Copy of e-poster for GC158 - Unlocking the Potential of Carbon Capture and Storage Value Chain for a Sustainable Net-Zero Future, AGU24, Washington, D.C., December 9-13, 2024

Modeling the Cost of CO_2 Saline Storage on a Regional and National Level

Authors: David Morgan[1], Travis Warner[1,3], Alana Sheriff[1,3], Chung Yan Shih[1], Derek Vikara[1, 3], Kolawole Bello[1,3], Taylor Vactor[1, 3], Mackenzie Mark-Moser[2], Guoxiang Liu[1], Luciane Cunha[1]

[1]*National Energy Technology Laboratory (NETL), 626 Cochrans Mill Road, Pittsburgh, Pennsylvania 15236, USA*

[2]*NETL, 1450 Queen Avenue, SW, Albany, OR 97321, USA*

[3]*Site Support Contractor*

Abstract

Large-scale decarbonization through carbon capture, transport, and storage (CCS) will be necessary to decarbonize the United States (U.S.) energy economy and reach the goal of net zero CO_2 emissions by 2050. Storage of CO_2 in onshore saline formations will be needed to implement CCS on a national scale. The cost of CO_2 storage is of great interest to developers of CO_2 storage projects, policy makers, and regulators. The National Energy Technology Laboratory (NETL) is releasing a major upgrade to its saline storage technoeconomic model, the FECM/NETL CO_2 Saline Storage Cost Model (CO2_S_COM). CO2_S_COM calculates revenue for a storage project assuming the operator is paid to store CO2 and includes all costs associated with a storage project, such as the costs of complying with the requirements of EPA's Class VI injection well regulations for wells injecting CO_2. The new features in CO2_S_COM include 1) an improved landing page for running the model, 2) a database of geologic properties for potential CO_2 storage formations that has been expanded to 314 formations in the lower 48 states, 3) a new algorithm for calculating the cost of drilling and completing injection wells, 4) a new process for inputting cost data for activities associated with the project, 5) a more transparent process for calculating cash flows for activities, 6) a clearer process for calculating the cost of financial instruments for financial responsibility, 7) improved graphical output of results and 8) a new capability to perform systematic sensitivity analysis. This paper will present results from the model on a national and regional level and identify the regions and storage formations in the United States with the lowest cost for storing CO_2. The paper will also present the results of sensitivity analyses identifying the input variables that have the greatest impact on costs. These input variables can be investigated further to determine if there are ways to reduce their influence on cost and lower the overall cost of storage.

Summary in plain English

To reach decarbonization goals in the United States, onshore CO_2 saline storage will be necessary. The National Energy Technology Laboratory (NETL) has developed a technoeconomic model for a CO_2 saline storage project. A new version of this model, the FECM/NETL CO_2 Saline Storage Cost Model (CO2_S_COM), is being released. This paper will describe the foundational aspects of this model and the new features. The paper will present the results of running the model and calculating revenues, costs and financial performance for the 314 storage formations in the model's geologic database. These results will be summarized on a national and regional level and identify the storage formations in each region that have the lowest costs for storing CO_2. The results of a sensitivity analyses will also be provided.

Overview

Large-scale removal of CO_2 from point source emitters through carbon capture and storage (CCS) will be necessary to decarbonize the United States (U.S.) energy economy and reach the goal of net zero CO_2 emissions by 2050. Storage of CO_2 in onshore saline formations will be needed to implement CCS on a national scale. The cost of CO_2 storage is of great interest to developers of CO_2 storage projects, policy makers, and regulators. How these costs vary regionally in the U.S. is also of great interest.

The National Energy Technology Laboratory (NETL), which is within the Office of Fossil Energy and Carbon Management (FECM) in the U.S. Department of Energy, has developed the FECM/NETL CO_2 Saline Storage Cost Model (CO2_S_COM) which is a screening-level technoeconomic model for a CO_2 saline storage project [1].

To inject CO_2 into the subsurface for storage in a saline formation, the site operator (assumed to also be the owner) must comply with the U.S. Environmental Protection Agency (EPA) regulations for Class VI injection wells under EPA's Underground Injection Control Program [2], which is authorized under the Safe Drinking Water Act. The objective of the Class VI regulations is to protect underground sources of drinking water (USDW) from potential contamination from activities associated with CO_2 injection operations. USDWs are defined as aquifers with less than 10,000 ppm salinity. The site operators must also comply with monitoring and reporting requirements under Subpart RR of the Greenhouse Gas Reporting Rule [3], which is authorized under the Clean Air Act.

CO2_S_COM is a cash flow model that calculates the revenues, costs and financial performance for a CO_2 storage project from the viewpoint of a CO2 storage operator who is independent of the CO_2 capture facility and CO2 pipeline operation. It is assumed that the operator of the CO_2 storage project is being paid to store CO_2, which is the source of the revenue for the project. CO2_S_COM includes all costs associated with CO_2 storage including the costs of complying with the requirements of the Class VI injection well regulations and Subpart RR.

This poster describes CO2_S_COM and presents results from the model. CO2_S_COM includes a database of potential storage formations in the lower 48 states of the U.S. and results are calculated for all the storage formations in the database. These results are presented on a national level and also a regional level. A sensitivity analysis is performed that illustrates the influence of changes to several input variables in CO2_S_COM.

Description of CO2_S_COM

In CO2_S_COM, costs are determined by estimating the costs of activities which are discrete items or actions that sustain costs and occur during the development and operation of a CO_2 storage project.

CO2_S_COM provides over two hundred activities and the user selects activities from this list to include in a project. CO2_S_COM calculates the cost of these activities which are expressed as cashflows.

Similarly, CO2_S_COM determines cashflows for revenue streams. The only revenue stream included in this analysis is the revenue associated with payments to the operator for injecting CO_2.

The cost of many activities and revenue streams depends on operational or physical (OpPh) process variables. Operational process variables include the maximum and average annual mass rate of CO_2 injection. The average annual mass rate of CO_2 injection is needed to determine the revenues generated each year of the project. Physical process variables include the areal extents of the CO_2 plume and pressure front, which both expand with time as more CO_2 is injected. These areas are used to determine how much land the operator must lease for surface access for equipment and for pore space rights and how large an area must be covered for certain geophysical technologies, such as 3D surface seismic for tracking the evolution of the CO_2 plume.

Many OpPh process variables depend on the geology where the storage project is being implemented. Key geologic properties include the depth to the top of the storage formation, and the thickness, porosity and permeability of the storage formation. The salinity of the storage formation is also important since the Class VI regulations only allow injection into formations with salinity greater than 10,000 ppm. CO2_S_COM has a database of geologic properties for potential storage formations across the lower 48 states. CO2_S_COM includes several simplified reservoir engineering equations for calculating OpPh process variables using the geologic properties.

To facilitate placing revenues and costs on the timeline for a storage project, CO2_S_COM divides a storage project into five stages. These are:

- <u>Site screening</u>: The operator screens one or more sites as prospects for storage (default value: 1 year).
- <u>Site selection and site characterization</u>: The operator picks one site for storage, performs detailed geologic characterization of this site, obtains access to the surface and pore-space rights from property owners, develops a detailed design for the site and prepares all necessary documents for the Class VI permit application. This stage concludes with the Class VI permit documents being submitted to the governing regulatory agency (default value: 2 years).
- <u>Permitting and construction</u>: The Class VI permit is reviewed by the regulatory agency and eventually conditionally approved. The operator drills and completes the injection wells and may revise the permit documents based on data acquired during the drilling. The operator also installs surface equipment needed for the project (such as piping, meters, onsite buildings, access roads) and monitoring equipment. This stage concludes when the agency has approved the Class Vi permit, and the operator is ready to begin injection (default value: 2 years).
- <u>Operations</u>: The operator injects CO_2 and performs monitoring and maintenance activities in compliance with the Class VI permit. The operator must monitor the evolution of the CO_2 plume and pressure front during injection and monitor for potential leakage of fluids (brine and CO_2)

out of the storage formation and into or toward USDWs. The operator also monitors equipment at the surface for evidence of CO_2 leakage into the atmosphere. Additionally, the operator monitors for evidence of induced seismic activity (default value: 30 years).

- Post-injection site care (PISC) and site closure: When CO_2 injection ceases, the operator must plug and abandon the injection wells. The operator removes unnecessary surface equipment. The operator must continue to monitor subsurface conditions until the CO_2 plume has stabilized (is not expanding) and pressures have declined to levels where the risk of fluid leakage out of the storage formation into a USDW is minimal. When these conditions are satisfied, the governing regulatory authority issues a finding of non-endangerment, and the site can be closed. Monitoring wells are plugged and abandoned, any remaining surface equipment is removed and the site surface is restored (default value: 50 years).

CO2_S_COM calculates the prospective storage resource for each storage formation which depends on the surface area, porosity, thickness, storage coefficient and density of CO_2 in the storage formation. If multiple storage projects operate simultaneously, the pressures developed by each project will propagate and the pressure at each location will be the sum of the pressures generated by each project. The Class VI regulations require the pressure at each location to be less than 90% of the fracture pressure of the storage formation. A pressure factor developed by Teletzke et al. [4] is used to reduce the number of storage projects that can be implemented in each storage formation to ensure that this pressure constraint is not violated. The pressure factor depends on the permeability of the formation and can greatly reduce the number of storage projects that can be operated simultaneously compared to the number of storage projects that could be operated if this constraint is ignored.

The Class VI permitting process requires the owner to demonstrate financial responsibility. The owner must establish one or more financial instruments to cover the cost of implementing four aspects of a saline storage project. The financial instruments are available to the regulatory authority to use in the event the operator of the storage site cannot perform any of these four aspects (i.e., the operator becomes financially insolvent). The first aspect is the cost of corrective action. The owner must identify all active and abandoned wells that penetrate the cap rock (i.e., the relatively impermeable rock layer overlying the storage formation). The owner must find these wells and demonstrate that they were properly plugged and abandoned. Any wells that were not properly plugged and abandoned must be plugged and abandoned either before injection begins or before the pressure front reaches these wells during injection. The second aspect is the cost of plugging and abandoning the CO_2 injection wells at the conclusion of injection. The third aspect is the cost of implementing PISC and site closure. The fourth aspect is the cost of implementing an Emergency and Remedial Response (ERR) Plan. The operator must identify ways in which fluid can be released into USDWs and devise remedial responses to address these releases. The design of the remedial responses is described in the ERR Plan. The Class VI regulations identify several financial instruments that can be used to address financial responsibility requirements. For this analysis a trust fund is used to address the cost of corrective action, injection well plugging and PISC and site closure. An insurance policy is used to address the cost of implementing the ERR Plan.

CO2_S_COM calculates the revenues from storing CO_2 in the subsurface and the costs of developing, operating and closing the site. Revenues and costs are presented as cash flows, first in constant dollars in the first year of the project and then in nominal dollars. All costs are classified as capital costs or operations and maintenance (O&M) costs. Capital costs are depreciated and used to calculate the tax-basis earnings which are used to calculate the taxes paid by the project. The project is financed with some combination of debt and equity and the principal and interest on debt are repaid using a cash sweep.

The cash flow to the owners is calculated as cash coming into the project minus cash going out of the project. The cash coming into the project is revenues, loaned money (debt) and payouts from the trust fund. The user must provide a price for storing CO_2 for revenues to be calculated. Although the trust fund is primarily available to the regulatory authority to cover aspects of financial responsibility, the authority can release money from the trust fund as items covered by the trust fund are executed by the operator and the authority determines the money remaining in the trust fund will adequately support future costs. In CO2_S_COM, it is assumed that money is released from the trust fund at the same time that items covered by the trust fundd are executed. Cash out of the project is capital costs, O&M costs, payments into the trust fund, principal and interest payments on debt and taxes.

With the user supplied price to store CO_2, CO2_S_COM calculates the cash flow to the owners in nominal dollars. This cash flow is discounted to present value dollars using the minimum desired internal rate of return on equity (IRReq) as the discount rate. The present value cash flow to the owners is summed to give the net present value (NPV) for the project. If the NPV for the project exceeds zero, then the price charged to store CO_2 is high enough to cover all costs including financing costs (i.e., interest and principal on debt and the minimum desired IRReq). A useful financial metric for a CO_2 storage project is the price to store CO_2 that makes the NPV for the project equal to zero. This is called the first-year break-even (FYBE) CO_2 price. At this price, all costs are covered including financing costs, so the project is viable, but just barely. The FYBE CO_2 price is also the all-in cost of the CO_2 storage project or the FYBE cost of CO_2 storage.

CO2_S_COM is publicly available on the NETL website. The most recent public version was published in 2017. Many changes have been made to CO2_S_COM since 2017. Many costs in CO2_S_COM depend on the geological properties of the storage formation. The 2017 version has geologic data for 228 potential storage formations, while the new version has 314 potential storage formations. The sheet that is the primary interface with the user has been significantly modified to organize inputs in a more logical manner. The costs for most activities are based on EPA reports published in 2010 [5]. Several costs, such as the cost of drilling and completing wells and the cost of 3D seismic surveys, have been updated. The algorithms for calculating the cost of financial instruments used to address financial responsibility have been revamped to make the calculations easier to understand.

The new version of CO2_S_COM and its user’s manual will be published early in 2025.

Inputs to CO2_S_COM

The inputs for the analysis with CO2_S_COM were based on the inputs used in the recently published NETL report entitled "Carbon Dioxide Transport and Storage Costs in NETL studies" [6]. Several key inputs are:

- During the site screening stage, one site is screened, and this site is selected as the storage site. The site screening includes two lines of 2D seismic. The site characterization stage involves drilling one stratigraphic well that is converted to a deep monitoring well, and performing a 3D seismic survey to characterize the geology over the maximum extent of the CO_2 plume area including an uncertainty factor.
- The storage coefficients used in the analysis are based on a study by IEA Greenhouse Gas Programme where storage coefficients were calculated based on lithology and depositional history of the storage formation [7]. This study generated three storage coefficients based on the probability distribution for the storage coefficients: the 10th percentile value (P10), the 50th percentile or median value (P50) and the 90th percentile value (P90). The P50 value was used for this analysis.
- The average annual mass flow rate for a storage project is 4.3 Mtonne/yr at 85% capacity factor for a maximum mass flow rate on an annualized basis of 5.07 Mtonne/yr.
- The number of injection wells is based on the maximum daily mass CO_2 flow rate through an injection well that the formation can sustain without exceeding the pressure constraint. This maximum value is based on the thickness and permeability of the storage formation using the algorithm developed by Valuri et al. [8]. If this calculated number exceeds 3,660 tonnes/day, then 3,660 tonnes/day is used as the maximum daily mass rate of CO_2 injection per injection well. The 3,660 tonnes/day is an estimate of the maximum mass flow rate that the well pipe can sustain.
- For monitoring during operations and PISC, one deep dual-completed monitoring well is installed for each injection well to characterize conditions in the storage formation and conditions in the permeable formations above the caprock. One shallow well is installed in groundwater for each injection well to characterize conditions in groundwater near the surface. It is assumed that the maximum number of deep monitoring wells installed is 15.
- A 3D seismic survey is performed every 5 years during operations and PISC to help track the evolution of the CO_2 plume and check for fluid leakage out of the storage formation.

The values for several input variables were varied in a sensitivity analysis. For each variable, a baseline or "best estimate" value was selected from Warner et al. [6] along with an "optimistic" value and a "pessimistic" value. The optimistic value should lower costs and the pessimistic value should increase costs. The input variables that were subjected to the sensitivity analysis and the values selected for each variable are the following.

- Storage coefficient:
    - Baseline: P50 storage coefficient

    - Optimistic: P90 storage coefficient
    - Pessimistic: P10 storage coefficient
- Duration of site selection and characterization stage:
    - Baseline: 2 years
    - Optimistic: 1 year
    - Pessimistic: 4 years
- Duration of PISC and site closure stage:
    - Baseline: 50 years
    - Optimistic: 25 year
    - Pessimistic: 50 years
- Deep monitoring wells:
    - Baseline: one dual completed monitoring well for each injection well; maximum number of deep monitoring wells is 15
    - Optimistic: one dual completed monitoring well for each injection well; maximum number of deep monitoring wells is 10
    - Pessimistic: one monitoring well for zones above the caprock per injection well, one monitoring well in the storage formation per injection well, maximum number of each type of monitoring well is 25
- Cost of 3D seismic:
    - Baseline: \$111,000 per mi^2 in 2023\$
    - Optimistic: \$100,000 per mi^2 in 2023\$
    - Pessimistic: \$133,000 per mi^2 in 2023\$

Results

CO2_S_COM was executed for all 314 storage formations in the geologic database. For each storage formation, the FYBE cost of storage and the prospective storage resource were estimated using the baseline values for input variables. The results of the analysis are presented from a national and regional perspective. Figure 1 presents the lower 48 states in the U.S. with each state that has storage formations placed in one of six regions: northeast, southeast, midwest, central, southwest and west. States that have not been assigned a region do not have storage formations in the CO2_S_COM geologic database.

Figure 2 presents the cost-supply curves from a national and regional perspective. The cost supply curves are generated by sorting the results for all the storage formations from low to high FYBE cost. For each FYBE cost, the prospective storage resource for that storage formation and all storage formations with lower FYBE cost are summed to give the cumulative prospective storage resource at that price point.

In Figure 2, there is more than 200 Gtonne of prospective storage resource nationally at \$8/tonne or less in 2023 dollars. From a regional perspective, all regions except the northeast have at least 60

Gtonne of prospective storage resource for $10/tonne in 2023 dollars or less. Unfortunately, the northeast has a little more than 1 Gtonne of prospective storage resource at a price of $40/tonne or less.

Figure 3 repeats Figure 1, but it also shows the best storage formation in each state. All costs are in 2023 dollars.

- Northeast: Waste Gate1 in Maryland ($8.58/tonne), Copper Ridge3 in West Virginia ($39.37/tonne), Rose Run3 in northeast Pennsylvania ($75.05/tonne) and Lockport6 in Kentucky ($158.31/tonne).
- Southeast: Lower Tuscaloosa1 ($7.82/tonne) in Alabama, Lower Tuscaloosa8 in Mississippi ($8.52/tonne), Lower Tuscaloosa 4 in Florida ($9.11/tonne), Lower Tuscaloosa5 in Georgia ($9.36/tonne) and Basal Sandstone TN2 ($51.69/tonne).
- Midwest: Mount Simon3 in Illinois ($7.43/tonne), MountSimon7 in Michigan ($7.57/tonne), Mount Simon6 in Indiana ($7.88/tonne), Knox5 in Kentucky ($10.88/tonne) and Mount Simon10 in Ohio ($13.92/tonne).
- Central: Frontier3 in Wyoming ($6.19/tonne), Arbuckle4 in Kansas ($8.37/tonne), Maha1 in Nebraska ($8.73/tonne), Tensleep5 in Utah ($8.96/tonne), Morrison1 in Colorado ($9.80/tonne), InyanKara1 in Montana ($10.53/tonne), InyanKara2 in South Dakota ($10.53/tonne) and InyanKara3 in North Dakota ($10.53/tonne).
- Southwest: Frio2 in Texas ($5.97/tonne), Wolfcamp2 in New Mexico ($7.32/tonne), Arbuckle1 in Oklahoma ($9.71/tonne) and Lower Tuscaloosa6 in Louisiana ($10.31/tonne).
- West: Forbes1 in California ($6.59/tonne).

The sensitivity analysis was performed in detail on two storage formations, Mount Simon3 in Illinois and Copper Ridge3 in West Virginia. Each input variable was altered by itself, first with the optimistic value and then the pessimistic value. Then all input values were changed to their optimistic value followed by all input values being changed to their pessimistic value. Figure 4 shows the results of this analysis for the Mount Simon3 storage formation. Changing the durations of the site selection and characterization stage produced the largest changes in the FYBE cost of CO_2 storage followed by changing the duration of the PISC and site closure stage. Changing the cost of 3D seismic also had a noticeable effect on the FYBE cost of storage. Changing all the input variables to their optimistic value caused the FYBE cost of storage to decrease from the baseline value of $7.43/tonne to $5.49/tonne. Conversely, changing all the input variables to their pessimistic value caused the FYBE cost of storage to increase from the baseline value of $7.43/tonne to $10.06/tonne.

Figure 5 shows the results of this analysis for the Copper Ridge3 storage formation. Once again, changing the durations of the site selection and characterization stage produced the largest changes in the FYBE cost of CO_2 storage followed by changing the duration of the PISC and site closure stage. As with the Mount Simon3 storage formation, changing the cost of 3D seismic had a noticeable effect on the FYBE cost of storage. Changing all the input variables to their optimistic value caused the FYBE cost of storage to decrease from the baseline value of $39.37/tonne to $22.37/tonne, while changing all the input variables to their pessimistic value caused the FYBE cost of storage to increase from the baseline value of $39.37/tonne to $67.44/tonne.

The sensitivity analysis was also performed on all 314 storage formations. First, all the input variables were changed to their optimistic values and FYBE costs and prospective storage resources were developed for all 314 storage formations. The prospective storage resource increases somewhat for each storage formation because a higher storage coefficient is used in the optimistic case. Next, all the input variables were changed to their pessimistic values and FYBE costs and prospective storage resources were developed for all 314 storage formations. The prospective storage resource decreases somewhat for each storage formation because a lower storage coefficient is used in the pessimistic case. The national cost-supply curves are shown in Figure 6 for the baseline case, optimistic case and pessimistic case. For the optimistic case, there is more than 200 Gtonne of prospective storage resource at less than $6/tonne in 2023 dollars. For the pessimist case, there is still 148 Gtonne of prospective storage resource available for $10/tonne or less.

Figures

Figure 1: Lower 48 States with Regional Definition

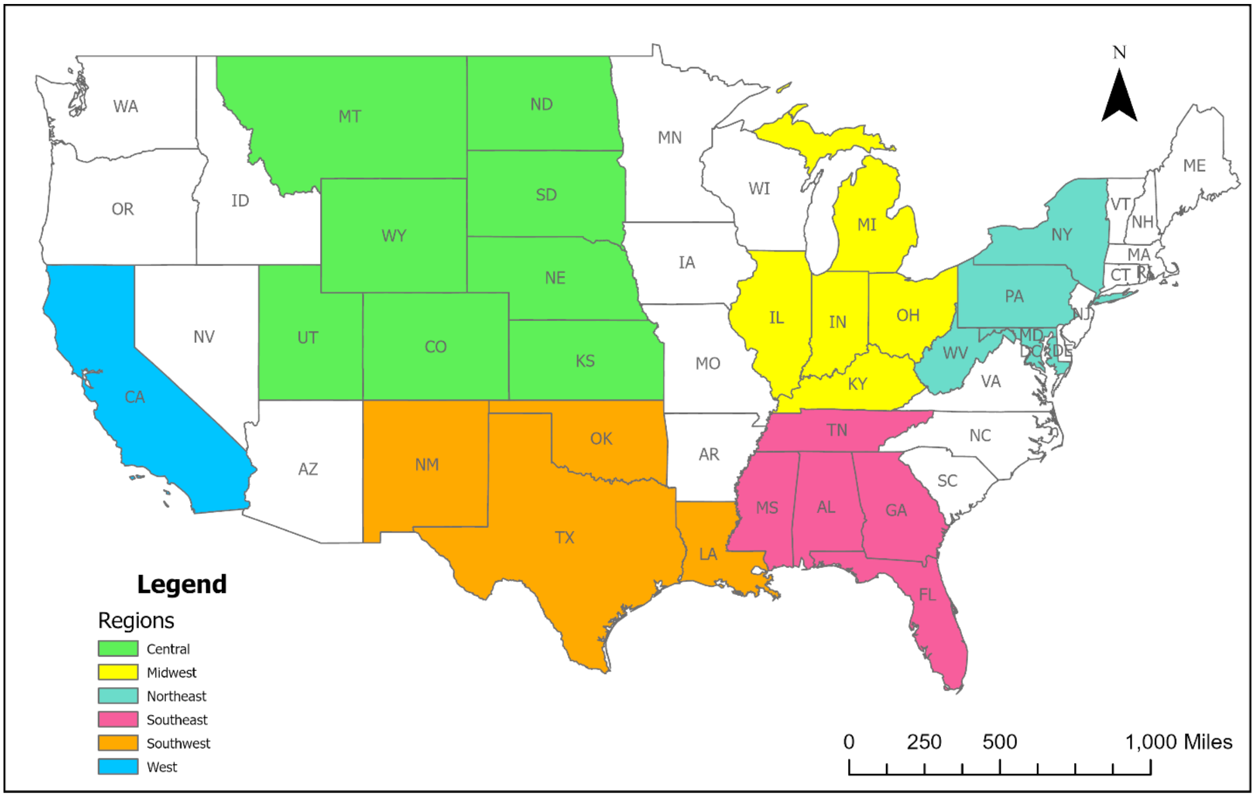


Figure 2: National and Regional Cost-Supply Curves for CO_2 Storage

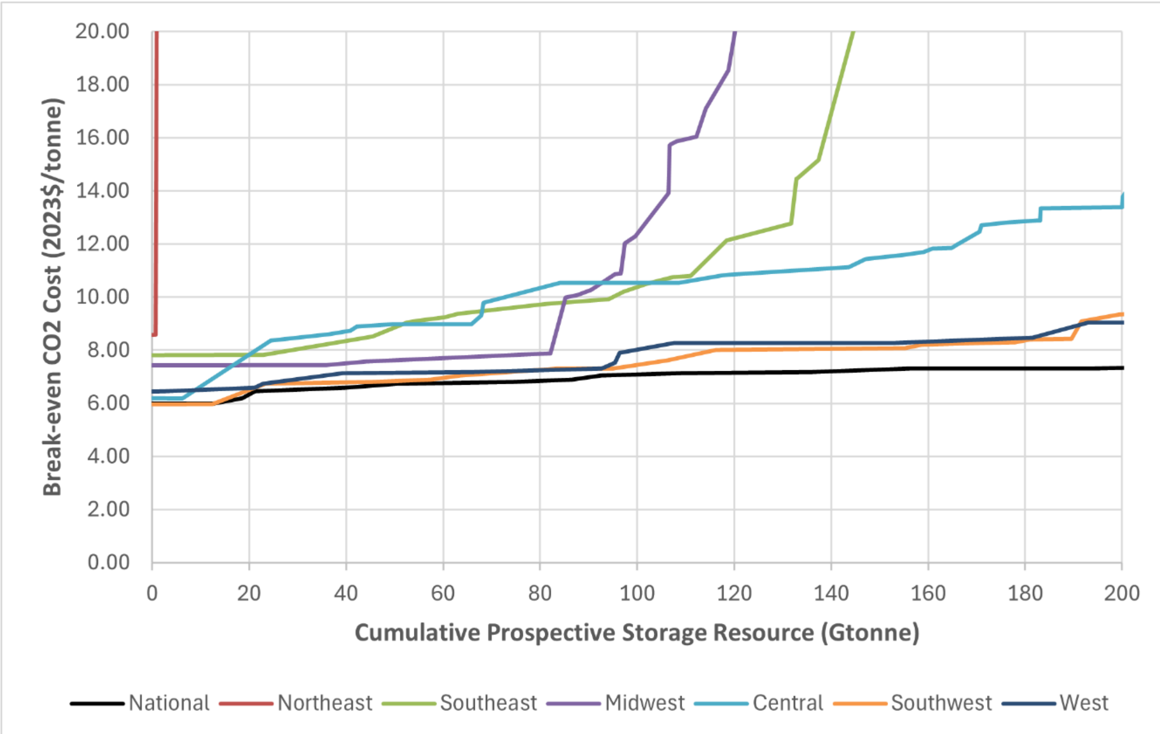


Figure 3: Lowest Cost Storage Formations in Each State

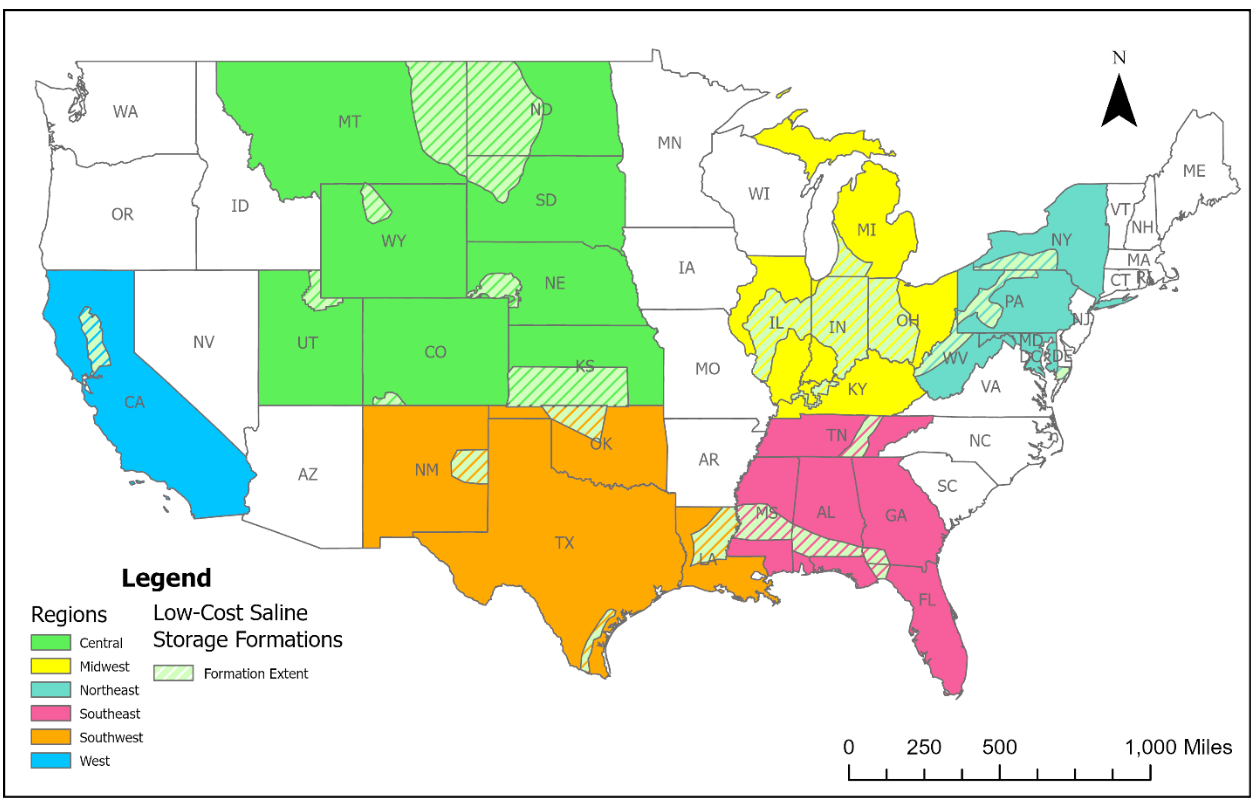


Figure 4: Sensitivity Analysis of Mount Simon3 Storage Formation

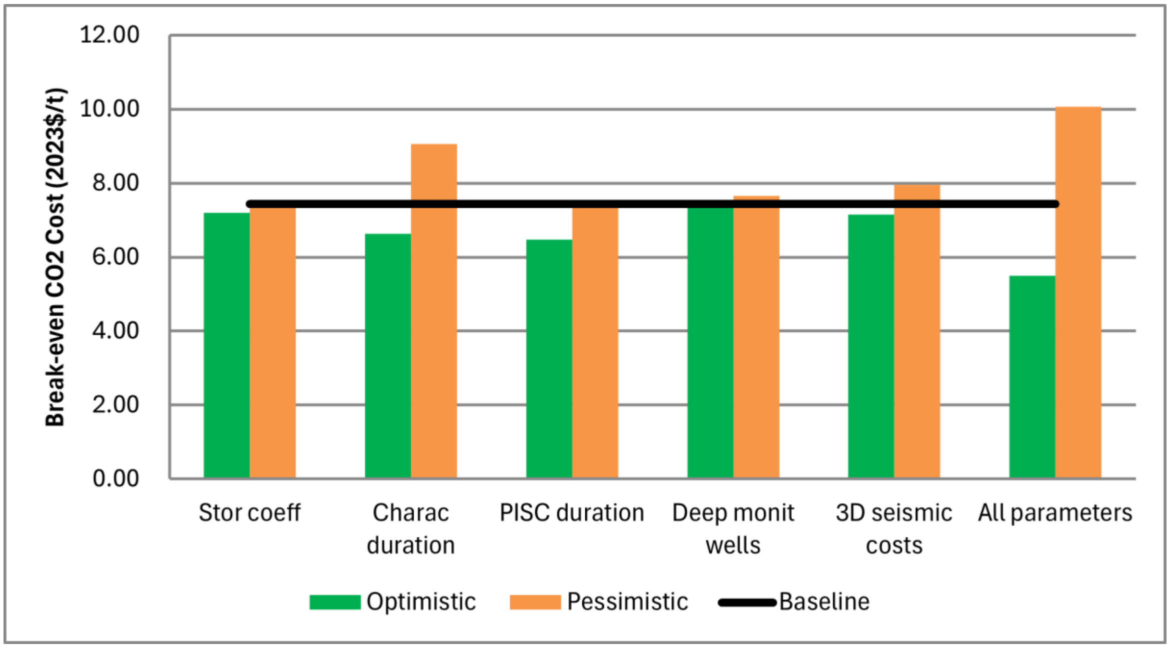


Figure 5: Sensitivity Analysis of Copper Ridge3 Storage Formation

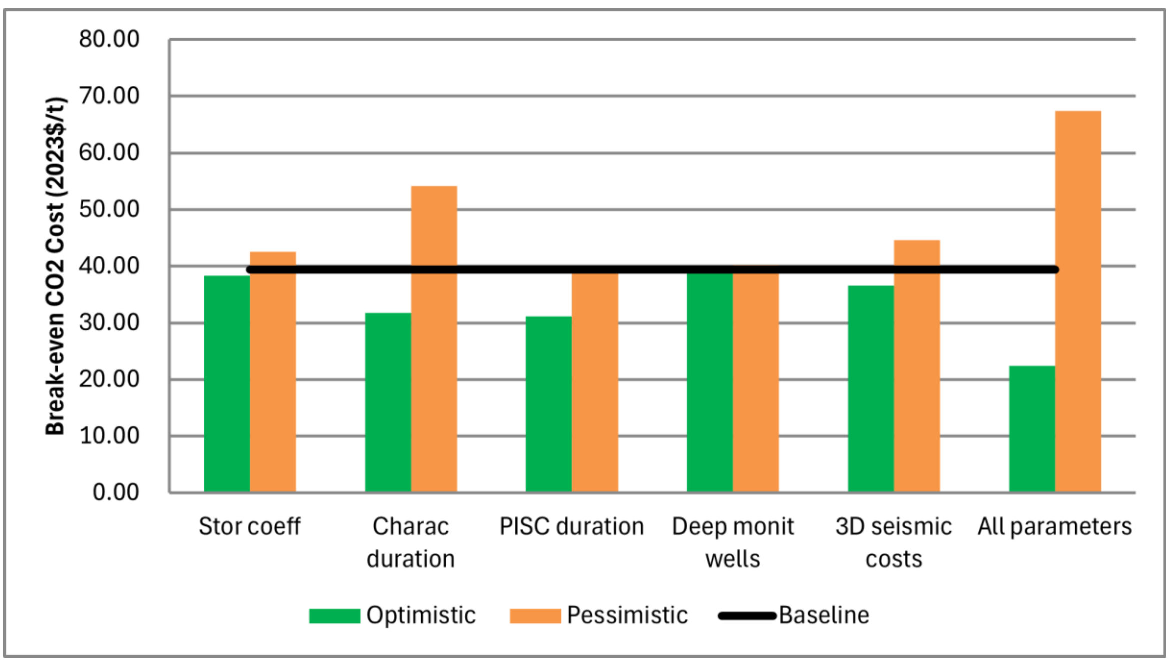
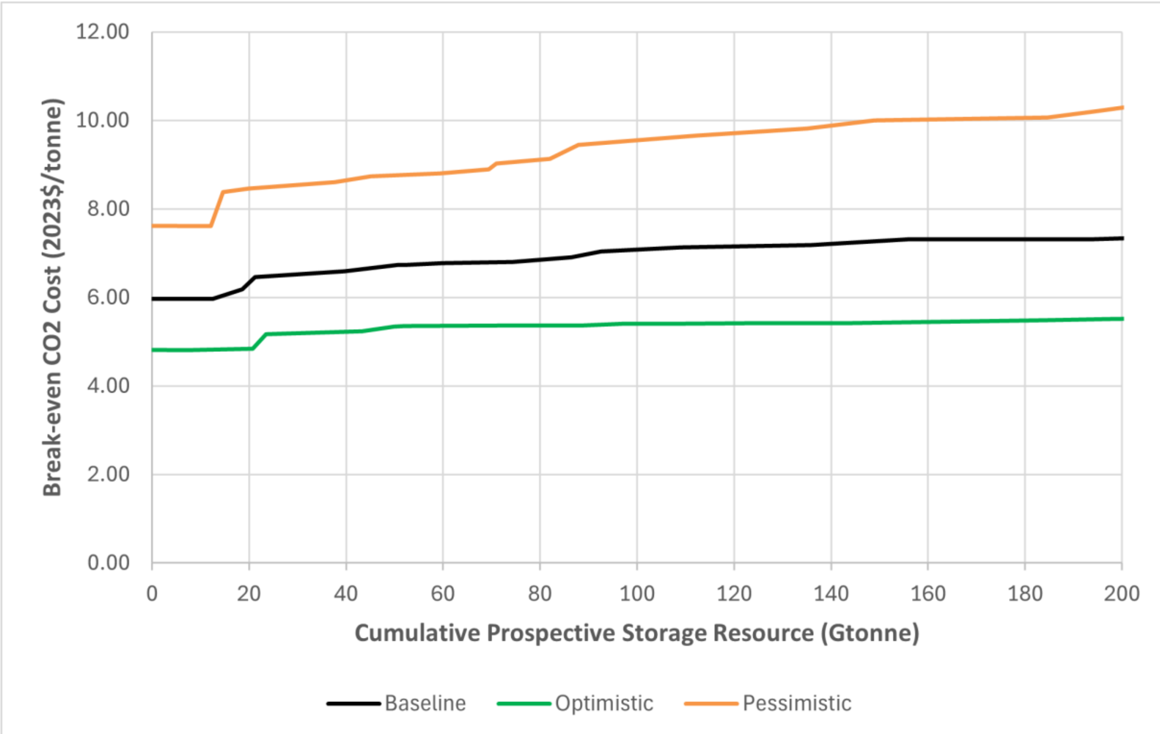


Figure 6: National Cost-Supply Curves for CO_2 Storage Baseline, Optimistic and Pessimistic Costs



References

1. Link to collection of files on NETL website:

https://netl.doe.gov/energy-analysis/search?search=CO2SalineCostModel

Collection includes:

Grant, T., D. Morgan, J. Valenstein, A. Poe, L. Demetrion, C. Shih, A. Guinan, S. Lin and D. Vikara, 2017. FE/NETL CO2 Saline Storage Cost Model: User's Manual, National energy Technology Laboratory, Pittsburgh, PA, DOE/NETL-2018/1873.

Grant, T. and D. Morgan, FE/NETL CO2 Saline Storage Cost Model, Excel file.

2. U.S. Environmental Protection Agency (EPA), 2010. Underground Injection Control Program: Criteria and Standards Applicable to Class VI Wells; 40 CFR 146.81-146.95, Washington, D.C.: U.S. EPA.

3. U.S. Environmental Protection Agency (EPA), 2010. Greenhouse Gas Reporting Program Subpart RR Geologic Sequestration of Carbon Dioxide - 40 CFR 98.440, Washington, D.C.: U.S. EPA.

4. Teletzke, G., J. Palmer, E. Drueppel, M. B. Sullivan, K. Hood, G. Dasari and G. Shipman, 2020. "Evaluation of Practicable Subsurface CO2 Storage Capacity and Potential CO2 Transportation Networks, Onshore North America," in 14th Greenhouse Gas Control Technologies Conference Melbourne 21-26 October 2018 (GHGT-14), Melbourne, Australia.

5. U.S. Environmental Protection Agency, 2010. "Cost Analysis for the Final GS Rule Appendix A-C PDF," EPA 816-R-10-013, Washington, D.C.

6. Warner, T., D. Vikara, D. Morgan, T. Grant, 2024. "Quality Guidelines for Energy System Studies: Carbon Dioxide Transport and Storage Costs in NETL Studies," National Energy Technology Laboratory, Pittsburgh, PA, July 2024, DOE/NETL-2024/4852.

7. IEA Greenhouse Gas R&D Programme (IEA GHG), 2009. "Development of Storage Coefficients for CO2 Storage in Deep Saline Formations," 2009/13.

8. Valluri, M., S. Mishra and P. Ganesh, 2021. "Injectivity index: a powerful tool for characterizing CO2 storage reservoirs - a technical note," Greenhouse Gases Science and Technology, vol. 11, pp. 256-265.