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The Implementation of Underground CO_2 Sequestration: Analysis of Caprock Leakage on the Todilto Shale of San Juan Basin

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Abstract

This paper presents comprehensive geological sequestration feasibility studies at the San Juan Basin. The CO_2 injection has targeted over 50 million metric tons of design within 30 years. There is a potential risk of leakage in a caprock due to pressure build-up resulting from CO_2 injection activities. This research aimed to quantify the risk of CO_2 leakage from the caprock to the underground drinking water source. This was achieved by employing different feasibility techniques to calculate the CO_2 saturation area with plume migration upward.

A compositional hydrodynamic simulator predicts the plume migration and pressure changes in the saline aquifer. A fluid model, the relative permeability, and the capillary pressure threshold for the Todilto barrier model were built and joined into an established geological model. The simulation model was initialized by performing a history match with historical water injection and recorded well head pressure (WHP). The fine grid caprock has been modeled as a shale rock barrier that sealed the upward plume migration. The underground CO_2 storage will be trapped under the Todilto shale formation. The first technique to assess the feasibility of caprock integrity was to calculate the capillary pressure threshold that will cause potential caprock failure leakage on Todilto. The effect of increasing pressure was evaluated through various critical storage trapping mechanisms, increasing plume size, and buoyancy effects on the caprock at the end of 100 years of monitoring. This work calculated the potential CO_2 volume that leaks from hypothetically caprock seal failure leakage. The plume surface area was also investigated as the implications of the geological subsurface. Secondly, an uncertainty analysis study was conducted to understand geological, capillary pressure, and rock properties that impact the caprock integrity. The results demonstrated that CO_2 injection on the Entrada geological saline dune has been sealed with ultra-low permeable Todilto Shale. In addition, the long-term CO_2 brine dissolution has a side effect of dissolution that weakens the caprock and then causes CO_2 leakage on the conductive fault. The techniques and analyses used in this study can serve as a guide to produce similar results for other geological dune saline reservoirs with Todilto caprock consisting of limestones and anhydrite.

Keywords: Carbon Capture and Storage; CO_2 Injection; Anhydrite Formation; Caprock; Todilto; Aquifer; Reservoir Simulation; San Juan Basin.

1. Introduction

CO_2 injection as sequestration has been a potential magnitude of sequestration actions. This policy requires all operators to assess potential scale storage into saline aquifers, thereby providing incentives for operators to level up the CO_2 geological sequestration project. These acts reduce emissions and address climate change mitigation's benefits. In the subsequent decades, the Carbon Capture, Utilization, and Storage (CCUS) will be essential to meet energy efficiency and climate goals worldwide. It is seen as the only option to reduce the CO_2 emissions from fossil power plants and gas processing plants to a near-zero level.

US regulation of CCS is based on the Underground Injection Control (UIC) program of the Safe Drinking Water Act in anticipation of the possibility of injection of CO2 affecting underground drinking water sources. As part of its UIC program, the US Environmental Protection Agency (EPA) adopted Class VI to regulate dedicated CO2 injection and long-term storage. Oil and gas operations are regulated by Class II of the UIC program. For Class VI, there are requirements for the selection, operation, monitoring, and closure of a site. To address any existing wells in the Zone of Review (AoR) that may serve as conduits for CO2 or other fluids to migrate into USDWs, owners or operators of Class VI wells must conduct an Area of Review (AoR) delineation and corrective action plan.

The AoR delineation must be based on computational modeling that accounts for the hydrodynamic properties of the injected CO_2, on the geological injection zone and confining zone, with the projected injection volumes and pressures. CO_2 injection can also induce stress change or reactivate seismic events that will be discussed in another work. However, faulted sedimentary basins should be studied carefully apart from this study.

This study aims to demonstrate the caprock integrity within the AoR delineation risk zone in an ongoing CarbonSAFE Phase III San Juan Basin project. This involves constructing a flow model containing a comprehensive geological feature set using geological characterization efforts. The aim is to sequester over 50 million metric tons of CO_2 over 30 years modeled using a multi-phase compositional simulator while considering caprock integrity risk in various leakage conduits.

As an AoR delineations result, potential impact zones on USDW will be evaluated as a result of CO2 injection activities. This study incorporates the existing water injection wells to evaluate the impact of the increasing pressure that is possible to cause a leak from the top seal and hypothetical leakage from the activated fault. As part of a comprehensive study, this work ranks and identifies the main uncertainties on the static property and sequestration injection plan.

2. Project Background

San Juan Basin CarbonSAFE Phase III: Ensuring Safe Subsurface Storage of CO_2 in Saline Reservoirs is being conducted under a U.S. Department of Energy (DOE) cooperative funding agreement led by the New Mexico Institute of Mining and Technology. The project aims to characterize the San Juan Basin's subsurface formations and test the feasibility of storing carbon dioxide in saline reservoirs. In addition, this project seeks to identify potential risks of CO_2 leakage into Underground Source Drinking Water (USDW) associated with CCS technologies and develop a sequestration plan. The local hydrology USDW of this work is Ojo Alamo sandstone which needs to be protected.

A feasibility study is being conducted to determine whether carbon dioxide can be stored in deep saline aquifers within the San Juan Basin and to accelerate a CCUS hub in the region. Figure 1 presents the geologic map and stratigraphy of the San Juan Basin.

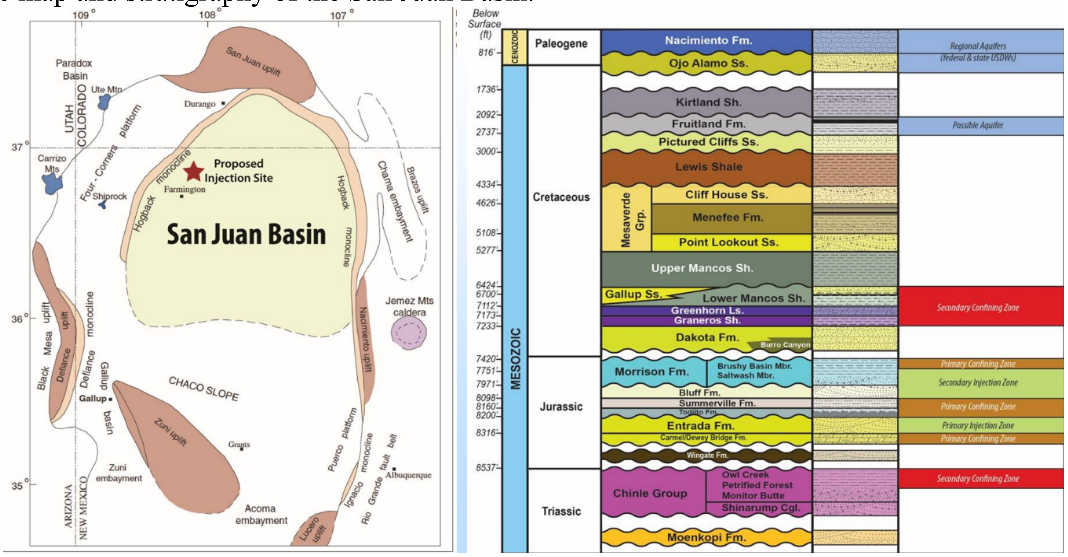


Figure 1. Geologic map and stratigraphy of the San Juan Basin (modified from Craigg, S.D., 2001)

A stacked reservoir in New Mexico has the best and safest potential to sequester large amounts of CO_2 according to the San Juan Basin CarbonSAFE group which has 7500 square miles. According to Vincelette and Chittum (1981) and company data, the storage properties within layers in the San Juan Basin have been described in Table 1.

Table 1. Formation layers in the San Juan Basin (Dana Ulmer-Scholl (1981))

No	Formation Names	Porosity, frac		Permeability, mD		Info
		Mean	Max	Mean	Max	
1	Dakota Sandstone	0.06	0.25	1.14	10	
2	Brushy Basin	0.10	0.38	0.5	40	Second Seal
3	Salt Wash Member	0.08	0.20	0.01	10	Possible Store
4	Bluff	0.10	0.28	0.1	50	Possible Store
5	Summerville	0.05	0.20	0.8	4.29	Prim Seal
6	Todilto	0.03	0.18	0.0001	1.9	Prim Seal
7	Entrada Sandstone	0.13	0.27	21	982	Prim Store
8	Carmel	0.04	0.15	1.55	10.49	bottom seal

The primary confining zones for the Entrada Sandstone reservoir are the Todilto and Summerville formations. The Todilto Formation was deposited approximately from 165 to 164 million years ago (Cather, 2020). This unit conformably overlies the Entrada Sandstone and fills in the preserved topography developed on the Entrada surface (Massé and Ray, 1995). The primary confining zones for the Entrada Sandstone reservoir are the Todilto and Summerville formations. If the Bluff Sandstone and the Salt Wash Member of the Morrison Formation are utilized for CO_2 storage, then the Brushy Basin Member of the Morrison Formation will be needed as a secondary seal.

According to Project DOE Narrative report (2023) - Dana Ulmer-Scholl, the paleogeographic San Juan basin region shows a large saline lake (not a marine embayment) in which the Todilto sediments were deposited. This large saline lake was fed by numerous streams that had their headwaters in the surrounding highlands. Herewith is the isopach for Todilto formation. These salina/lacustrine deposits consist of two major facies:

- Lower, organic-rich carbonate facies containing stromatolites and planar algal structures with anhydrite nodules and minor interbeds of sandstone, siltstone, shale,
- An upper anhydrite unit that is present in the center of the basin and thickens dramatically to the southeast greater than 150 feet).

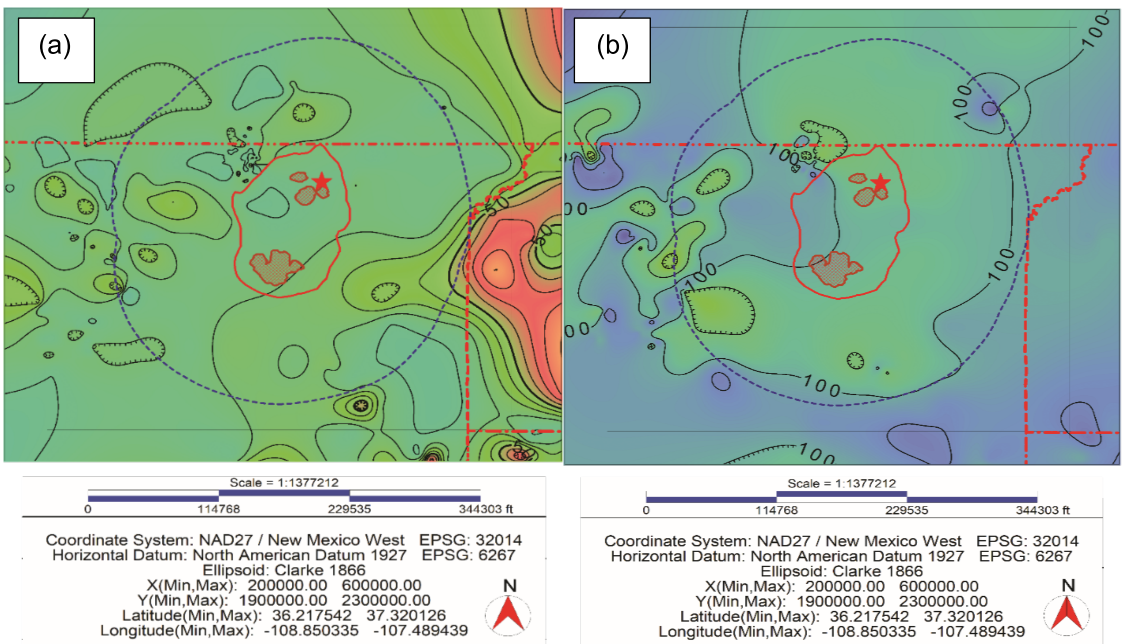


Figure 2. a) An isopach map of the Todilto Formation (CI = 10 feet) b. An isopach map of the Summerville Formation (CI = 20 feet).

Overlying the Todilto Formation, the Summerville Formation is another potential seal within the AoR (Figure 2.b). The Summerville unit is present throughout the San Juan Basin. In the AoR, the Summerville ranges in thickness from 75 to 250 feet shown in Figure 2. The Summerville deposits consist of thin-bedded, reddish brown, gypsum- and/or anhydrite-cemented fine-grained sandstones, siltstones, and mudstones. The Summerville depositional environments range from hypersaline tidal flats, coastal plain/sabkha, and fluvial to lacustrine (Anderson and Lucas, 1992; Lucas, 2020b). Throughout the Four Corners area, the deposits have undergone soft-sediment deformation on the seafloor, and large (30 feet wide) sandstone pipes are present in the San Juan Basin that represent early diagenetic structures. These features may diminish seal integrity. Based on well log measurements, porosity ranges from 0 to 15% (averages 1.2%) and permeability ranges from 0.0 to 0.5 mD (averages 0.1 mD).

3. Methods

3.1. Research Workflow

The work is to deploy state-of-the-art sequestration CCS technology that will incorporate the geological aspect, hydrodynamic modeling, petrophysical analysis, well test reports, and reservoir engineering sense to define site investigation of the AoR. The research workflow is presented in Figure 3. This comprehensive workflow is developed to prove that the geological area has an injection zone with sufficient areal extent, thickness, porosity, and permeability to receive and store the anticipated volume of CO_2. Well logs, well injection data, and 3D seismic data are currently used to model the dynamic behavior of the San Juan Basin. A few commingle layers are being opened while injected with water.

This workflow starts with the preparation of data. Data includes well coordinates and trajectory, core and log properties, and dynamic data such as step rate test reports, injection data, fluid properties, and wellhead pressures. The history-matching process calibrates the input geological data into reservoir-measured data, which matches the behavior pressure data and injection data. The base case hydrodynamic model is run, initial delineation AoR is analyzed and quantified.

3.2. AoR Delineation

An AoR is a region around an injection well where USDW (Underground Sources of Drinking Water) may be endangered by injection activity. AoR represents a boundary representing storage projects where USDW is susceptible to the highest impacts due to CO_2 injections into storage reservoirs. The authors will use the hydrostatic method to delineate AoR. Pressure increment can be defined as the maximum allowable pressure on the injection layers using a hydraulic gradient that calculates pressure increment which lifts the reservoir saline water to the USDW through the potential conduit.

3.2.1. Equilibrate pressure scenario: pressure front based on displacing fluid initially present in the borehole for hydrostatic cases

When storage systems have a long production history, under-pressurized cases are more likely to occur. Like the under-pressurized case, the hydrostatic case takes pressure increments into account that could lead to critical pressure, which would force fluid through the wellbore. A uniform density linear approach is used in equation (1) to calculate the minimum increased pressure threshold. If the pressure value increases less than the threshold of pressure increases (ΔPc) the fluid initially in the wellbore may leak into the USDW layer.

$$\Delta P_c = \frac{1}{2} g \cdot \mathcal{E} \cdot (z_u - z_i)^2 \quad (1)$$

$$\mathcal{E} = \frac{\rho_i - \rho_u}{(z_u - z_i)} \quad (2)$$

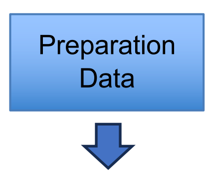
ρu = Density of the injected USDW, ρl = Density of the injected layer, g = acceleration due to gravity,

Zu = Depth of the injected USDW, Zl = Depth of the injected layer, $\mathcal{E} = Epselon$

Currently, our best estimates suggest the SJB CarbonSAFE project's storage reservoir will follow a normal or under-pressure gradient, a hydrostatic condition that is suitable for this study. Thus, this study will use the equilibrate method.

3.2.2. Threshold Pressure Measurement

The caprock plays a role in keeping a gas within the matrix in the term of shale. Gas must be contained by the matrix reservoir before it reaches the overpressure required to trigger a leak right before threshold pressure can be encountered. This initiation phase will be non-wetting since gas will be forced through the wetting phase (drainage stage) to displace the matrix with 100% saturation water. The ability to understand the shale location is also an important component of the study.



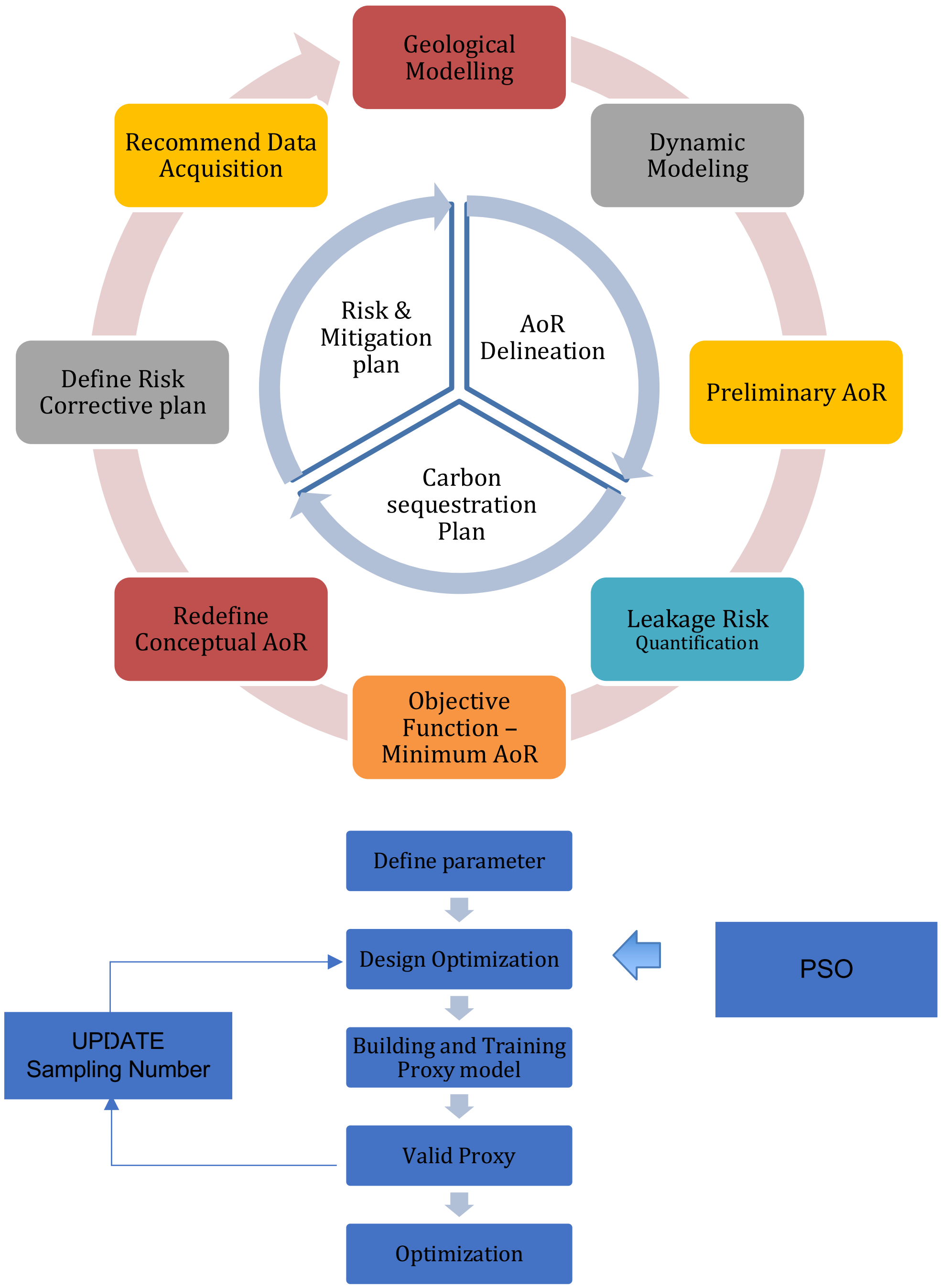


Figure 3. Schematic chart of Research Workflow

Capillary Pressure

In a water-gas system, the capillary pressure is calculated as the pressure in the gas phase subtracted from the pressure in the water phase. When gas is introduced into a rock that is already fully saturated with water, the gas will naturally tend to fill the larger pores and travel through the larger pore throats. In this process, the gas finding its way through these pathways typically happens with little to no significant alteration in the saturation levels of either the gas or water phases. For the gas to displace the wetting phase, which is water in this scenario, from the largest capillary pores, a minimum level of capillary pressure is necessary. This required pressure is referred to as the entry pressure (Pc entry), and its specific value is termed the displacement pressure. When considering the largest pore throat to be circular with a radius 'r', σ= IFT (Interfacial tension), Θ = contact angle, the formula to determine the entry pressure is shown in equation (3).

$$P_c^{entry} = \frac{2\sigma \cos\theta}{r} \tag{3}$$

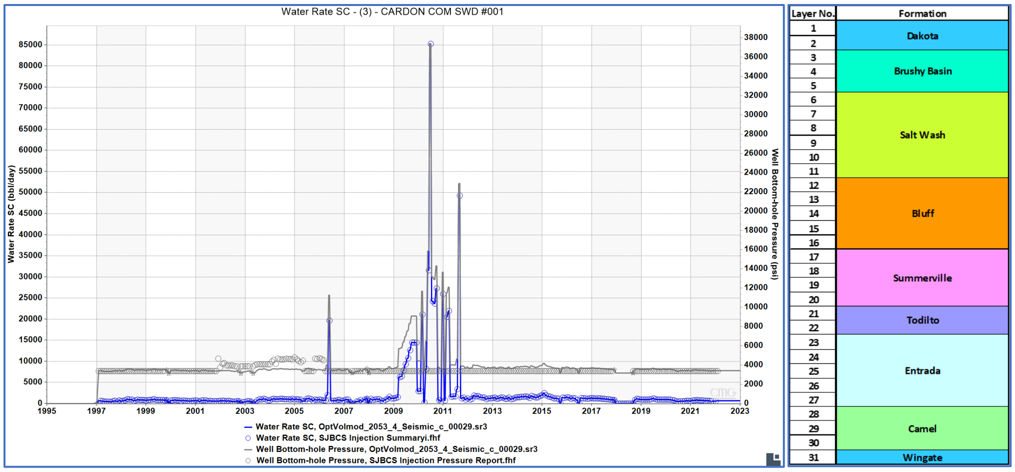
3.3. Model Development

The hydrology dynamic model of SJB CarbonSAFE is built using a sophisticated geological static model, which is simulated using a multi-phase compositional simulator. The model then needs to be simplified by running 10 layers instead with the same configuration as 60 miles by 60 miles, with grids of 244 × 247 × 59 (I, J, and K) and 1000 ft size of each grid. There are nine stratigraphic layer zones on the model, which are Dakota, Brushy Basin, Saltwash, Bluff, Summerville, Todilto, Entrada, Camel, and Wingate formations. The stratigraphic of 9 layers will be sectored into 5 zones on the model, which are Summerville, Todilto, Entrada, Camel, and Wingate formations model in Figure 4b. A summary of the input data is shown in Table 2.

Table 2 San Juan Basin Aquifer Dynamic Model Initialization

Reservoir Parameter	Value	Remarks
Dimension Dynamic model	241 × 242 × 29	60 miles by 60 miles, 1000 ft, 1,691,338 grid block
Net-to-Gross ratio (NTG)	1	Full basin scale grid model
Initial water saturation (Swi)	100%	Saline-Aquifer with 50,000 ppm salinity assumption
Relative permeability	1 RT	1 rock type
Injection wells	34 Injection Water and 1 Injection Gas	Three wells dominated 50% Cumulative volume injection
Initial Pressure at Entrada	3500 psia	
Geological zones	5	Summerville, Todilto, Entrada, Camel, and Wingate
Fluid compositions	3	CO_2, H_2O, CH_4 (tracing component)
Boundary Model	2 types	Edge reservoir 200, 10 pore Volume multiplier

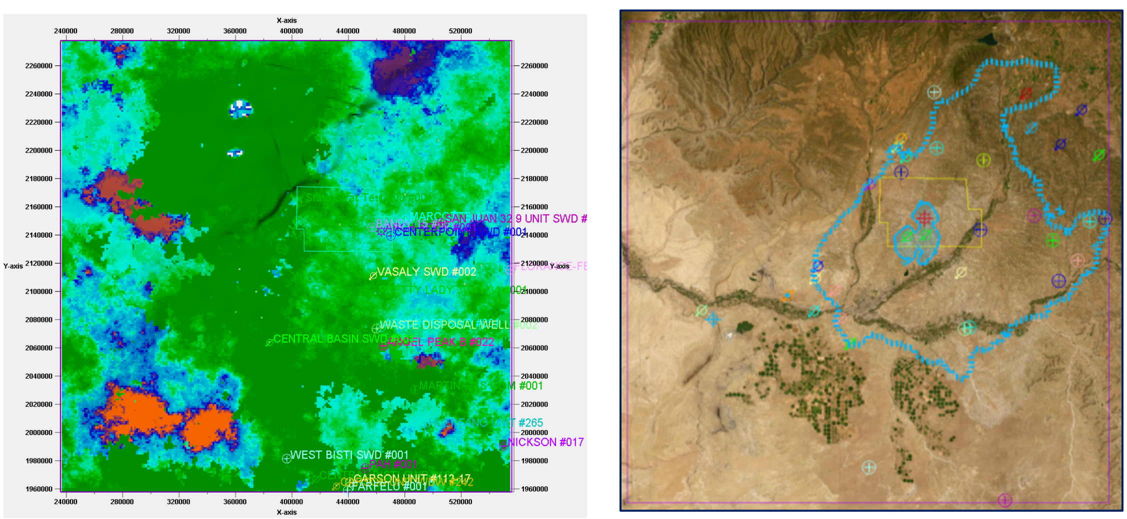
The field injection history started in early 1994, with injection history into Salt Wash, Bluff, and Entrada formations within 6000 to 9000 ft in MD, as shown in Figure 4. Ultimately, there are 35 injector wells included in the dynamic simulation model. Based on the well diagram, these are vertical wells. At the end of the historical simulation run, the reservoir pressure has a build-up pressure effect + 100 psi increase at the Northeast. Preliminary AoR model made delineation of AoR of 40 miles (figure 5b) which put 15 wells in risky zone, therefore this zone needs to be narrower which would subsequently reduce the number of smaller numbers of risky wells.



(a) (b)

Figure 4. a) History matching BHP responses of the Water Injector (WI) CARDON COM SWD and b) Formation horizons delineated in the static geological numerical model

Figure 4 reflects reasonable matches between simulation results and well history data as per 30% well contribution volume injected. Currently, the history-matching result matches the relative permeability, reservoir flow type, permeability estimation, and pressure history. The simulation results match the pressure responses, indicating that the rock model and fluid properties converge well. Permeability x thickness model at the Entrada layer, as shown in Figure 5a. Nevertheless, In the San Juan basin layer, Todilto shows permeability vs porosity value trends in Figure 6.



(a) (b)

Figure 5. a) Transmissibility (kh) distribution in the reservoir 3D model at Entrada Layer (left) and b) Preliminary AoR delineation (right)

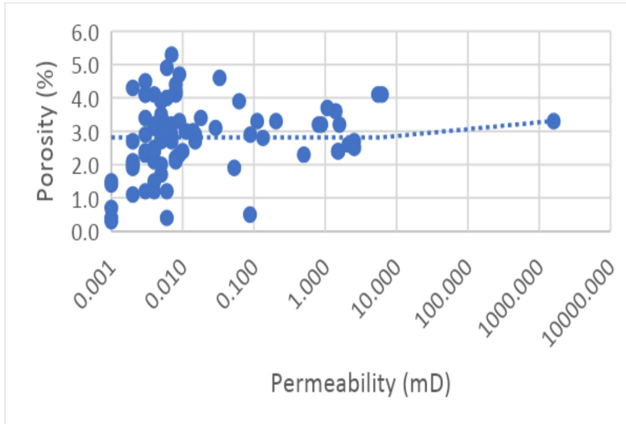


Figure 6. Todilto correlation Permeability and porosity

The rock sample of the Carbon Safe Strat Test #1 derived MICP (Mercury Injection Capillary Pressure) test lab test shows capillary pressure with Swi data and a capillary pressure prediction for the caprock in Figure 7a (purple). Figure 7b shows the relationship used to evaluate the seal capacity (Workshop Bryan, Carbon Safe#1, Nov 23). MICP test shows seal intervals above 8000 ft, indicating Pc can be greater than 1500 psi. The calculation of threshold pressure is built into the hydrodynamic model, as shown in Figure 7a. By using the equation (3), Entrada sandstone has a capillary pressure of 52 psi.

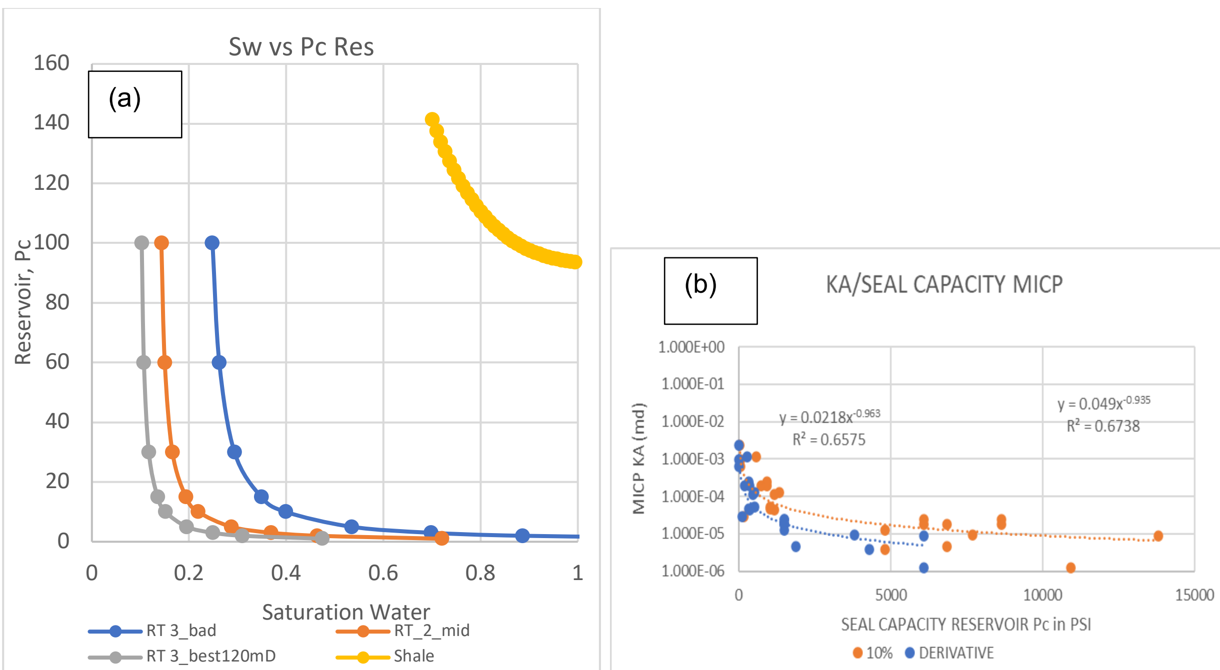


Figure 7. a) MICP Test lab and b) Seal Capacity Reservoir

The displacement pressure of a seal depends on both the seal character (pore throat radius) and the wetting properties of the fluids (interfacial tension and contact angle). Within the drainage process, the nonwetting phase (gas) capillary pressure must exceed the wetting phase (water) capillary pressure before entering the water-saturated rock. By incorporating equation (3), the entry capillary pressure shale has been calculated as 125 psi using a radius pore of 6×10^{-5}m. Yet, Pc at Entrada Sandstone, calculated as 52 psi below the shale Pc, does not allow the CO_2 gas to have the drainage process onto the shale layer.

3.4. Neural Network Model Optimization

This study shows that the workflow of how to get well placement selection is the ultimate development scenario prediction. The well placement also affects the project's operational costs, environmental risks, and monitoring requirements. Therefore, well placement should be optimized based on the target aquifer's geological characterization, geophysical and geochemical characteristics, and project objectives and constraints. This workflow offers infill wells named Sinj1, CM1, and SJB wells. The surface area is also far from the communal area, making this selection the best case. Based on current geological knowledge and land accessibility considerations, a maximum of three injectors appears to be sufficient and will be explained in the result and discussion.

Well-placement and operating conditions are the two base factors that must be determined. The well-placement factor mainly considers the reservoir properties, surface accessibility, and land ownership while staying within the licensed seismic area. The forecasting starts with the maximum deployment of one to three infill wells; group injection will be implemented as the primary constraint of a maximum of 2 million tons of CO_2 injection per year. The bottom hole pressure limit is set to be 90% of the formation fracture pressure at the shallowest completion depth of each well, which is defined as the second constraint.

The simulation is run on the full-scale brown saline field following the history matching period with the base case scenarios shown in Table 3 and the following assumptions:

1. Input data consists of static models (Porosity, Permeability) with dynamic reservoir data (SCAL data, PVT, Completion Diagram, and water injection history).
2. The Initialization stage is to get the equilibrium phase which calibrates the compositional phase fluid with the pressure related to the layer.
3. History Matching: With the knowledge of the most influential variable to match the pressure of the field history from dynamic simulation is carried out.
4. Scenario design: CO_2 injection starts on January 1st, 2025, and ceases on January 1st, 2056, for a total of 30 years. Forwarding after the CO_2 active injection, an additional 100 years is simulated with no CO_2 injection as a post-monitoring period till the end of the simulation.
5. Maintain the water injection rate at the end of history matching till the end of the simulation
6. Optimization: Group constraint of 1 to 3 wells with a maximum CO_2 injection rate of 2 million tons per year for over 30 years.
7. The maximum constraint of BHP is calculated with the fracture pressure gradient of each well (0.9×0.63 psi/ft × TVD)
8. The CO_2 injection targets the Entrada layer.

Table 3 Probabilistic forecasting cases of CO_2 injection for building a proxy model

No	Parameters	Minimum	Maximum
1	Gas Inj Group Target	103 MMscfd	120 MMscfd
2	BHP, psia	3900	4600
3	Well Placement Sinj1, CM1, SJB: I, J, K	Seismic Line Boundary map as a region of Well Placement	
4	Perforation on Entrada		
5	Permeability Sinj1, CM1, SJB1		

One of the challenges of carbon capture and storage (CCS) is to ensure that the injected CO_2 does not leak back into the groundwater from the caprock conduit layer. However, achieving high CO_2 plume saturation depends on several factors, such as injection rate, reservoir permeability, heterogeneity, fault play system, and capillary pressure. Therefore, this work has two objective functions which are minimizing AoR and maximizing the storage while sequestration of a minimum of 50 million metric tons.

This work shows an optimization framework that submits various parameters and controls reservoir simulation models using a total of 84 scenarios. This experiment data uses the PSO method to optimize the models thus trained as proxy models. The study will focus on the highest CO_2 storage with the minimum plume CO_2 saturation and lower impact pressure. In this work, the RBF neural network has been chosen to get the best placement. It shows that the proxy model generates a good match with various pairs of parameters (Figure 8).

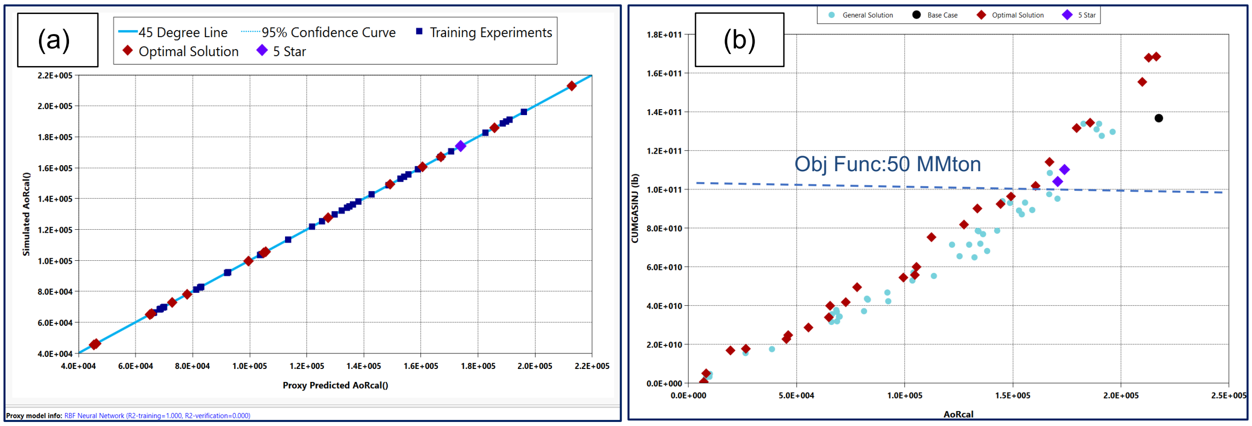


Figure 8. a) Proxy Model and b) Pareto function CO_2 storage vs AoR calculation

Prediction scenarios have been carried out using various strategies. This probabilistic forecasting uses 140 scenarios in total. This workflow includes a strategy assisted by studying the distribution transmissivity that can improve the injectivity conformance, which also reconsiders the risk map well and fault placement. This strategy is to screen fully potential infill well placement from the hydrostatic model. The distribution of geological property has a big impact on the storage volume. For this reason, it is necessary to understand the rock property to get a more representative model.

4. Results and Discussion

4.1. Caprock Integrity Analysis with Uncertainty Study Analysis

The fluid moves from an injection zone through a confining caprock layer after CO2 injection, which causes reservoir pressure to increase above critical pressure. A lateral flow of fluid will occur when fluid is injected under pressure. With several low permeability confining layers, the overlying drinking water formations should be isolated from injection reservoir. Conduits and permeable zones in the confining layer can allow fluid to flow from the injection zone into the drinking water formation. However, when the increasing capillary pressure Entrada is higher than the shale capillary pressure entry, this leads to the leakage of the rock containment or caprock shale. The MICP test analysis is used to understand leakage pathways of the rock and caprock threshold pressure prediction.

The workflow now extends back to the static geomodel parameters in the multi-analyzation platform. This includes static model parameters—such as fault positions to affect the best options in optimizing well location (Figure 14). Scenario 54 has a tendency risk in the fault section at hogback as a monocline. The hogback monocline study will be a part of this study. Therefore, this plan needs to be revisited.

This leads to future actions to anticipate risk and operational challenges while anticipating a physical process that requires further investigation. The migration and trapping of the CO_2 depend on capillary pressure, salinity gradient, and fluid flow movement. These processes affect the storage captivity and the efficiency of CO_2 sequestration in saltwater reservoirs.

After the developed framework is applied to the full-scale model to minimize the AoR and maximize the highest CO_2 Storage that has a limit of a minimum of 50 million metric tons using Neural

Network, we find the optimal storativity of 65 million tons with an AoR delineation radius of 14 miles. We have selected scenario 54 because it has the best placement location and lower BHP with 3 candidate wells. Then, the second-best scenario is scenario 66 with a focused single injector well.

In the context of the Entrada sandstone, the capillary pressure curves can vary among different lithofacies. This means that the capillary pressure can influence the extent and shape of the CO_2 plume as it spreads within the reservoir. The heterogeneity of the rock, including variations in permeability and thickness, can lead to differences in capillary pressure, which can affect the distribution and migration of the CO_2 plume over time.

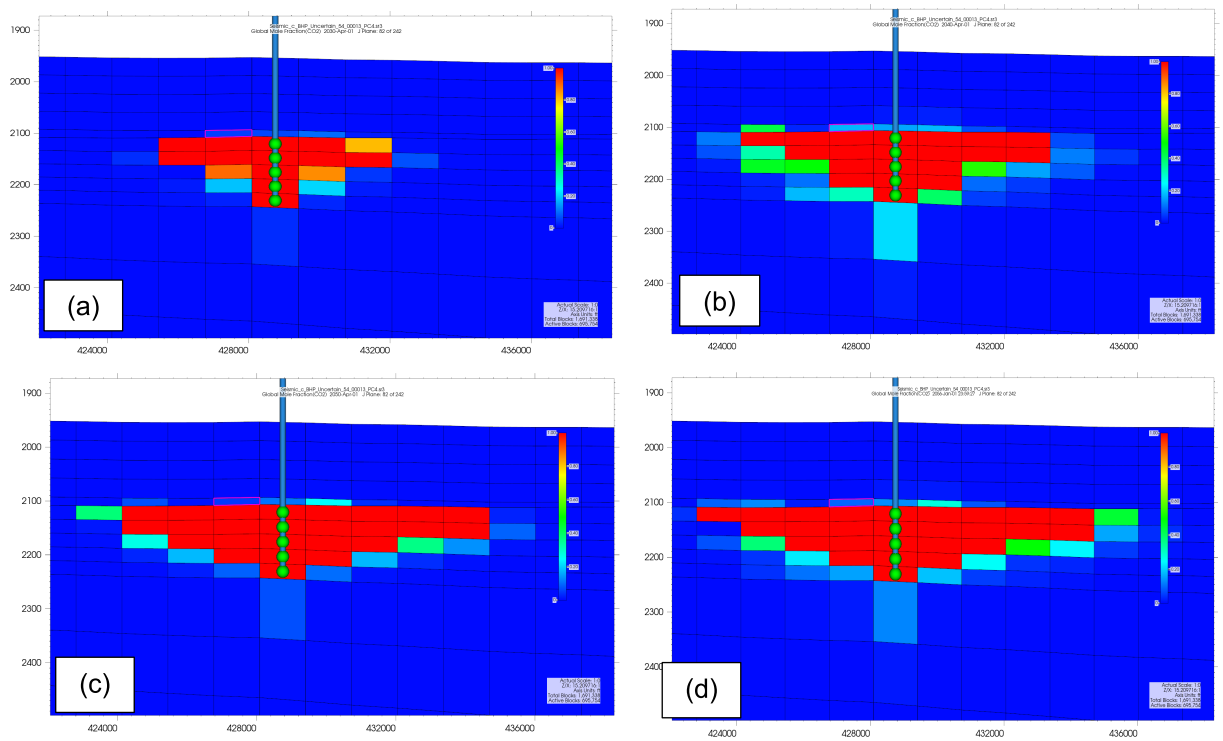
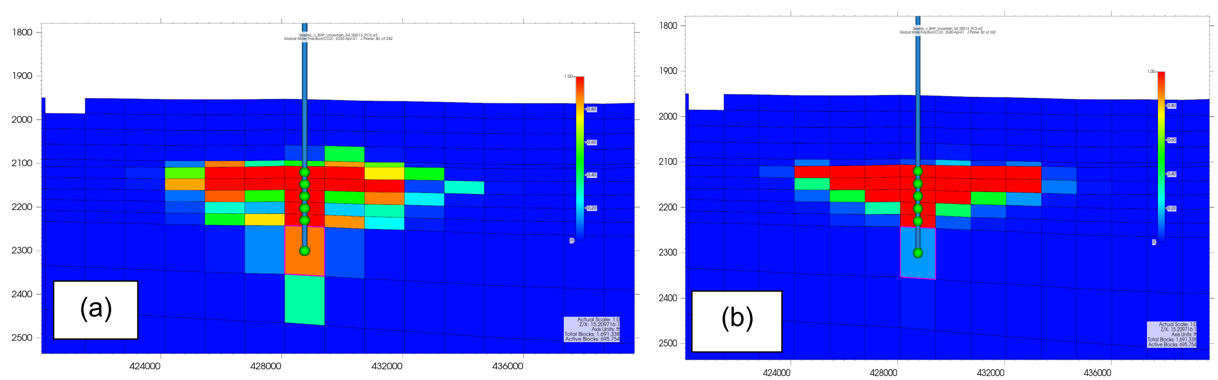


Figure 9. Monitoring on the CM1 with Pc of 50 psi for (a) 5, (b) 15, (c) 25, and (d) 30 years resulting in the radius of 3000 ft, 5000 ft, 5500 ft, and 6000 ft, respectively



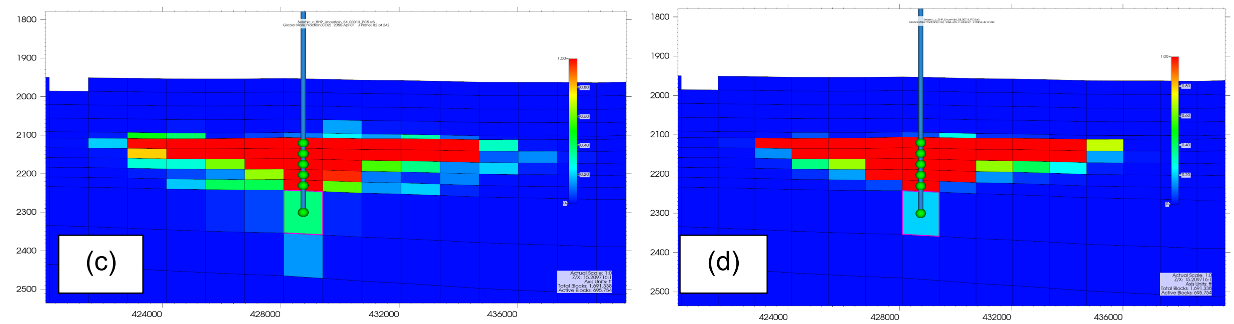


Figure 10. Monitoring on the CM1 well with Pc of 100 psi for (a) 5, (b) 15, (c) 25, and (d) 30 years resulting in the radius of 3437 ft, 4375 ft, 6000 ft, and 6250 ft, respectively

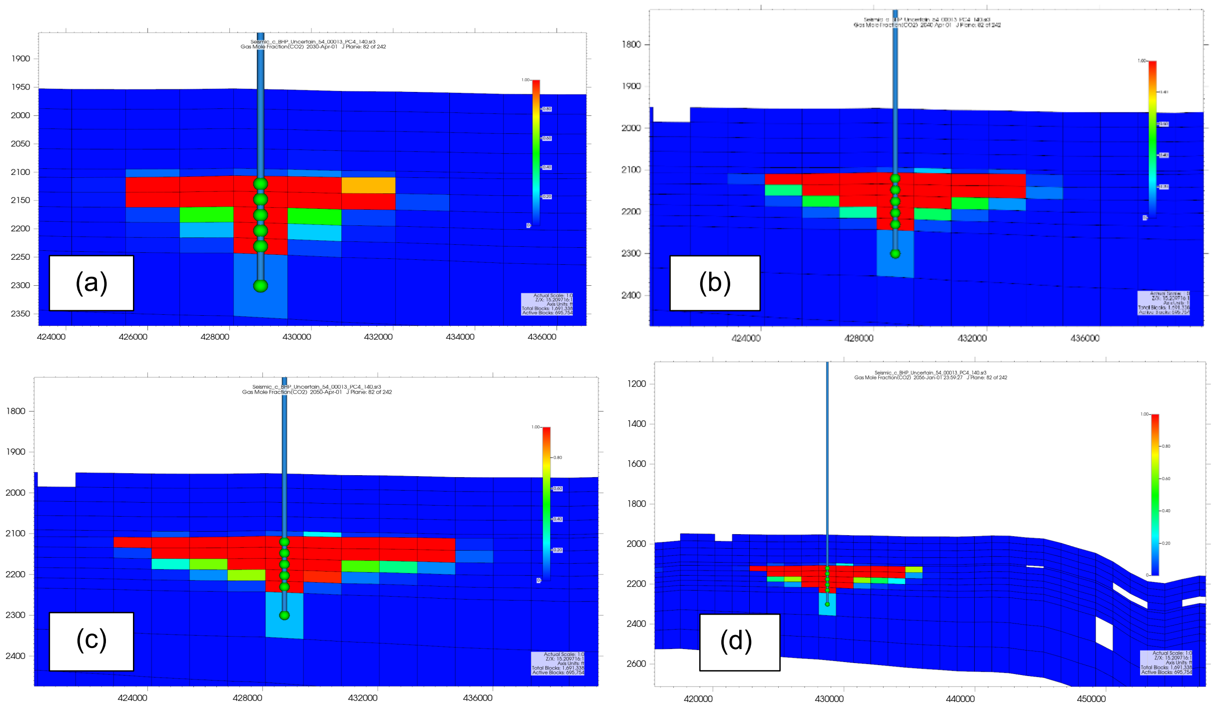


Figure 11. Monitoring on the CM1 with Pc = 140 psi for (a) 5, (b) 15, (c) 25, and (d) 30 years resulting in the radius of 3400 ft, 4600 ft, 6000 ft, 6250 ft, respectively

Figs. 9. and 10 illustrate that the Pc threshold pressure for shale can be breached at 50 psi. Moreover, when the shale's psi is set to 105, the Entrada Pc is slightly above the shale's; this results in breaches. Permeability is also considered in this phenomenon, as shown in Figure 12. In this case, this small amount cannot be detectable on the top 3rd layer of Summerville. From Figure 11, Summerville shows no sign of breach at Pc 140 psi in low permeability. Despite the lack of pc scenario, the geological permeability model for Todilto displays an optimistic model, with a carbon footprint can reach 3rd Summerville layer. In spite of this, there are no breaches in the 2nd Summerville layer, as shown in Figure 17.

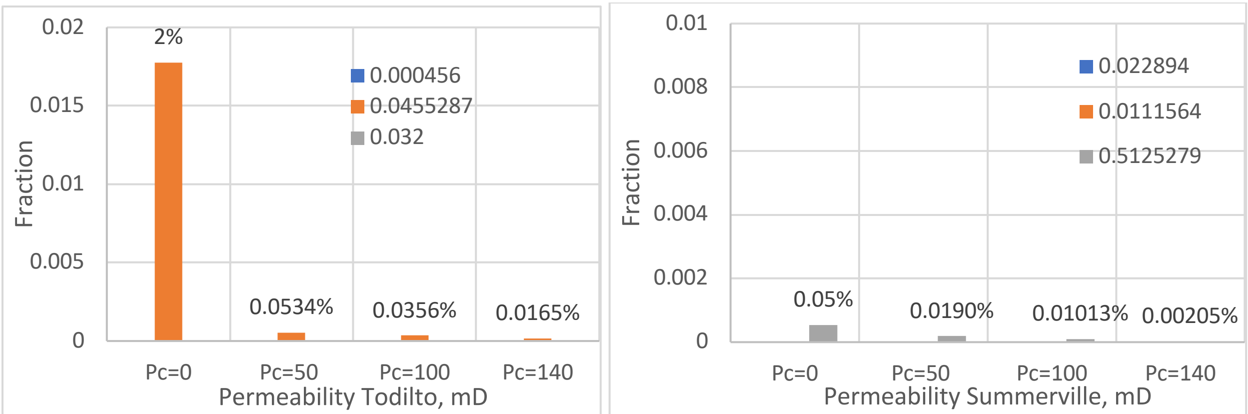
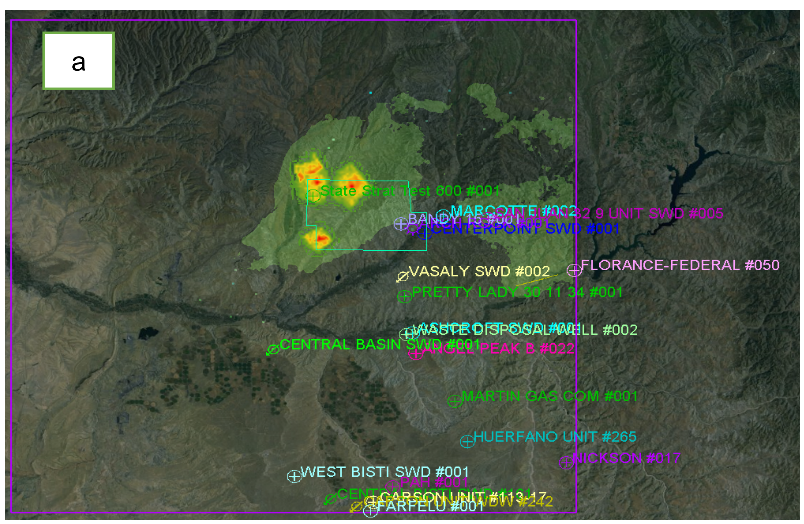


Figure 12. CO_2 Leakage fraction volume of CO_2 injection cumulative on each permeability at various Pcs in the Todilto and Summerville formations

4.2. AoR Delineation with 3 injector wells

The workflows also offer an uncertainty analysis of the best possible solutions including an operational and sequestration development plan while selecting the optimum goal which is to minimize the AoR and maximize cumulative CO_2 injection. The main output is optimal development operation in the best locations for infill wells. The selection of scenario 54 has met the objective, as shown in Figure 13(a) which has a minimum AoR of 160000 grid quantity and a minimum of 50 MMton. This study also mitigates risk that improves the sequestration decision plan. In Figure 13(b), the green circle line indicates AoR within a 14-mile diameter encircling the gas plume saturation.



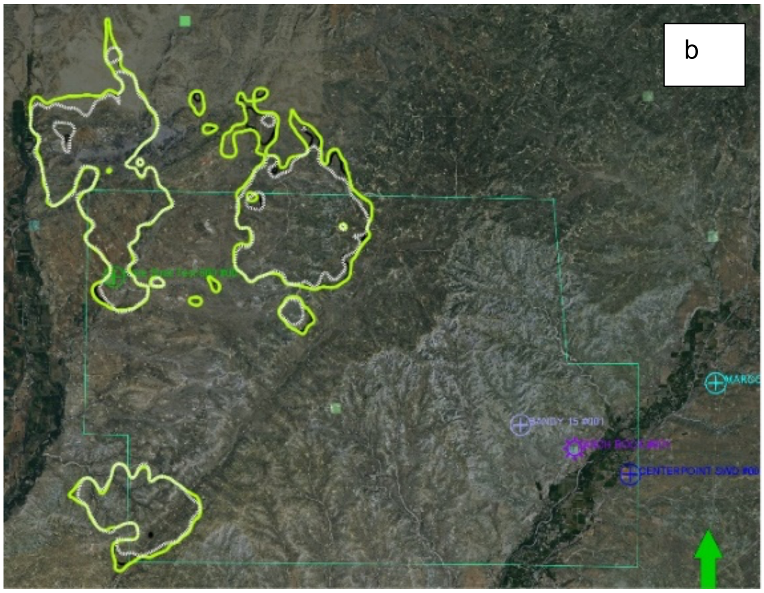


Figure 13. a) 30 years of Plume monitoring (white), 100 years of monitoring (black), 150 years of monitoring (green), and b) AoR delineation using Hydrostatic case for three injectors with 2 (of 3) risk wells

This study has used a probabilistic method using scenario 54, to have total of 69 scenarios. This is an integrated approach to field development simulation that accounts for the uncertainty in dynamic parameters, with a particular focus on the impact of spatial and temporal variability in bottom-hole pressure CO_2 sequestration, however from Figure 14, the gas injection rate does not influence injectivity performance.

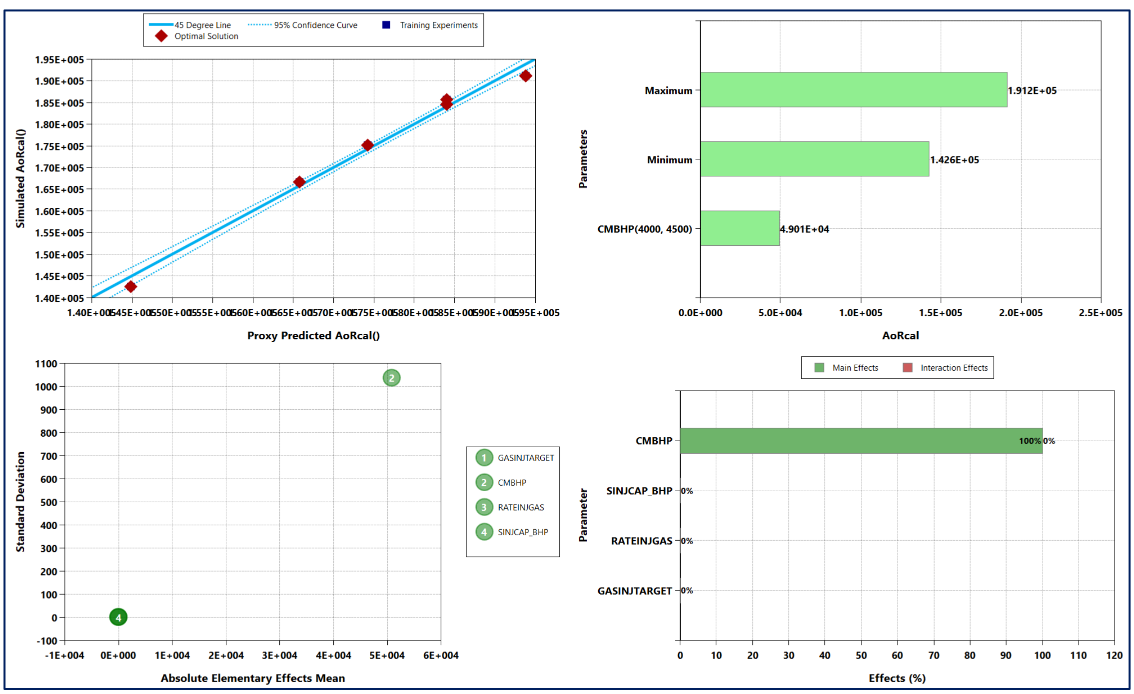


Figure 14. Probabilistic distribution of parameters with PSO engine 3 wells scenario

The experiment tables were performed by running CMOST-CMG using an optimization engine. The result for scenario 54 on which three wells that have relatively injectivity conformance will have more distributed pressure. Therefore, it is concluded that three injection infill wells have a storativity CO_2 volume of 50-59 MMton.

There is an estimated storage capacity of 50 million tons for three infill wells (scenario 54). In other words, CO_2 storage within the Entrada layer is only 57 million tons at the end of the simulation. Based on Figure 15, the peak rate injection rate for each well of SJBS1, Sinj1, and CM1 is around 57, 36, and 18 MMScf/day, respectively. The permeability of infill wells is the most significant factor for their CO_2 injectivity performance.

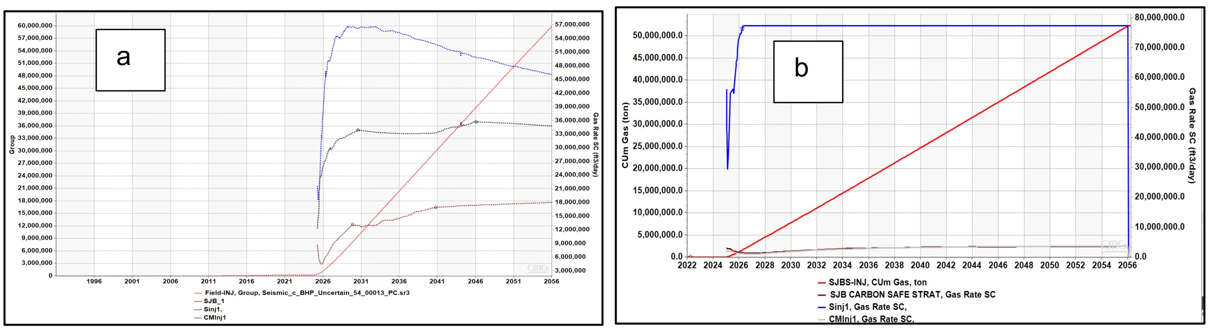


Figure 15a.Cumulative injection of CO_2 gas for 3 injectors 15b. Cumulative injection of CO_2 for a focused single injector well

4.3. AoR Delineation with a focused single injector well

Understanding the effects of supercritical CO_2 gas plumes on capillary pressure is essential for carbon capture and storage (CCS) applications. Carbon dioxide injection can form a supercritical gas plume on capillary pressure at high pressure and temperature. After gas is injected into pore spaces, the formed CO_2 gas plume displaces the original fluid, causing a pressure gradient that drives the fluid flow. An interface between a water or oil phase and a non-wetting phase (CO_2) has a capillary pressure equal to the difference in pressure that drives the fluid flow.

In this prediction scenario, there is scenario 66, which has minimum AoR delineation and reaches 50 MMton. This scenario shows only 6 categorized wells that need corrective action plan wells. The probabilistic study shows that the maximum storage volume for one well in this study is only in the range of 50 to 57 MMton. It must also be done on a narrower area with other configuration well placement to get more storage volume.

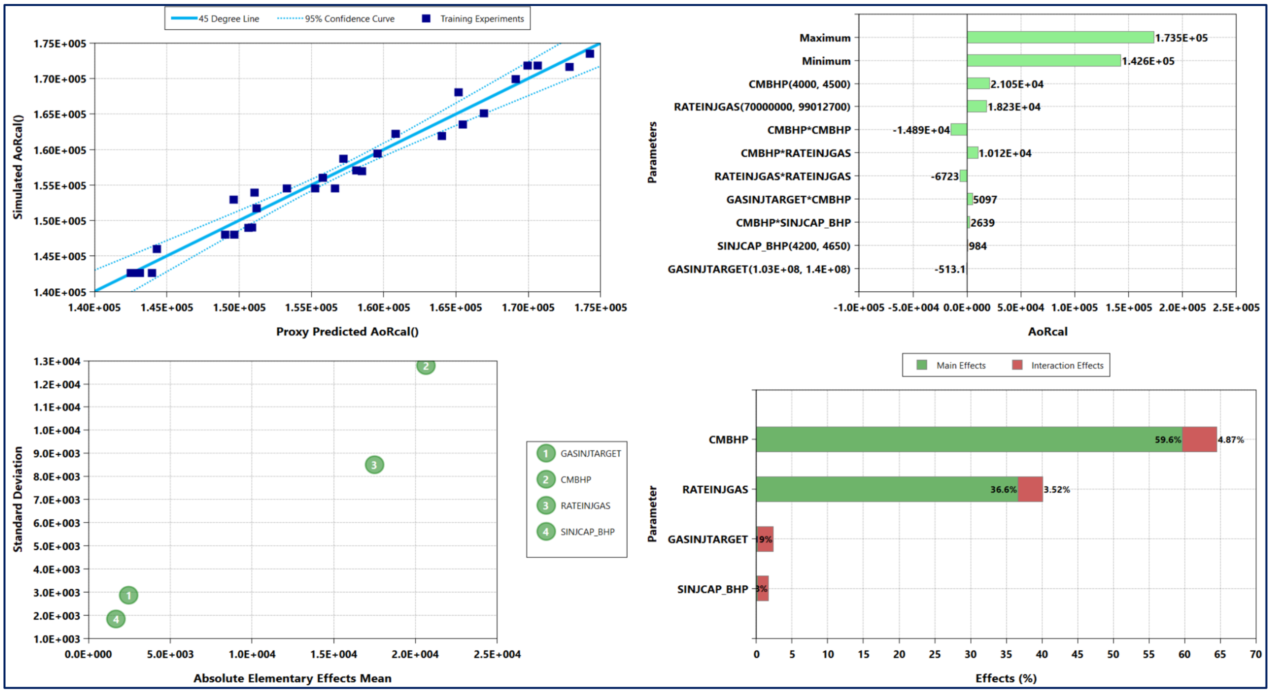


Figure 16. Probabilistic distribution of parameters of PSO engine for a focused single injector well

It can be seen that all possible field operation aspects include the injection gas, gas monitoring target, gas injection target, and BHP of shale, with a total scenario of 116 scenarios. The risk of using variables has been reduced, as seen from the narrower distribution of the final alignment results compared to the initial study design. However, when using this variable in the optimization process, injectivity performance, well placement, operation condition, and the bottom hole pressure have tremendous effects on the objective function shown in Figure 16.

The capillary entry pressure is particularly important in the shale caprock case due to its low permeability. Incorporating the capillary entry pressure into the model is essential to accurately predict the CO_2 behavior within the reservoir and prevent potential leakage through the caprock. This will ensure the integrity of the caprock and CO_2 sequestration operations safety. Without Pc, the caprock shale model which has a permeability value of 0.001 mD, has potential leakage into the USDW after 7 years of CO_2 injection (Figure 17). However, another option is to use pessimistic permeability shale on the geological model to avoid the sequestration reach into the 3rd Summerville layer.

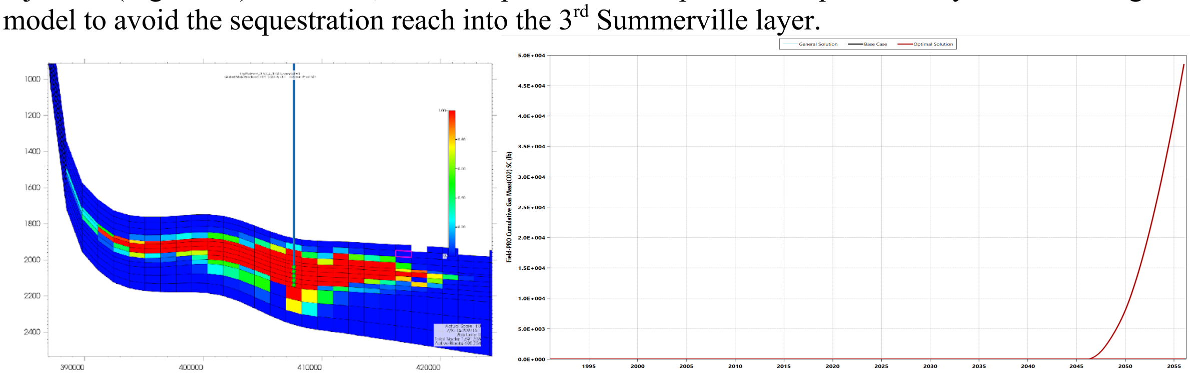


Figure 17. CO_2 leakage cumulative on the caprock of the Todilto layer

Using CMOST-CMG, the leverage tools and machine learning found that those experiments conclude that a single injection infill well can cause higher pressure build-up. However, it is still possible to store a significant volume of CO_2, between 50-57 MMton, with a BHP injector constraint of 4100-4250 psia. This is because a lower BHP reduces the pressure in the well, reducing the possibility of fractures and resulting in smaller AoR delineation. However, this focused single injector well has experienced higher pressures and has a slightly wider AoR delineation than the 3 injector wells.

As the result of the probabilistic cases, this hydrostatic pressure method case for scenario 66 demonstrates an area of extent of a layer of AoR receiving the total anticipated volume of 57 MMton of the carbon dioxide stream in 180.000 grid quantity. This focused single well shows no risk of fault interference within AoR delineation, which lay below the hogback monocline. In the carbon sequestration context, it helps understand the potential impact area of the CO_2 injection and develop appropriate monitoring and mitigation strategies. The AoR profile calculation is shown in Figure 18, where the green circle line indicates AoR within a 15-mile diameter encircling the gas plume saturation. The threshold pressure for the hydrostatic case is given as 50 psia. Within this AoR delineation boundary, it has been suggested that 6 water injection wells need to be revisited.

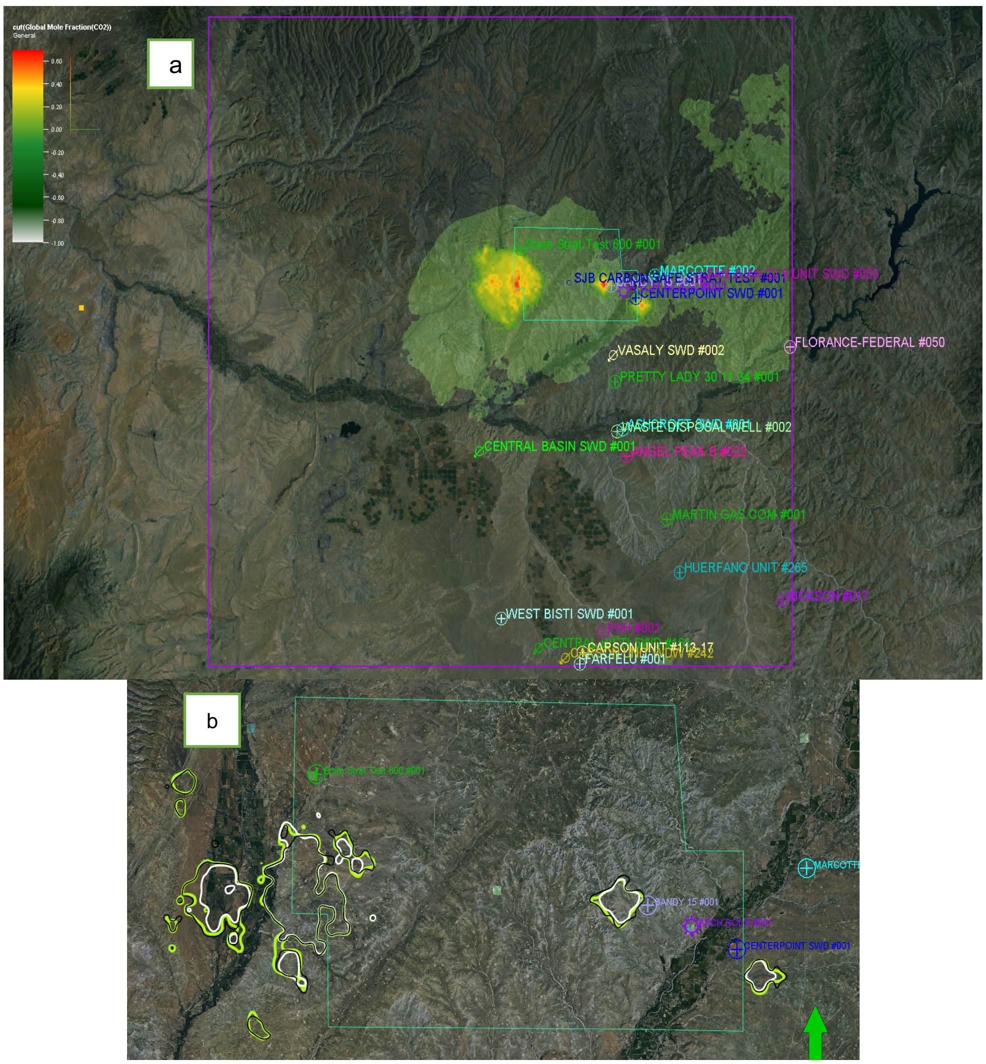


Figure 18. a) AoR delineation using Hydrostatic case for one focused injector well with 3 risk wells (of 6) b) 30 years of Plume monitoring (white), 100 years of monitoring (black), 150 years of monitoring (green)

4.4. Well Risk Integrity

Well integrity is important to analyze because it has been identified as the biggest risk contributing to the leakage of CO_2 from underground storage sites. EPA has identified major contamination pathways; CO_2 can escape from the target injection reservoir layer through hypothetical conduit wellbore and enter USDWs. Therefore, it is essential to identify and evaluate the interference wells and their potential impacts on the project's performance and safety.

Through the Optimization of Neural Network, the AoR delineation has been shrunk into 30 miles diameter coverage for 6 risky wells that need to be revisited for scenario 66 which has a focused single injector well, yet scenario 54 offers 3 candidate injector wells that have only a 14-mile radius which has 2 wells that need to be revisited. The list of risks through injector wells is in Table 4.

Table 4. List of well risks based on AoR on 1 focused injector well and 3 injector wells

Well	Info	AoR 1 well	AoR 3 wells
State Start Test 600	No Data	x	x
Brandy 15	Good	√	
Arch Rock 001	Mud Loss	x	
Centerpoint SWD 001	Good	√	√
San Juan 32 9 swd 005	Good	√	
Florance Federal	No Cement	x	x

It is necessary to conduct further investigation (both by field survey and well mechanics) to confirm as categorized as risk wells to perform corrective plans as stated on EPA 40 CFR 146.84.

5. Conclusions

This study aims to demonstrate the caprock integrity of the AoR delineation risk zone in an ongoing CarbonSAFE Phase III San Juan Basin project. Appropriate historical fields to diagnose and quantify the saline aquifer characterization. Based on the discussions from the previous section, the following conclusions can be summarized:

- Entrada is the effective formation for effective storage of 50 million metric tons and has sealing capability. The Todilto Formation confining zone is overlain by the competent Summerville Formation.
- Using Capillary pressure in the model has effectively sealed the Carbon Sequestration in the San Juan Basin. Todilto and Summerville show a more optimistic permeability model that needs to be revisited.
- Using Neural Network Optimization for AoR delineation has been shrunk into 2 cases: a 30-mile diameter coverage for 3 risky wells with a focused single injector well, and 3 candidate injector wells that have only a 14-mile diameter and have 2 risky wells that need to be revisited.
- The AoR delineation has been done using hydrostatic methods showing that 3 injectors have more distributed pressure than 1 focused injector. Identifying the depth of the lowermost USDW and the depth of injection zones is essential to delineate the AoR on the smaller 3-well case which has a diameter of only 14 miles, rather than the 1 focused injector that has a diameter of 30 miles. However, the 3 wells have risky fault locations, yet a focused single well shows no risk fault interference which AoR delineation lay below the hogback monocline.

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