue gas properties from each unit were quantified using stack testing and used as the basis for the pre-feasibility studies. Two representative units, one gas and one coal, were selected and evaluated as base cases to assess the capture technology design for both flue gas types. The capture plants were designed for a 90% or greater capture rate to maximize the volume of CO_2 captured.

To support the team's work on this task, Southern Company provided the team with requisite information about the existing emissions and expected amount that could be captured and transported. Trimeric participated in design discussions led by Southern Company and prepared a preliminary model of the pipeline to estimate pipeline diameter and to evaluate the need for pump stations.

Subtask 7.2 – Selecting Engineering Contractor for Engineering Services

A battery limit between the technology vendor and the plant owner was defined. Along with the CCSKC, the CO_2 technology vendor, MHIA provided required flue gas inlet conditions, cooling requirements, demineralized water requirements, regeneration energy (steam) requirements, and auxiliary power requirements for their systems based on the size of the capture facilities. Stantec Consulting's engineering services were required for engineering design and costing of items outside of the capture technology vendor(s) scope. Utility usage rates for each item were determined.

Subtask 7.3 – Establish Basis of Design

A Basis of Design document for the two selected units was prepared. This document includes power station loading, site conditions, flue gas properties, and cooling type and capacity. Results of flue gas stack testing combined with the prescribed flue gas inlet requirements from the CO_2 capture technology vendor(s) determined flue gas pretreatment requirements, which included particulate removal, desulphurization, and flue gas cooling.

Deliverable 7.3, Basis of Design, was completed on September 21, 2022, and submitted to NETL. The file is provided as Appendix 15.

Subtask 7.4 – Permitting Considerations

Permitting requirements pertaining to state CO_2 regulations, water rights, air emissions, and land rights were identified. In both Mississippi and Alabama, the local state environmental agency would be the regulatory authority for both air and water. For both of those permits, the design basis for the carbon capture unit would indicate the potential impacts to the emissions of these sites and would inform the level of analysis required to modify existing permits or obtain a new permit. Air emissions could be impacted by detailed design beyond the pre-FEED design assessment conducted as part of this project and so the eventual pathway cannot be determined exclusively.

Subtask 7.5 – Flue Gas Supply System

A flue gas supply system is required to intercept and transport the flue gas from the existing stack to the inlet of the flue gas pre-treatment process. In the Plant Daniel FEED, the layout of the flue gas supply system was designed to include three-way vertical shaft intercept dampers at the stack breaching, ducting, and a guillotine gate in the common duct for double block and bleed requirements. SCS expected that a similar design of the ducting and stack penetration could be applied to Plant Ratcliffe.

For Plant Miller, SSEB previously defined flue gas parameters; Stantec defined interconnection point and configuration, connection to capture plant, developed material takeoff, equipment list and cost estimate.

Subtask 7.6 – Flue Gas Pre-Treatment Process

Flue gas treatment currently exists at the proposed power plants. The need for additional flue gas pretreatment such as particulate removal, additional desulphurization, and flue gas cooling was determined by comparing the current temperature and composition analysis of the flue gas exiting the power stations against the flue gas requirements specified by the CO_2 capture technology vendors. The combined cycle power plants, Plant Daniel and Plant Ratcliffe, only require cooling of the flue gas via a direct contact cooler prior to the absorber. The coal plant, Plant Miller, will require deep flue gas desulfurization, meaning the direct contact cooler would additionally be designed for sulfur removal.

Subtask 7.7 – Regeneration Energy Source Evaluation

The team evaluated energy requirements of the selected CO_2 capture technologies that dictate steam specifications for solvent regeneration. There are two options for sourcing this energy; steam extraction from the power station's turbine or the addition of a purpose-built auxiliary steam generator. For the fully integrated steam supply, work focused on examining the location of the stream extraction point and determining the tie in location of the condensate returning from the capture island. For the auxiliary steam supply, work focused on sizing the auxiliary steam generating facility, consulting with technology vendors for supply and costing, and accounting for interconnections between the capture and generating facilities. For Plant Miller and Plant Ratcliffe, extraction from the existing steam system was determined to be the most economic option, as was the case with the Plant Daniel FEED.

Subtask 7.8 – Additional Cooling Capacity

Addition of a carbon capture facility increases the cooling requirements of the power plant by approximately 50%. Current excess heat rejection capacity at the power plants were determined. Using excess capacity attained by offloading the condenser (in the case of an integrated steam extraction for regeneration energy) was evaluated, and the feasibility of additional water draws and/or use of flue gas moisture condensate was assessed. However, modifying the existing cooling loop is challenged by mismatched conditions for carbon capture condensate and existing steam cycle condenser cooling needs. Forced draft cooling tower additions were assumed for both Plant Miller and Plant Ratcliffe, as also was determined in the Plant Daniel FEED.

Subtask 7.9 – CO_2 Compression and Dehydration

The compression and dehydration system was sized based on the volume of CO_2 processed and the desired pipeline delivery pressure and moisture content. Required compression pressures for the respective locations were determined by the pipeline lengths and characteristics between the proposed CO_2 sources and injection location.

Subtask 7.10 – CO_2 Pipeline Infrastructure

Pipeline capacity was designed based on anticipated CO_2 volumes. Pipeline design was created to abide by construction codes and follow all required environmental specifications including installation of monitoring equipment. Routing and tie in locations of the pipelines from the power plants to a central pipeline network for efficient delivery of the CO_2 to the proposed injection sites were determined.

Subtask 7.11 – Balance of Plant

Balance of plant tasks included miscellaneous activities such as utilities, water and air, material, waste handling, and environmental impact. For this work package, the scope included materials handling, waste disposal, water supply, water treatment facilities, demineralized water supply, and plant air/instrument air supply.

Task 8.0 – Project Integration

Subtask 8.1 –CO_2 Delivery and Well Infrastructure Needs

In July 2022 advancing the project to meet CarbonSAFE Phase IV requirements, SSEB began work with Trimeric and ARI to develop a SOW for a pipeline FEED study based on DOE's FEED elements as outlined in FOA 2711 for CarbonSAFE III.5. Trimeric discussed this SOW with an engineering design company and obtained budgetary quotes for the FEED study work for a pipeline to transport CO_2 from Plant Ratcliffe to the Storage Complex (approximately 5 miles). The quotes ranged from $300,000 for a low-effort study to $1.5 million for a robust, comprehensive FEED. Project Consulting Services, Inc. (PCS) was contracted to prepare a pipeline FEED study to convey CO_2 from Plant Ratcliffe to the Kemper storage facility.

A desktop review was performed to identify a conceptually feasible pipeline route to measure, transport, and distribute dense phase CO_2 from Plant Ratcliffe. The review consisted of assessing the environmental, design, and constructability aspects from a high level. Pipeline alignment was evaluated with an associated high-level total installed cost, project schedule, permit matrix, risk factors, relevant maps, and explanatory narrative for ARI's consideration in advance of a more detailed evaluation.

The initial evaluation considered transport of CO_2 from Plant Ratcliffe to the Storage Complex in a single pipeline with a network of laterals that would distribute the CO_2 to two injection wells. The Pipeline FEED Map in **Figure 55** shows the location of the two prospective injection well locations, MPC 19-2 and MPC 32-1, and the potential pipeline routes. The pipeline FEED study focused on just the first two injection wells but was designed to accommodate future expansion.

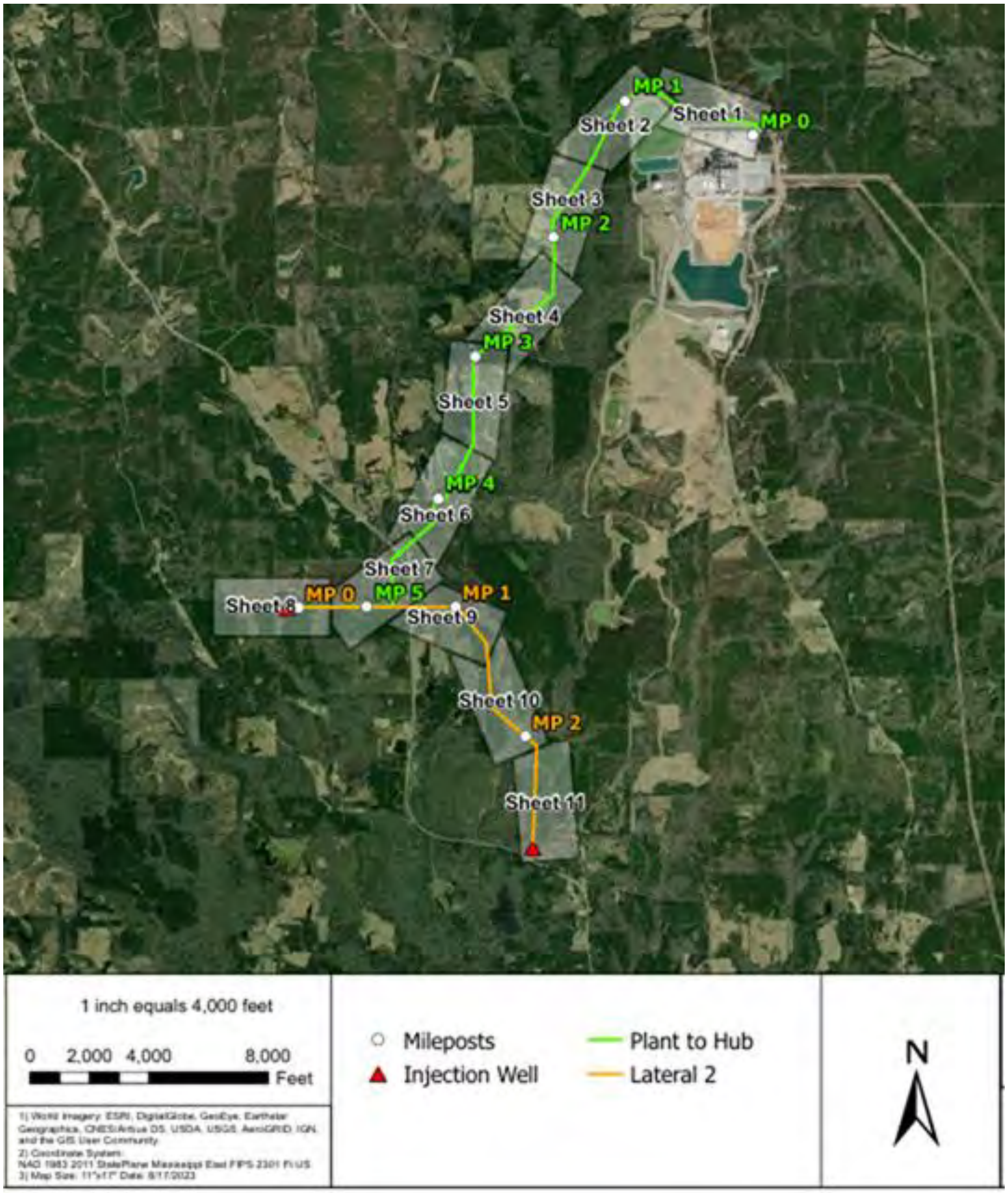


Figure 55 *Pipeline FEED Map*

On September 8, 2023, the PCS, Trimeric, ARI and CRI participated in a Process Hazard (HAZOP) Analysis for the pipeline.

On December 7, 2023, Trimeric submitted the HAZOP report and the FEED report for the Kemper pipeline and surface facilities to SSEB for review. SSEB submitted/uploaded the report on June 3, 2024.

Subtask 8.2 – Pore/Surface Rights and Right of Way Requirements

In March 2024, Mississippi Power withdrew its permit application for two Class VI wells at EPA Region 4 due primarily to regulatory uncertainty. As a result of this action, Subtask 8.2 became obsolete, and no work occurred in support of the Pore/Surface Rights and Right of Way requirements.

Subtask 8.3 – Financial and Contractual Model(s)

In March 2024, Mississippi Power withdrew its permit application for two Class VI wells at EPA Region 4 due primarily to regulatory uncertainty. As a result of this action, Subtask 8.3 became obsolete, and no work occurred in support of the Financial Contractual Model(s).

Task 9.0 – UIC Permitting

The Project Team utilized the results of the characterization and reservoir modeling work conducted during Phases II and III of the project to assemble and submit a UIC Class VI Permit to Construct application to EPA Region 4. The objective was to obtain a Permit to Construct for two injection wells that would deliver CO_2 to the identified storage interval of the Paluxy Formation through two proposed injection wells by the end of the Phase III performance period. The Project Team began the writing process for the permit application in the 2nd quarter of 2022. Application documents were drafted in accordance with the EPA guidelines for submitting a UIC Class VI application and covered all aspects of the project, including geologic site characterization, numerical modeling, well construction, development of a monitoring plan for both active and post-injection phases, implementation of a quality assurance plan, financial assurance, and post-injection site closure.

The permit application for the MPC 19-2 injection well was submitted in October 2022. The Project Team addressed a Notice of Deficiency (NOD) provided by EPA Region 4, with responses returned in January 2023. The permit application was then deemed to be Administratively Complete and entered the Technical Review phase. The Project Team then began to work on the construction of a second permit application for the additional proposed injection well, MPC 32-1. However, after continuing dialog between the Project Team and EPA Region 4, it was determined that since both of the planned injection wells share the same AoR, only one permit application would be needed for the project.

With the notice that only one permit application would be needed, the Project Team made modifications to the original permit application submitted for the MPC 19-2 injection well to include the necessary information accounting for the proposed MPC 32-1 injection well. This version of the permit application was then submitted in March 2023. An NOD was received in April 2023, to which the Project Team provided responses in May 2023. The application permit was then determined to be administratively complete, and the Technical Review period was initiated by EPA Region 4.

A Request for Additional Information (RAI) was received by the Project Team in August 2023, which initiated a series of communications with EPA Region 4. The Project Team answered specific questions pertaining to the development of numerical simulations and reservoir models and provided further details. These discussions continued through February 2024, when a second RAI was issued to the Project Team. While work had begun to address this, the decision was made by MPC to withdraw the permit application. Because of this, the Project Team ceased efforts to address the latest RAI from EPA Region 4. Please refer to Subtask 1.5 for additional information regarding the MPC decision.

Deliverable 9, Application for Underground Injection Control Class VI Permit to Construct, was completed on August 31, 2022. Deliverable 9 verified achievement of Milestone 9, Submit UIC Class VI Permit to Construct Application. The application submission memo is available as Appendix 16.

Subtask 9.1 – Project Description and Site Characterization

A rigorous description of the project was assembled for the UIC Class VI application. This included administrative information, such as the proposed well location(s) and an overview of the proposed project, a detailed description of the geology, including natural and induced seismicity, numerical modeling inputs and results, and the AoR and corrective action plan.

Project Description

The Kemper County Storage Complex was hosted through the coordinated efforts of MPC and Southern Company. The project was managed by the SSEB and ARI. Collectively, the Project Team was working toward the development of a regional CO_2 Storage Complex in Kemper County, Mississippi, adjacent to the MPC Plant Ratcliffe facility. Characterization of the subsurface demonstrated an excellent storage and confinement opportunity capable of securely sequestering commercial-scale quantities of CO_2.

The plan for the project was to have post-combustion CO_2 captured from MPC's natural gas power generation unit at Plant Ratcliffe and transported through pipelines to the injection locations. In order to accomplish the projected storage volumes, the plan was to develop two injection well locations, each capable of maintaining an annual injection rate of 2.9 MMT of CO_2. The primary goals of the project are to:

- Reduce CO_2 emissions from Southern Company facilities in order to aid site hosts in meeting their commitment to a low carbon future;
- Potentially utilize captured CO_2 for enhanced hydrocarbon recovery and other business opportunities;
- Geologically store more than 50 MMT of CO_2 over a timeframe of 30 years; and
- Monitor the subsurface CO_2 movement to ensure safe, secure, and long-term geological storage.

The Kemper County Storage Complex was planned to provide a safe, secure, and long-term CO_2 storage opportunity for a substantial portion of Southern Company's emissions from power generation facilities. In future years, the Storage Complex, given the world-class reservoir characteristics and storage capacities within the saline reservoirs, demonstrated the potential to be developed into a commercial-scale storage hub linking multiple emissions sources to a single storage location.

Site Characterization

Geological site characterization was conducted during both CarbonSAFE Phase II and Phase III of the Kemper County Storage Complex project development. These efforts included the drilling of six stratigraphic test wells (three in each CarbonSAFE Phase), acquiring 290ft of core over targeted injection and confining units, a suite of geophysical logs from each stratigraphic test well, as well as the acquisition of 92 linear miles of 2D seismic.

Integration of the collected subsurface characterization data provided the Project Team a refined understanding of the reservoir conditions for the development of the Kemper County Storage Complex. This information was then utilized to populate the reservoir simulation models that provided the calculations of storage capacity and afforded the Project Team a first look at predicted CO_2 plume and associated pressure front movement extending away from the injection well locations.

The characterization work identified the primary injection and storage interval to be the Paluxy Formation. The Tuscaloosa Marine Shale would serve as the primary confining interval across the project area. Within the Paluxy Formation, several thin shaley interbeds were observed from the geophysical logs which will act as baffles, minimizing vertical migration of CO_2 within the Paluxy Formation. Several additional potential storage intervals were also identified as a result of this work, the Big Fred Sand, Dantzler Sand, and the Lower Tuscaloosa Massive Sand. For the purposes of the Class VI Permit Application, all modeling and storage resource estimation was conducted including only the available reservoir within the Paluxy Formation.

The Project Team was able to establish that the deepest USDW within the project area is the Eutaw-McShan aquifer. This lies above the primary confining interval of the Tuscaloosa Marine Shale. Additionally, several shallow freshwater aquifers were identified that lie within the near-surface Tertiary formations present at the project location. Between the shallow freshwater aquifer and the deep USDW within the Eutaw-McShan is the Selma Chalk and Porters Creek Clay which act as regional aquitards. For the purposes of designing a feasible UIC Class VI Permit Application, a strategy could be employed to continuously sample these shallow and deep aquifers to monitor for the presence of potential CO_2 leakage from the injection interval.

An analysis of the seismic history of the region was carried out using information provided by USGS publications. Central Mississippi was found to have a historically low earthquake risk as this area falls within what is considered the Stable Continental Region. Those earthquakes that have been registered are very low in magnitude and occur at irregular intervals.

Characterization efforts for the Kemper County Storage Complex have identified an exceptional CO_2 storage opportunity within the Cretaceous-aged Paluxy Formation. The Tuscaloosa Marine Shale is the primary confining interval which directly overlies the injection zone and acts as a regional confining unit throughout the Gulf Basin that is capable of preventing the vertical migration of CO_2 out of the injection interval. This low porosity (2-4%) and low permeability (< 1mD) unit is comprised of interbedded dark-gray shale, siltstone, and sandstone that modelling indicates will retain a vertical column of CO_2 of 100m before any intrusion is observed. The Paluxy Formation sandstone has a porosity that ranges from 26 – 33% and an observed permeability of 1.8 D. The lack of observed faults within the project area and low abundance of reactive minerals within the confining interval and injection interval demonstrate the suitability of this reservoir for the safe and long-term secure storage of CO_2 within the subsurface.

Subtask 9.2 – Construction and Operational Plans

Subtask 9.2 activities entailed the development of injection well construction, pre-operational testing, injection well operation, monitoring, mechanical integrity testing, and well P&A plans for incorporation into the UIC Class VI application.

The injection wells are designed to accommodate the mass of CO_2 that will be delivered to the storage site, considering key characteristics of the CO_2 storage reservoir that affect the well design.

Numerically modeled bottomhole pressure estimates were teamed with injection volumes to optimize the wellhead pressure requirements, as well as the sizes of the wellbore casing and tubulars using a commercially available nodal analysis program. Key facets of the well design include the use of a 4 ½-inch diameter injection string set on a packer within a 9 5/8-inch-long string. The tubing was designed to be entirely L-80, 13 chrome (13Cr), while the long string would be 13Cr from total depth to above the primary confining unit (about 3,000 ft) with mild steel run to surface. **Figure 56** depicts the injection well completion design. Expected wellhead injection pressure is about 1,200 psia using this well configuration.

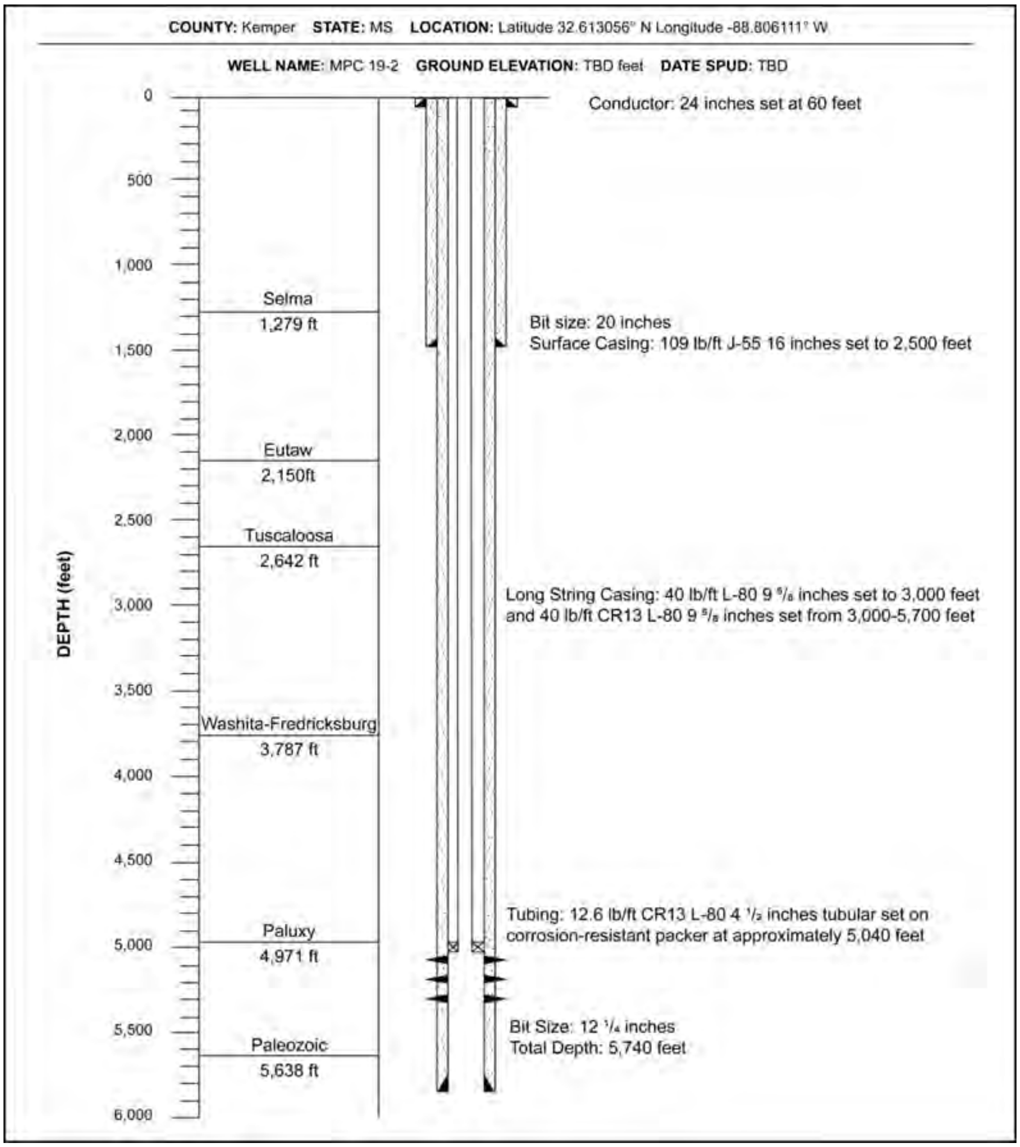


Figure 56 *Injection well completion design*

Subtask 9.3 – Site Closure and Demonstration

The PISC-SC was developed to describe the activities that would be carried out by MPC to meet the UIC Class VI Permit requirements. This plan includes an overview of computational modeling, sensitivity analysis, post-injection monitoring, and site care and closure plans that will be enacted at the end of the active injection phase of the project. The PISC-SC covers the pressure front and CO_2 plume monitoring after the 30 years of injection operations are terminated, as well as predictions on plume migration. The monitoring of groundwater quality post-injection will focus on assuring demonstration of CO_2 containment and non-endangerment of USDW.

Computational modeling of the Kemper County Storage Complex for the PISC was conducted to represent 30 years of injection and 20 years of post-injection monitoring. The rate of the CO_2 plume migration was shown to slow with time during the post-injection phase and demonstrate predictable behavior. At the end of the 20-year proposed PISC timeframe, the plume was shown to have reached 73% of its maximum size (**Figure 57**).

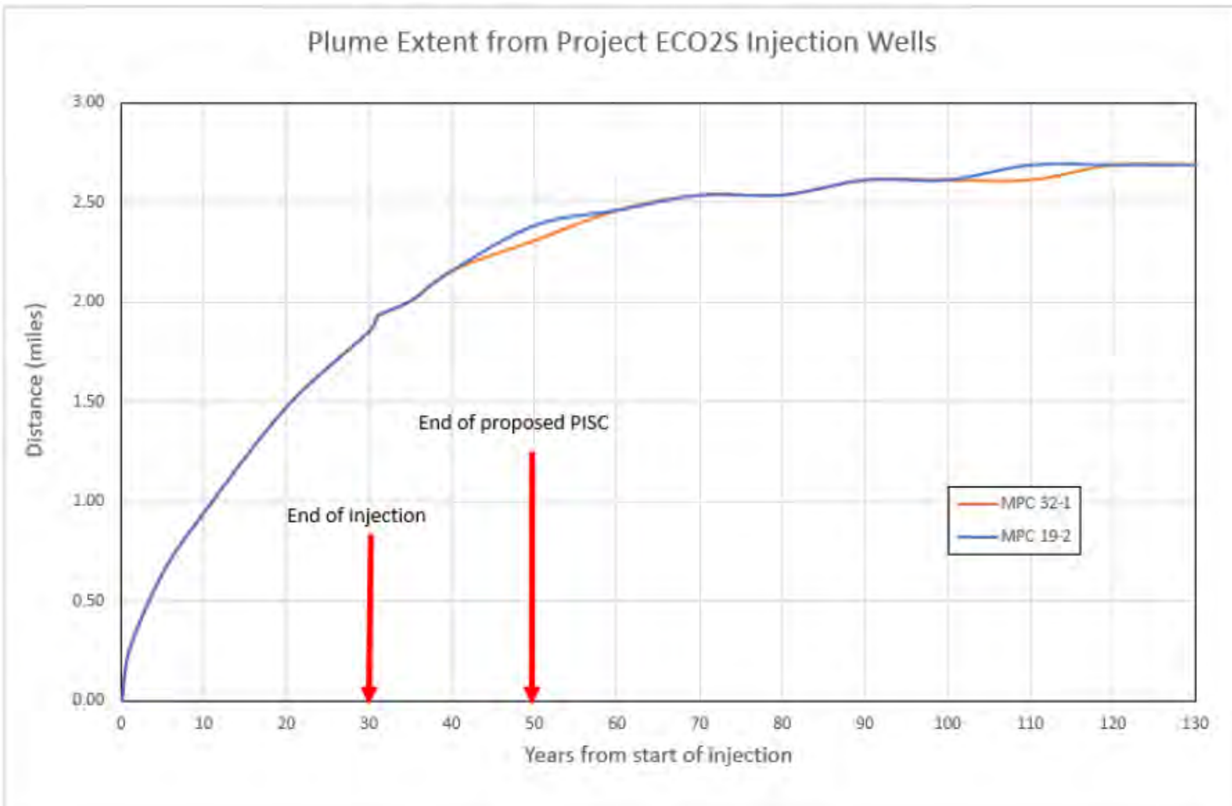


***Figure 57** Rate of CO_2 plume migration from MPC 19-2 and MPC 32-1.*

To assess the sensitivity of factors associated with the predictability of plume growth, several key reservoir parameters were evaluated to assess their impact upon the AoR (**Table 11**). In all cases, the pressure front did not expand beyond the CO_2 plume and the plume exhibited predictable behavior from 20 to 50 years post-injection, supporting this supposition.

The modeled CO_2 plume maps for each sensitivity case overlain at 20 years and 50 years is provided in **Figure 58**. The predictability of the CO_2 movement is readily apparent despite the variation of key input parameters. Further, most of the plume movement occurs prior to 20 years of post-injection time. in all cases, the modeled plume is contained well within the monitoring field, as outlined in the Testing and Monitoring Plan. Coupling these outcomes increases the Project Team's confidence in the baseline assessment and firmly indicates that a 20-year PISC-SC timeframe is sufficient to demonstrate a lack of fugitive CO_2 movement and non-endangerment of USDW.

***Table 11** 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 size was determined to be 16 square miles.*

Sensitivity Case	Base value	Sensitivity value(s)	CO_2 plume (miles^2)
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

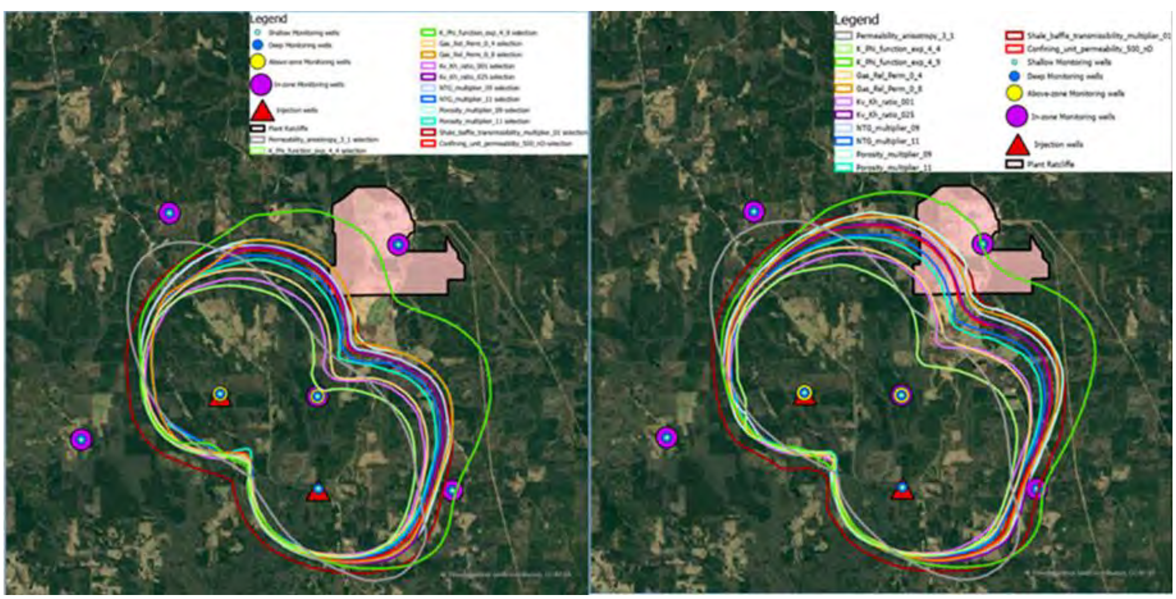


***Figure 58** Modeled CO_2 plume maps for each sensitivity case overlain at 20 years and 50 years post-injection.*

Subtask 9.4 – Public Outreach and Engagement

Subtask 9.4 was created to support the Project Team's public outreach related to MPC's UIC Class VI permit application. This activity was not initiated.

Subtask 9.5 – Address EPA Comments on Class VI Permit Application

The initial UIC Class VI Permit application was submitted in October 2022 for the MPC 19-2 injection well. It was deemed to be administratively completed in January 2023, after an NOD was provided that highlighted some missing information pertaining to model specifications that needed to be included within the EPA GSDT data upload. Since the Kemper County Storage Complex intended to utilize two simultaneous injection wells, the original plan was to submit separate Class VI permit applications for each well. However, continuing dialogue with EPA Region 4 established that, since both injectors shared the same AoR, both could be included within the same permit application. Therefore, the Project Team modified the permit application to include both the MPC 19-2 and MPC 32-1 injection wells. This application was submitted in March 2023 after addressing comments provided within an RAI that focused mostly on ensuring that consistency in nomenclature and unitization was used throughout the documents. The permit application was deemed to be administratively complete in May 2023, and the technical review phase began.

In August 2023, the Project Team received an additional RAI from the EPA's technical review team. One of the primary topics included within this communication from EPA Region 4 was related to the specific input parameters and modeling methodologies. Responses were provided by the Project Team and submitted in October 2023. However, dialogue continued as the EPA technical reviewers still had questions pertaining to the reservoir simulation models provided. Several conversations between November 2023 and January 2024 were held between the Project Team and EPA Region 4 that provided constructive feedback so that each party was clear on what input parameters and results were being sought after. Throughout January and February 2024, the Project Team worked on incorporating the requested modifications to reservoir simulation methods. Work was eventually stopped in March 2024 due to the notification from MPC that they would be pulling the permit application from the EPA review, effectively ending the technical review process. Please refer to Subtask 1.5 for additional information regarding MPC's decision.

Task 10.0 – Knowledge Dissemination and Technology Transfer

The Project Team engaged in a robust stakeholder outreach strategy to promote acceptance of the project. Highlights are provided below.

Subtask 10.1 – Community Outreach and Education

Community outreach and education was performed as needed, related to activities at all field site locations.

SSEB issued a new project announcement to its Board and Associate Members on September 17, 2020. Content was approved in advance of release by the NETL Federal Project Manager and MPC's communications team.

In the first quarter of 2021, SSEB updated its website to include Project ECO$_2$S Phase III, https://www.sseb.org/programs/eco2s.

Throughout April and May 2021, SSEB coordinated a press release with the CCS Knowledge Centre, Southern Company, and NETL.

During April 2021, a fact sheet regarding the project's geophysical surveys was developed and approved. The fact sheet was created as an educational tool for potential interactions with the public regarding the seismic data acquisition activity that occurred in June 2021 (see Subtask 5.2).

Subtask 10.2 – Regulatory Outreach

Outreach to the regulatory community was conducted as drilling permit applications were prepared and submitted to the MOGB.

On December 16, 2020, Kimberly Gray of SSEB, Richard Esposito of Southern Company, and George Koperna and Dave Riestenberg of ARI participated in a pre-meeting with DOE and other CarbonSAFE project leads regarding information exchange with EPA. The meeting facilitated briefings on the CarbonSAFE projects and EPA guidance regarding the permitting process and the GS Data Tool.

Throughout BP1, the team participated in calls with EPA headquarters and Region 4 personnel to discuss the GSDT submission process for the UIC Class VI permit application.

Subtask 10.3 – Knowledge Sharing through Conferences, Workshops, and Technical Papers

Kimberly Gray, SSEB, and Dave Riestenberg, ARI, jointly presented Project ECO_2S Phase III during the CarbonSAFE kickoff meeting on October 21, 2020. This presentation verified the completion of Milestone 10.3. SSEB updated its project website and prepared outreach materials to begin promoting the project through a variety of appropriate venues.

SSEB prepared a presentation outlining the status of its Carbon Management Program, which included recent activities related to Project ECO_2S Phase III. Kenneth Nemeth virtually delivered the presentation during the Midland CO_2 Conference on December 8, 2020.

On March 12, 2021, Dave Riestenberg (ARI) gave a presentation entitled "Large Volume CO_2 Storage in the Southeastern U.S.; Reservoir Characterization of the Project ECO_2S Storage Complex" at the American Association of Petroleum Geologists (AAPG) CCUS conference. The presentation provided an overview of the ECO_2S CarbonSAFE project, including potential capacity at the site, work to date and goals for 2021.

Jalal Jalali (ARI) presented findings from ARI's simulation work to date at the GHGT 15 meeting held on March 15-18, 2021. The presentation, "Large volume CO_2 storage and plume management in the southeastern U.S.; reservoir characterization and simulation," was an overview of the paper accepted for the GHGT 15 meeting on the reservoir simulation for Project ECO_2S.

Kenneth Nemeth, SSEB, presented "Recent Activities, New Board Members, and 2021 Elections Insights" during the SSEB Associate Members virtual meeting on April 6, 2021. His presentation included a brief overview of the project and recent activities.

On July 8, 2021, SSEB hosted its Annual Energy Briefing to Southern Legislative Leaders. Georgia State Representative Lynn Smith, who serves as the Board's Vice Chair, presided over the meeting. Numerous Legislative Leaders from Southern States participated in a roundtable discussion on legislative action in the states. CCUS was included in the discussion. Further, Kenneth Nemeth presented recent Project ECO_2S activities to the members.

SSEB's 61st Annual Meeting was held in Oklahoma City, Oklahoma, on September 28-30, 2021. The event was hosted by SSEB's Chairman, The Honorable Kevin Stitt, Governor of Oklahoma. On September 28, 2021, the Board Members convened for a meeting of its Executive Committee. During the meeting, members received project briefings from the SSEB staff. Kenneth Nemeth and Kimberly Gray presented the SSEB Carbon Management Program status, which included recent Project ECO_2S activities. On September 29, 2021, during the Board's Annual Business Session, the financial status of SSEB's CCUS programs were presented to members and all participants.

During September and October 2021, OSU delivered the following presentations:

- September, Southern States Energy Board 61st Annual Meeting, theme session on carbon capture, utilization and storage, Oklahoma City, Oklahoma;
- September, Sedimentology and CO_2 Sequestration (theme session), Society of Exploration Geophysicists and American Association of Petroleum Geologists IMAGE Conference, Denver, Colorado;
- October, Challenges and Opportunities of Carbon Capture, Utilization, and Storage (workshop), Balkan Geophysical Society Congress, hosted by the Romanian Society of Applied Geophysics (virtual); and
- October, Fundamentals of Carbon Capture, Utilization, and Storage (short course), Midcontinent Section American Association of Petroleum Geologists Annual Meeting, Tulsa, Oklahoma.

GSA presented preliminary Project ECO_2S Phase III results at the American Geophysical Fall Meeting in New Orleans on December 15, 2021.

OSU and ARI delivered a short course and presentations during the CCUS Conference, which was held in Houston, Texas, in late March 2022, including:

- Storage in Geologic Formations, by Jack Pashin and Dave Riestenberg, in Fundamentals of Carbon Capture and Storage (short course);
- Subsurface Storage Part IV (Technical Session), Mudstone baffles, barriers, and Seals in an onshore gigatonne-class Storage Complex, by Conn Wethington, Jack Pashin, and Jamar Bynum; and
- Jack Pashin also chaired the Subsurface Storage Part III session at the conference.

In October 2022, ARI presented at the SPE Annual Technical Conference and Exhibition entitled 'Building the Permit for the First Carbon Storage Hub in the United States' which detailed the process for submitting a UIC Class VI Permit Application using the Kemper County Storage Complex as an example.

The paper "Regulatory Donut Holes in the CCS Underground Injection Control Program; A Blessing or a Curse?", which was written by ARI, IOM Law and SSEB earlier in 2022, was presented at the

GHGT-16 conference by IOM Law in October 2022. In November, the paper was published on an open-source website: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286135.

Trimeric prepared a paper and a poster for submission to GHGT-16 Conference. The work is entitled "The Engineer's Guide to CO_2 Transportation Options." This poster was presented at the GHGT-16 in October 2022. DOE-NETL approved Ray McKaskle's travel to present the poster. The paper and poster include discussion of pipeline design considerations that were explored in this project.

Katherine Dombrowski of Trimeric joined a meeting hosted by Southern Company at the National Carbon Capture Center, which was attended by BSEE, BOEM, and industry partners working on carbon capture, transportation, and storage. Trimeric presented on process engineering considerations associated with CO_2 transportation by pipeline, including learnings from the ECO_2S project.

John Koster and Timmon Drumm of the Geological Survey of Alabama presented a poster entitled "Results of Pseudo-3D Seismic Interpretation Delineating Stacked Reservoir for Future CO_2 Storage at Project ECO_2S, Kemper County, MS" at the annual AGU conference in December 2022.

On February 8, 2023, the SSEB Associate Members (industry partners) convened for an annual winter meeting in Washington, DC. During the meeting, Kenneth Nemeth presented recent CCS project activities that are funded through DOE FECM agreements and project partners. This presentation included a report on Project ECO_2S.

IOM Law and ARI prepared and presented a poster for the CCUS Conference in Houston, Texas, in April 2023. The poster addressed the long-term liabilities for CO_2 storage in Mississippi. IOM Law presented the poster.

SSEB hosted its Joint Annual Energy Briefing to Southern Legislative Leaders and Committee on Carbon Management meeting on July 8, 2023, in Charleston, South Carolina. Dr. Ben Wernette, SSEB's Principal Scientist and Strategic Partnerships Lead, presented, "New Energy Ventures Benefit Southern States – Leadership in the South" that included the status of the ECO_2S project. State legislative leaders from across the Board's 18 member jurisdictions and its Associate Members (industry partners) attended the event.

Two presentations were given at the DOE Fossil Energy Carbon Management annual meeting that was held in Pittsburgh, Pennsylvania, from August 28–August 31, 2023. The first, given by Ben Roth, ARI, was a project update entitled, "Establishing an Early CO_2 Storage Complex in Kemper County, Mississippi" and provided an annual update on the project's progress over the course of the Federal fiscal year. The second presentation was entitled, "Update on Semi-Airborne, Controlled Source Electromagnetic Survey at a Potential Carbon Storage site in Kemper County, Mississippi" given by Rick Hammack of NETL. The purpose of the presentation was to provide an update on the acquisition and analysis of the aerial electromagnetic survey that was obtained for the ECO_2S project site.

GSA team presented their findings at the International Meeting for Applied Geoscience & Energy in Houston, TX, on August 30, 2023.

SSEB's 63rd Annual Meeting was hosted by South Carolina Governor Henry McMaster on September 27-29, 2023, in Greenville, South Carolina. The program included meetings of the Board's Executive Committee and Associate Members, as well as a business session and multiple plenary sessions.

The meeting included broad overviews relating to CCUS and decarbonization technologies as well as efforts to engage with legislative leaders representing the southeast. A highlight of the event was a keynote address provided by The Honorable Brad Crabtree, DOE's Assistant Secretary for FECM, on September 28. The FECM exhibit was also displayed throughout the conference, providing participants with a unique opportunity to explore FECM's vast project portfolio including activities supported throughout the SSEB region (**Figure 59)**.

***Figure 59** A group photograph at the DOE exhibit, including Tom Sarkus, National Energy Technology Laboratory; Joe Giove, Director of Business Operations in the Office of Carbon Management, FECM; Brad Crabtree, Assistant Secretary, FECM; Georgia Gov. Brian Kemp; First Lady of Georgia Marty Kemp; Dan Brouillette; and South Carolina Gov. Henry McMaster, served two years as SSEB's Chairman.*

During the SSEB Executive Committee meeting on September 27, 2023, Dr. Ben Wernette presented an update on the Board's Carbon Management Program that included Project ECO_2S.

During the Annual Board Business Session on September 28, 2023, the SSEB Treasurer, Senator Ken Yager of Tennessee, presented the Board's Financial Report for FY23 and the Budget for FY24. His presentation included a brief report on the financial aspects of all SSEB projects, including Project ECO_2S. This report was prepared by SSEB staff and reviewed with the Treasurer in advance of the meeting.

One presentation was given at the DOE FECM annual meeting that was held in Pittsburgh, Pennsylvania, from August 5-8, 2024. It was given by Dave Riestenberg, ARI, and was a project update entitled "Establishing an Early CO_2 Storage Complex in Kemper County, Mississippi". The presentation provided an update on the project's progress over the course of the Federal fiscal year. SSEB personnel Patti Berry, Dr. Ben Wernette, and Dr. Nicholas Kaylor participated in the event.

SSEB's 64th Annual Meeting was hosted by Tennessee Governor Bill Lee on September 22-24, 2024, in Chattanooga, Tennessee. The event was attended by over 250 individuals. The program showcased a Governors Energy Caucus with Governor Lee and special guests Governor Jeff Landry of Louisiana, Governor Henry McMaster of South Carolina, and Governor Jim Pillen of Nebraska. The agenda also included meetings of the Board's Executive Committee and Annual Board Business Session, Associate Members, as well as multiple plenary sessions. The meeting included broad overviews relating to CCUS and decarbonization technologies as well as efforts to engage with legislative leaders representing the southeast. The FECM exhibit was also displayed throughout the conference, providing participants with a unique opportunity to explore FECM's vast project portfolio including activities supported throughout the SSEB region (**Figure 60**).

Figure 60 *The Honorable Jim Pillen, Governor of Nebraska, visited the DOE FECM exhibit in Chattanooga. He is pictured here on the right with Joe Giove, DOE FECM, on the left.*

On February 19, 2025, Project Team members participated in a workshop that focused on disseminating knowledge pertaining to the CCUS industry. Project ECO$_2$S was used as an example to demonstrate the Class VI permitting process and ongoing review phases with EPA. The program was run through Electric Utility Conference International (EUCI), which designs focused conferences and training opportunities for professionals within the energy and utilities sectors as well as other industries.

The Project ECO$_2$S Phase III Final Presentation was delivered by Kenneth Nemeth and Patti Berry, SSEB, Ben Roth, ARI, and Brian Hill, CRI, on June 20, 2025. Approximately 18 people attended the call representing DOE, NETL, SSEB, ARI, and CRI. Following the presentation, Project Team members in attendance responded to questions from DOE and NETL.

Subtask 10.4 – International Collaboration

Chapter 2 Norwegian researchers participated in several virtual meetings, and the in-person risk assessment meeting held in Birmingham, Alabama, at the NCCC May 3–4, 2022.

The 'CLIMIT SUMMIT' CCS R&D Conference was held in Larvik, Norway, on February 7-9, 2023. On February 7, the ECO$_2$S Partners hosted a "side event" and workshop entitled *"Building an Onshore Commercial CCS Project in the US."* SSEB and IOM Law planned and organized the workshop. SSEB's Patti Berry chaired and moderated the workshop. It began with a keynote address by Mark Ackiewicz of DOE's Office of Fossil Energy and Carbon Management (FECM) that centered on the FECM's Office of Carbon Management Technologies priorities related to the CarbonSAFE program and commercial CCS deployment. Dave Riestenberg of ARI presented "Characterizing a Large-scale Commercial Site for CarbonSAFE" to showcase the geologic data acquisition and analyses work conducted to support the Storage Complex. George Koperna of ARI presented the ECO$_2$S experience with EPA's UIC permitting process in a presentation entitled "Building the Permit for the 1st Carbon Storage Hub in the US." Ingvild Ombudstvedt of IOM Law presented "Regulatory Donut Holes" and shared findings from the partners' analyses of US and international CCS legal frameworks. "Risk – A Phased Approach" was presented by CRI's Brian Hill and examined the evolution of project risks. Katherine Dombrowski of Trimeric presented findings from the conceptual pipeline study in a talk entitled "Pipeline and Surface Facility Design Considerations." The session concluded with a presentation on "Onshore v. Offshore Storage" by Niels Peter Christensen of Christensen CCUS Consult. Following the workshop, SSEB, ARI, and IOM Law sponsored a networking event that featured Dr. Richard Esposito, Southern Company, sharing his observations on the development of commercial CCUS projects in the US.

IOM Law, ARI, and Southern Company prepared a poster for the TCCS conference in Trondheim, Norway. The poster was presented by IOM Law and addressed the long-term liabilities for CO_2 storage in Mississippi.

Christensen CCS Consult organized a workshop and networking event at the CO_2GeoNet 16th Open Forum on October 2, 2023. The workshop theme is Building Onshore CO_2 Storage in the US and Europe. A link to program is provided here: https://conference2023.co2geonet.com/

On behalf of the ECO$_2$S Project, Christensen CCS Consult organized a scientific workshop at the 16th CO_2GeoNet Open Forum – the European Network of Excellence on the Geological Storage of CO_2. The workshop was held at San Servolo Island, in Venice, Italy, on October 2, 2023, and was entitled "Building Onshore CO_2 Storage in the US and Europe". There were six speakers from the ECO$_2$S Project Team and two invited speakers from Denmark and France. Registered attendees for the workshop included 74 people from 23 different countries. Following the workshop, CO_2GeoNet and the ECO$_2$S Project jointly organized the traditional welcome and networking event.

The ECO$_2$S Project Team speakers were:

- Richard Esposito, Southern Company, Implications of policy decisions and incentives on the deployment of commercial-scale CCUS in the United States
- Patti Berry, Southern States Energy Board, The ECO$_2$S Phase III project
- David Riestenberg, Advanced Resources International, Storage site development and characterization

- George Koperna, Advanced Resources International, Permitting & moving toward operational stage.
- Katherine Dombrowski, Trimeric, Project infrastructure & CO_2 supply options
- Ingvild Ombudstvedt, IOM Law, Apples & Oranges? - comparing the regulatory setting: US & Europe

The presentations are available online at conference2023.co2geonet.com.

Publications, conference papers, and presentations

On March 12, 2021, Dave Riestenberg, ARI, gave a presentation entitled: "Large Volume CO_2 Storage in the Southeastern U.S.; Reservoir Characterization of the Project ECO_2S Storage Complex" at the AAPG CCUS conference. The presentation provided an overview of the ECO_2S CarbonSAFE project, including potential capacity at the site, work to date and goals for 2021.

Jalal Jalali, ARI, presented findings from ARI's simulation work to date at the GHGT-15 meeting held on March 15-18, 2021. The presentation was an overview of the paper accepted for the GHGT-15 meeting on the reservoir simulation for the ECO_2S Project.

Jack Pashin, OSU, October 2021, Sedimentology of Cretaceous carbon sinks and seals at the Kemper County Energy Facility, Mississippi, USA. Challenges and Opportunities of Carbon Capture, Utilization, and Storage (workshop), Balkan Geophysical Society Congress, hosted by the Romanian Society of Applied Geophysics (virtual).

Jack Pashin, OSU, October 2021, Fundamentals of Carbon Capture, Utilization, and Storage (short course), Midcontinent Section American Association of Petroleum Geologists Annual Meeting, Tulsa, Oklahoma.

The ARI team provided final edits to the SPE manuscript (ID: RE-1122-0010.R2) entitled "Building an EPA Class VI Permit Application" authored by George Koperna, Dave Reisenberg, Jeremy Leierzapf, and Benjamin Roth of ARI, Richard Esposito of Southern Company, and Kimberly Gray of SSEB. The Technical Paper has been published in the SPE Reservoir Evaluation & Engineering-Reservoir Engineering Journal and is available online at https://onepetro.org/REE/article-abstract/26/03/1032/518769/Building-an-EPA-Class-VI-Permit-Application.

ARI submitted abstracts to the 2022 SPE ATCE (October 2022) and the 2022 AIChE Annual Meeting (November 2022) on the ECO_2S permitting experience.

Wethington, C., Achang, M., Pashin, J. C., and Urban, S., 2021, Geologic framework of an anthropogenic carbon capture and sequestration system at the Kemper County Energy Facility, east-central Mississippi (technical presentation): 2021 American Association of Petroleum Geologists Midcontinent Section Meeting Proceedings, p. 69.

Pashin, J. C., Wethington, C., Urban, S., Achang, M., Riestenberg, D., and Esposito, R. A., 2021, Stratigraphy and sedimentology of Mesozoic-Cenozoic strata in a world-class CO_2 storage complex, Kemper County Energy Facility, Gulf of Mexico Basin, Mississippi, USA (technical presentation): Society of Exploration Geophysicists and American Association of Petroleum Geologists IMAGE Conference Proceedings, unpaginated.

Wethington, Conn, Pashin, J. C., Wethington, Jamar, Esposito, R. A., and Riestenberg, David, 2022, Mudstone baffles and barriers in Lower Cretaceous strata at a proposed CO_2 storage hub, Kemper County, Mississippi, United States (refereed publication): Frontiers in Energy Research, v. 10, article 904850, 17 p. doi: 10.3389/fenrg.2022.904850

Conclusion

The “Establishing an Early CO_2 Storage Complex in Kemper County, Mississippi: Project ECO_2S” Phase III project represented a significant and technically robust effort to advance carbon storage readiness in the southeastern United States. Building on Phase II’s successful demonstration of viable subsurface storage potential, Phase III achieved critical milestones in site characterization, regulatory preparation, risk assessment, and infrastructure planning to support a Class VI UIC permit application. Key accomplishments included:

- Drilling three characterization wells and collecting geophysical logs and 290 feet of core through confining and injection intervals;
- Acquiring a modern, Multi-2D/pseudo-3D 92-mile seismic survey;
- Establishing that the plan for a system of monitoring wells for in-zone, above-zone, and deep and shallow aquifers was adequate to continually observe plume and pressure front development versus repetitive, high-cost 3D seismic surveys;
- Developing a comprehensive monitoring and risk management plan;
- Performing preliminary assessments of CO_2 capture and transport options;
- Distributing over a dozen publications as a result of the work conducted;
- Supporting multiple MS and PhD graduate students to fulfill future workforce development goals;
- Plugging and abandoning five wells during project closeout in accordance with MSOGB and MSDEQ requirements;
- Verifying that the Kemper County Storage Complex can store more than 50 MMT of CO_2 within the prescribed CarbonSAFE timeline of 30 years.

Ultimately, the Project Team was able to establish a world-class gigatonne CO_2 Storage Complex. The results showcase an optimal business development opportunity for CCUS deployment at scale, which could be coupled with revenue generating offtake agreements for enhanced hydrocarbon recovery and other utilization options to amplify its commercial and economic viability in the region.

Despite these achievements, evolving regulatory requirements and strategic decisions by Mississippi Power Company led to the withdrawal of the UIC Class VI Permit to Construct application in March 2024. Subsequent efforts to reconfigure the project without MPC's involvement explored alternative pathways but ultimately concluded in the formal decision to close the project in March 2025.

The extensive data collection, modeling, and planning work completed during Phase III has produced valuable insights and technical resources. The results contained in this final report and its appendices contribute to the broader field of CCUS knowledge and provide a strong foundation for commercial business development of CCUS technologies in the region and beyond.

List of Acronyms and Abbreviations

2D	Two Dimensional
3D	Three Dimensional
AoR	Area of Review
API	American Petroleum Institute
ARI	Advanced Resources International
BIA	Bureau of Indian Affairs (DOI)
CarbonSAFE	Carbon Storage Assurance Facility Enterprise
CCS	Carbon Capture and Storage
CCSKC	Carbon Capture Knowledge Centre
CIBP	Cast-Iron Bridge Plugs
CO_2	Carbon Dioxide
CRI	Crescent Resource Innovation
CX	Categorical Exclusion
D	Darcy
DMP	Data Management Plan
DNV	Det Norske Veritas
DOE	Department of Energy
DOI	U.S. Department of Interior
EA	Environmental Assessment
ECO_2S	Establishing an Early CO_2 Storage Complex in Kemper County, Mississippi
ECT	Environmental Consulting & Technology, Inc.
EIV	Environmental Information Volume
EPA	US Environmental Protection Agency
EQ	Environmental Questionnaire
FARC	Federal Assistance Reporting Checklist
FECM	Office of Fossil Energy and Carbon Management (DOE)
FEED	Front-End Engineering and Design
FFACTA	Federal Funding Accountability and Transparency Act
FSRS	Federal Subaward Reporting System
FWS	U.S. Fish and Wildlife Service
GSA	Geological Survey of Alabama
GSDT	Geologic Sequestration Data Tool
GUI	Graphical User Interface
HAZOP	Process Hazard Analysis
HSE	Health, Safety, and Environmental
IDP	Inadvertent Discovery Plan
mD	Millidarcy

MDAH	Mississippi Department of Archives and History
MDWFP	Mississippi Department of Wildlife, Fisheries, and Parks
MHIA	Mitsubishi Heavy Industries
MICP	Mercury Injection Capillary Pressure
MMT	Million Metric Tons
MOU	Memorandum of Understanding
MPC	Mississippi Power Company
MSDEQ	Mississippi Department of Environmental Quality
MSOGB	Mississippi State Oil and Gas Board
nD	Nanodarcy
NGCC	Natural Gas Combined Cycle
NEPA	National Environmental Policy Act
NETL	National Energy Technology Lab
NHPA	National Historic Preservation Act
NOD	Notice of Deficiency
NORM	Naturally Occurring Radioactive Material
NRAP	National Risk Assessment Partnership
NRAP Open-IAM	National Risk Assessment Partnership Open Integrated Assessment Model
NSealR	NRAP Seal Barrier Reduced-Order Model
OSU	Oklahoma State University
P&A	Plugged and Abandoned or Plugging and Abandonment
P_{10}, P_{50}, P_{90}	Efficiency factors with which the utilization of the pore volume in a CO_2 storage reservoir has been estimated with certainties of 10, 50, and 90% (Goodman et al., 2011), %
PCS	Project Consulting Services, Inc.
PISC	Post Injection Site Care
PISC-SC	Post Injection Site Care and Site Closure
PMP	Project Management Plan
PPE	Personal Protection Equipment
PSI	Pounds per square inch
RAI	Request for Additional Information
RCA	Routine Core Analysis
ROI	Region of Influence
ROM	Reduced-Order Model
RPPR	Research Performance Progress Reports
SCS	Southern Company Services
SF425	Federal Financial Report (form)
SHPO	State Historical Preservation Office
SOPO	Statement of Project Objectives
SOW	Scope of Work

SS	Subsea Feet
SSEB	Southern States Energy Board
TDS	Total Dissolved Solids
TMP	Technology Maturation Plan
TRL	Technology Readiness Level
UAB	University of Alabama at Birmingham
UIC	Underground Injection Control
USACE	U.S. Army Corps of Engineers
USDW	Underground Sources of Drinking Water
USGS	U.S. Geological Survey
VIPERS	Vendor Invoicing Portal & Electronic Reporting System
WLAT	Well Leakage Analysis Tool

Appendices

01	Project Management Plan
02	Data Management Plan
03	Technology Maturation Plan
04	Risk Assessment Report – Initial
05	Risk Assessment Report – Final
06	Well Drilling Permits
07	Geologic Catalog of Materials
08	As Built Well Construction
09	P&A Forms and NORM Survey Records
10	Computational Model Plan
11	Area of Review and Corrective Action Plan
12	PISC and Site Closure Plan
13	Building The Permit for the First Carbon Storage Hub in the United States
14	CO_2 Capture Feasibility Assessment for Plant Ratcliffe
15	Basis of Design (CONFIDENTIAL)
16	Application Submission Memo