1 Abstract

Geological sequestration of carbon dioxide CO_2 is widely recognized as an effective strategy for reducing greenhouse gas emissions and mitigating climate change. Numerical reservoir simulation plays a critical role in evaluating the feasibility and performance of CO_2 injection projects under realistic subsurface conditions. In this study, a three-dimensional compositional reservoir model was developed using the CMG-GEM simulator to analyze the behavior of CO_2 injection in a deep saline formation.

The reservoir model incorporates detailed grid geometry, rock and fluid properties, relative permeability, and capillary pressure relationships. Gravity–capillary equilibrium was used to initialize reservoir pressure and saturation distributions, ensuring realistic initial conditions. CO_2 was injected through dedicated injector wells under pressure-controlled operating constraints. Simulation outputs were processed using Microsoft Excel to evaluate injection performance and multiphase flow behavior.

The results indicate stable reservoir pressure behavior under constant bottom-hole pressure–controlled injection, with CO_2 migration governed by relative permeability and capillary pressure effects

2 Introduction

The continuous increase in atmospheric carbon dioxide (CO_2) concentration due to fossil fuel combustion has intensified global concerns related to climate change and environmental sustainability. Carbon capture and storage (CCS) has emerged as a viable mitigation strategy, wherein CO_2 is captured from large emission sources and injected into deep geological formations for long-term storage. Among various storage options, deep saline aquifers are considered highly suitable due to their large storage capacity, widespread availability, and limited interference with hydrocarbon production.

Successful implementation of CO_2 sequestration projects requires a thorough understanding of subsurface fluid flow, pressure evolution, and multiphase interactions between injected CO_2 and resident fluids. Direct field experimentation for such processes is often expensive and time-consuming, making numerical reservoir simulation an essential tool for feasibility assessment and performance evaluation. Simulation studies enable prediction of reservoir response under different injection scenarios, helping to assess pressure buildup, CO_2 plume migration, and storage security.

Compositional simulators are particularly important for CO_2 injection studies because of the complex phase behavior, density variations, and miscibility effects associated with supercritical CO_2 at reservoir conditions. CMG-GEM is a fully implicit compositional reservoir simulator capable of modeling multiphase, multicomponent flow with detailed equations of state, relative permeability, and capillary pressure formulations. Its ability to incorporate gravity-capillary equilibrium and flexible well controls makes it well suited for geological storage applications.

In this study, CMG-GEM is used to develop a three-dimensional reservoir model to simulate CO_2 injection into a deep formation. The model integrates realistic grid geometry, rock and fluid properties, and flow relationships to analyze pressure behavior, gas saturation distribution, and multiphase flow dynamics during the injection period. The results provide insights into reservoir response and demonstrate the applicability of numerical simulation for evaluating CO_2 sequestration performance.

3 Problem Statement and Objectives

3.1 Problem Statement

The long-term storage of carbon dioxide (CO_2) in deep geological formations requires careful evaluation of reservoir response to sustained injection. Key challenges associated with CO_2 sequestration include managing reservoir pressure buildup, understanding multiphase flow behavior, and predicting the migration of the injected CO_2 plume. Improper injection design or unfavorable reservoir properties may lead to excessive pressure increase, reduced injectivity, or compromised storage integrity.

Due to the complexity of subsurface processes and the limitations of direct field-scale experimentation, numerical simulation is essential for assessing the feasibility and performance of CO_2 injection projects. A detailed reservoir model is required to capture the effects of rock and fluid properties, relative permeability, capillary pressure, and gravity on CO_2 movement and pressure evolution. Therefore, a systematic simulation-based study is needed to analyze reservoir behavior under controlled CO_2 injection conditions.

3.2 Objectives

The primary objectives of this study are as follows:

- To develop a three-dimensional compositional reservoir model for CO_2 injection using the CMG-GEM simulator.
- To initialize the reservoir model under gravity-capillary equilibrium conditions to obtain realistic pressure and saturation distributions.
- To simulate CO_2 injection through designated injector wells under specified operating constraints.
- To analyze injection performance and pressure behavior under pressure-controlled injection conditions.
- To evaluate gas saturation distribution and CO_2 plume migration behavior.
- To assess the influence of relative permeability and capillary pressure on multiphase flow during CO_2 injection.

4 Model Description

A three-dimensional reservoir model was constructed in the CMG-GEM compositional simulator to represent a deep geological formation suitable for CO_2 storage. The model consists of a structured grid with uniform spacing in the horizontal directions and layered discretization in the vertical direction to capture depth-dependent pressure effects. The reservoir depth corresponds to conditions where CO_2 exists in a dense or supercritical state.

Rock properties such as porosity and permeability were assigned uniformly across the model, based on representative values for deep saline formations. Multiphase flow behavior was defined using relative permeability and capillary pressure relationships to account for interactions between CO_2 and formation fluids.

The fluid system was modeled using a compositional approach, with CO_2 defined as the injected component. Initial reservoir pressure and saturation distributions were established using gravity-capillary equilibrium. One or more injector wells were specified to introduce CO_2 into the reservoir under controlled operating conditions. This model setup provides a simplified yet realistic framework for analyzing pressure evolution and CO_2 migration during injection.

5 Methodology

The CO_2 injection study was carried out using a systematic numerical simulation workflow in the CMG-GEM compositional simulator. The methodology adopted in this work is summarized in the following steps.

1. **Grid and Model Construction:** A three-dimensional reservoir grid was generated to represent the deep geological formation. The grid discretization was selected to adequately capture spatial variations in pressure and saturation while maintaining numerical stability.

2. **Assignment of Rock Properties:** Reservoir rock properties, including porosity and permeability, were assigned to the grid cells. These properties were defined based on representative values for deep saline formations and were assumed to be spatially uniform for simplicity.

3. **Fluid System Definition:** A compositional fluid model was defined with CO_2 as the injected component. Appropriate equations of state were used to describe phase behavior under reservoir pressure and temperature conditions.

4. **Relative Permeability and Capillary Pressure:** Multiphase flow behavior was characterized using relative permeability and capillary pressure functions. These relationships were incorporated to account for interactions between CO_2 and formation fluids during injection.

5. **Initialization of Reservoir Conditions:** Initial pressure and saturation distributions were established using gravity-capillary equilibrium. This ensured a realistic representation of in-situ reservoir conditions prior to the start of CO_2 injection.

6. **Well Configuration and Injection Control:** Injector wells were defined within the model, and CO_2 injection was specified through appropriate well controls such as injection rate or bottom-hole pressure constraints.

7. **Simulation Execution and Data Extraction:** The simulation was executed over the specified injection period. Key output variables, including reservoir pressure and gas saturation, were extracted and processed using Microsoft Excel for further analysis.

6 Simulation Setup

This chapter describes the input parameters and configuration used to perform the CO_2 injection simulation in CMG-GEM. The simulation setup includes reservoir and grid parameters, rock and fluid properties, initial conditions, and well and injection specifications.

6.1 Reservoir and Grid Parameters

The reservoir model was discretized using a three-dimensional structured grid representing a deep geological formation. The grid configuration was selected to capture pressure and saturation variations while maintaining computational efficiency. Depth conditions correspond to supercritical CO_2 storage environments.

Table 1: Reservoir and grid parameters

Parameter	Description
Model Type	3D compositional reservoir model
Simulator	CMG-GEM
Grid Type	Structured grid
Depth Range	Deep reservoir conditions

6.2 Rock Properties

Rock properties were assigned uniformly throughout the reservoir model. These properties represent typical characteristics of deep saline formations and were used to evaluate CO_2 injectivity and flow behavior.

Table 2: Reservoir rock properties

Property	Value
Average Porosity	0.18
Horizontal Permeability (mD)	150
Vertical Permeability (mD)	15
Rock Compressibility (1/psi)	3.0×10^{-6}

6.3 Fluid and Relative Permeability Data

A compositional fluid model was used with CO_2 defined as the injected component. Multiphase flow behavior was represented using relative permeability and capillary pressure relationships to describe interactions between gas and formation fluids.

Relative permeability curves were defined for the gas and water phases, with critical saturation values selected based on representative reservoir conditions. Capillary pressure functions were included to account for capillary effects during CO_2 migration.

6.4 Initial Conditions

Initial reservoir pressure and saturation distributions were established using gravity-capillary equilibrium. This approach ensured realistic in-situ conditions prior to the start of CO_2 injection and allowed for stable numerical performance during simulation.

Table 3: Initial reservoir conditions

Parameter	Description
Initialization Method	Gravity-capillary equilibrium
Initial Fluid System	Formation water with dissolved gas
Reference Depth	Model-defined

6.5 Well and Injection Parameters

CO_2 was injected into the reservoir through designated injector wells. The injection process was controlled using predefined operating constraints to ensure stable and continuous injection throughout the simulation period.

Table 4: CO_2 injection parameters

Parameter	Value
Well Type	Injector
Injected Fluid	CO_2
Injection Control	Bottom-hole pressure controlled
Injection Start Date	January 2023

6.6 Relative Permeability and Capillary Pressure Functions

The multiphase flow behavior in the reservoir was defined using relative permeability and capillary pressure functions for water, oil, and gas phases. Figures 1,2 and 3 shows the relative permeability and capillary pressure relationships used in the model. These functions control phase mobility and fluid distribution during CO_2 injection.

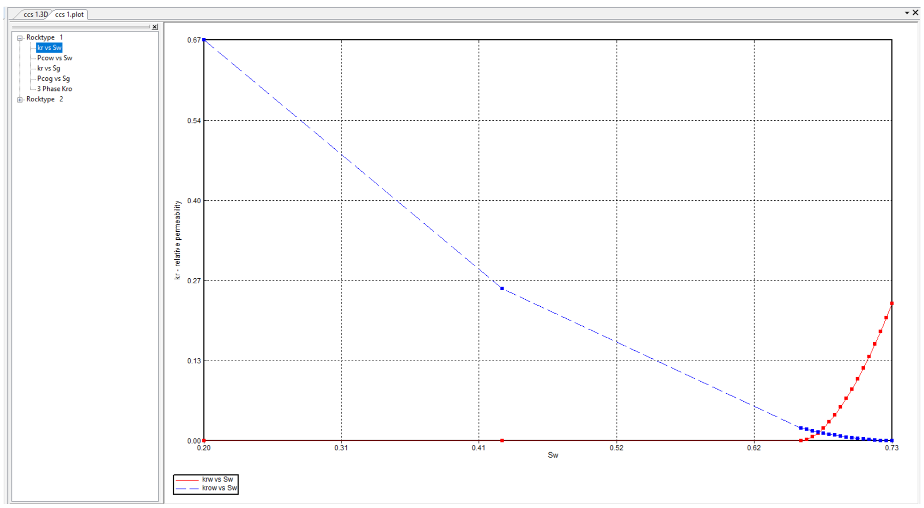

Figure 1: kr vs Sw

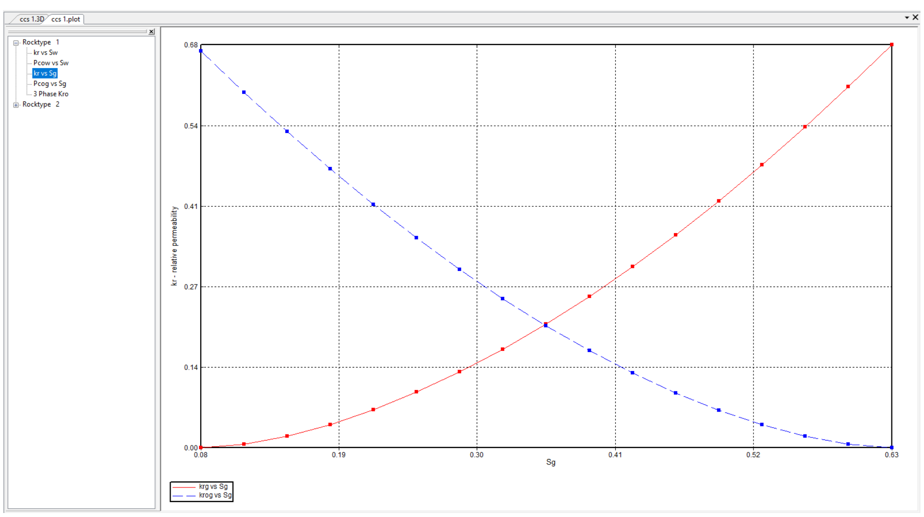

Figure 2: kr vs Sg

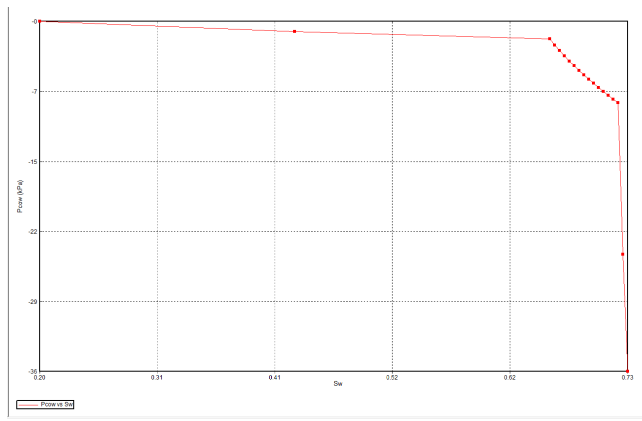

Figure 3: Pcow or Pcog

Detailed numerical input data and time-dependent injection schedules processed using Microsoft Excel are provided in the Appendix.

7 Results

This chapter presents the results obtained from the CMG-GEM simulation of CO_2 injection. The results are organized into rock–fluid flow characteristics, CO_2 composition behavior along the injection wells, and time-dependent reservoir response. Simulation outputs were post-processed using CMG visualization tools and Microsoft Excel.

7.1 CO_2 Composition Profiles Along Injection Wells

The distribution of CO_2 composition along the injection well provides insight into phase behavior and dissolution processes. Figure 4 shows the variation of CO_2 mole fraction in the aqueous phase along the injection well depth. The results indicate a gradual increase in dissolved CO_2 with depth, reflecting higher pressure conditions that enhance CO_2 solubility in formation water.

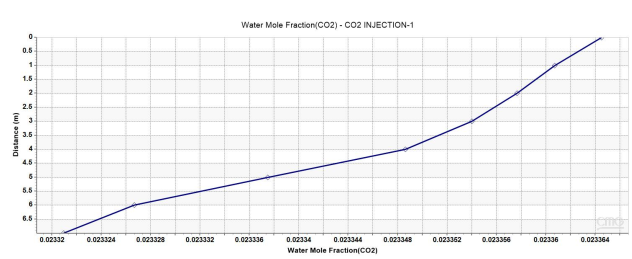

Figure 4: Water Mole fraction Co2 injection 1

The gas-phase CO_2 mole fraction along the injection well is shown in Figure 5. The gas phase remains highly enriched in CO_2 across the well depth, confirming effective injection of nearly pure CO_2 into the reservoir.

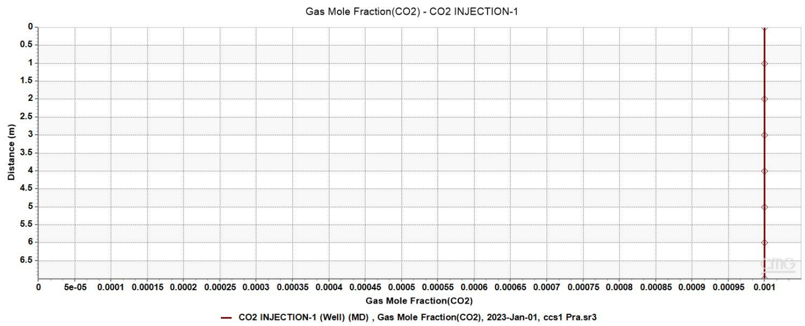

Figure 5: gas-phase CO_2 mole fraction

7.2 CO_2 Molality Distribution

The distribution of CO_2 molality along the injection wells provides insight into the dissolution behavior of CO_2 in formation water under reservoir conditions. Figure 6 presents the CO_2 molality profiles along two injection wells.

Both wells exhibit a gradual increase in CO_2 molality with depth, indicating enhanced CO_2 solubility at higher pressures in deeper sections of the reservoir. The similarity in molality trends between the two wells suggests consistent injection behavior and comparable reservoir response across the injection locations.

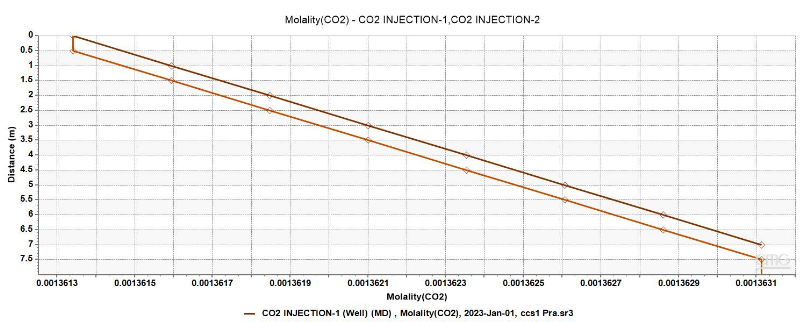

Figure 6: CO_2 Molality Distribution

7.3 Injection Well Performance

The injection performance of the CO_2 wells was evaluated using cumulative injected gas volume and injection rate histories obtained from CMG-GEM simulation outputs and post-processed using Microsoft Excel. The results for both injection wells are presented to assess consistency and operational behavior under pressure-controlled injection.

7.4 Cumulative Injected CO_2 Volume

Figure 7 shows the cumulative injected CO_2 volume as a function of time for Injection Well–1. The cumulative injection increases steadily throughout the simulation period, indicating continuous and stable injection performance.

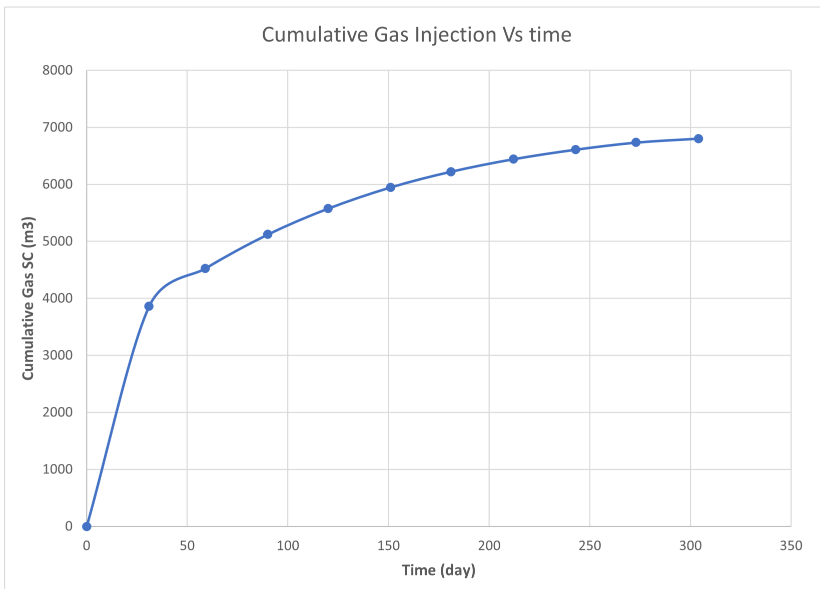

Figure 7: cumulative injected CO_2 volume as a function of time

Figure 8 presents the cumulative injected CO_2 volume for Injection Well–2. A similar increasing trend is observed, demonstrating comparable injection behavior between the two wells.

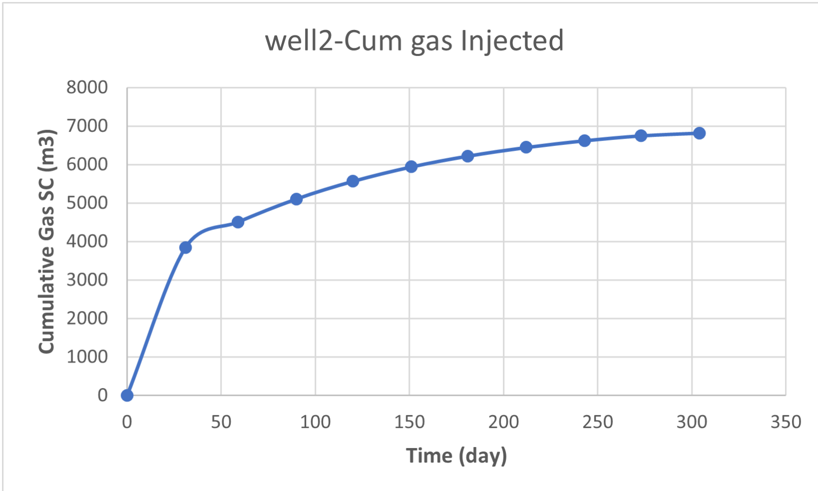

Figure 8: cumulative injected CO_2 volume as a function of time

7.5 CO_2 Injection Rate History

The variation of CO_2 injection rate with time for Injection Well–1 is shown in Figure 9. The injection rate is initially high and gradually decreases with time as the reservoir pressure near the well increases under constant bottom-hole pressure control.

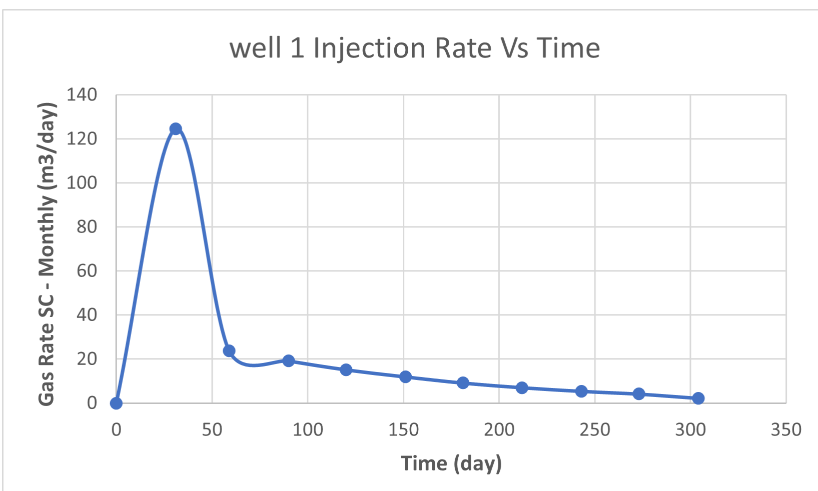

Figure 9: injection rate with time

Figure 10 shows the injection rate history for Injection Well–2. The declining trend is consistent with pressure-controlled injection behavior and indicates similar reservoir response for both wells.

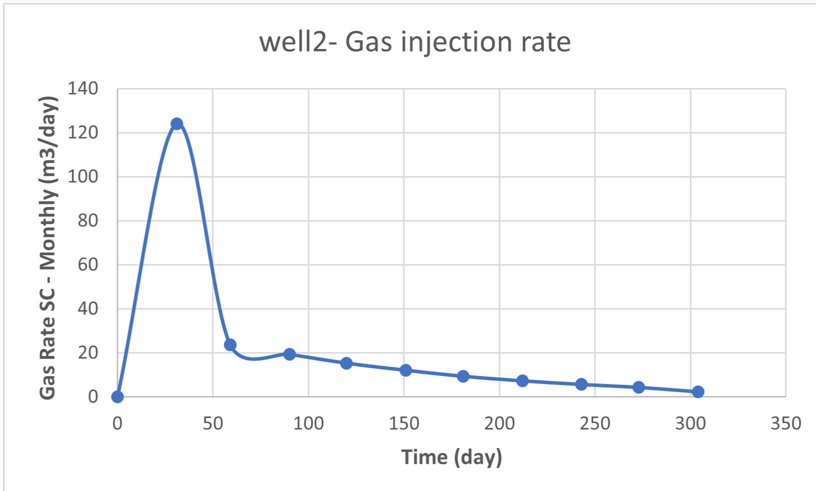

Figure 10: injection rate with time

The bottom hole pressure history for both Injection Wells is shown in Figure 11. The pressure remains constant throughout the injection period, confirming pressure-controlled injection operation.

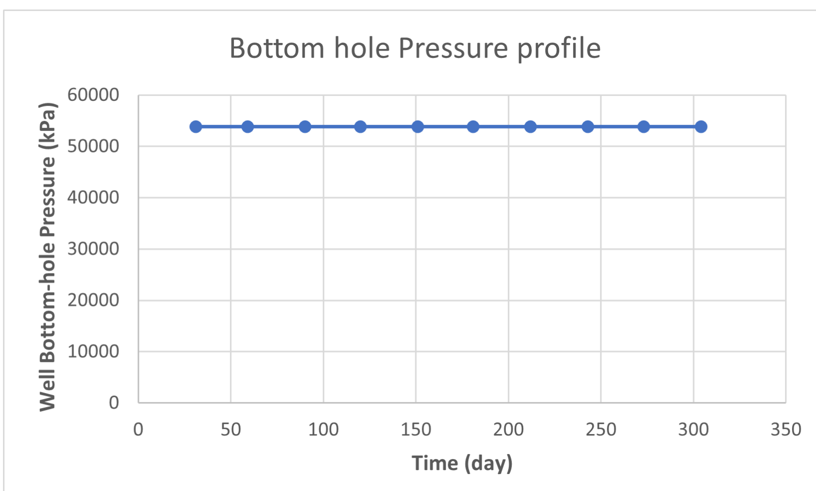

Figure 11: bottom hole pressure history for both Injection Wells

8 Discussion

This chapter interprets the results obtained from the CO_2 injection simulation and discusses the governing physical mechanisms influencing injection performance and reservoir response. The discussion focuses on pressure-controlled injection behavior, injection well performance, CO_2 dissolution characteristics, and the role of multiphase flow properties in the context of geological CO_2 storage.

8.1 Pressure-Controlled Injection Behavior

The injection wells in this study were operated under a constant bottom-hole pressure constraint. As observed in the simulation results, the bottom-hole pressure remains constant throughout the injection period, while the CO_2 injection rate gradually declines with time. This response is characteristic of pressure-controlled injection operations and reflects the simulator's adjustment of injection rate to maintain the specified pressure limit.

At early stages of injection, reservoir pressure near the wellbore is relatively low, resulting in higher injectivity and elevated injection rates. As injection continues, local reservoir pressure increases and gas saturation near the wellbore rises. These changes lead to increased flow resistance due to multiphase flow effects and reduced effective permeability to gas. Consequently, the injection rate decreases to satisfy the imposed pressure constraint.

Pressure-controlled injection is commonly preferred in CO_2 sequestration projects because it minimizes the risk of excessive pressure buildup, thereby protecting caprock integrity and reducing the likelihood of fracture initiation or induced seismicity.

8.2 Injection Performance and Well-to-Well Consistency

The cumulative injected CO_2 volumes for both injection wells increase smoothly over the simulation period, indicating continuous and stable injection behavior. The absence of abrupt changes or irregularities in cumulative injection trends suggests favorable reservoir injectivity and numerical stability of the simulation.

Injection rate histories for both wells exhibit similar declining trends under constant bottom-hole pressure control. This similarity indicates consistent reservoir response across the injection locations and suggests that the reservoir properties governing injectivity are comparable at both well positions. Such consistency is desirable in multi-well CO_2 storage projects, as it supports predictable injection performance and simplifies operational planning.

8.3 CO_2 Dissolution and Molality Behavior

The molality profiles of CO_2 along the injection wells provide insight into the dissolution behavior of injected CO_2 in formation water. The observed increase in CO_2 molality with depth reflects higher pressure conditions in deeper sections of the reservoir, which enhance the solubility of CO_2 in the aqueous phase.

The similarity in molality trends between the two injection wells suggests that dissolution processes are primarily controlled by reservoir pressure and fluid properties rather than localized well effects. Dissolution of CO_2 into formation water represents an important trapping mechanism, as it reduces the mobility of free-phase CO_2 and contributes to long-term storage security through solubility trapping.

8.4 Implications for Geological CO_2 Storage

The simulation results indicate that the modeled reservoir can accommodate sustained CO_2 injection under pressure-controlled conditions without excessive pressure buildup. The declining injection rates observed under constant pressure control reflect increasing flow resistance rather than operational instability, supporting the suitability of the reservoir for long-term CO_2 storage.

The presence of dissolved CO_2, as indicated by molality profiles, highlights the contribution of solubility trapping in addition to structural and residual trapping mechanisms. Together, these mechanisms enhance storage security and reduce the risk of CO_2 migration beyond the intended storage formation.

Overall, the results demonstrate that compositional reservoir simulation using CMG-GEM provides a robust framework for evaluating CO_2 injection performance and storage feasibility. The methodology applied in this study can be extended to assess alternative injection strategies, reservoir properties, and long-term storage scenarios.

9 Conclusions

A compositional reservoir simulation study of CO_2 injection was conducted using the CMG-GEM simulator to evaluate injection performance and reservoir response under pressure-controlled operating conditions. Based on the simulation results and subsequent analysis, the following conclusions can be drawn.

- The reservoir model successfully simulated sustained CO_2 injection under constant bottom-hole pressure control. The bottom-hole pressure remained stable throughout the injection period, confirming correct implementation of pressure-controlled injection strategy.

- CO_2 injection rates decreased gradually with time while cumulative injected volumes increased smoothly. This behavior reflects increasing flow resistance near the injection wells due to rising reservoir pressure and multiphase flow effects, rather than operational instability.

- Consistent injection performance was observed across both injection wells, as indicated by similar cumulative injection trends and rate histories. This suggests comparable reservoir response and favorable injectivity at the selected well locations.

- CO_2 molality profiles along the injection wells showed an increase in dissolved CO_2 concentration with depth, highlighting the influence of pressure on CO_2 solubility in formation water. This behavior supports the occurrence of solubility trapping as an important storage mechanism.
- Multiphase flow behavior, governed by relative permeability and capillary pressure relationships, plays a critical role in controlling injectivity, pressure response, and CO_2 distribution within the reservoir. Accurate representation of these properties is essential for reliable CO_2 sequestration simulations.
- Overall, the results indicate that the modeled reservoir can accommodate CO_2 injection under the specified conditions without excessive pressure buildup, supporting its suitability for geological CO_2 storage.

The study demonstrates the applicability of CMG-GEM as an effective tool for evaluating CO_2 injection performance and provides a structured simulation workflow that can be extended to investigate alternative injection strategies, reservoir heterogeneity, and long-term storage behavior in future studies.

10 Appendix

10.1 Injection Performance Data

This appendix contains the time-dependent injection performance data exported from CMG-GEM and processed using Microsoft Excel.