Southwest Regional Partnership on Carbon Sequestration (Phase III)

Topical Report: Quantitative Risk Assessment

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Abstract

Carbon capture, utilization, and storage (CCUS) in geological formations plays a key role in mitigating anthropogenic CO_2 emissions and achieving the aggressive goal of net-zero greenhouse gas emissions. Quantitative risk assessment is crucial for ensuring the safety and reliability of geologic carbon storage (GCS) by evaluating CO_2 migration in subsurface, forecasting potential leakage and induced seismicity risks, and optimizing operational and monitoring plans. We present the use, progress, and research trends of risk assessment from the Southwest Regional Partnership on Carbon Sequestration (SWP) as an example of large-scale CCUS projects in North America. The information provided in this report can help readers understand the significance of risk and uncertainty assessment and apply them effectively in large-scale CCUS projects.

Table of Contents

List of Figures

List f Tables

1. Introduction

The demand for low-carbon energy sources is increasing worldwide to mitigate the effects of greenhouse gas emissions and limit the rise of global average temperature. The United States (U.S.) has set an ambitious goal of achieving a carbon-pollution-free power sector by 2035 and net-zero greenhouse gas emissions by 2050 [1]. Carbon capture, utilization, and storage (CCUS) in geological reservoirs is among the key strategies being employed to achieve this goal and reach mid-century climate targets [2,3].

The Southwest Regional Partnership on Carbon Sequestration (SWP) has conducted its Phase III since 2013, and has successfully injected and stored approximately 800,000 metric tons of CO_2 in an active CO_2-enhanced oil recovery (CO_2-EOR) site, the Farnsworth Unit (FWU) in northern Texas [4–6]. The SWP project has demonstrated commercial CCUS field operations, including reservoir engineering, monitoring, simulations, and risk evaluations, to ensure safe and secure sequestration of CO_2. The SWP project has also contributed significantly to the development of best practices manuals for geologic carbon storage. Overall, the SWP project has made substantial progress in advancing the commercial deployment of CCUS technologies, providing valuable insights and lessons for future CCUS projects.

Quantitative risk and uncertainty assessment for the SWP FWU project includes CO_2 storage capacity and trapping mechanisms, leakage pathways through wells and caprocks, CO_2 leakage into overlying USDWs, and geomechanical risks and induced seismicity [7]. Geo-cellular models created with characterization data, along with advanced approaches have been employed to improve the effectiveness of risk quantification. This report reviews the latest findings of risk and uncertainty assessment and provides insights from the SWP project, to guide future risk assessment applications in large scale CCUS projects.

2. Geomechanical Risk and Uncertainty

The investigation of geomechanical risk assessment – specifically, caprock failure – attributable to CO_2 injection, as presented in a simplified hypothetical geological model, was the focus of research undertaken by Lee et al. [8]. Their comprehensive approach amalgamates the implementation of a multilaminate model [9], the creation of a Response Surface Model [10] in conjunction with the Box-Behnken design, the execution of associated numerical modeling experiments, and the utilization of Monte Carlo simulations. Probability distributions to encapsulate the inherent variability (elastic and mechanical properties of the caprock and aquifer formations) and uncertainty in prediction estimates (vertical displacement, total strain, and F value) were employed. This approach allows for a thorough probabilistic evaluation of caprock failure in association with CO_2 storage.

Lee et al. [8] concluded that while the Young's modulus of the caprock is the primary determinant of equivalent total strain, it does not provide a reliable measure for caprock integrity. The caprock can accommodate significant deformation without failure, if it possesses a low Young's modulus and high mechanical strength properties, such as the friction angle and uniaxial compressive strength. Similarly, vertical displacement was found to be an unreliable indicator for caprock integrity, as caprock failure can occur across a broad spectrum of vertical displacements, particularly when both the Young's modulus and mechanical strength properties have wide ranges. The study identified the F-value as the most dependable indicator for caprock failure, although it is a theoretical attribute (the shortest distance between the Mohr circle and the nearest failure envelop used to measure the sensitivity to failure) and not physically measurable in the field. Deviatoric stress levels were found to vary based on stress regimes, with the maximum levels observed under extensive and compressive stress regimes. Lastly, the study demonstrated the efficacy of the multilaminate framework and the Mohr-Coulomb constitutive model in providing a simplified, yet effective, probabilistic model of the mechanical behavior of fractured rocks, reducing mathematical and computational complexities.

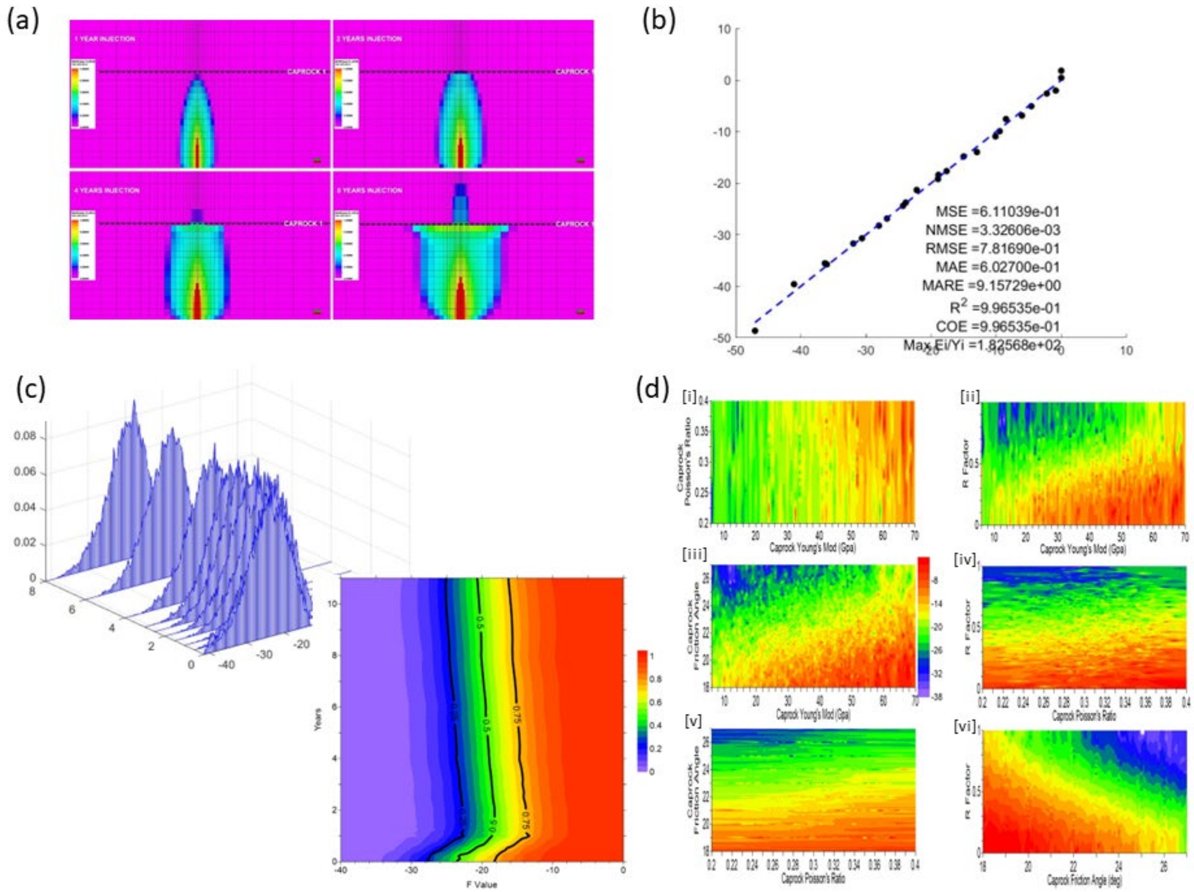

Figure 1. Simulated CO_2 gas saturation during injection for case #12 (a), cross-plot of observed vs. predicted F value at t=1 year (b), PDFs and contour map of CDF for F value (c), F-value after 1 year injection [i] caprock Poisson's ratio vs. caprock Young's modulus, [ii] caprock friction angle vs. caprock Young's modulus, [iii] caprock friction angle vs. caprock Poisson's ratio, [iv] R' index vs. caprock Young's modulus, [v] R' index vs. caprock Poisson's ratio, and [vi] R' index vs. caprock friction angle.

3. Risks of Storage Capacity and Reservoir Performance

In the FWU CO_2-EOR project, the primary objectives are to enhance oil production and to permanently sequester as much CO_2 as possible. The uncertainties of co-optimization of CO_2 sequestration and oil recovery were quantified with Monte Carlo sampling, response surface methodology (RSM), and machine learning (ML) approaches (Fig. 2) [11–14]. Critical uncertainty parameters of reservoir permeability, reservoir permeability anisotropy, water alternating gas (WAG) cycle, bottom hole injection pressure, initial oil saturation, and oil price were identified. These studies provided useful insights for understanding the potential of CO_2 sequestration at a CO_2-EOR site and increasing the confidence level for decision-making and management to optimize field operations.

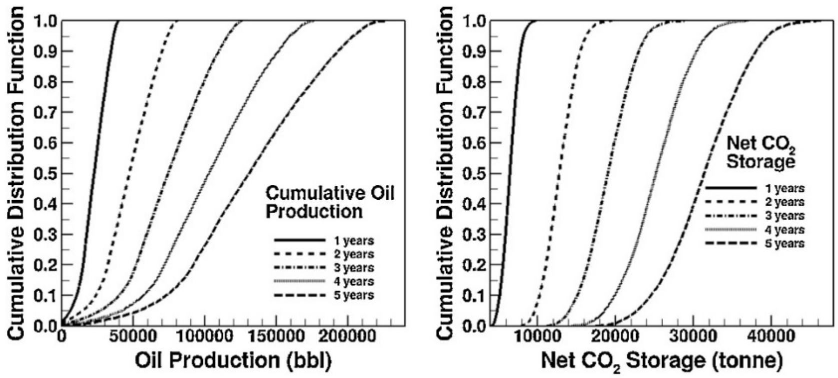

Figure 2. Cumulative distribution functions (CDFs) of emulated cumulative oil production and net CO_2 storage using response surface models [12].

Long-term CO_2 storage capacity and trapping mechanisms at the FWU were evaluated through numerical simulations and polynomial chaos expansion (PCE) [15–17]. The trapping mechanisms of hydrodynamic trapping, oil dissolution trapping, aqueous dissolution trapping and mineral trapping were specifically evaluated (Fig. 3). Results suggest that hydrodynamic trapping and oil dissolution trapping are the two major trapping mechanisms (Fig. 2 (b)) [15,18]. Mineral dissolution near the injection well may cause up to a 2.7% increase in porosity with WAG cycles by the end of injection phase, and precipitation near the production well may cause porosity reduction after 1,000 years, indicating slight mineral trapping [16]. In a risk assessment study of the FWU, mineral trapping after 600 years could be from negligible to 10% with low and high reactive surface area (RSA) settings (Fig. 2 (c)) [17].

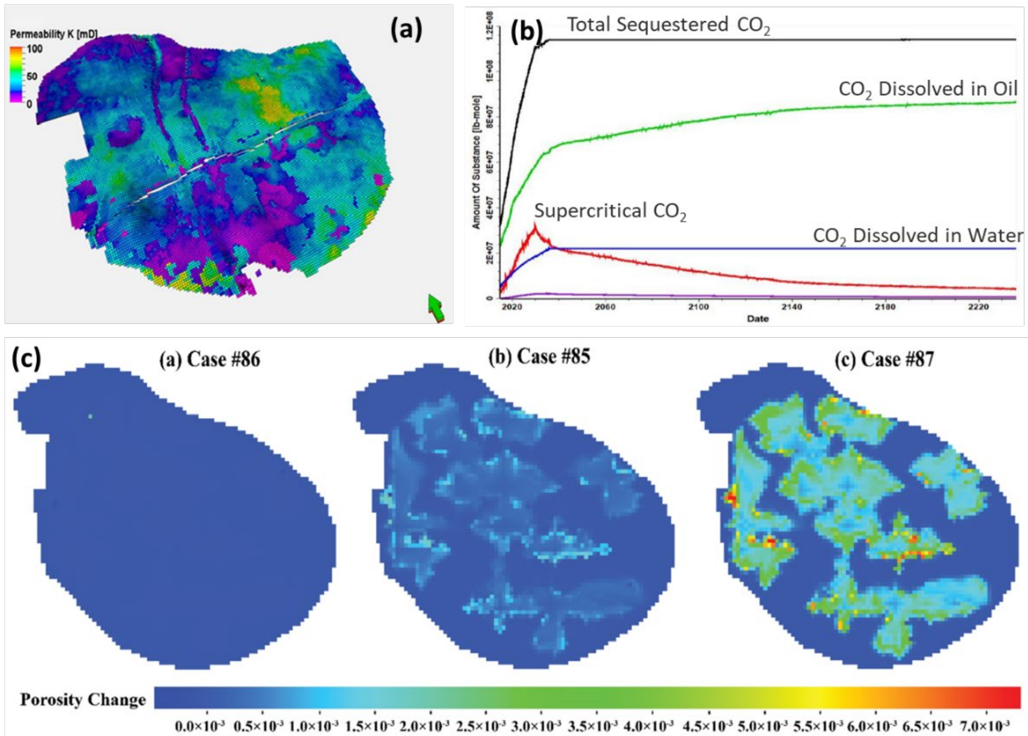

Figure 3. Long-term CO_2 trapping mechanisms at the FWU: (a) the FWU reservoir model [18], *(b) simulated major trapping mechanisms over time* [18], *and (c) simulated porosity loss after 600 years* [17].

4. Quantitative Brine and CO_2 Leakage Risk Assessment

4.1. Legacy Well Leakage Risk Assessment by the NRAP Tool

Potential CO_2 and brine leakage from legacy wells at the FWU was analyzed using National Risk Assessment Partnership (NRAP) tools of Integrated Assessment Model for Carbon Storage (NRAP-IAM-CS) [19] and Reservoir Reduced-Order Model Generator (RROM-Gen) [20].

Storage reservoir simulation results of 11 permutation scenarios provided different pressure and CO_2 saturation results as the input for the leakage risk assessment. Simulation duration was assigned with 25 years of injection and 50 years of post-injection site care (PISC) period. These fields were converted by RROM-Gen and inputted to the NRAP-IAM-CS for risk quantification of CO_2 and brine leakage calculations. About 31 legacy wells were identified as potential leakage pathways (Fig. 4). Several different wellbore permeability probability distribution models were examined (Table 1). In each case, 1,000 realization probability simulations were conducted by sampling among the 11 reservoir simulation results (MS8 topical report).

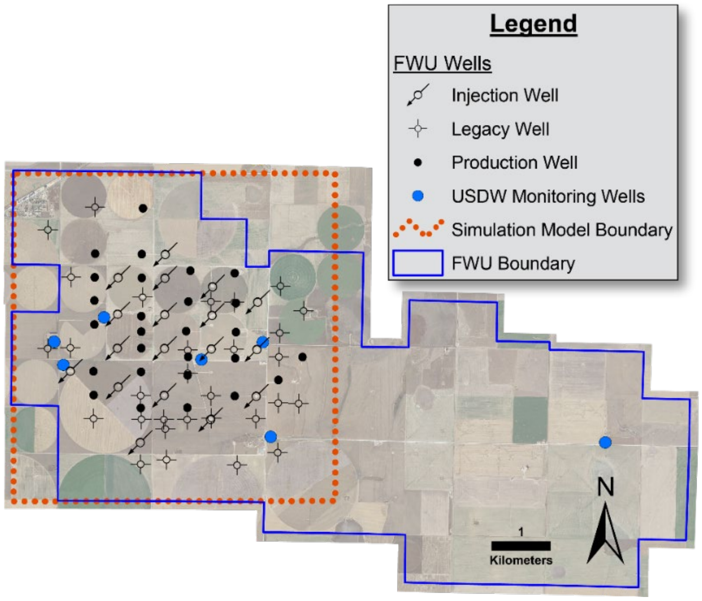

Figure 4. Injection wells, legacy wells, and shallow groundwater monitoring wells in the FWU.

Table 1. Wellbore integrity permeability distribution of different cases.

Model	Distribution Type	Wellbore Permeability (m^2) Minimum	Medium	Maximum
Alberta	Uniform	10^{-20}, 95.4%	10^{-17}-10^{-14}, 4.4%	10^{-13}-10^{-12}, 0.2%
Gulf of Mexico	Uniform	10^{-20}, 88%	10^{-17}-10^{-14}, 11.4%	10^{-13}-10^{-12}, 0.6%
FutureGen_Low	Log-normal	10^{-20}, 90%		10^{-17}-10^{-15}, 10%
FutureGen_High	Log-normal	10^{-20}-10^{-18}, 90%		10^{-15}-10^{-13}, 10%
Open Well (hypothetical)				Open wellbore, 100%
Cemented Well (hypothetical)				5×10^{-11}, 100%

The results suggest that multiple factors can affect the potential CO_2 and brine leakage risk, such as wellbore pressure, CO_2 saturation in the reservoir, the distance between a legacy well and the nearby injection wells, and wellbore integrity condition. In the worst scenario of open well condition for all the legacy wells, the results suggest that about 10,000 tons (0.1% of the total injected CO_2 of about 10 million tons) may leak into the overlying underground source of drinking water (USDW) aquifer at the end of 50 years PISC period. With the cement well setting for all the legacy wells and hypothetically assuming all wellbores fail, the accumulative leakage at the end of PISC period is 0.04% of the total injected CO_2. Per Table 1, the likelihood of these two well integrity scenarios is near zero. Details of this assessment can be referred to the Milestone Report MS8 and Chu et al., [20].

4.2. Wellbore and Caprock Leakage Risk Assessment

Leakage risks through wellbores, caprocks, and faults at the FWU were evaluated using multiple approaches, including response surface methodology (RSM)[21], two-way coupling of hydrodynamic flow and mechanics simulations [22,23], reactive transport simulations calibrated with field observations [24], coupling of reactive transport and mechanics simulations [25], and interpretations of seismic reflection datasets [26] (Fig. 5). Results suggest that wellbore cement would maintain its integrity and structure after 100 years of interacting with CO_2. However, when CO_2 flows through any fractures between the cement and caprock, there may be a higher risk for the limestone caprock integrity [24]. CO_2 migration into the caprock and mineralogy alteration may be minimal without pre-existing fractures connecting the reservoir and the caprock because of a high capillary entry pressure [25]. According to evaluations on geomechanics changes at the field, it is unlikely for induced fractures to occur in the caprock, or for CO_2 to escape from either the caprock or the existing faults [22,23,25,26].

By considering up to 10% potential fracturing zones (micro fractures/cracks) of the FWU wellbores with permeability of 10^{-14} m^2, CO_2 leakage through wellbores could be negligible (< 10^{-10} kg/(m^2·year)) because (1) lack of continuous leakage channels and (2) being trapped by cement [21]. These results indicate low risks on sealing formation integrity and potential risks.

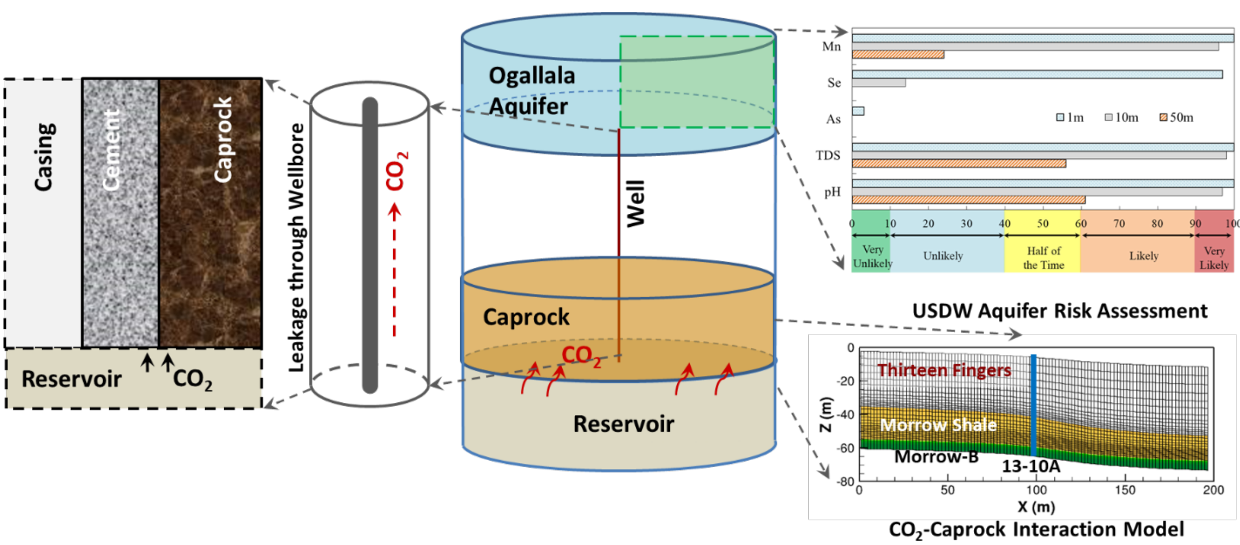

Figure 5. Quantitative risk assessment of potential leakage through wells and caprock.

Natural seismicity around the FWU was characterized within a region approximately 180 km × 220 km [27]. This study suggests that the seismic risk for commercial-scale CO_2-EOR and storage at the FWU is low. A borehole geophone array consisting of 16 three-component geophones and a surface seismic array with 20 stations were deployed to monitor induced microseismicity at the FWU. Few microseismic events were detected using the surface seismic array. Continuously recorded borehole microseismic data were analyzed, and a few high-frequency (150-350 Hz) microseismic events and more than 13,000 low-frequency events (5-50 Hz) were detected from August 2019 to June 2021. The magnitudes of most detected microseismic events range from -1 to 0.5.

4.3. Potential Chemical Impacts of Leakage on the USDW Aquifer

The Ogallala (High Plains) aquifer, the largest USDW in North America, lies above the FWU. It is a major source of water for irrigation and municipal needs in northern Texas and the only USDW aquifer in the FWU area [28]. Quarterly shallow groundwater monitoring measurements date back to 2013, with no evidence of reservoir fluid infiltration into the Ogallala aquifer at the FWU. Samples of the Ogallala were collected, and CO_2-sediment interaction and trace metal release mechanisms were evaluated using laboratory-scale batch and column experiments, as well as numerical simulations (Fig. 6) [29–31]. Results suggest that CO_2 intrusion into the Ogallala sediment leads to calcite and dolomite dissolution, which releases trace metals of Mn, Zn, and U into the aqueous phase because of their impurities. Both carbonate mineral impurity and cation exchange dominate the mechanisms of trace metal release.

Risk assessment with RSM considered potential CO_2 leakage rates ranging from 0 to 30,000 kg/year (1g/s) from a single legacy well [21,32]. Results suggest that it is highly possible of detecting changes in pH, total dissolved solids (TDS), and Mn concentration within a 10 m radius from the leaky well after 10 years of leakage. However, the distance between monitoring wells and legacy wells could reach up to 1,000 m, indicating it may be difficult to detect a leakage plume solely through shallow groundwater monitoring. Effective early detection may require the use of multiple tools, such as borehole CO_2 monitoring, 4D seismicity, and water samples from deeper saline aquifers.

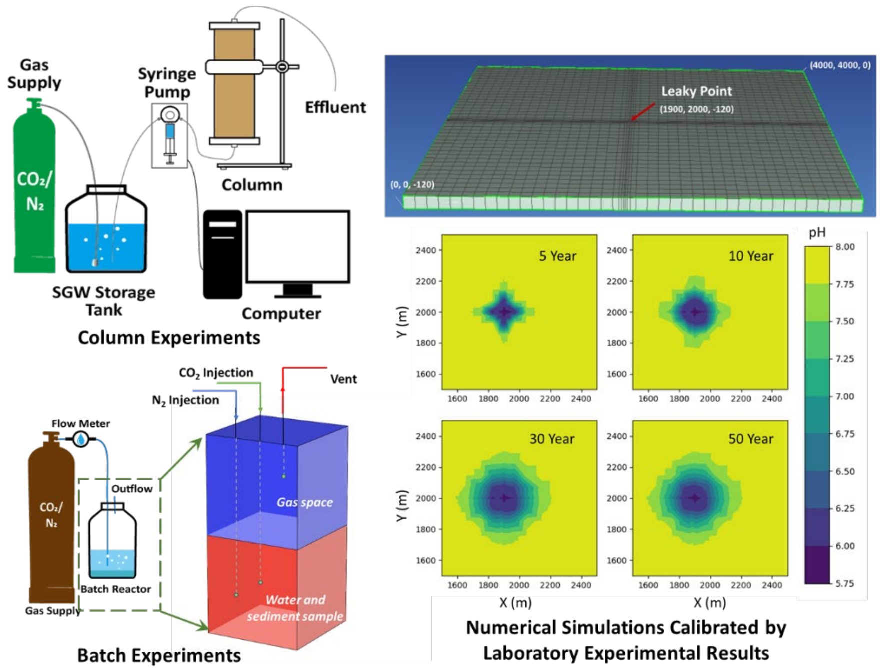

Figure 6. Approaches of potential chemical impacts of CO_2 leakage on the USDW aquifer.

5. Uncertainty Reduction

Risk assessment of potential leakage relies on effective reservoir modeling and simulations. Over time, as computational capacities advance and site characterization data expand and improve, reservoir simulation models evolved through several generations since the SWP FWU project (refer to Fig. 7). To quantify potential leakage (and risk of that leakage), NRAP tools and simulation results from each generation of reservoir models were used. Findings suggest that updating simulation models with site-specific characterization data is critical, as the uncertainty of the forecasted leakage rate was reduced (Fig. 7 (d)).

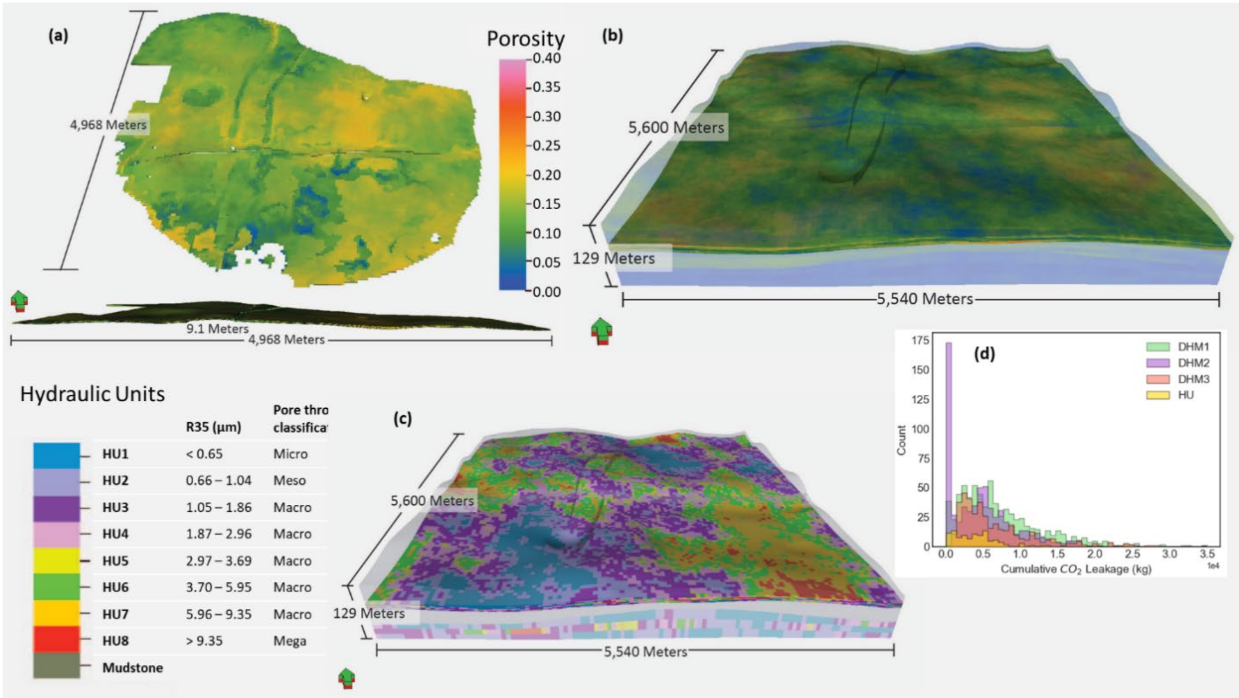

Figure 7. Reservoir simulation models created over time and the forecasted accumulative CO_2 leakage with different generations of reservoir models: (a) first generation of dynamic history match (DHM) model (2015 and 2016, DHM1 and DHM2) [33], *(b) updated DHM model (DHM3), (3) updated DHM model with hydrostratigraphic units (HU)* [34], *and (4) the forecasted accumulative CO_2 leakage at the end of simulation after 72 years (22 years injection and 50 years post-injection monitoring). Uncertainty reduces with the updates of the reservoir models.*

6. Summary

Risk assessment is crucial for CCUS projects, and it has been largely developed in the past ten years with numerous advanced approaches. With the goal of net-zero greenhouse gas emissions by 2050 in the U.S. and the recent amendment of the 45Q tax credit for GCS, CCUS has greatly increased the attractiveness for investment. Intensive risk and uncertainty assessment should be applied to ongoing and new CCUS projects. The SWP reached many major accomplishments and identified best “lessons learned” from risk assessment of the FWU project, serving as an example of a risk assessment framework for commercial-scale CCUS projects. A detailed overview of risk assessment in the SWP project can be also found in Xiao et al. [7].

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Disclaimer

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