MODELING AND SIMULATION OF C02 SEQUESTRATION IN A DEPLETED RESERVOIR USING CMG-GEM

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CERTIFICATION

This is to certify that this project work titled: **MODELING AND SIMULATION OF CO2 SEQUESTRATION IN A DEPLETED RESERVOIR USING CMG-GEM** was carried out by EDERHEHWEVWE EMUDIAGA with the Matriculation Number **ENG2002605** of the Department of Petroleum Engineering, Faculty of Engineering, University of Benin, Benin City, Edo State, Nigeria

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DEDICATION

This work is dedicated to Almighty God, whose grace and strength made every step of this journey possible.

To my family, for their endless love, sacrifices, and prayers that kept me going.

And to my friends, for their encouragement, laughter, and unwavering support through it all.

This achievement is as much yours as it is mine.

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ABSTRACT

This research focuses on modeling and simulating CO_2 injection and storage in a depleted sandstone reservoir using the CMG-GEM compositional simulator to evaluate the potential of geological carbon sequestration as a sustainable emission reduction strategy. A 3D reservoir model was constructed based on available structural and petrophysical data to replicate the dynamic behavior of CO_2 during and after injection. The simulation was performed under varying pressure and compositional conditions to assess injectivity, storage capacity, and reservoir response over a 69-year period.

Results revealed effective CO_2 migration through the formation, with plume dispersion influenced by permeability variations across the ten layers. The estimated total CO_2 storage capacity of the reservoir was approximately 136,863 tonnes, indicating substantial potential for long-term containment. Pressure analysis showed a gradual and controlled buildup within safe limits, confirming caprock stability and the absence of leakage or fracture risk. Additionally, the molality plots demonstrated consistent distribution of CO_2 within the formation, with concentration stabilization after a five-year halt and resumption of injection in 2050, reflecting strong reservoir retention.

Overall, the study confirms that the selected depleted reservoir can serve as a viable site for CO_2 sequestration. The findings also highlight the importance of optimizing well placement, incorporating residual and mineral trapping mechanisms, and extending simulation timeframes to improve prediction accuracy and long-term storage performance.

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CHAPTER ONE

1.0 INTRODUCTION

The need for accurate and reliable methods to analyze and predict subsurface fluid behavior has become essential in modern petroleum engineering. Reservoir simulation serves as a virtual laboratory that helps engineers understand how fluids such as oil, gas, and water move within a reservoir under different production and injection conditions. It bridges the gap between theory and real field performance, allowing better decision-making in field development, production planning, and environmental management.

Over the years, simulation tools have evolved from simple analytical models to advanced compositional simulators capable of handling complex multiphase flow problems. One such advanced simulator is the Computer Modelling Group – General Equation of State Model (CMG-GEM), which can model gas injection, compositional changes, and carbon dioxide (CO_2) sequestration processes within the reservoir.

This study centers on evaluating the potential of a depleted oil and gas reservoir for long-term carbon dioxide (CO_2) storage using compositional reservoir simulation. By constructing a static grid and running dynamic simulations, the research aims to understand how much carbon dioxide (CO_2) the reservoir can hold, how it moves within the formation, and how securely it can be trapped over time.

1.1 BACKGROUND OF STUDY

Climate change persists as one of the most pressing challenges of our time, fueled by the relentless rise in anthropogenic carbon dioxide (CO_2) emissions originating from the combustion of fossil fuels for energy and industrial processes (Intergovernmental Panel on Climate Change [IPCC], 2014). Stabilizing the atmospheric concentration of CO_2 is not merely an environmental aspiration but a fundamental prerequisite for achieving the ambitious targets outlined in international agreements, most notably the Paris Agreement, which aims to limit global warming to well below 2°C above pre-industrial levels. While the global deployment of renewable energy sources like solar, wind, and geothermal is accelerating at an unprecedented rate, the stark reality is that fossil fuels continue to constitute the backbone of the world's energy supply—a situation projected to persist for several decades during the energy transition.

This creates a significant socio-economic dilemma for resource-rich nations such as Nigeria, whose national budgets and economic stability are deeply intertwined with revenues

generated from oil and gas exports (International Energy Agency [IEA], 2021). Consequently, Carbon Capture and Storage (CCS) has emerged as a critical technological pathway, offering a pragmatic transitional strategy that reconciles the continued, necessary use of hydrocarbons with the urgent imperative to drastically reduce their net carbon footprint (Metz *et al*., 2005; Herzog, 2011).

The Carbon Capture and Storage (CCS) process is a sophisticated technological chain that involves three primary steps: capturing CO_2 from large-point emission sources such as power plants and industrial facilities, transporting it (typically via pipeline), and securely injecting it into deep subsurface geological formations for permanent isolation from the atmosphere. A variety of geological formations are considered suitable for this purpose, including deep saline aquifers, predominantly unmineable coal seams, and depleted oil and gas reservoirs. Among these, depleted hydrocarbon reservoirs are frequently regarded as particularly attractive candidates for several compelling reasons. First, they have demonstrably proven their ability to trap buoyant fluids, namely oil and natural gas, over geological timescales of millions of years, providing inherent confidence in their containment security. Second, they benefit from a wealth of existing infrastructure including wells, pipelines, and seismic data that can be repurposed, significantly reducing the capital costs associated with greenfield Carbon Capture and Storage (CCS) projects. Finally, these reservoirs are among the most well-characterized subsurface structures on Earth, having been extensively studied throughout decades of exploration and production activities, which provides a robust geological dataset for risk assessment (Holloway, 2005; Bachu, 2008).

An additional powerful economic driver is the potential to couple CO_2 storage with Enhanced Oil Recovery (EOR). In this process, injected CO_2 interacts with residual oil to mobilize it, increasing overall field recovery while simultaneously sequestering carbon, thereby creating a valuable revenue stream that can help finance the Carbon Capture and Storage (CCS) operation and improve its commercial viability (Lake *et al*., 2014; Moritis, 2010).

Nevertheless, the repurposing of depleted reservoirs for CO_2 storage is not without significant technical complexities and uncertainties that must be meticulously addressed to ensure safe and effective implementation. The ultimate success of any storage project hinges on two paramount factors: the long-term integrity of the sealing caprock and the meticulous management of reservoir pressure during and after injection. A traditional and conservative engineering guideline has been to maintain injection pressures below the initial reservoir pressure that existed prior to production—a threshold known to have been safely contained by the geological seal in the past (Vander Meer, 1992). However, this heuristic requires

careful re-evaluation because supercritical CO_2 behaves fundamentally differently from the hydrocarbons originally produced. Crucially, CO_2 has a much lower interfacial tension when in contact with formation brine. This property reduces the capillary entry pressure of the caprock, which is the primary mechanism preventing the upward migration of a non-wetting phase like CO_2. This means the capillary sealing capacity of the caprock can be compromised at pressures significantly lower than the fracture pressure or even the minimum principal stress (Hildenbrand *et al*., 2004). Therefore, relying solely on the fracture pressure as an absolute upper limit can be dangerously misleading, as capillary breakthrough and leakage initiation may occur well before this point (Oldenburg, 2007).

Potential leakage pathways through the caprock system represent the most critical risk to the long-term security of geological storage. Once the capillary threshold of the seal is exceeded, CO_2 can escape via two main mechanisms: as a free-phase gas through compressible Darcy flow via fractures or permeable faults, or through the much slower process of molecular diffusion dissolved in the formation brine (Celia *et al*., 2015). Of the two, the first is by far the more concerning, as it can facilitate rapid and voluminous movement of CO_2 into overlying aquifers or even back to the atmosphere, potentially negating the climate benefit and posing a risk to freshwater resources and ecosystem health.

To mitigate these risks, persistent uncertainties regarding the precise storage capacity, the predictable behavior and eventual immobilization of the CO_2 plume, and the dominance of different trapping mechanisms (structural, residual, solubility, and mineral trapping) over time must be resolved through comprehensive, site-specific assessments before any large-scale injection commences (Szulczewski *et al*., 2012).

In Nigeria, a major oil-producing nation, research and development into Carbon Capture and Storage (CCS) applications remain in a nascent stage. The limited studies that have been conducted have predominantly focused on the theoretical storage potential of saline aquifers while largely overlooking the country's extensive inventory of matured and depleted oil and gas fields that could represent readily available, cost-effective, and locally relevant storage sites. Their strategic implementation could form a cornerstone of a national carbon management strategy. However, the current lack of detailed, publicly available case studies and high-fidelity, site-specific dynamic modeling has unfortunately restricted the serious consideration of these assets in both national energy policy and regional climate action plans (Akanji *et al*., 2017).

To effectively bridge this knowledge gap, advanced compositional reservoir simulators such as the Computer Modeling Group's General Equation-of-State Model (CMG-GEM) provide an invaluable toolset. These sophisticated numerical models are uniquely capable of simulating the complex coupled physical and chemical processes involved in CO_2 storage, including multiphase flow (CO_2 and brine), thermodynamic phase behavior, dissolution, geochemical reactions, and long-term plume dynamics under realistic geological conditions (Nghiem *et al*., 2009). A substantial body of prior research has demonstrated the utility of such simulators in critically evaluating key performance metrics such as well injectivity, reservoir pressure buildup and management, the spatial evolution and stabilization of the CO_2 plume, and the quantitative assessment of potential leakage risks (Kumar *et al*., 2005; Celia *et al*., 2015).

This type of predictive modeling is not an academic exercise; it is crucial for developing the practical, validated guidelines and operational envelopes required by both policymakers drafting regulations and engineers designing safe injection projects. Therefore, this research employs the Computer Modeling Group's General Equation-of-State Model (CMG-GEM) simulator to conduct a rigorous numerical investigation into the behavior of injected CO_2 within a representative depleted Nigerian reservoir. The study is designed to quantitatively assess critical aspects including dynamic storage capacity, plume migration pathways, the kinetics of trapping mechanisms, and caprock stability. The findings aim to generate a robust scientific basis to inform Carbon Capture and Storage (CCS) deployment in Nigeria, addressing a vital national data gap. Furthermore, by demonstrating the technical viability and safety of utilizing depleted reservoirs, this work contributes valuable insights to the global effort of mitigating climate change through geological carbon sequestration.

1.2 STATEMENT OF THE PROBLEM

Carbon dioxide (CO_2) due to fossil fuel combustion has intensified the urgency of addressing climate change. While global initiatives emphasize renewable energy development, fossil fuels remain deeply embedded in the world's energy mix, particularly in developing economies (IPCC, 2021). To bridge this transition, Carbon Capture and Storage (CCS) has emerged as a viable solution, allowing for the continued use of fossil fuels while mitigating ^{4}emissions.

A critical challenge, however, lies in ensuring the safe and permanent storage of captured CO_2. Among the available geological options, depleted oil and gas reservoirs are considered promising because of their proven capacity to hold hydrocarbons securely over geological

timescales (Bachu, 2008). Yet, despite this advantage, significant uncertainties persist regarding CO_2 injection and long-term containment. These uncertainties include the accurate estimation of storage capacity, prediction of CO_2 plume migration, understanding of trapping mechanisms, and the long-term integrity of reservoir seals (IPCC, 2021; Lake *et al*., 2014).

The lack of site-specific data further complicates reliable project implementation. Without detailed reservoir simulations and risk assessments, stakeholders risk overestimating storage capacity or underestimating leakage potential, which could lead to environmental, economic, and regulatory setbacks. This creates a pressing need for rigorous, context-based studies using advanced reservoir simulation tools to model CO_2 injection under realistic conditions.

Therefore, this study seeks to address these gaps by applying compositional reservoir simulation (CMG-GEM) to evaluate the capacity, plume behavior, and storage security of a depleted reservoir. The findings are expected to provide practical insights that will support decision-making for safe CCS deployment, particularly in regions still dependent on fossil fuel resources.

1.3 AIM

The aim of this study is to evaluate the potential of a depleted oil and gas reservoir for long-term CO_2 sequestration through compositional reservoir simulation using CMG-GEM, with emphasis on storage capacity, migration behavior, trapping mechanisms, and reservoir integrity.

1.4 OBJECTIVES

To achieve this aim, the study seeks to:

1. Model CO_2 injection into a depleted reservoir using CMG-GEM to simulate reservoir performance.
2. Estimate the CO_2 storage capacity of the reservoir during the injection period.
3. Analyze the movement, distribution, and plume migration of injected CO_2 over time.
4. Evaluate pressure variations and their implications for reservoir integrity.
5. Investigate the stability of CO_2 in the reservoir

1.5 LIMITATIONS

This research, though valuable, has certain limitations.

First, the study is based mainly on numerical reservoir simulation (CMG-GEM). While advanced, the software cannot fully capture all physical processes, such as mineral trapping or complex geomechanical effects, which limits the accuracy of long-term predictions.

Second, the work depends on field data. Although real reservoir information is used, uncertainties in parameters such as porosity, permeability, and sealing capacity may affect the reliability of the results.

Third, the model requires assumptions that simplify reservoir conditions. Real reservoirs are highly heterogeneous, and such variations cannot be completely represented in simulations.

Fourth, this study focuses on technical evaluation only. Broader aspects like economic feasibility, regulatory issues, and environmental monitoring are outside its scope.

Finally, the research is restricted to one depleted reservoir case, and the findings may not apply directly to other storage options such as saline aquifers or coal seams.

Despite these limitations, the study contributes useful insights into the potential of depleted reservoirs for safe and long-term CO_2 storage.

1.6 SCOPE OF STUDY

This study examines the potential of a depleted oil and gas reservoir for carbon dioxide (CO_2) sequestration using numerical simulation. The focus is on evaluating storage capacity, CO_2 plume movement, pressure changes, and long-term stability within the reservoir.

The research is limited to technical and reservoir-engineering aspects. Parameters such as porosity, permeability, pressure, temperature, and production history are considered in building the reservoir model. Rock and fluid properties, including pressure–volume–temperature (PVT) data, are used to describe reservoir conditions accurately.

Simulation is conducted with the Computer Modeling Group's GEM simulator. GEM is suitable for this work because it can represent multiphase flow, compositional behavior, and CO_2–reservoir interactions. The model is applied to predict CO_2 storage performance, plume migration, trapping efficiency, and pressure evolution over time.

The scope does not include policy, environmental regulations, or cost analysis. Other storage formations, such as saline aquifers and unmineable coal seams, are also outside the study's coverage. The emphasis is on depleted reservoirs because they have proven fluid-trapping capacity, existing wells and infrastructure, and reliable historical data. These factors make them practical and cost-effective sites for CO_2 storage.

The study aims to generate technical results that support the understanding of CO_2 injection in depleted reservoirs. It provides insights into storage security, potential leakage risks, and

the role of different trapping mechanisms. Although the findings are specific to the selected reservoir, the outcomes are expected to contribute to the broader application of carbon capture and storage (CCS) technologies.

1.7 SIGNIFICANCE OF STUDY

The growing concern over climate change has intensified the search for reliable technologies to mitigate greenhouse gas emissions, with Carbon Capture and Storage (CCS) recognized as one of the most promising approaches (Metz *et al*., 2005; Herzog, 2011). Within CCS, geological storage in depleted oil and gas reservoirs has attracted increasing attention due to their proven capacity to securely trap hydrocarbons over geological timescales, existing infrastructure, and the availability of geological and production data (Holloway, 2005; Szulczewski *et al*., 2012). Despite these advantages, uncertainties remain regarding CO_2 storage capacity, plume migration, trapping mechanisms, and long-term reservoir integrity (Van der Meer, 1992; Oldenburg, 2007). This study is significant in bridging such gaps through advanced simulation.

Several studies emphasize the importance of evaluating CO_2 storage potential in depleted reservoirs using robust modeling tools. For instance, Nghiem *et al*. (2009) highlighted the role of compositional simulators like CMG-GEM in capturing the thermodynamic behavior of injected CO_2 under reservoir conditions. Similarly, Kumar *et al*. (2005) demonstrated that predictive modeling can provide critical insights into pressure build-up, injectivity, and long-term plume stabilization. However, most existing works are either generalized case studies or focused on aquifers, with limited attention given to depleted reservoirs in regions relevant to Nigeria. This underscores the necessity of site-specific simulation studies to provide localized insights that guide policy and industry.

The study also holds economic and technological significance. Beyond its role in safe storage, CO_2 injection has been shown to enhance oil recovery (EOR), thus providing dual benefits of emission reduction and incremental hydrocarbon production (Jarrell *et al*., 2002; Moritis, 2010). By evaluating CO_2 injection in a depleted reservoir through simulation, this research provides evidence-based guidance on optimizing both environmental and economic outcomes. Moreover, the findings will be useful to engineers, policymakers, and industry stakeholders in developing strategies that align with global energy transition goals while addressing Nigeria’s reliance on fossil fuels.

In terms of methodology, this research applies advanced reservoir simulation using CMG-GEM, which allows for a detailed analysis of CO_2 storage dynamics, including capacity estimation, plume behavior, and trapping mechanisms under realistic reservoir conditions (Nghiem *et al*., 2009). Prior works such as those of Oldenburg (2007) and Szulczewski *et al*. (2012) confirm that simulation results provide critical inputs for risk assessment, project feasibility, and long-term monitoring frameworks. The proposed study therefore contributes not only to academic knowledge but also to practical CCS implementation in Nigeria and similar contexts. By doing so, it supports global climate mitigation efforts while offering locally relevant insights for sustainable energy development.

CHAPTER TWO

LITERATURE REVIEW

2.0 OVERVIEW

This chapter focuses on the literature review, the contributions of other scholars related works is discussed in this chapter

2.1 INTRODUCTION TO CO_2 SEQUESTRATION, GLOBAL CO_2 EMISSIONS AND CLIMATE CHANGE.

The continuous use of fossil fuels such as coal, oil, and gas has greatly increased the concentration of carbon dioxide in the atmosphere. Since the Industrial Revolution, global carbon emissions have risen sharply, leading to higher temperatures and unstable climate patterns (World Economic Forum, 2021).

Carbon dioxide traps heat in the atmosphere through the greenhouse effect, causing global warming and severe environmental impacts like rising sea levels, droughts, and stronger storms (Intergovernmental Panel on Climate Change, 2022). These changes threaten ecosystems and human livelihoods worldwide (Anderson *et al*., 2019).

To address this challenge, carbon capture and storage (CCS) has emerged as a practical solution. The method involves capturing CO_2 from major sources, compressing it, and injecting it deep underground for long-term storage (International Energy Agency, 2020). Depleted oil and gas reservoirs are considered ideal for this process due to their proven capacity to securely hold fluids over time (United Nations Environment Programme, 2021).

Reservoir simulation helps predict how injected CO_2 behaves under subsurface conditions, ensuring safety and efficiency in storage operations

(Garcia *et al*., 2021). Thus, CO_2 sequestration plays a vital role in reducing emissions and supporting global efforts to combat climate change.

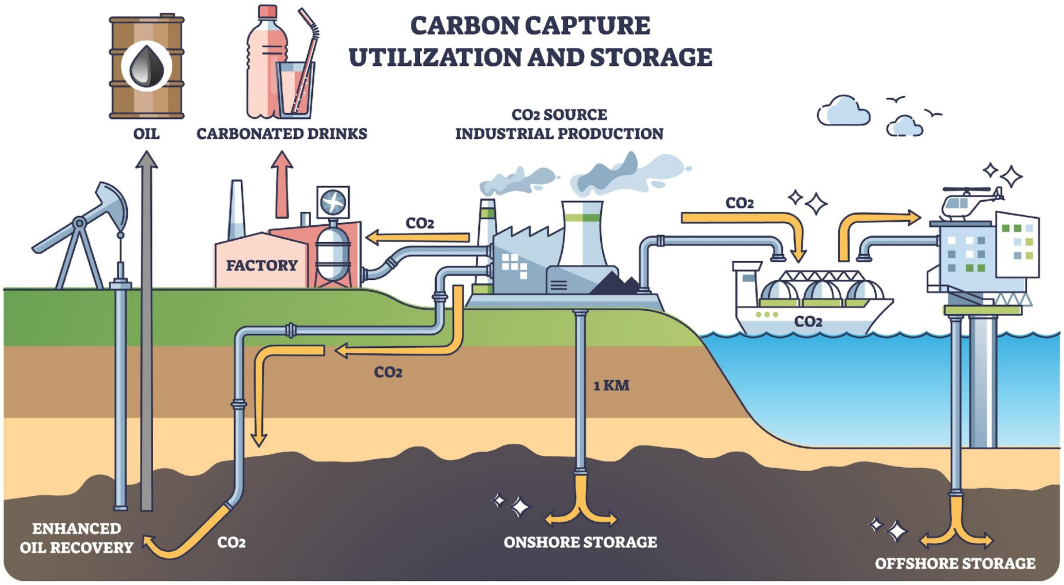
2.2 THE ROLE OF CARBON CAPTURE STORAGE(CCS) IN LOWERING EMISSIONS.

Carbon Capture and Storage (CCS) is a vital technology for tackling global climate change by reducing the amount of carbon dioxide (CO_2) released from major industrial and energy sources. It targets facilities such as power plants, cement factories, and refineries, where CO_2 is captured before it reaches the atmosphere, then compressed and moved to secure underground formations (International Energy Agency, 2022).

The CCS process generally includes three main stages — capture, transport, and storage (World Economic Forum, 2021). During capture, CO_2 is separated from other gases through chemical or physical processes. In the transport stage, the gas is safely conveyed through high-pressure pipelines or ships to storage sites. Finally, the storage phase involves injecting CO_2 deep underground, usually into depleted oil and gas fields or deep saline formations that can securely contain it for thousands of years (National Grid, n.d.; Britannica, n.d.).

Beyond emission control, CCS has potential economic and environmental benefits. The stored CO_2 can be used for enhanced oil recovery (EOR), which improves oil extraction efficiency while simultaneously storing carbon underground (Global CCS Institute, 2023). This dual function makes CCS both an environmental protection tool and a driver of industrial productivity.

Researchers see CCS as a key pathway toward achieving net-zero emissions, as it complements renewable energy systems by addressing emissions from hard-to-decarbonize industries (Cook and Zakkour, 2017; Bui *et al*., 2018). By combining CCS with renewable energy expansion and energy efficiency measures, nations can maintain economic development while moving toward a low-carbon future.



(Yousef *et al*, 2024)

Figure 2.1 CARBON CAPTURE UTILIZATION AND STORAGE

2.3 A HISTORY OF CARBON CAPTURE STORAGE (CCS).

The practice of injecting carbon dioxide (CO_2) into underground formations began several decades ago, not as a climate solution but as a method to enhance oil recovery. In the early 1970s, petroleum engineers in the Permian Basin of Texas began using CO_2 to boost oil production by improving reservoir pressure and lowering oil viscosity (Kuuskraa and Wallace, 2014). This early industrial experience provided valuable knowledge about how CO_2 behaves in the subsurface, forming the technical basis for later carbon storage projects.

As global awareness of greenhouse gas emissions increased in the late 1980s, researchers and policymakers began exploring the potential of using the same injection techniques for climate mitigation instead of oil recovery (World Energy Council, 2019). This marked a turning point where CO_2 injection evolved from a production tool to an environmental management strategy.

A major breakthrough came in 1996 with the Sleipner Project in the North Sea, operated by Equinor, which became the first commercial-scale CO_2 storage project in a deep saline aquifer (Holloway, 2005). It demonstrated that large volumes of CO_2 could be safely injected and monitored underground. Other successful projects soon followed, including the Weyburn project in Canada (2000) and In Salah in Algeria (2004), both of which proved the long-term technical and economic feasibility of geological storage (IEA, 2021).

More recently, large-scale initiatives such as the Gorgon project in Australia and the Quest project in Canada have strengthened global confidence in CCS as a key technology for emission reduction (Global CCS Institute, 2023). The experience gained from decades of CO_2 injection in oil and gas operations now serves as a solid foundation for deploying CCS on a broader scale to address climate change.

2.4 WHY SIMULATION MODELING IS KEY IN SEQUESTRATION WORK

Now, this is where we, as petroleum engineers, come into play. In EOR, our goal is to produce a fluid. In sequestration, our goal is to contain a fluid forever. The subsurface is a very uncertain environment. We deal with high pressures, different types of rocks, and complex fluid dynamics. So, how are we going to predict how a huge plume of CO2 is going to behave in the future, hundreds or even thousands of years from now?

We can't just guess. That's where numerical simulation comes from useful to essential. By creating detailed computer models of the subsurface, we can run hundreds of scenarios, for different injection rates, different geological faults, etc. That's where a tool like CMG (Computer Modelling Group) comes in. We can use it to model the multi-phase flow of CO2 within the reservoir, to understand the injectivity and storage capacity of the reservoir, and the long-term containment and potential leakage as well. Simulation is our lab. We can try out different scenarios and design effective projects without drilling a single well.

2.5 GEOLOGICAL CO2 STORAGE OPTION

2.5.1 DEPLETED OIL AND GAS RESERVOIRS

This seems like the obvious choice for us. The use of depleted hydrocarbon reservoirs for CO2 storage is highly advantageous due to existing infrastructure and a wealth of historical data from exploration and production activities (Benson, 2005). After all, these are formations that have already contained hydrocarbons for millions of years. So we have a head start by saying a lot: Existing Infrastructure Advantage Most of the heavy lifting has already been done. We have existing wells, pipelines, surface facilities, etc. This dramatically reduces the upfront investment and project duration. Better Data Availability This is huge. We have years of historical production data, seismic surveys, well logs, core samples, etc. We understand the geology, pressures, and fluid behavior. This reduces the geological uncertainty dramatically. Suitable for CMG Simulation Because we have detailed data on the porosity,

permeability, and reservoir heterogeneity, these formations are ideal for constructing detailed reservoir models in CMG. We can simulate the CO2 plume migration, pressure buildup, and long-term containment with a lot of confidence.

2.5.2 DEEP SALINE AQUIFERS

Deep saline aquifers offer the largest potential storage capacity, they also present significant challenges due to a lack of detailed characterization data compared to oil and gas fields (Metz et al., 2005). This is the big one in terms of capacity. A saline aquifer is an underground formation filled with briny water. These exist everywhere on earth and represent a huge, globally significant storage resource.

Larger capacity, but more uncertainty Because of the size of the potential resource, these aquifer formations have the potential to take up a lot more CO2 than depleted reservoirs. However, we know less. We haven't studied and drilled for these reservoirs as much.

Challenges in characterizing Because we know less, we have a lot more geological uncertainty. We don't have the same level of well logs and seismic data that we have for depleted reservoirs. There's a huge exploration component that needs to be done, which is expensive. Characterizing a saline aquifer reservoir requires new, expensive exploration. There is geological uncertainty. There is a risk that the plume could encounter unexpected geological features that might reduce containment (e.g. unmineable coal seams, permeable zones, etc.). This introduces uncertainty into the simulation process.

This is one of the less popular options but it's an interesting one. Unmineable coal seams are too deep or too thin to be economically mined. The special part of the property is that coal can adsorb, or stick to, relatively large amounts of CO2 on its internal surfaces.

Unmineable coal seams can store CO2 through adsorption, a process where CO2 molecules adhere to the coal surface, but this storage method is not as commonly modeled using standard reservoir simulation tools (White et al., 2005). The process also allows the methane, which is also adsorbed in the seam, to be released. This provides an additional economic incentive.

Not as Popular for CMG Models: Although it's an interesting option, it's not as popular for commercial scale sequestration studies. The amount of storage capacity available with this option is generally much smaller than aquifers or reservoirs. The flow mechanism within the porous medium is controlled by adsorption and desorption processes, which are different from the conventional fluid flow models used in CMG simulations for oil and gas reservoirs.

2.5.3 UNMINEABLE COAL SEAMS

Unmineable coal seams have become a promising option for carbon dioxide (CO_2) storage, offering geological stability and potential economic value. These seams are coal deposits that are too deep, thin, or fractured to be mined economically. When CO_2 is injected into them, it adsorbs onto the coal surface, displacing methane naturally trapped within the formation (International Energy Agency, 2021). This process, known as CO_2-enhanced coalbed methane recovery, provides the dual benefit of permanent CO_2 storage and the extraction of useful natural gas (World Coal Association, 2020).

The adsorption mechanism is driven by the strong physical and chemical attraction between CO_2 molecules and the porous coal structure. Because CO_2 has a higher adsorption capacity than methane, the injected gas effectively replaces methane, which can then be produced as an energy source (Liu and Harpalani, 2018). Research indicates that CO_2 can remain securely trapped for long geological periods due to the coal's low permeability and strong adsorption properties (Global CCS Institute, 2022).

Field projects in the United States, Canada, and China have confirmed the feasibility of CO_2 injection in unmineable seams (U.S. Department of Energy, 2023). For instance, the Allison Unit Project in New Mexico and the Qinshui Basin Project in China both achieved stable CO_2 retention and enhanced methane recovery over several years of monitoring. Despite these encouraging results, challenges persist, such as reduced permeability caused by coal swelling and the need for precise multi-phase gas flow modeling (Energy Futures Initiative, 2021).

Nevertheless, integrating CO_2 storage with methane recovery makes this approach economically attractive, especially in coal-rich regions. As research advances, unmineable coal seams remain a vital and sustainable pathway for carbon management and emission reduction.

2.5.4 BASALT AND OTHER REACTIVE ROCK FORMATIONS

Basalt formations and other reactive rocks have recently gained attention as promising candidates for CO_2 sequestration due to their unique geochemical reactivity. When CO_2 is injected into basalt, it reacts with calcium, magnesium, and iron silicate minerals present in the rock to form stable carbonate minerals, effectively turning gaseous CO_2 into solid rock (CarbFix Project Report, 2022). This mineralization process provides a highly secure and permanent method of carbon storage, minimizing the risk of leakage over time (World Economic Forum, 2023).

Field experiments, such as those conducted by the CarbFix project in Iceland, have demonstrated the success of this process on a commercial scale. In this project, more than 95 percent of injected CO_2 was converted into carbonates within two years, confirming the rapid and stable nature of the mineralization mechanism (Matter et al., 2016). Similarly, pilot studies in Washington State and India have shown that reactive basalts can effectively trap CO_2 while maintaining reservoir integrity (National Renewable Energy Laboratory, 2022).

Unlike other storage options that rely primarily on physical trapping, basalt formations rely on chemical bonding, making the storage essentially irreversible (Intergovernmental Panel on Climate Change, 2021). This provides a distinct advantage for long-term carbon containment. However, the main limitations include the need for sufficient reactive mineral content, high water availability to facilitate reactions, and a detailed understanding of the subsurface geochemistry (British Geological Survey, 2020).

The environmental safety and permanence of CO_2 storage in basalt formations align well with global carbon neutrality goals. The method is particularly suited for volcanic regions and coastal environments with suitable geological characteristics. As field trials continue to demonstrate its reliability, the use of basalt and other reactive rocks stands out as one of the most scientifically secure and environmentally responsible pathways for large-scale CO_2 sequestration.

2.6 PHYSICAL AND THERMODYNAMIC PROPERTIES OF CO2

2.6.1 CO2 PHASE BEHAVIOR AT HIGH PRESSURE/TEMPERATURE.

The most important thing to remember about CO2 is its phase behavior. In ambient conditions, it is a gas. In the deep geological reservoir, it switches between a conventional gas or liquid state. The easiest way to visualize this is on a phase diagram, which shows the different states of a substance (solid, liquid, gas) as a function of pressure and temperature.

The important point on this diagram for CO2 is the critical point, which is at 31.1∘C at 7.38 Mpa (~1,070 psi). Below this point, CO2 exists as a conventional gas or liquid. Most geological storage will occur in most geological storage sites (typically deeper than 800 meters), the pressure and temperature is greater than this point. In this regime, CO2 exists in a special state called a supercritical fluid (Sco2).

2.6.2 SUPERCRITICAL CO2 PROPERTIES (DENSITY, VISCOSITY, MOBILITY).

Supercritical CO2 is not a gas and not a liquid. It has properties of both. This “hybrid” property is what makes it attractive for sequestration.

Supercritical CO2 has a density more like a liquid (typically between 400 and 800 kg/m³), but it is hundreds of times more dense than CO2 at the surface. A high density is a good property for storage because it means we can pack a huge amount of mass into a relatively small volume. In other words, we can get a lot of storage out of a given reservoir.

In contrast to its liquid-like density, Sco2 has a viscosity more like a gas, often 10-100x lower than water or oil. Sco2 has a low viscosity, which means it can flow through the small pore spaces in reservoir rock with relatively little resistance.

Mobility in reservoir engineering is a fluid’s ability to move through porous media. It is defined as the ratio of its permeability and viscosity (k/μ). Because Sco2 has an extremely low viscosity, it has a very high mobility. High injectivity is one of the reasons we want to use Sco2 for sequestration. On the other hand, high mobility also increases the risk of viscous fingering, which is a tendency for the CO2 to bypass the resident fluid (brine) and flow along a few high permeability paths, leaving a lot of the reservoir dead behind it.

2.6.3 WHY THEY ARE IMPORTANT TO DETERMINING INJECTIVITY AND STORAGE IN CMG.

These are not just interesting academic properties; they are critical to how we model and manage a sequestration project. In a simulator like CMG (Computer Modelling Group), these properties are critical inputs to the thermodynamic models.

Injectivity: The high mobility and low viscosity of supercritical CO2 are what allow for high injectivity, which is the rate at which we can inject CO2 for a given pressure. The higher the injectivity, the fewer number of wells we would need to store our target amount of CO2 and therefore the cheaper the project. However, the simulation must also consider other thermodynamic effects, such as the Joule-Thomson effect. When high-pressure CO2 is allowed to expand into a lower-pressure reservoir, it can often flash and cool dramatically, and in the case of CO2 this extreme cooling can cause it to freeze into solid dry ice or hydrates that plug out the wellbore and greatly reduce injectivity. CMG’s compositional simulator, GEM, is capable of accurately representing this phase behavior and its impact on well performance.

Storage Behavior: The ability of Sco2 to be liquid-like is what allows for the solubility trapping and residual trapping of CO2 CMG models the phase behavior of CO2 interacting with the formation brine (solubility trapping) and getting stuck in the pore spaces by capillary forces (residual trapping). The liquid-like quality of Sco2 also plays a role in structural trapping because the more liquid-like CO2, the more dense, and therefore less likely to be buoyantly lifted through pore spaces and out through a leaking caprock. Ultimately, it is the physical properties of CO2 that dictate the long-term security of a storage site and the ability of the site to do its job, and these properties are what drive the complex calculations that a tool like CMG performs to determine the fate of the injected CO2 hundreds or even thousands of years in the future

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2.7 TRAPPING MECHANISMS OF CO2

2.7.1 STRUCTURAL TRAPPING (FAULTS, ANTICLINES)

Structural trapping is the most dominant and "near field" mechanism of CO_2 storage, because it depends on the geological arrangement of the subsurface. Structural trapping is controlled by the following "permeability contrast": porous reservoir rock (e.g., sandstone) and impermeable caprock (e.g., shale, salt). Some factors that affect trapping efficiency include: Caprock Properties: The sealing quality of the caprock is important. A high-quality caprock should not have fractures, faults, or micro-fractures that allow the CO_2 to escape. The effectiveness of a caprock is often described by the entry pressure, which is the minimum pressure at which a non-wetting fluid such as CO_2 will displace the wetting phase (brine) and flow through the pores of the rock. Anticlinal and Fault Closures: These are natural "traps" where the buoyant CO_2 accumulates. Faults can seal or conduct the CO_2, depending on their characteristics (e.g., low permeability or high permeability and fractured). This factor is often represented by fault transmissibility multipliers in reservoir simulation models.

In CMG-IMEX, structural trapping is managed with a simple black-oil model where CO_2 is represented as an immiscible, light hydrocarbon phase. The software approximates sealing by setting the permeability of caprock grid cells to zero or near-zero values. It manages faults by adjusting the fault transmissibility multipliers to represent sealing or conductive faults. This approach manages structural trapping effectively for fluid migration on short time scales. It does not, however, account for the critical effect of CO_2 dissolution into the aqueous phase and the resulting density changes that aid trapping on long time scales.

CMG-GEM, the compositional simulator, offers a more accurate representation. Structural trapping is modeled with 3D structural grids that accurately match geological surfaces, and it is managed by defining explicit caprock barriers with PVT data that reflects the CO_2-brine-rock system. Fayyaz (2024) and others have shown that compositional models are crucial to accurately predict the footprint of the plume and potential spill points, which are important inputs to assessing long-term site stability.

2.7.2 RESIDUAL TRAPPING (CAPILLARY FORCES)

Residual trapping is a physical process in which CO_2 is permanently trapped in the pore space of the reservoir rock (secondary trapping mechanism). It is a consequence of capillary forces and interfacial tension between CO_2 and the formation brine.

A trailing plume of disconnected CO_2 blobs ("ganglia") is left behind by the migrating CO_2 plume. The degree of residual trapping is a function of relative permeability curves and the wettability of the rock.

Hysteresis: Is the relative permeability of the CO_2 phase and the brine phase depends on the past saturation history (i.e. whether the saturation is increasing or decreasing). Hysteresis models account for the fact that when the CO_2 plume recedes (imbibition process) the trapped CO_2 saturation can be much higher than the mobile CO_2 saturation (drainage process).

CMG-IMEX models residual trapping indirectly. It uses relative permeability curves with hysteresis to account for the immobilization of CO_2. Although this can give a reasonable estimate of the amount of trapped CO_2, it is a macroscopic effect. It does not capture the pore-scale physics.

CMG-GEM offers a more robust model. It uses capillary pressure functions and more advanced hysteresis models (usually based on the Land or Killough models). This allows GEM to more accurately account for the saturation history and the irreversible immobilization of CO_2 as the plume moves and recedes further. Kourlianski (2022) stresses the importance of these models in ensuring accurate long-term irreversible trapping of a significant fraction of the injected CO_2, thereby mitigating the risk of future leakage.

2.7.3. SOLUBILITY TRAPPING (DISSOLUTION IN FORMATION WATER)

When CO_2 dissolves into the saline formation water, in the form of carbonic acid, this has two positive effects.

1. It removes CO_2 from the buoyant free phase, and hence reduces the risk of the plume migrating upwards.

2. It can increase the brine density, leading to density-driven convective mixing, which enhances the dissolution process.

The solubility of CO_2 in brine depends on temperature, pressure and salinity. For typical reservoir conditions (high pressure and low temperature), a large amount of CO_2 can dissolve. CMG-IMEX is lacking the compositional and thermodynamic fundament to do this. Since CMG-IMEX treats CO2 as a separate immiscible phase, it is not possible to model the phase equilibrium and mass transfer between CO2 and brine, and you would have to resort to some sort of simple model where maybe you could fudge some sort of solubility factor into it. But even then you could not possibly capture the dynamic non-equilibrium character of dissolution and density driven convection.

CMG-GEM, on the other hand, is a compositional simulator that is perfect for a problem of this nature. GEM can explicitly account for the phase equilibrium of the CO2-H2O-salt system as described by an equation of state such as Peng-Robinson. Thus GEM can simulate the dissolution ofCO2into the brine and the resulting convective instabilities that follow. As shown by MousaviMirkalaei & Khanifar (2023), this includes the development of dissolved CO2 density fingers that sink and mix with the deeper brine. This mechanism can have a significant impact on long-term trapping and stability.

2.7.4. MINERAL TRAPPING (LONG-TERM GEOCHEMICAL REACTIONS)

Mineral trapping is the most secure and long-term storage mechanism. It involves the reaction of dissolved CO_2 with rock minerals to form stable carbonate minerals, such as calcite (CaCO3), magnesite (MgCO3), and dolomite (CaMg(CO3)2). This process is very slow, taking hundreds to thousands of years to become a significant trapping mechanism, but it permanently immobilizes the CO_2. The reactions are as follows:

CO_2 dissolves in brine: $CO2(g) + H2O(l) \leftrightarrow H2CO3(aq)$ (Carbonic Acid)

Carbonic acid dissociates: $H2CO3 \leftrightarrow H+ + HCO3^-$ (Bicarbonate)

Mineral dissolution: $CaAl2Si2O8$ (Anorthite) $+ 8H+ \rightarrow Ca2+ + 2Al3+ + 2SiO2+4H2O$

Carbonate precipitation: $Ca2+ + HCO3^- \leftrightarrow CaCO3(s) + H+$

CMG-IMEX is a flow simulator and does not have the capability to model complex geochemical reactions. Therefore, it is entirely unsuitable for evaluating the long-term contribution of mineral trapping.

CMG-GEM, when coupled with its geochemical reaction module (CMG-GEM's STARS module or an external reactive transport code like PHREEQC), can simulate this process. It couples the fluid flow equations with reactive transport models that track the concentration of aqueous species and the dissolution/precipitation rates of minerals. As documented by Pillardou (2023), these coupled simulations can model the slow, progressive formation of stable carbonate minerals, providing a more complete picture of the long-term fate of the injected CO_2. This capability makes GEM an essential tool for long-term risk assessment and for demonstrating the permanent storage of CO_2 over geological timescales.

2.8 RESERVOIR SIMULATION FOR SIMULATION FOR CO_2 STORAGE

Reservoir simulation Reservoir simulation is a fundamental part of designing and operating Carbon Capture and Storage (CCS) projects. Its purpose is to provide a model of the subsurface behavior of CO_2 being injected, to assist with project security and sustainability over the long-term. This comprehensive discussion outlines the need for simulation, basic descriptions of what is predicted, a structured simulation workflow, and comparison of the most commonly used simulation software packages along with a discussion on the subtle differences between black-oil and compositional models.

2.8.2 WHAT PREDICTIONS DOES A GOOD CCS RESERVOIR SIMULATION PRODUCE

A successful reservoir simulation for CCS produces a large number of detailed predictions that are important for project planning.

Path and Spatial Extent of the Buoyant CO_2 Plume Migration: The simulator tracks the path followed by the buoyant CO_2 plume and its spatial extent in the porous reservoir. This allows the clear visualization of the footprint of the plume and to verify that it is contained within the target structural trap, and also to identify spill points where the plume may escape past the limits of the trap.

Pressure Field Distribution: Simulation is more than just a visualization of fluid movement. It models the pressure field response of the reservoir to the continuous injection. This is an important prediction for geomechanical stability. If the pressure buildup induced by injection is too high, it may induce seismicity (as has been observed) or cause the caprock to fracture,

thus providing a direct pathway for CO_2 to escape. The simulator allows the engineer to control injection rate to ensure it stays within safe pressure limits.

Granular Trapping Components: An important result is the component-wise quantification of the relative contributions of the four main trapping components: structural, residual, solubility, and mineral. Zanini (2023) and others have demonstrated that simulations can follow the dynamically changing composition of the injected \(\mathrm{CO}_2\) as it goes from being a relatively mobile phase (initially dominated by the structural trapping component) to a permanently immobilized phase, being trapped by capillary forces, dissolved into the brine, and reacting to form stable carbonate minerals.

2.8.3 A STRUCTURED SIMULATION WORKFLOW

The process of building and running a simulation for CCS is a structured, multi-step workflow that ensures accuracy and reliability. It begins with gridding, the process of translating the geological model of the reservoir into a three-dimensional grid of discrete cells. The resolution of the grid is one of the finer grids required to accurately resolve the physics of capillary pressure, dissolution kinetics, and density-driven convection, all of which are important for accurate trapping estimates (Suriano, 2022). with pre-injection pressure, temperature, and fluid saturations. The final and most complicated step is the rock and fluid models. This includes specifying the petrophysical properties such as porosity and permeability for each cell in the grid, and providing the multiphase flow properties such as relative permeability and capillary pressure curves, which govern the movement of the immiscible CO_2 phase. Finally, a detailed PVT (pressure-volume-temperature) model of the thermodynamic properties of the CO_2 brine system is required.

2.8.4 COMPARING RESERVOIR SIMULATORS

The choice of simulator software is a critical decision that determines the level of physical and chemical accuracy that a study can achieve.

IMEX (Black-Oil Simulators): IMEX and other similar black-oil simulators run on a simplistic thermodynamic model, treating fluids as distinct and immiscible oil, gas, and water phases. This fundamental limitation means that these simulators can only provide a very rough estimate of the solubility and mineral trapping components, as they cannot model the mass transfer between CO_2 and the aqueous phase. Their main benefit is that they are computationally efficient, and can therefore be used for rapid early-stage screenings of

potential storage sites, sensitivity analyses, or for teaching purposes, where a simplified representation of the migration of the plume and structural trapping is sufficient.

GEM (Compositional Simulators): However, GEM is the industry standard for compositional CCS simulators for detailed and long-term CCS assessments. The strength of GEM lies in its compositional framework and ability to model the full thermodynamic phase behavior of the CO_2 brine system, allowing it to accurately simulate CO_2 dissolution and subsequent density driven convective mixing that enhances solubility trapping (Suriano *et al*., 2022). In combination with its geochemical reaction modules, GEM can also model the slow but permanent mineral trapping process.

STARS (Thermal/Chemical Simulators): STARS and other simulators are not a primary tool for conventional saline aquifer storage, but are instead specialized for processes where thermal (e.g. thermal enhanced recovery) and more generally complex chemical effects play a significant role, e.g. when multiple components phase behavior is not adequately represented by a compositional simulator like GEM. STARS is overkill for standard geological storage and in general a thermal chemical simulator like STARS is more physics than is needed for conventional geological storage and generally not appropriate for standard geological storage assessments.

2.8.5 CONCLUDING ON THE SUITABILITY OF SIMULATORS

The suitability of a simulator is dictated by the research question. IMEX provides a highly valuable and computationally efficient tool for rapid feasibility assessments and screening studies, but by lacking in physics IMEX is not suitable for a comprehensive long term assessment of risk. GEM, with its compositional and geochemical capabilities, is the more suitable tool to simulate all four trapping mechanisms to the highest level of simulation fidelity. By simulating the system using GEM you are being more rigorous and, in our opinion, more scientifically defensible which is essential when publishing high impact research papers and gaining regulatory acceptance for large-scale CCS projects.

2.9 CMG-GEM AND ITS APPLICATION IN CO_2 STORAGE STUDIES

CMG-GEM is a compositional simulator developed by the Computer Modelling Group (CMG) for advanced reservoir engineering applications. Unlike black-oil simulators such as IMEX, GEM uses an equation-of-state approach to model complex phase behaviour and multicomponent flow of fluids. Owing to its ability to simulate compositional changes,

miscibility effects, and chemical reactions, GEM has become an important tool in studies related to Carbon Capture and Storage (CCS), particularly for CO_2 sequestration in depleted hydrocarbon reservoirs (CMG, 2024).

When applied to CO_2 storage, GEM runs on a compositional framework that models the interactions between CO_2, hydrocarbon components, and formation brine. The simulator can represent the displacement of remaining hydrocarbons by injected CO_2 and track the transition of the injected gas through multiple phases over time. This makes GEM particularly suitable for assessing the storage efficiency, injectivity, and pressure evolution of depleted reservoirs during CO_2 injection (Hamed and Shirif, 2025).

In several studies, GEM has been used to evaluate CO_2 injection strategies and the resulting behaviour in depleted oil and gas reservoirs. Gumrah et al. (2008) employed GEM to model CO_2 storage in an oil reservoir, highlighting its ability to handle reservoir heterogeneity and compositional interactions between the injected CO_2 and residual hydrocarbons. Similarly, Energies (2024) reported that GEM effectively simulated pressure build-up and plume migration during CO_2 injection, demonstrating its value for short- to medium-term performance prediction and risk assessment.

The simulator has also been applied in studies investigating the effects of reservoir characteristics such as porosity, permeability, and residual gas saturation on CO_2 storage capacity. Results from these simulations indicated that GEM could accurately predict the behaviour of CO_2 under reservoir conditions, including miscible and immiscible displacement, dissolution of CO_2 in formation fluids, and its long-term containment within the reservoir structure (Open Research Europe, 2025).

Although GEM is highly detailed, its compositional nature makes it computationally intensive compared to black-oil simulators. It also requires accurate PVT data, relative permeability correlations, and compositional properties of both the reservoir fluids and injected CO_2 for reliable simulation outcomes. Nevertheless, GEM remains one of the most suitable simulators for comprehensive studies of CO_2 sequestration in depleted reservoirs, as it provides insights into both storage performance and potential recovery of residual hydrocarbons (CMG, 2024).

In summary, CMG GEM has proven to be a robust and versatile simulator for CO_2 sequestration studies in depleted reservoirs. Its ability to model complex phase behaviour, compositional changes, and pressure evolution makes it ideal for assessing both the storage potential and dynamic response of the reservoir. This capability positions GEM as a critical tool for understanding and optimising CO_2 sequestration processes in depleted fields.

2.9.1 CASE STUDIES AND RESEARCH APPLICATIONS

In the literature, there are several examples of CMG GEM being applied to different aspects of CO_2 injection and storage. For instance, Gumrah et al. (2008) employed GEM to simulate CO_2 injection in an oil reservoir and demonstrated that the simulator could effectively capture the compositional interactions between injected CO_2 and residual hydrocarbons. Their findings showed that GEM could accurately predict phase changes, dissolution, and miscibility effects within the reservoir, making it a suitable tool for long-term compositional analysis. Similarly, Hamed and Shirif (2025) conducted a study using GEM to assess CO_2 storage performance in depleted reservoirs. They reported that GEM was capable of modelling pressure build-up, gas migration, and compositional variations with high precision, thereby improving the understanding of storage efficiency and reservoir behaviour under different injection scenarios.

Furthermore, Energies (2024) applied CMG GEM to investigate the impact of reservoir heterogeneity on CO_2 plume migration and pressure distribution. Their study highlighted the strength of GEM in capturing the complex dynamics of multiphase and multicomponent flow in heterogeneous systems. The simulator's predictive accuracy was particularly evident in identifying zones of potential leakage and estimating the long-term stability of the injected CO_2.

Additionally, several carbon capture and storage (CCS) research projects have adopted a tiered modelling approach in which GEM is used as the main compositional simulator following initial screening with simpler black-oil simulators such as IMEX. Alsousy (2023) emphasized that while IMEX serves effectively for preliminary assessments, GEM provides a more comprehensive understanding of reservoir performance by incorporating detailed compositional and thermodynamic behaviour of CO_2 during sequestration.

2.9.2 SIGNIFICANT LIMITATIONS AND NEED FOR A TRANSITION

Despite its advanced compositional framework and wide application in CO_2 storage studies, CMG GEM still presents certain limitations that restrict its ability to fully capture the complex geochemical and geomechanical processes occurring during long-term CO_2 sequestration. Although GEM provides a more detailed representation of multiphase and multicomponent flow than black-oil simulators, there are still key areas where its predictive capabilities can be improved for more accurate and comprehensive simulations (Yousef *et al*., 2024).

One significant limitation of GEM lies in its restricted geochemical coupling. While it can simulate dissolution and miscibility processes between CO_2 and formation fluids, GEM alone does not inherently model the long-term geochemical reactions between dissolved CO_2 and reservoir minerals that lead to mineral carbonation. These reactions, which result in the formation of stable solid carbonates, are crucial for assessing the permanence of CO_2 storage. Therefore, external coupling with geochemical simulators such as TOUGHREACT or PHREEQC is often required to represent this process more accurately (Liu *et al*., 2025).

Another limitation is related to computational demand and data dependency. GEM simulations require detailed PVT data, precise relative permeability curves, and accurate thermodynamic correlations. The lack of such data, which is common in depleted fields, can introduce uncertainty into the simulation results (Singh and Hamed, 2023). Moreover, its compositional nature makes GEM computationally intensive, leading to high processing times for large-scale or long-term simulations, especially when fine grids or complex coupling schemes are applied.

These challenges have led researchers to advocate for integrated simulation approaches, combining GEM with specialized geochemical and geomechanical models to enhance the accuracy of CO_2 storage predictions. Hybrid frameworks are being developed to improve computational efficiency and incorporate reactive transport and geomechanical feedback in a unified workflow (Raza et al., 2024). While GEM remains the most robust commercial simulator for compositional CO_2 sequestration studies, continuous development and hybridization with advanced modelling tools are essential for achieving the level of accuracy required for long-term risk assessment and commercial-scale carbon storage.

2.10 RISKS AND CHALLENGES IN CO_2 SEQUESTRATION.

Carbon Capture and Storage (CCS) is a key technology to achieve climate change mitigation. Successful CCS application depends on a good understanding of related risks. The objective of CO_2 sequestration is to store CO_2 permanently and securely. However, permanent and secure storage is challenged by leakage, geomechanical instabilities, and prolonged monitoring. This review attempts to compile the main risks reported in the literature. The focus is on the role of fluid flow, geomechanics, and monitoring to ensure the integrity of a storage site.

2.10.1. PATHS FOR CO_2 LEAKAGE.

The integrity of a target storage formation is governed by the presence of an impermeable caprock and the absence of any conductive pathway that allows the buoyant supercritical CO_2 plume to ascend towards the surface. Although an impermeable caprock offers the first line of seal, pre-existing faults and fractures in the subsurface are potential risks. The geological discontinuity causes a transmissive fault or fracture for CO_2 to escape if its original fault trace is reactivated by the increase in pore pressure of the reservoir (Khalid, 2024). In addition to this, other faults induced by abandoned and old wells exist as a major and often neglected risk. The wellbores were drilled for exploring the subsurface for oil and gas. The faults caused by these wells can act as a preferential leakage path if the cement in the wellbore has deteriorated with time (Babarinde *et al*., 2023). The CMG-GEM simulator was employed for a case study in Saudi Arabia to simulate the CO_2 injection into the Reservoir, and the simulation result shows that if the fault zone is not properly accounted for and managed, the security of the entire storage site will be jeopardized (Khan *et al*., 2020).

2.10.2. PRESSURE BUILD-UP AND FRACTURING RISK.

A large volume of CO_2 is injected into a confined subsurface reservoir during the CO_2 sequestration process. The pore pressure of the reservoir increases with injection, and if the pore pressure exceeds the fracture gradient of the caprock, hydraulic fracturing will be induced. The induced fractures provide new pathways for the CO_2 to leak to the surface. Moreover, the increase in pore pressure decreases the effective stress on the pre-existing faults, and the faults will slip if the effective stress drops below the critical value. The fault reactivation not only induces a leakage path but also causes induced seismicity. Therefore, it is not surprising that simulation studies focus on the need for coupled flow–geomechanical models to properly evaluate the changes in stress and pressure within the formation. The results are also used to determine the injection rate that is below the critical value that causes caprock fracture and fault reactivation (Tan *et al*., 2022).

2.10.3. GEOMECHANICAL MODELLING COUPLING WITH CMG'S GEM SIMULATOR.

Coupling CMG's GEM simulator with a geomechanical simulator enables simulation of pore pressure–stress interaction. Engineers and geologists can use this coupling to model and predict the key geomechanical risks, such as pore pressure–stress coupling, fault reactivation and fracture propagation. Case history studies have shown that including geomechanical

effects in the model leads to an improvement in the reliability of the risk assessment, especially when the geological environment is highly faulted and fractured (Khan *et al*., 2020).

Storage models can help engineers select a safe location and injection rate for the storage site. Understanding the long-term behavior of injected CO_2 is critical to the overall storage project, and a monitoring program should be implemented for decades after injection has finished. The aim is to provide confidence that the injected CO_2 is safely stored and to provide early warning of any possible plume migration or leakage risks, including geomechanical changes, such as subsidence or uplift. A variety of monitoring techniques can be used to achieve these goals. These include surface and downhole seismic imaging techniques to monitor the movement of the CO_2 plume; geodetic techniques, such as GPS deformation monitoring to measure any surface uplift or subsidence induced by changes in pressure; and wellbore logging with downhole pressure and temperature sensors to measure pressure and temperature gradients in the reservoir (Tan *et al*., 2022). This continuous, multidimensional monitoring provides confidence in the containment process and provides information to mitigate risk for the lifetime of the project (Khalid, 2024).

Key risks: The main risks for geological CO_2 sequestration are CO_2 leakage through natural faults and legacy wells and caprock fracturing induced by pressure changes. The long-term behavior of the plume is uncertain.

CHAPTER THREE
METHODOLOGY

3.1 INTRODUCTION

This chapter outlines the procedures and methods adopted for the simulation of carbon dioxide (CO_2) injection and storage in a depleted oil and gas reservoir using the CMG-GEM compositional simulator. The methodology involves model construction, fluid and rock

property definition, initialization, and dynamic simulation runs. Each step in this process was systematically designed to replicate real field behavior while ensuring the model was suitable for long-term CO_2 sequestration analysis.

The study utilizes real reservoir data obtained from a depleted sandstone reservoir, characterized by adequate porosity, permeability, and pressure conditions favorable for CO_2 storage. These real data were integrated with synthetic elements where necessary to ensure numerical stability and accurate representation of the reservoir system.

For this project, three primary modules were accessed centrally through the CMG Launcher: the Builder, which was used for model setup and configuration; the Results module, which handled visualization and analysis of simulation outputs; and CMOST, which was employed for optimization and sensitivity analysis.

3.1.1 CMG Technology Launcher

The Computer Modelling Group (CMG) Technology Launcher served as the central interface for accessing all simulation modules used in this study. It provides an integrated environment through which different CMG applications can be managed, organized, and executed efficiently. The launcher was the starting point for the workflow, connecting the Builder, GEM, Results, and CMOST modules required for the simulation and analysis of CO_2 injection and storage in the depleted reservoir.

Within the CMG Launcher, the Builder module was used to construct the reservoir model, define grid geometry, assign rock and fluid properties, and set boundary and initial conditions. The GEM simulator, which is compositional in nature, performed the actual numerical simulation of CO_2 injection processes, accounting for phase behavior, pressure, and temperature variations over time. The Results module enabled visualization and interpretation of simulation outputs such as pressure distribution, CO_2
saturation, and gas migration patterns. The CMOST tool, on the other hand, provided capabilities for optimization, uncertainty analysis, and sensitivity studies to evaluate the effects of varying reservoir parameters on CO_2 storage efficiency.

The launcher's structured interface ensured smooth transition between the modeling, simulation, and analysis stages, thereby maintaining workflow consistency and minimizing data handling errors. This centralized integration of CMG modules enhanced the accuracy, efficiency, and reproducibility of the modeling process, making it an essential component of the overall simulation methodology.

Figure 3.1 CMG Launcher Interface

3.2 Reservoir model setup

This section describes the development of the reservoir model for the CO_2 sequestration simulation. The model was constructed in CMG Builder using real reservoir data from a depleted sandstone oil and gas reservoir. The dataset comprises structural, petrophysical, and production information, which were integrated to build a representative static model. The model setup involved grid design, definition of property arrays, and specification of rock compressibility, forming the basis for subsequent fluid flow and CO_2 injection analyses.

3.2.1 Grid System

The grid system defines the three-dimensional structure of the reservoir model. It divides the entire reservoir into smaller computational blocks that enable CMG GEM to simulate fluid flow, pressure variations, and CO_2 migration patterns throughout the formation.

For this study, a corner-point grid system was adopted because it provides flexibility in capturing geological complexity, such as layer variations and structural dips, which are common in sandstone reservoirs. The grid framework was constructed in three directions — I, J, and K, representing the x, y, and z axes of the model domain.

Each grid block was assigned key reservoir properties such as porosity, permeability, and saturation, allowing spatial heterogeneity to be represented realistically. Grid refinement was applied in regions close to the injector and producer wells to improve the accuracy of flow behavior and pressure prediction in those high-activity zones.

Other parameters such as porosity type, pinch-out thickness, and pore volume cut-off were specified to maintain geological consistency, and numerical stability during simulation. The detailed grid configuration parameters are presented in Table 3.1

.

Table 3.1: Summary of Grid Configuration Parameters

PARAMETER	**DESCRIPTION**
Grid Type	Corner-point grid
Grid Dimensions	136 x 47 x10
Total active blocks	63,920

Porosity type	Single
Pinch-out thickness	0.0002 ft
Pore volume cut-off	0 ft^3
Named faults	0
Geological faults	2

3.2.2 Array Properties

The array properties represent a key stage in the model setup and form an essential part of the simulation methodology. They describe the geological and petrophysical characteristics of the reservoir grid, defining how properties such as porosity, permeability, and thickness vary spatially within the formation.

In this study, the array data were imported directly from the geological model used for the reservoir setup. The reservoir was subdivided into 10 layers to capture vertical variations in rock and fluid properties. These properties include parameters such as grid top, bottom, thickness, and permeability in the I, J, and K directions, as well as porosity and non-equilibrium water saturation.

Together, they provide a realistic representation of the reservoir's heterogeneity and were fundamental to achieving an accurate and reliable simulation of CO_2 movement and storage within the depleted reservoir.

3.2.3 ROCK COMPRESSIBILITY

Rock compressibility is an important component of the reservoir model, as it determines how the rock framework and pore spaces respond to changes in pressure and temperature. It directly influences the reservoir's capacity to store and transmit fluids during CO_2 injection and depletion. In this study, compressibility parameters were specified to account for the influence of pressure and temperature on porosity changes. Defining these parameters helped ensure that the simulation results represented realistic reservoir behavior and provided dependable predictions of CO_2 storage efficiency.

Table 3:2 ROCK COMPRESSIBILITY PARAMETERS

Parameter	Description	Unit	Value
CPOPR	Pressure defence of	1/psi	0.0005

	formation porosity/ Rock compressibility		
PRPOR	Reference pressure for calculating the effect of rock compressibility	Psi	14.6923
DCPOR	Pressure dependence of rock compressibility	1/psi*psi	0
TRPOR	Reference temperature for calculating the effect of rock compressibility	°F	77
CTPOR	Thermal expansion coefficient of formation porosity	1/F	O

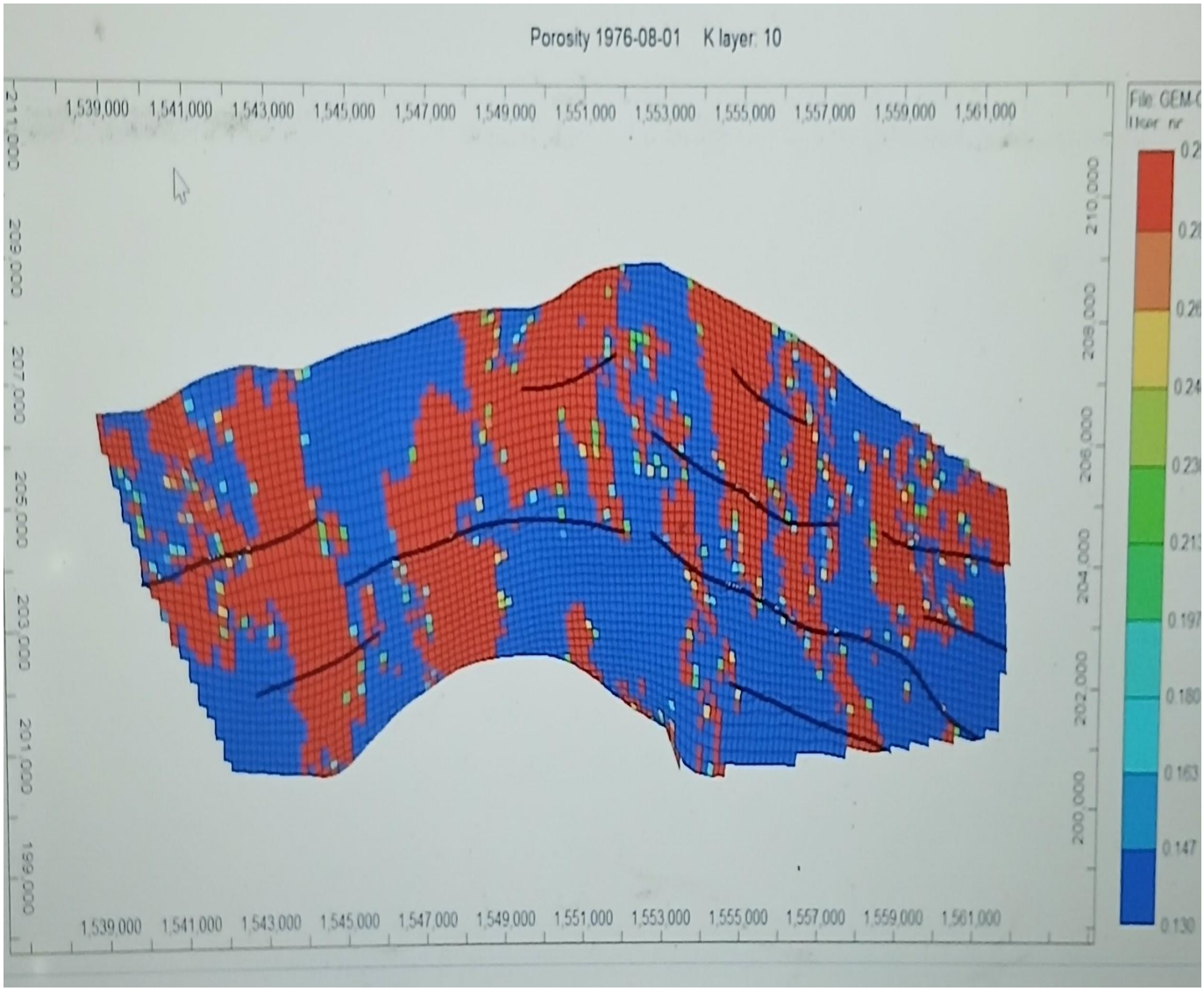

Figure 3:1 2D areal view of porosity in layer 10, showing spatial variation from low (cool colors) to high (warm colors).

3.3 COMPONENT SET UP

The component setup defines the fluid system used in the compositional simulation. In this study, the reservoir model was designed with four main components: CO_2, CH_4, FC10, and FC11. CO_2 and CH_4 represent the injected gas and the main hydrocarbon component, respectively, while FC10 and FC11 are pseudo-components representing heavier hydrocarbon fractions.

3.3.1 Equation of State (EOS)

The Equation of State defines the thermodynamic relationship between pressure, temperature, and composition for all components in the reservoir model. It was used to describe the interaction and phase behavior between injected CO_2, CH_4, and the lumped hydrocarbon components (FC10 and FC11).

To ensure accuracy in predicting multiphase behavior and mixing effects, parameters such as the binary interaction coefficients (BIN) and the hydrocarbon–hydrocarbon interaction parameters (PVC3) were included. These define the degree of miscibility and influence the predicted phase equilibrium during simulation.

Table 3.3 EOS SET PARAMETERS

Component	**Hydrocarbon**	**Crit.pressure** **atm**	**Crit. temperature** **K**	**Acen-tric factor**	**Mol. Weight** **g/gmole**	**Volume shift**
CO2	No	7.2800000 E +01	3.0420000 E + 02	2.2500000 E -01	4.4010000 E +01	0.0000000 E +00
CH4	Yes	4.5400000 E +01	1.9060000 E +02	8.0000000 E -03	1.6043000 E +01	0.0000000 E +00
FC10	Yes	2.5010000 E +01	6.2210000 E +02	4.4377400 E -01	1.3400000 E +02	0.0000000 E +00
FC11	Yes	2.3170000 E +01	6.4360000 E +02	4.7748200 E-01	1.4700000 E +02	0.0000000 E +00

3.3.2 SOLUBILITY DATA (SOLUBILITY)

The solubility data define how much CO_2 can dissolve in the reservoir fluids at varying pressure and temperature conditions. This parameter is crucial in simulating the interaction between injected CO_2 and the existing hydrocarbons within the depleted sandstone reservoir. In this study, the solubility data were incorporated to account for dissolution trapping, a key mechanism that enhances CO_2 retention and reduces the risk of leakage over time. This ensures that the model accurately represents the physical behavior of CO_2 during and after injection.

TABLE 3.4: SOLUBILITY DATA FOR CO_2 AND RESERVOIR FLUIDS

Component	**Henry's constant Psi**	**Ref. Pressure Psi**	**Vinifinity m^3/kgmole**
Co2	6.8700911E +04	3.0000000E +03	1.4792362E -02
CH4	1.3260792E +06	3.0000000E +03	3.7042528E -02
FC10	1.469549E +21	3.0000000E +03	1.9644118E -01
FC11	1.469549E +21	3.0000000E +03	2.1907394E -01

3.4 ROCK- FLUID INTERACTION

The rock–fluid interaction defines how fluids such as CO_2, oil, water, and gas behave within the reservoir rock. It controls the displacement, flow, and trapping of fluids, which are critical to predicting CO_2 movement and long-term storage efficiency.

In this study, Rock Type 1 was used to represent the sandstone reservoir. The model included relative permeability tables for both the water–oil and liquid–gas systems. The water–oil table describes how the mobility of oil reduces as water saturation increases, while the liquid–gas table defines how CO_2 (as the gas phase) interacts with the liquid phase during injection and migration.

The liquid–gas table also contained liquid saturation and gas saturation data, which specify how each phase changes with pressure and saturation levels. These datasets are essential for capturing gas breakthrough, dissolution, and residual trapping processes within the reservoir.

By including these relationships, the model realistically represents multi-phase flow conditions and provides a reliable basis for assessing CO_2 injectivity, mobility, and storage stability.

TABLE 3.5(A): RELATIVE PERMEABILITY – WATER–OIL SYSTEM

Sw	**Krw**	Krow
0.28	0	0.75
0.29	0	0.697694
0.3	0	0.647875
0.325	0.000147628	0.434028
0.35	0.00118103	0.347507
0.375	0.00398597	0.273324
0.4	0.00944822	0.210529
0.425	0.0184536	0.158173
0.45	0.0318878	0.115308
0.475	0.0506366	0.00809848
0.5	0.0755858	0.0542535
0.525	0.107621	0.0341655
0.55	0.147628	0.0197717
0.575	0.196494	0.0101231
0.6	0.255102	0.0101231
0.625	0.32434	0.00427068
0.65	0.405093	0.00126539
0.675	0.498246	0.000158173
0.7	0.604686	0
0.71	0.651181	0
0.72	0.7	0

TABLE 3.5(B): RELATIVE PERMEABILITY–LIQUID SATURATION

SI	Krg	Krog
0.3	0.75	0
0.305	0.73321	0
0.31	0.716672	0
0.350938	0.590519	0.0000171081
0.391875	0.480114	0.00136864
0.432813	0.384406	0.00461918
0.47375	0.302346	0.0109492
0.514685	0.232883	0.0213851
0.555625	0.174969	0.0369534
0.596562	0.127552	0.0586807
0.6375	0.089584	0.0875933
0.678438	0.0600143	0.124718
0.719375	0.00377932	0.171081
0.760313	0.0218711	0.227708
0.80125	0.011198	0.295627
0.842187	0.00472415	0.375864
0.883125	0.00139975	0.469445
0.924063	0.00017496	0.577397
0.965	0	0.700746
0.9725	0	0.725094
0.98	0	0.75

TABLE 3.5(C): RELATIVE PERMEABILITY – GAS SATURATION

Sg	Krg	Krog
0.02	0	0.75
0.275	0	0.725094
0.035	0	0..700746
0.075937	0.00017469	0.577397
0.116875	0.00139975	0.469445
0.157813	0.00139975	0.375864
0.19875	0.00472415	0.295627
0.239687	0.011198	0.227708
0.280625	0.0218711	0.171081
0.321562	0.0377932	0.124718
0.3625	0.089584	0.0875933
0.403438	0.127552	0.0586807
0.444375	0.174969	0.0369534
0.485312	0.232883	0.0213851
0.52625	0.302346	0.0109492
0.567187	0.384406	0.00461918
0.608125	0.480114	0.00136864
0.649062	0.590519	0.000171081
0.69	0.716672	0
0.695	0.73321	0
0.7	0.75	0

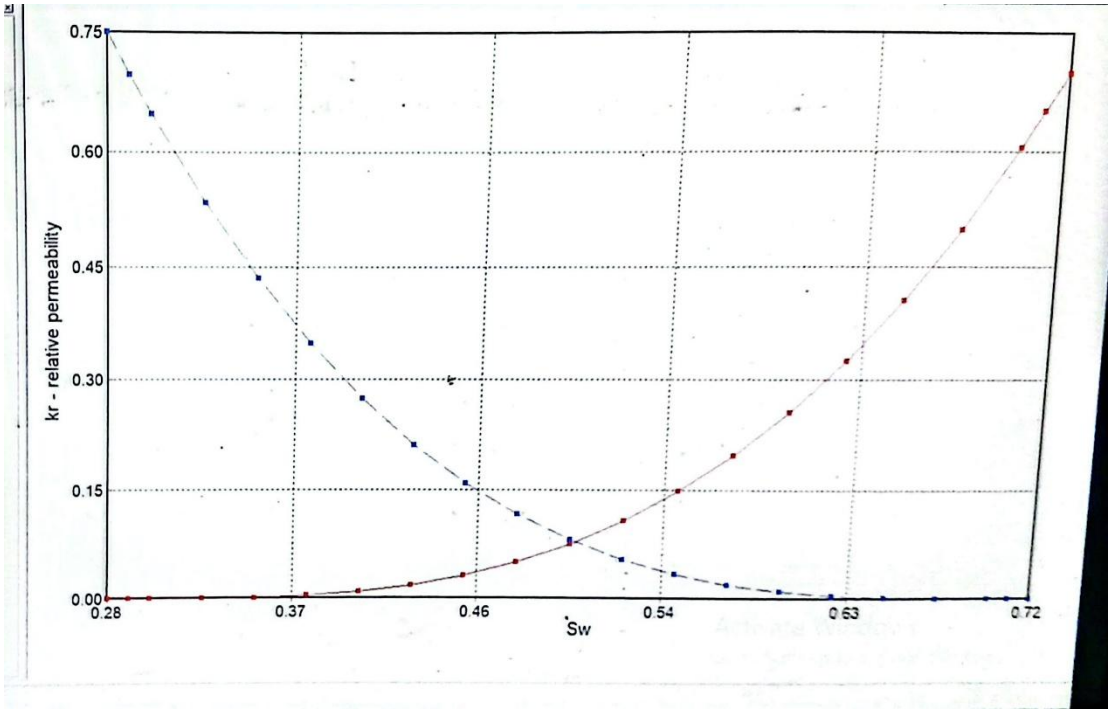

Figure 3:2 Relative Permeability vs Water Saturation (Kr vs Sw) – Water–Oil System

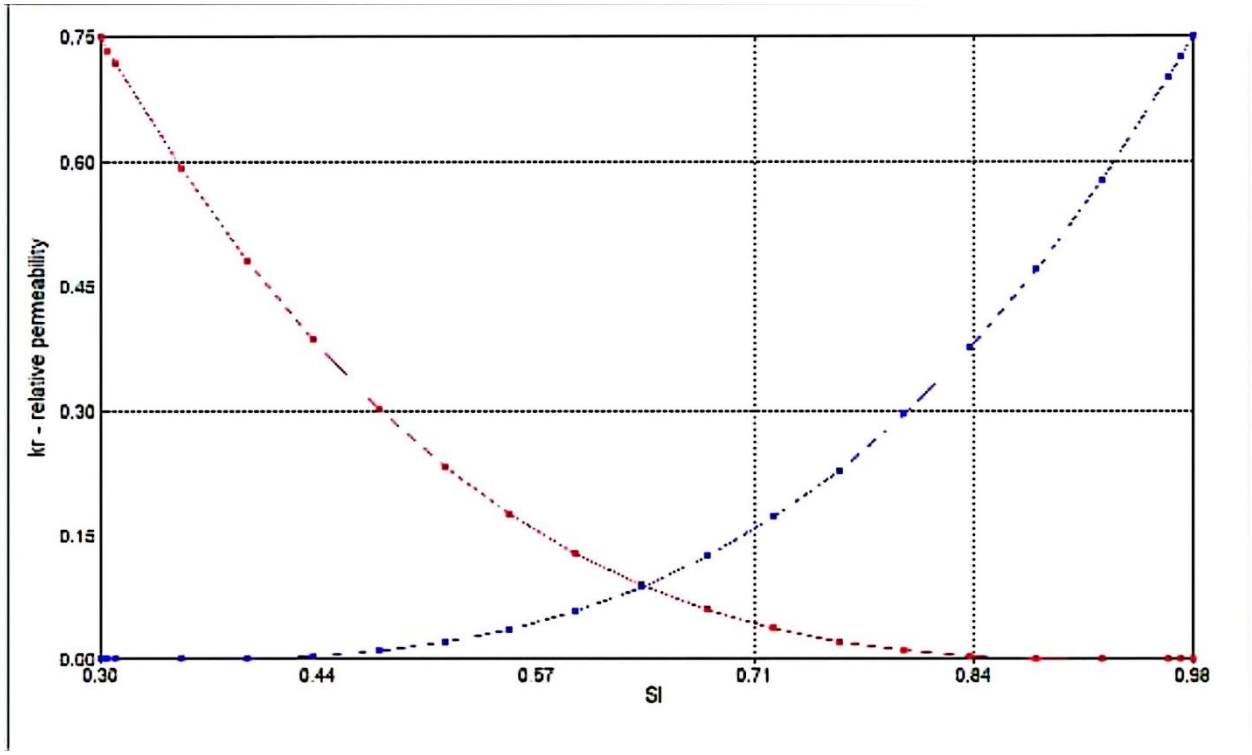

Figure3:3 Relative Permeability vs Gas Saturation (Kr vs Si) – Gas–Liquid System

3.5 NUMERICAL, WELLS AND RECURRENT SETTINGS

3.5.1 NUMERICAL SETUP

In the numerical setup of the simulation, the convergence tolerance was defined to control the accuracy of the calculations. This parameter ensures that changes in pressure, saturation, and component concentrations at each time step remain within an acceptable error range. By doing so, the simulation produces stable and reliable results while efficiently handling the multiphase, multicomponent behavior of CO_2 injection in the reservoir**.**

3.5.2 WELLS AND RECURRENT SETTINGS

The wells and recurrent settings represent the operational stage of the CO_2 sequestration process, marking the transition from model setup to dynamic simulation. This stage defines how CO_2 is injected, produced, and monitored within the reservoir over time.

Five wells were modeled in total, consisting of four injection wells and one production well, strategically placed to ensure effective CO_2 distribution and pressure management within the reservoir. The injector wells served as the entry points for CO_2, while the producer well allowed for controlled fluid withdrawal and performance evaluation.

Recurrent data were defined to specify the injection schedule, flow rates, and production limits at different time steps. These parameters helped replicate real field operations and assess the reservoir's response to continuous CO_2 injection, pressure variation, and trapping behavior throughout the project period

FIGURE 3:4 Reservoir Model Showing the Distribution of the Five Wells

CHAPTER FOUR
RESULTS AND DISCUSSIONS

4.1 EVALUATION OF CO_2 STORAGE CAPACITY OF THE RESERVOIR DURING THE INJECTION PERIOD

From the figure 4:1 it shows a plot of Aqueous Component Moles (CO_2) against time for the entire reservoir field. The plot illustrates a steady increase in the amount of CO_2 dissolved in the reservoir water from 1976 to 2045. This trend indicates continuous CO_2 accumulation within the reservoir during the injection period, demonstrating effective solubility trapping.

In 1976, before injection began, the CO_2 content in the reservoir was 6.717×10^6 gmol. By 2045, this value had increased to 3.11724×10^9 gmol, showing a significant rise in the total amount of CO_2 stored

Calculation of total CO2 stored

CO2 at 2045 = 3.11724 x 10^9 gmol

CO2 at 1976 = 6.717 x 10^6 gmol

Molar mass of CO2 = 44g/mol

Step 1: Convert to gmol to grams

Mass in 1976 = 6 717 x 10^6 x 44

= 2 95548 x 10^8g

Mass in 2045 = 3.11724 x 10^9 × 44

= 1.3715856 x 10^11g

Step 2 : calculate net CO2 stored

Net mass =1.3715856 x 10^11 - 2.95548 x 10^8

= 1.36863 x 10^11 g

Step 3 : convert grams to tonnes

1.36863 x 10^ 11 ÷ 10^6= 136863 tonnes

Therefore, the total CO_2 stored in the reservoir from 1976 to 2045 is approximately 136,863 tonnes, confirming the reservoir's strong solubility trapping potential and its ability to retain large quantities of CO_2 over time.

Figure 4.1: Variation of Aqueous CO_2 Moles in the Reservoir from 1976 to 2045

4.2 CO_2 DISTRIBUTION ACROSS RESERVOIR LAYERS

The CO_2 injection process spanned from 1976 to 2045, covering a total period of 69 years. Due to the extensive duration and multiple reservoir layers involved, it was not practical to analyze all 69 years across all 10 layers. Therefore, three representative years—1976, 2025, and 2045—were selected to evaluate the CO_2 distribution trend. Similarly, three key layers (Layers 10, 5, and 1) were chosen for detailed assessment, representing the lower, middle, and upper zones of the reservoir, respectively. These selected layers provide a clear understanding of CO_2 migration, accumulation, and trapping behavior over time within the reservoir.

4.2.1 CO2 DISTRIBUTION ACROSS RESERVOIR LAYERS (1976)

At the onset of CO_2 injection in 1976, simulation results showed noticeable differences in CO_2 distribution across the selected reservoir layers. The recorded average molality values were 8.067×10^{-5} in Layer 10, 8.062×10^{-5} in Layer 5, and 1.889×10^{-6} in Layer 1. CO_2 concentration was more pronounced in deeper layers, while the upper zone displayed minimal accumulation.

Figure 4.1(a) illustrates Layer 10, where the highest CO_2 molality was recorded. This indicates the layer served as a major storage zone due to favorable petrophysical properties, such as higher porosity and permeability, allowing efficient CO_2 injection and distribution.

Figure 4.1(b) represents Layer 5, which also exhibited high CO_2 presence. The close molality to Layer 10 suggests strong vertical and lateral connectivity, enabling effective migration of injected CO_2 across both layers. This behavior indicates an active flow region contributing significantly to overall storage performance.

Figure 4.1(c) depicts Layer 1, which showed the lowest CO_2 concentration. This can be attributed to its distance from injection wells, lower permeability, or tighter rock structure restricting gas migration. The reduced CO_2 presence in this upper layer also suggests its potential function as a cap or sealing zone, preventing vertical escape of injected CO_2.

This distribution pattern highlights the reservoir's heterogeneity and confirms that deeper zones served as the main CO_2 storage regions, while the upper zone acted as a natural barrier restricting upward gas movement.

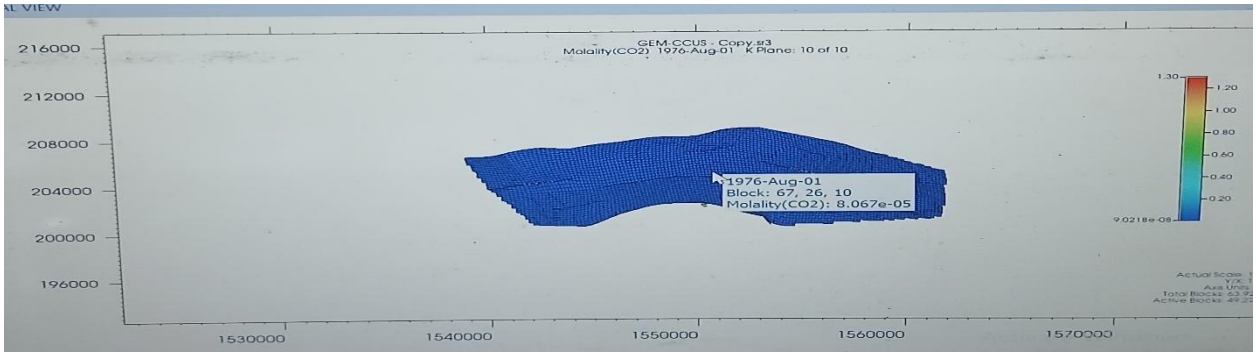

Figure 4.2(a) CO2 molality distribution in layer 10 (1976)

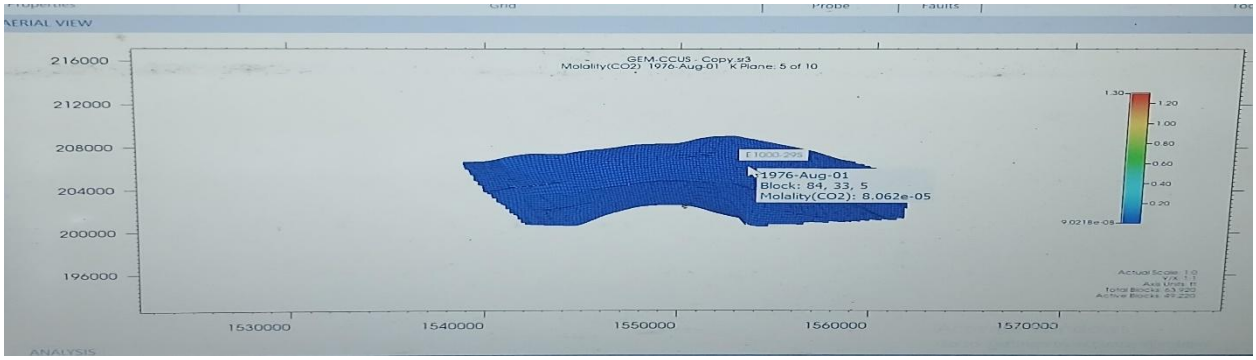

Figure 4.2(b) CO2 molality distribution in layer 5 (1976)

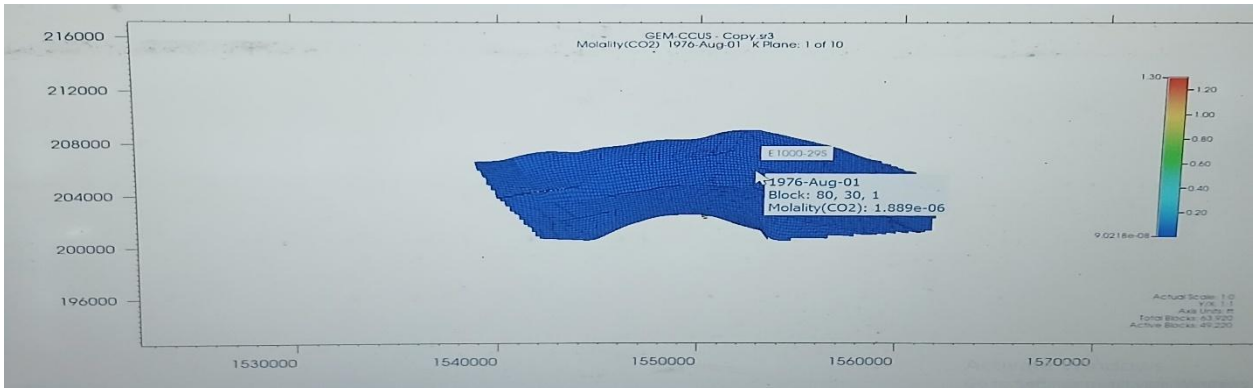

Figure 4.2(c) CO2 molality distribution in layer 1 (1976)

4.2.2 CO2 DISTRIBUTION ACROSS RESERVOIR LAYERS (2025)

By the year 2025, the simulated reservoir model revealed a distinct distribution of CO_2 across the ten layers, with noticeable variations in molality indicating the dynamic response of the formation to prolonged injection activity. The selected layers — 10, 5, and 1 — were examined to represent the lower, middle, and upper sections of the reservoir, respectively.These zones highlight how geological and fluid flow characteristics influence CO_2 accumulation and movement within the formation.

Figure 4.3(a) displays the CO_2 distribution in Layer 10, where the highest molality of 1.290514 mol/kg was observed. This deepest and most porous layer serves as the principal storage zone for the injected CO_2. The high concentration confirms that deeper layers provide the most favorable conditions for large-scale storage due to their superior pore volume, high pressure retention, and strong sealing capacity from overlying strata. This pattern indicates that structural and solubility trapping mechanisms are effectively operating at depth, leading to long-term immobilization of CO_2 within the rock matrix and formation water.

Figure 4.3(b) presents the CO_2 molality profile in Layer 5, where the value increased substantially to 0.3290651 mol/kg. This middle zone serves as a transitional region, receiving part of the upward and downward CO_2 movement within the reservoir. The concentration here reflects active CO_2 mobility and partial entrapment due to the combination of pressure, temperature, and intermediate porosity. Such a pattern demonstrates the efficiency of the reservoir in distributing CO_2 across its connected pore networks while still maintaining structural stability. It also highlights the significance of residual and dissolution trapping in ensuring long-term containment within mid-depth intervals.

Figure 4.3(c)) shows the CO_2 molality distribution in Layer 1, where the recorded value of 0.0028527 mol/kg indicates minimal CO_2 presence near the upper region of the reservoir. The limited concentration at this depth suggests that only a small portion of CO_2 migrated upward through available pore spaces. This behavior is expected, as upper layers generally possess lower permeability and act as natural seals, restricting significant vertical migration. The slight increase in molality, however, implies some degree of diffusion and dissolution of CO_2 into the formation fluids, contributing to the dissolution trapping mechanism.

Overall, the 2025 simulation results indicate that CO_2 injection and migration within the reservoir have stabilized over time. The progressive increase in molality with depth signifies successful downward movement and containment of CO_2 in the designated storage

formations. The layered distribution pattern validates the suitability of the reservoir for geological CO_2 sequestration, demonstrating its potential to safely contain injected carbon dioxide while minimizing risks of upward leakage or surface escape.

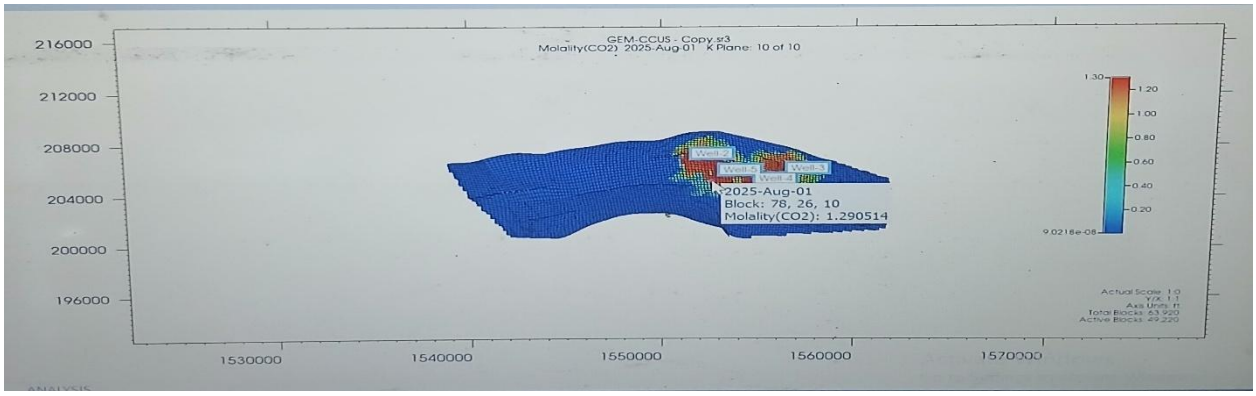

Figure 4.3 (a) CO2 molality distribution in layer 10 (2025)

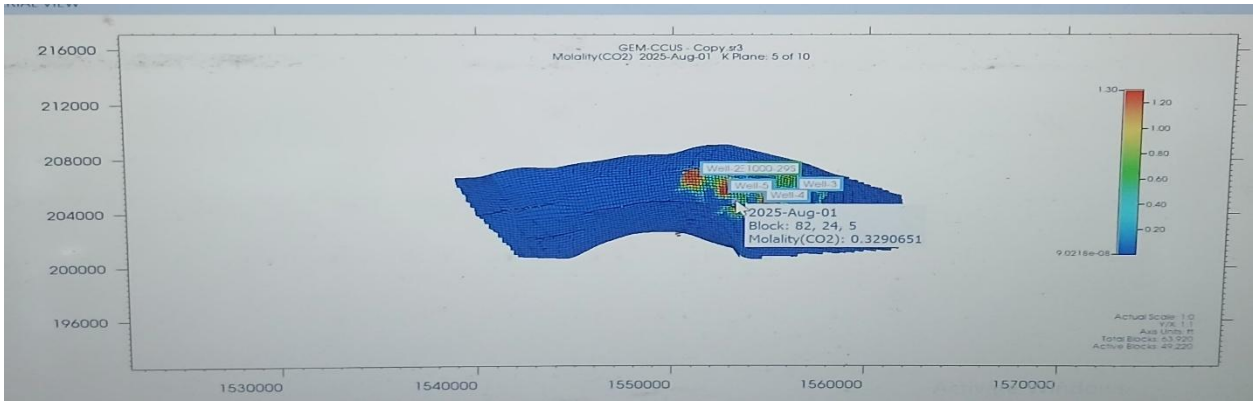

Figure 4.3(b) CO2 molality distribution in layer 5 (2025)

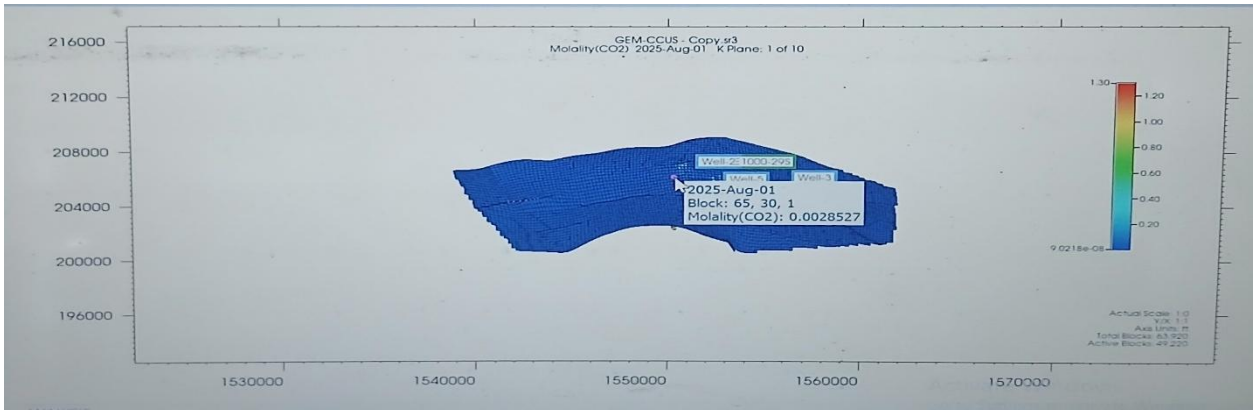

Figure 4.3(c) CO2 molality distribution in layer 1 (2025)

4:2:3 CO2 DISTRIBUTION ACROSS RESERVOIR LAYERS (2045)

By the end of the simulation period in 2045, the distribution of CO_2 within the reservoir layers showed significant evolution compared to the earlier years. The recorded molality values were 1.233356 in Layer 10, 0.1472597 in Layer 5, and 0.0098795 in Layer 1. These results indicate a continued dominance of CO_2 concentration in the deeper zones, though the overall spread of CO_2 had extended upward over time.

Figure 4.3(a) shows that Layer 10 retained the highest CO_2 molality in 2045. This confirms that it remained the principal storage zone throughout the injection period. The stable accumulation of CO_2 here suggests effective containment, likely due to high porosity and pressure support. This behavior reflects the long-term stability of CO_2 storage in the deeper formations, where geological properties favor retention and minimize leakage risk.

Figure 4.3(b) illustrates a notable reduction in CO_2 molality in Layer 5 compared to earlier years. The decrease from previous concentrations suggests redistribution or pressure equalization effects as CO_2 continued migrating within the reservoir. Nevertheless, the moderate presence of CO_2 implies that this layer still played a supportive role in overall storage, contributing to the reservoir's total containment capacity.

Figure 4.3(c) reveals a slight increase in CO_2 molality within Layer 1 relative to the early years. This upward movement indicates limited vertical migration of CO_2 into the uppermost section of the reservoir, possibly through connected pores or minor fractures. However, the low concentration suggests that Layer 1 continued to act as an effective sealing zone, restricting further gas movement beyond the reservoir boundary.

Overall, the 2045 results demonstrate a mature stage of CO_2 sequestration, where injected gas has reached equilibrium within the formation. The deeper layers, particularly Layer 10, sustained most of the injected volume, ensuring long-term storage integrity, while the upper layers provided natural containment to prevent escape into overlying strata.

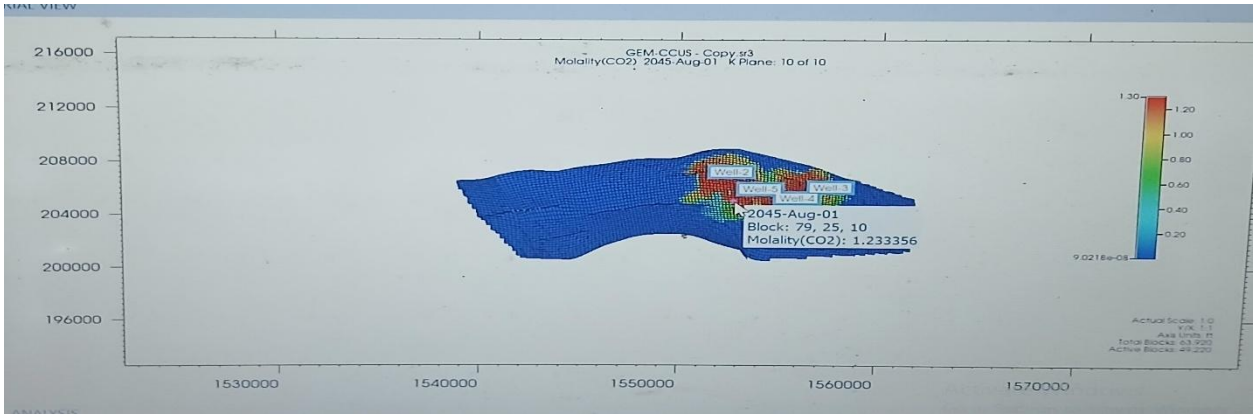

Figure 4.4(a) CO2 molality distribution in layer 10 (2045)

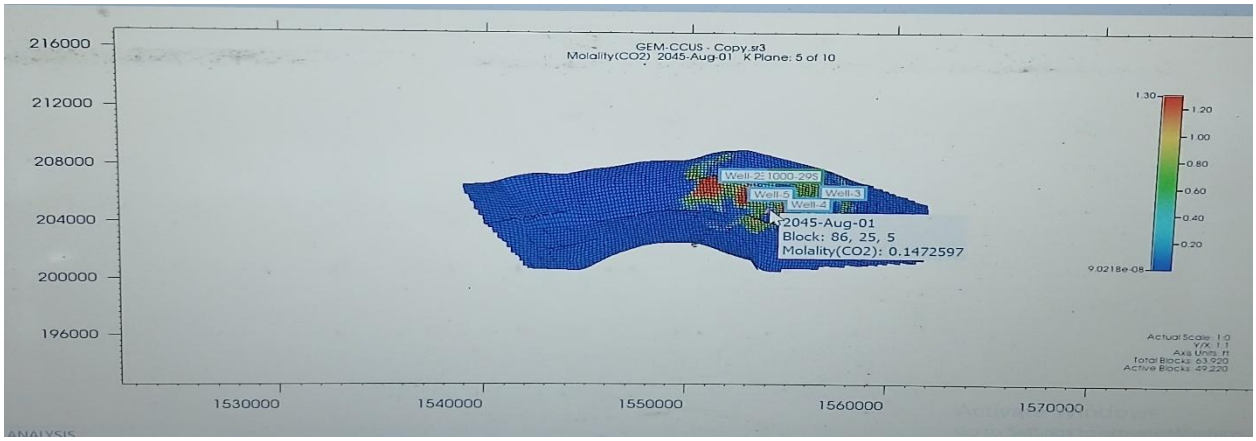

Figure 4.4(b) CO2 molality distribution in layer 5 (2045)

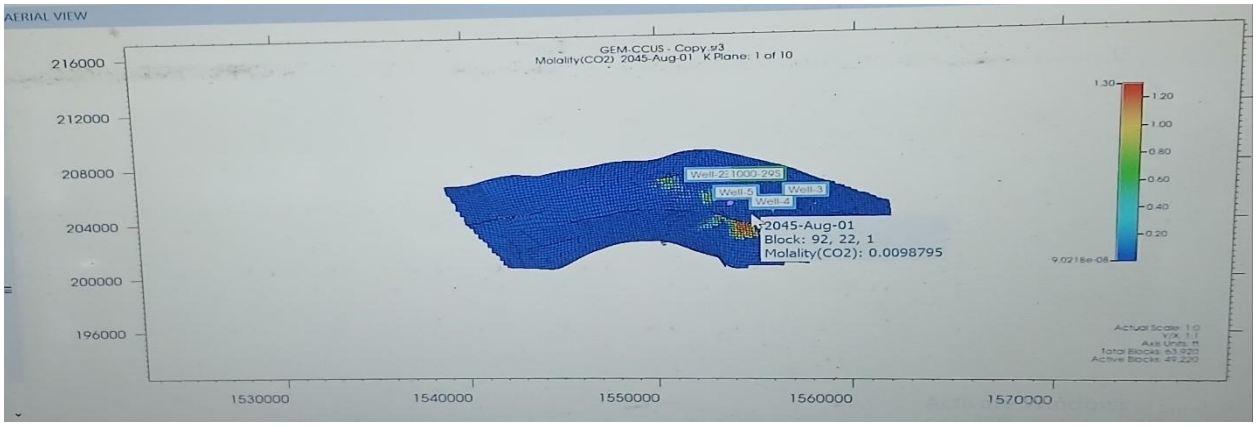

Figure 4.4(c) CO2 molality distribution in layer 1 (2045)

4.3 PRESSURE VARIATIONS AND IMPLICATIONS FOR RESERVOIR INTEGRITY

This section examines reservoir pressure evolution during the injection period and discusses implications for reservoir integrity. Pressure maps and time series for 1976, 2025 and 2045 are used to identify pressure build-up, pressure fronts, and any locations approaching critical thresholds (for example, fracture pressure). Results guide operational recommendations for safe injection.

4.3.1 PRESSURE VARIATION ACROSS RESERVOIR LAYERS (1976)

As presented in **Table 4.1,** the pressure distribution across the selected reservoir layers in 1976 revealed a relatively consistent pattern, with average pressures of 3341.147 psi in Layer 1, 3344.069 psi in Layer 5, and 3344.307 psi in Layer 10. This slight pressure increase with depth follows the natural hydrostatic gradient, reflecting a reservoir in equilibrium before the commencement of CO_2 injection.

The close similarity in pressure between Layers 5 and 10 suggests strong vertical communication and uniform stress distribution within the deeper sections of the formation. Such behavior indicates that the reservoir had good permeability continuity, which is favorable for even fluid displacement once injection begins.

Layer 1, having the lowest pressure, likely experienced lower overburden stress due to its shallower depth. This difference may also suggest that the upper zone acts as a transition or sealing unit, reducing vertical fluid migration and helping to maintain reservoir containment.

From an integrity standpoint, the uniform pressure observed across all layers signifies that the reservoir was structurally stable and stress balanced at the start of injection operations. This implies that the formation could safely accommodate additional CO_2 without exceeding its fracture or capillary entry pressure limits, which is an essential condition for ensuring long-term storage safety and maintaining reservoir integrity throughout the injection period.

TABLE 4.1: PRESSURE DISTRIBUTION ACROSS RESERVOIR LAYERS (1976)

LAYERS	AVERAGE PRESSURE (PSI)
1	3341.147
5	3344.069
10	3344.307

4.3.2 PRESSURE VARIATION ACROSS RESERVOIR LAYERS (2025)

From **Table 4.2,** the average reservoir pressures in 2025 are 3465.005 psi at Layer 1, 3471.032 psi at Layer 5, and 3482.851 psi at Layer 10. Compared to 1976, these values show a noticeable pressure increase across all layers, with the highest change observed in Layer 10. The increase indicates that CO_2 injection has significantly influenced the reservoir pressure profile over time.

The higher pressure in Layer 10 suggests that the injected CO_2 has concentrated more in the deeper zones where permeability is higher, enhancing storage efficiency. However, the rise also implies an increase in pore pressure, which could lead to formation stress and potential fracturing if the pressure exceeds the reservoir's safe limit. Layer 5 shows a moderate pressure rise, indicating good vertical communication between layers, while Layer 1 has the least pressure build-up, showing that the upper zones provide some pressure containment.

In terms of reservoir integrity, the observed pressure changes imply that the formation is still maintaining stability under CO_2 injection, but continuous monitoring is essential to ensure that pressure buildup does not exceed the fracture gradient or compromise wellbore and seal integrity over time.

TABLE 4.2: PRESSURE DISTRIBUTION ACROSS RESERVOIR LAYERS (2025)

LAYERS	AVERAGE PRESSURE (PSI)
1	3465.005
5	3471.032
10	3482.851

4.3.3 PRESSURE VARIATION ACROSS RESERVOIR LAYERS (2045)

From Table 4.3, the average reservoir pressures in 2045 are 3530.008 psi at Layer 1, 3539.606 psi at Layer 5, and 3544.696 psi at Layer 10. These values represent a significant increase compared to earlier simulation years, reflecting the cumulative effect of continuous CO_2 injection over nearly seven decades.

Layer 10 maintained the highest pressure, showing that the deepest section of the reservoir has reached a mature stage of CO_2 storage. The persistent rise in pressure here indicates long-term retention and compaction effects caused by gas accumulation within pore spaces. This condition suggests that the formation is approaching its maximum storage potential, emphasizing the need for careful management to avoid fracturing or breaching structural limits.

In Layer 5, the pressure continued to increase moderately, demonstrating active communication between the lower and upper zones. This trend suggests that injected CO_2 and formation fluids have achieved near pressure equilibrium within the middle zones. The balanced buildup reduces the likelihood of sudden pressure spikes, thereby supporting reservoir stability and sustaining effective containment.

Layer 1 showed a mild but noticeable rise in pressure compared to previous years. This indicates limited vertical pressure transmission from deeper layers, possibly due to gradual pore connection or compaction-driven migration. The layer's ability to contain this transmitted pressure without failure reaffirms its sealing strength and its role as a natural barrier preventing CO_2 escape.

Overall, the 2045 results signify a stabilized yet high-pressure environment, typical of reservoirs nearing the end of long-term injection. The maintained integrity across all layers confirms that the reservoir structure has adapted well to prolonged stress, ensuring continued containment efficiency and storage security for the injected CO_2.

TABLE 4.3: PRESSURE DISTRIBUTION ACROSS RESERVOIR LAYERS (2045)

LAYERS	AVERAGE PRESSURE (PSI)
1	3530.008
5	3539.60
10	3544.696

4.4 STABILITY CO2 IN THE RESERVOIR

From **Figure 4.1** the plot of aqueous CO_2 concentration shows a nearly straight line, indicating that the dissolved CO_2 remained stable throughout the injection period. This steady behavior confirms there was no leakage or sudden fluctuation in the reservoir, suggesting strong solubility trapping and stable reservoir conditions.

The CO_2 distribution across the layers in 2045 also supports this. The deeper zones maintained high molality, while the upper zones showed little change, proving that the gas stayed confined within the main storage layers and did not migrate upward.

The pressure trend across the reservoir showed a smooth and gradual rise with no sudden spikes, confirming that the reservoir maintained its structural integrity throughout the injection and post-injection phases.

Lastly, comparing **Figures 4.5(a)** and **Figure 4.5(b),**the molality distributions appear almost identical. Even after five years of injection halt, there was no sign of movement or loss of CO_2. This confirms that the reservoir successfully retained the injected CO_2, demonstrating long-term storage stability.

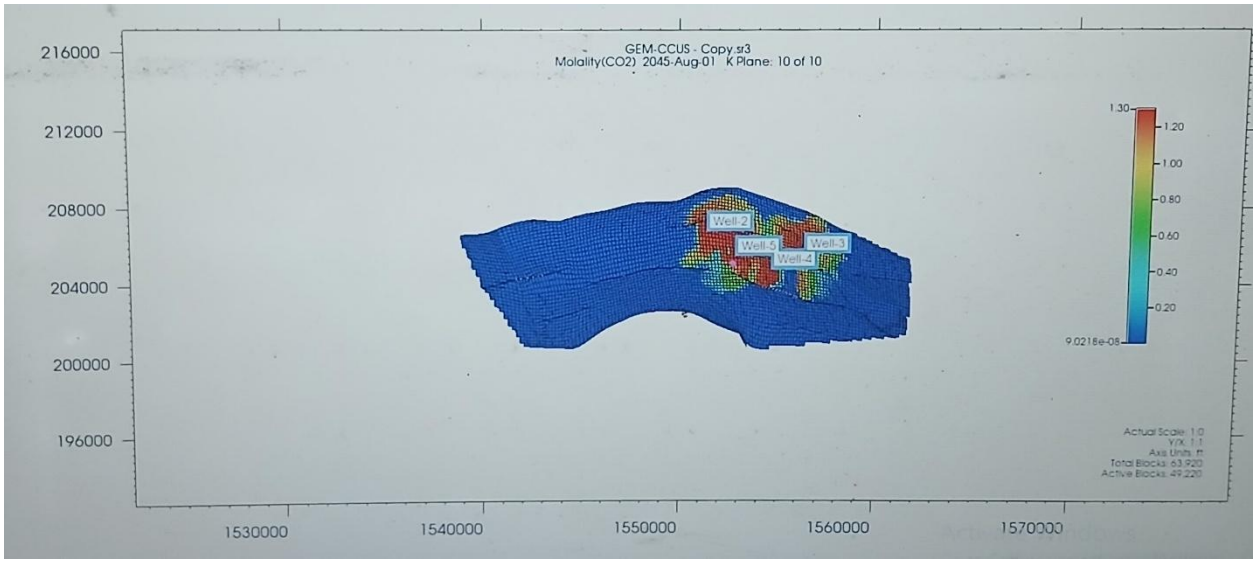

Figure 4.5(a): CO_2 Molality Distribution in Layer 10 (2045)

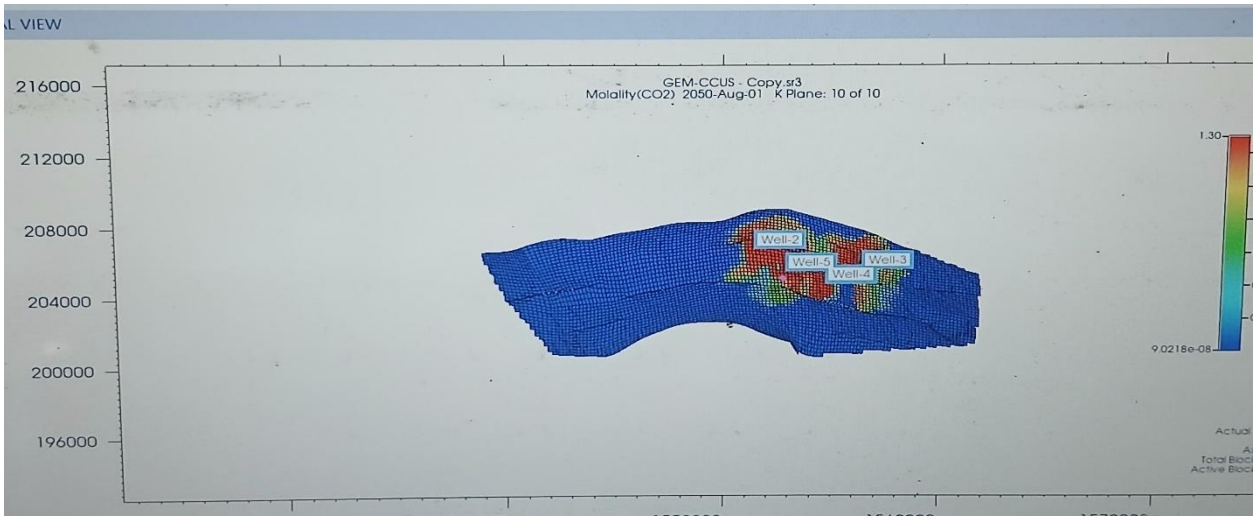

Figure 4.5(b): CO_2 Molality Distribution in Layer 10 (2050 After Five-Year Halt)

CHAPTER FIVE
SUMMARY, CONCLUSION AND RECOMMENDATIONS

5.1 SUMMARY AND CONCLUSIONS

This study investigated the injection and long-term storage of CO_2 in a depleted sandstone reservoir using CMG-GEM. The simulation assessed reservoir performance, CO_2 distribution, pressure behavior, and storage stability over a 69-year period (1976–2045). The following conclusions are drawn based on the objectives of the study:

1. Modeling CO_2 Injection Using CMG-GEM

The study successfully simulated CO_2 injection into a depleted sandstone reservoir using CMG-GEM over a 69-year period (1976–2045). The ten-layer reservoir model accurately represented the formation, allowing detailed monitoring of pressure, molality, and CO_2 plume distribution. The simulation demonstrated realistic flow behavior and controlled injection performance, validating the model's reliability for assessing long-term CO_2 storage.

2. Estimating CO_2 Storage Capacity

The total CO_2 storage capacity was estimated by tracking molar content, increasing from 6.717×10^6 gmol in 1976 to 3.11724×10^9 gmol in 2045, equivalent to approximately 136,863 tonnes. This indicates substantial storage potential and confirms that the reservoir can safely accommodate large volumes of CO_2.

3. Analyzing Movement, Distribution, and Plume Migration

CO_2 distribution analysis showed higher concentrations in deeper layers (Layers 5 and 10) due to favorable permeability and porosity, while the upper layer (Layer 1) acted as a sealing zone, restricting upward migration. This demonstrates effective containment and minimal leakage risk throughout the injection period.

4. Evaluating Pressure Variations and Reservoir Integrity

Pressure increased gradually from 3341 psi in 1976 to 3545 psi in 2045, indicating stable pressure propagation and mechanical balance. The absence of extreme pressure fluctuations confirms that the reservoir maintained its integrity during continuous CO_2 injection.

5. Investigating CO_2 Stability in the Reservoir

Even after a five-year halt in injection (2045–2050), the CO_2 molality distribution remained nearly unchanged. This confirms the long-term stability of the stored CO_2 and its secure trapping within the formation.

Taken together, these findings show that the depleted sandstone reservoir provides a stable, high-capacity, and geologically secure environment for CO_2 sequestration, with favorable

storage characteristics, controlled pressure behavior, and long-term stability suitable for effective carbon storage operations.

5.2 RECOMMENDATIONS

From the outcomes of this study, several measures are suggested to enhance future CO_2 storage simulations and improve the overall efficiency of sequestration in depleted reservoirs:

1. Incorporate More Trapping Mechanisms:

Future work should include other forms of trapping such as residual and mineral trapping. Residual trapping ensures that part of the injected CO_2 remains locked within pore spaces, while mineral trapping allows chemical reactions that convert CO_2 into stable carbonates. Considering these effects would give a more realistic picture of the long-term storage potential.

2. Optimize and Expand Injection Well Placement:

The placement and number of injection wells should be reviewed to achieve better coverage and pressure control across the reservoir. Properly spaced wells can enhance fluid movement, reduce localized overpressure, and improve the uniform spread of injected CO_2 within the storage zone.

3. Increase the Simulation Duration:Running the model for a longer period than the present 74 years would help evaluate the behavior of stored CO_2 after injection stops. This would show how the gas stabilizes over time and how pressure changes affect long-term containment.

4. Carry Out Sensitivity Studies:

A sensitivity analysis is needed to test how variations in rock and fluid properties—such as permeability, porosity, injection rate, and temperature—affect CO_2 storage results. Such analysis will help identify which parameters most strongly control storage efficiency and movement within the reservoir.

5. Use a More Advanced Compositional-Reactive Model:

Future studies should integrate reactive transport modeling into CMG-GEM simulations to account for possible chemical reactions between CO_2, formation water, and rock minerals. This approach would make the prediction of CO_2 behavior more precise and provide deeper insight into long-term storage security.

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