The Cooling Effect of Joule Thomson on CO2 Storage during Start-Up Period: Integration of Reservoir and Wellbore

BY

HEDYE MOABRAKI

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College of Environmental and Land Engineering

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Supervisors:

Professor Dario Viberti

Professor Ashkan Jahanbani Ghahfarokhi

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Declaration

This project report is submitted in partial fulfillment of the requirements for the degree of Master of Engineering in Georesources and Geoenergy Engineering.
I declare that this thesis was composed by me, that the work contained herein is my own, except where explicitly stated otherwise in the text, and that it has not been submitted, in whole or in part, for any other degree or professional qualification.

Hedye Moabaraki

This thesis was conducted under the supervision of Prof. Dario Viberti from Politecnico di Torino and Prof. Ashkan Jahanbani from Norwegian University of Science and Technology.

Abstract

The ongoing challenge of mitigating climate change has emphasized the importance of technologies like Carbon Capture and Storage (CCS). Among various options, the sequestration of CO2 in depleted gas fields presents a promising solution, particularly due to the availability of well-characterized geological data and the inherent capacity of these fields to store large volumes of CO2. However, injecting CO2 into these reservoirs, introduces significant thermal and geomechanical challenges.

This thesis investigates the near wellbore effects during CO2 injection, focusing on the Joule-Thomson cooling effect, which can lead to substantial temperature drops and associated risks such as hydrate formation, wellbore thermal stress, and potential over-pressurization.

Using the CMG STARS simulator, this study models the thermal and fluid dynamics within the wellbore and reservoir to predict the behavior of CO2 during injection. The Flexible Wellbore (FLX-WELLBORE) option is employed to capture the complex interactions between the wellbore and reservoir. The findings provide a detailed understanding of the near wellbore effects, offering insights into best practices for safe and efficient CO2 injection. This research contributes to the broader goal of enhancing CCS strategies and supporting global efforts to reduce greenhouse gas emissions.

Dedication

I would like to acknowledge the unwavering love and support of my parents, who have enabled me to pursue my studies abroad. Their encouragement and belief in me have been the foundation of my success. I am also deeply grateful to my dear cousin Ghazal, whose constant emotional support provided me with the strength to persevere even in difficult times.

This MSc thesis marks the culmination of an enriching educational journey at the Politecnico di Torino, complemented by a rewarding exchange program at NTNU.

First and foremost, I would like to express my deepest gratitude to Professor Dario Viberti for his exceptional guidance and mentorship. His critical feedback and insightful questions challenged me to view my work from broader perspectives. Since my initial fluid mechanics course at Politecnico di Torino, I have been captivated by his teaching style and dedication. Over the course of my master's program, he provided unwavering support not only in my academic endeavors but also in personal matters. It has been a privilege to learn under someone with such a profound commitment to academic research.

I would also like to extend my heartfelt thanks to Professor Ashkan Jahanbani from NTNU. His pragmatic approach and continuous support were invaluable to my research on Carbon Capture and Storage (CCS). His deep understanding of the underlying physics greatly enhanced my grasp of the thermodynamic aspects of compositional simulations. Additionally, I am grateful for the opportunities he provided, including the invitation to attend two significant conferences in Norway, which kept me abreast of the latest challenges in the oil and gas industry. His support was instrumental in helping me navigate the challenges of adapting to a new environment as an Erasmus student.

My sincere appreciation also goes to Behnam Tavagh Mohammadi, whose extensive experience in simulation and reservoir engineering offered crucial guidance in using CMG software. The weekly progress meetings with Professor Jahanbani and Behnam were pivotal in advancing this thesis.

I am also indebted to Professor Alireza Alamatsaz, my undergraduate mentor, who offered his expertise and assistance with CMG software during challenging moments in my thesis work. His willingness to help and his humanity are truly commendable.

This work would not have been possible without the contributions of these individuals, and I am deeply grateful for their support.

Contents

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Abbreviations

CCS Capture and Storage.

CMG Computer Modelling Group.

CO2 Carbon Dioxide.

ECBM Enhanced Coal Bed Methane.

EGR Enhanced Gas Recovery.

EOR Enhanced Oil Recovery.

FLX-WELLBORE Flexible Wellbore.

GEP Global Energy Perspective.

GHG Greenhouse Gas.

Note: Author abbreviations are shown in their corresponding reference entry.

Nomenclature

C_P Heat capacity at constant pressure.

H Enthalpy.

H_{in} Enthalpy at the inner boundary of the section.

H_{out} Enthalpy at the outer boundary of the section.

P Pressure.

P_{BHF} Pressure at the bottom-hole.

P_{res} Reservoir pressure.

Q Heat transfer coefficient.

Q_j Includes contributions from work done by pressure and any external heat sources.

S_j Saturation of phase j.

T Temperature.

T_W Temperature of the wall layer.

U_j Total internal energy of phase j.

V Volume of the fluid.

$\Delta T_{\text{adiabatic}}$ Adiabatic temperature change.

λ Thermal conductivity.

$\mathbf{u}_j$ Darcy velocity of phase j.

μ_{JT} Joule-Thomson coefficient.

ϕ Porosity.

$\rho(r)$ Density at radius r.

ρ_W Density of the wall layer.

ρ_j Density of phase j.

$c_p(r)$ Specific heat capacity at constant pressure at radius r.

c_{p_W} Specific heat capacity of the wall layer.

g Gravity.

h_j Enthalpy of phase j.

h_{in} Height at the inner boundary.

h_{out} Height at the outer boundary.

$k(r)$ Thermal conductivity at radius r.

k_W Thermal conductivity of the wall layer.

q_T Source/sink term for energy.

q_j Source or sink term for phase j.

r Radial coordinate.

t Time.

A Constant coefficient in the equation.

B Constant coefficient in the equation.

C Constant coefficient in the equation.

M Mass flow rate at the bottom-hole.

Chapter 1

Introduction

1.1 Carbon Problem

The “carbon problem” refers to the ongoing increase in atmospheric concentrations of the greenhouse gas carbon dioxide (CO2) observed over the last two centuries. This increase is being driven almost entirely by anthropogenic emissions, with most of the emissions associated with combustion of fossil fuels (20).

In 2015, representatives from 198 nations convened in Paris for the Global Climate Change Summit and collectively established the "Paris Agreement" as a framework for global temperature regulation (United Nations, 2015). This landmark agreement, outlined in the UN Paris Agreement (2015), aims to bolster the implementation of the United Nations Framework Convention on Climate Change (COP21 Paris Agreement)(27; 29).

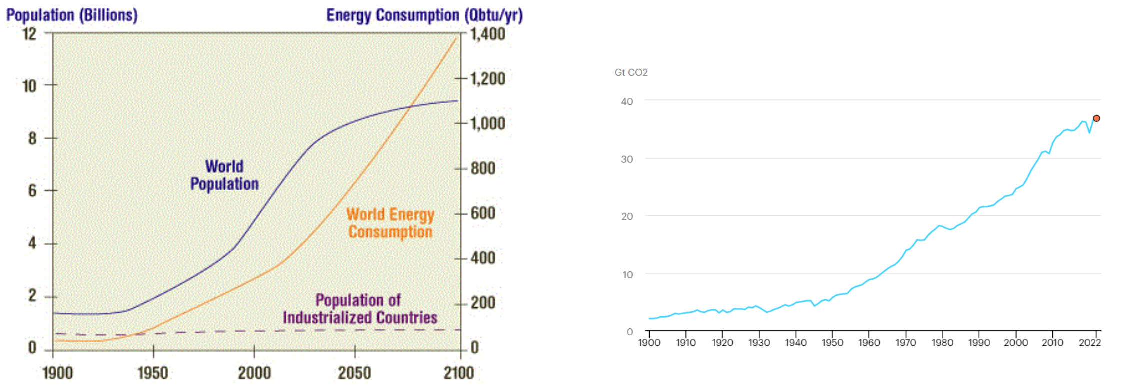
Its objectives include:

1-Limiting the global average temperature increase to well below 2°C above pre-industrial levels and striving to cap the increase at 1.5°C above pre-industrial levels, acknowledging the substantial risk reduction associated with this target.

2-Enhancing adaptation capabilities to mitigate the adverse impacts of climate change and promoting resilience to climate-related challenges, all while ensuring sustainable food production.

3-Aligning financial investments with a trajectory towards low greenhouse gas emissions and climate-resilient development (29).

On the other hand, according to the Global Energy Perspective (GEP), the world's primary energy demand is expected to escalate annually owing to the ongoing growth in the global population (13).



(a) World population and energy demand growth

(b) Global CO2 emissions from energy combustion and industrial processes

Figure 1.1: Global CO2 emissions and population growth with energy demand.

Figure 1.1 illustrates the relationship between world population growth and energy consumption rates. As the global population increases, the demand for primary energy, particularly in sectors like transportation and manufacturing, also rises. This growing energy consumption leads to greater reliance on fossil fuels, resulting in higher CO2 emissions, which exacerbate climate change. Addressing these challenges is critical for achieving sustainable development and reducing environmental impacts.

Hence, there is an immediate need for implementation of various actions to reduce CO2 emissions to mitigate these changes, including increased energy supply from renewable and nuclear sources, increased energy efficiency and moving to fossil fuel based power with carbon capture and storage (CCS)(12).

1.2 CCS and CO2 storage options

As a potential large-scale solution to mitigate the issue of atmospheric carbon, Carbon Capture and Storage (CCS) has emerged as a viable option. The concept of CCS is simple: capture the CO2 produced when the chemical energy in fossil fuels is converted to electrical energy, and sequester the captured carbon somewhere other than the atmosphere(20).

The most likely location for large-scale sequestration is in deep geological formations, where the CO2 would be injected into formations that are:

1-Sufficiently permeable to accept large quantities of CO2

2-Overlain by low-permeability formations that trap the injected buoyant CO2.

The primary advantage of implementing CCS technology lies in the availability of existing required technology, reducing the necessity for significant new technological developments for its large-scale application. However, ongoing research focuses on enhancing efficiencies and developing low-cost capture technologies. Furthermore, the oil industry's experience with injecting gases and liquids into deep subsurface formations, particularly in CO2 injection for enhanced oil recovery, provides an additional advantage. Nevertheless, the permanent injection of CO2 into deep geological sites like saline aquifers, un-mineable coal seams, or highly depleted oil/gas fields presents distinct challenges and experiences compared to past practices(27).

The concept of CCS involves capture of the CO2 prior to release to the atmosphere and storage (or sequestration) away from the atmosphere. In principle, technology exists to achieve both of these steps.

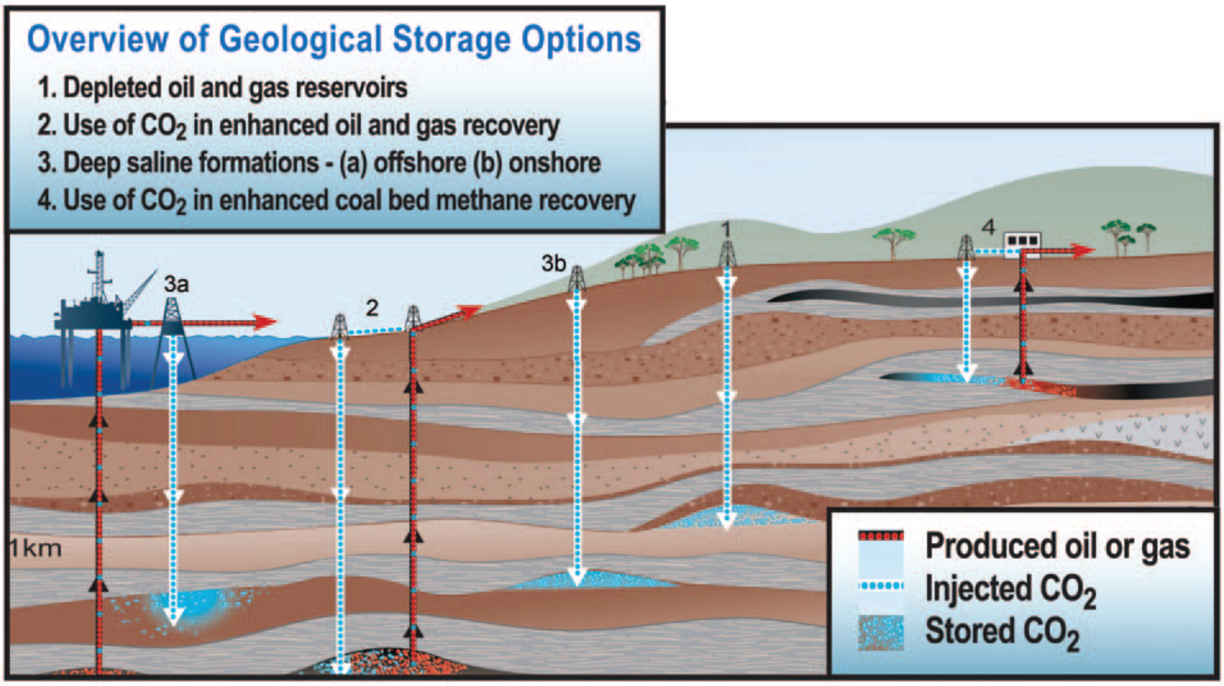


Figure 1.2: Geological formations and reservoirs for CO2 sequestration

Various locations, as shown in Figure 1.3, can serve as potential sites for CCS, with deep sedimentary basins being a prominent choice for large-scale CO2 injections. These basins may encompass depleted oil and gas reservoirs, whether for enhanced oil recovery purposes or not, along with unminable coal seams and deep saline aquifers(6).

When selecting sites for CCS deployment, the criteria should include formations that are deeper than 800 meters, feature a substantial and extensive sealing layer, have enough porosity to store large volumes, and possess sufficient permeability to allow for high injection flow rates without the need for excessive pressure(6).

Figure 1.3: Sedimentary basins showing suitability as sequestration sites(12)

Figure 1.3 highlights global regions with varying potential for CO2 storage in sedimentary basins. It categorizes areas as highly prospective, prospective, and non-prospective based on the likelihood of finding suitable storage sites like saline formations, oil, gas fields, or coal beds. The map is based on partial data, with quality varying across regions, and should be used as a general guide, recognizing that information may change over time with new data(11).

Among the CO2 storage options available, highly depleted oil/gas fields stand out as optimal locations for the large-scale by of captured CO2 emitted by industrial sources and fossil-fuel power plants.

Depleted fields possess the advantage of being pressure-depleted, enabling CO2 injection without exceeding the reservoir's initial discovery pressure, thus avoiding potential damage to the reservoir, cap rock, and wellbores. In contrast, saline aquifer sites necessitate injection above hydrostatic pressure, particularly around the injection wells, despite pressure management efforts. Additionally, compared to depleted gas and oil reservoirs, saline aquifer sites lack comprehensive geological data, as aquifers are typically considered non-reservoir layers and are therefore not extensively investigated(9; 15; 10).

In contrast to saline aquifers, depleted gas fields are better characterized given the availability of geological data, such as pressure, porosity and permeability, derived from years of gas production, as well as seals that have successfully retained hydrocarbon gas for millions of years, and may offer a shorter route to practical implementation for early CCS projects(10).

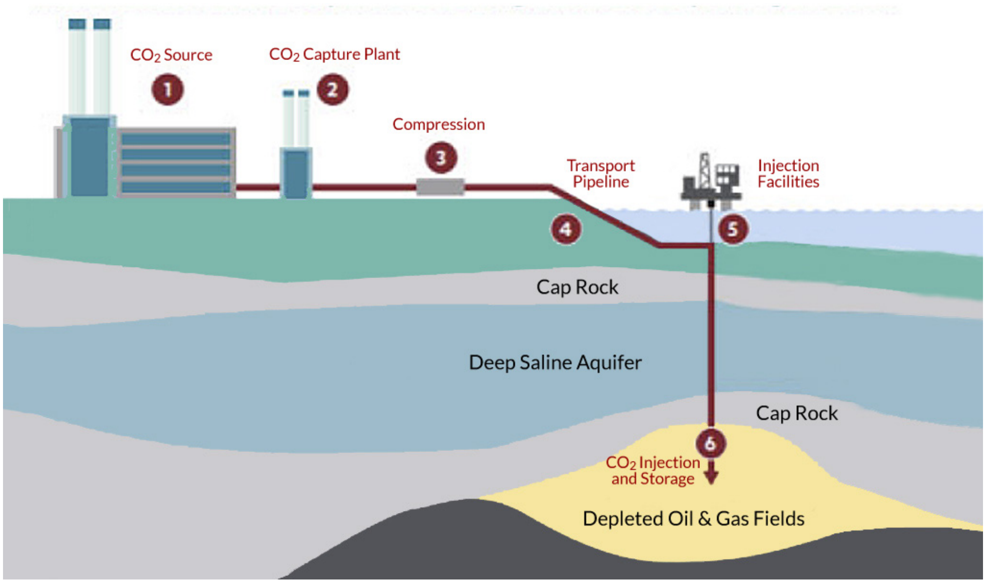


Figure 1.4: Steps in CO2 capture and injection into depleted oil and gas field

Given the potential advantages of depleted fields, there are several obstacles to consider, notably due to the low reservoir pressures and the unique thermodynamic properties of CO2. The commencement of CO2 injection into depleted gas fields with low pressure entails significant safety and operational challenges.

1.3 Problem Statement and Significance of Study

To ensure the economical transportation of large quantities of CO2, typically on a mega-tons scale, the majority of CCS pipelines must operate in the dense or supercritical phase rather than in vapor form. The most cost-effective method for transporting captured CO2 for subsequent storage involves utilizing high-pressure pipelines to maintain its dense phase(4; 15).

Hence, CO2 transported through the sub-sea pipeline to the injection well typically arrives at pressures approximately 65 bar and temperatures spanning from 4 to 8 degrees Celsius. However, as the pressure diminishes significantly at the wellhead, uncontrolled CO2 injection initiates swift quasi-adiabatic expansion, known as "Joule-Thomson expansion," causing a drop in temperature.

Joule-Thomson expansion presents several potential risks, including:
1-Hydrate and ice formation due to the contact of cold CO2 with interstitial and formation water, leading to potential blockage.
2-Thermal stress on wellbore casing steel caused by temperature gradients, possibly resulting in fractures and CO2 leakage.
3-Over-pressurization and CO2 backflow into the injection system due to violent evaporation of superheated liquid CO2 upon entry into the 'low-pressure' wellbore.

Figure 1.5 illustrates the key characteristics and components of an injection well that connects the upstream CO2 source to the storage reservoir. When CO2 is injected into the formation, its expansion and cooling due to the pressure differential between the injected fluid and the pressure at the top of the well can lead to ice formation as a result of the Joule-Thomson effect.

Developing effective start-up injection strategies to prevent the outlined risks is essential. A reliable model for predicting the behavior of injected CO2 especially regarding pressure and temperature variations along the well and upon reaching the depleted reservoir layers is key to this effort. However, heating the CO2 stream prior to injection is an option but highly costly due to the large volumes involved, which are on a mega-ton scale(22).

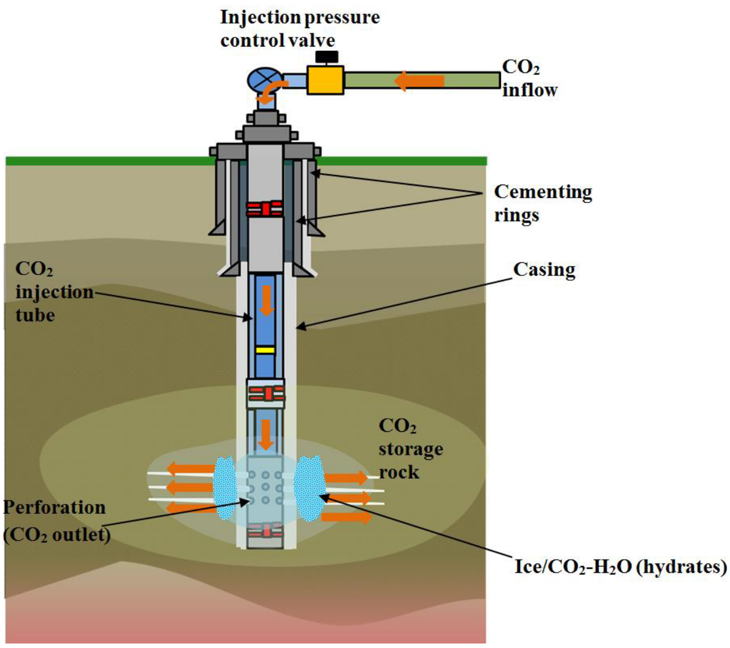


Figure 1.5: Schematic diagram of CO2 injection and the Joule-Thomson effect

1.3.1 Previous Work

Efforts have already been made to analyze the injection of CO2 from wells into underground reservoirs. However, As highlighted by A. Battistelli, M. Carpita, M. Marcolini from Saipem Italy (2010) and Linga and Lund (2016), there has been limited focus on modeling the transient behavior of CO2 flow within injection wells(3; 18).

This thesis explores the creation of a model to forecast the thermal characteristics of CO2 during injection. The model is generated using CMG STARS.

1.3.2 Study Aim and Objectives

The primary objective of this study is to provide an environmentally sustainable solution to address the challenge of global temperature rise, commonly known as "global warming," through CCS. Specifically, this study focuses on modeling the transient flow dynamics of carbon dioxide (CO2) during geological sequestration. Main objectives are:

1-Validate transient flow models for injecting CO2 into depleted gas fields

2-Conduct sensitivity analysis regarding pressure, and temperature variations

The thesis consists of four chapters: Chapter 2 provides a review of literature, discussing the existing challenges in the widespread implementation of CCS and recent publications related to CO2 injection. It also delves into a detailed examination of the Joule-Thomson expansion cooling effect, which explains the flow of expanding CO2 into the injection well.
Chapter 3 presents the methodology used in the thesis, along with the results obtained from simulations. It provides a detailed explanation of the model construction process and highlights innovative techniques employed to address challenges encountered during model development.
Chapter 4 summarizes the conclusions drawn from the study and offers recommendations for future research.

Chapter 2

literature review

In connection with Chapter 1, this section reviews literature discussing the current obstacles and challenges in the widespread implementation of CCS, along with a thorough examination of recent publications related to CO2 injection. It also provides a detailed and comprehensive analysis of the Joule-Thomson expansion effect, which elucidates the flow of expanding CO2 into the injection well.

2.1 CCS in potential geological formations

Following the capture and compression of CO2, it is transported to a selected geological reservoir for long-term storage. As depicted in Figure 2.1, potential reservoirs for CO2 storage include depleted oil or gas fields, deep saline aquifers, and un-mineable coal seams. Deep sedimentary basins serve as the primary targets for large-scale CO2 injections, utilizing a combination of reservoirs and aquifers for storage purposes(20).

Understanding that these stable natural geological reservoirs chosen for CO2 injection have existed for millions of years, it's important to assess if they will retain their original characteristics without the injected CO2, like naturally occurring CO2-containing reservoirs, and if they are suitable for the intended purpose.

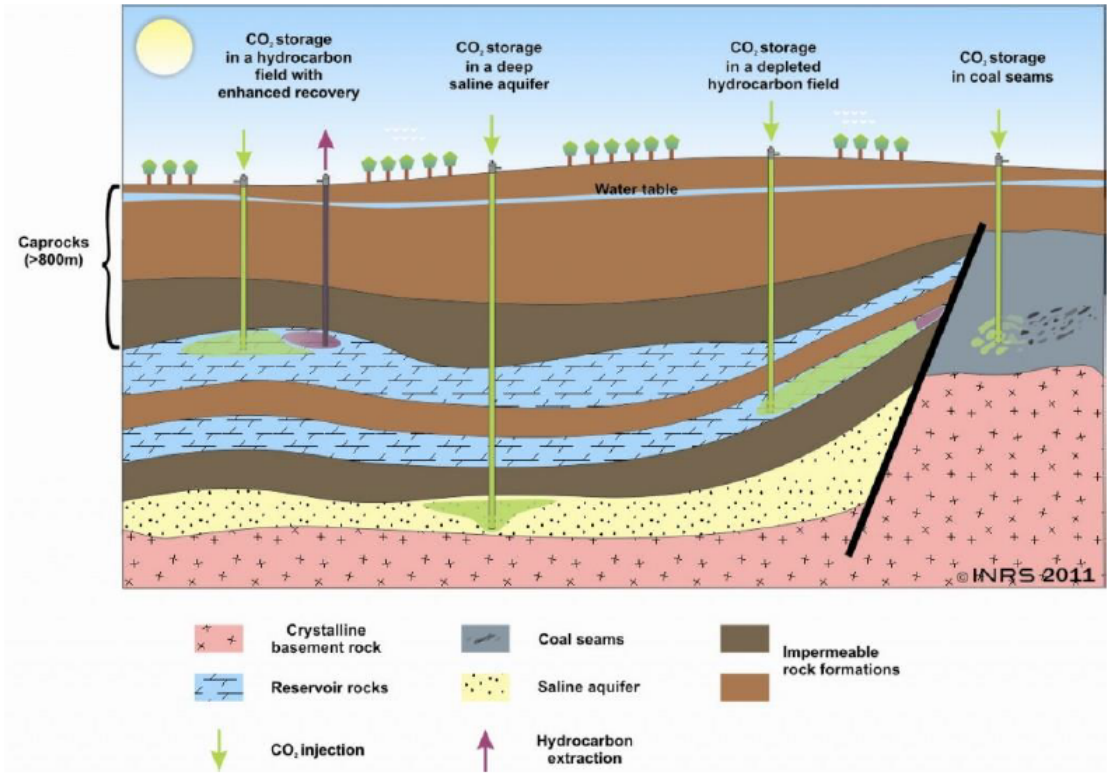


Figure 2.1: Types of Geological Formations for CO2 Storage

The geological storage of CO2 offers a novel approach to mitigating greenhouse gas (GHG) emissions. While injecting CO2 into oil or gas fields is not a new concept, as Enhanced Oil Recovery (EOR) has utilized CO2 injection to enhance hydrocarbon field productivity since the 1970s, there are distinctions. Unlike CCS projects, CO2 EOR initiatives do not necessitate the same level of scrutiny regarding the structure of the oil and gas formations they exploit, as these formations were not initially developed for CCS purposes(2).

As depleted oil and gas fields are viewed as favorable storage sites for CCS, concerns regarding capacity and injectivity are anticipated to be minimal during the shift from CO2 EOR to CCS. Nevertheless, the injection of CO2 into a highly depleted, low-pressure oil or gas field poses a distinct challenge compared to EOR practices(2; 20).

Aspect	CO2-EOR	CCS
Purpose	Increase oil and gas production efficiency (tertiary recovery) to optimize the hydrocarbon-bearing reservoir.	Reduce greenhouse gases (GHG) emissions to the atmosphere in support of climate change mitigation activities.
CO2 Lifecycle	Captured from a natural or anthropogenic source, transported, injected into the hydrocarbon-bearing formation and recycled through a closed circuit process.	Captured from an anthropogenic source, transported and injected into the depleted hydrocarbon formation for safe and permanent sequestration.

Table 2.1: Fundamental Differences between CO2-EOR and CCS Projects

In geological reservoirs, porous rocks like sandstone and certain carbonate formations have pores capable of retaining CO2. A successful CO2 sequestration process relies on having an appropriate storage medium.This medium includes a highly impermeable cap-rock situated above the reservoirs, typically made of fine-grained material or rock salt.

This cap-rock serves a dual purpose: it maintains the injected CO2 at the desired depth and effectively seals the reservoir. Additionally, the storage medium must exhibit geological stability, lack leakage paths, and employ effective trapping mechanisms(25).

I will provide a concise overview of different geological formations, examining their potentials and limitations for CO2 storage:

2.1.1 CO2 Geological Storage in Depleted or Depleting Oil and Gas Fields

CO2 injection into geological formations within oil and gas fields serves either for enhanced oil recovery (EOR) or for permanent storage. In EOR, CO2 boosts pressure to aid in oil or gas extraction, while in permanent storage; it serves as an environmental intervention measure. The process involves injecting CO2 into depleted gas fields, a relatively new practice requiring further research and development(20).

Depleted oil and gas fields stand out for their well-documented geological data, including pressure, porosity, and permeability, accumulated over years of production. These fields also boast seals that have effectively contained hydrocarbons for extended periods, potentially suitable for the implementation of CCS projects(10; 27).

2.1.2 CO2 Geological storage in Deep Saline Aquifers

Deep saline aquifers are rock formations characterized by their porous, permeable nature and saturation with saltwater, which is significantly saltier than seawater and unsuitable for consumption. The impermeable layer surrounding these aquifers restricts the lateral and vertical movement of injected CO2, allowing for gradual migration. These aquifers are considered the most promising option for geological CO2 storage due to their substantial capacity(13).However, the risk of CO2 leakage poses a significant challenge to their widespread deployment for large-scale applications.

A notable illustration of CCS in deep saline aquifers is the Sleipner project in Norway, launched in 1996. Over the years, Sleipner has emerged as a prominent example of large-scale CCS deployment. By 2023, the project had successfully injected a substantial volume of over 23 million tonnes of CO2 into saline aquifers(26; 17).

2.1.3 CO2 storage in un-mineable coal seams

Geologically, CO2 storage in coal seams that are not economically feasible for mining can involve a process known as Enhanced Coal Bed Methane (ECBM). In this method, CO2 is injected into the coal seams to displace methane, allowing for methane recovery while trapping the CO2 within the coal pores(27; 20).

To summarize, the discussion so far has offered a thorough examination of various geological formations that are viable for carbon capture and storage (CCS). The table created compares these formations, outlining their respective advantages and disadvantages. It emphasizes the economic and operational suitability of oil and gas fields, deep saline aquifers, and unmineable coal seams for long-term CO2 sequestration.This overview provides a solid foundation for understanding the potential of different geological structures in effectively implementing CCS, considering factors such as storage capacity, proximity to emission sources, and potential risks like CO2 leakage.(27).

Storage type	Advantages	Disadvantages
Oil and gas fields	• Leak-proof cap-rocks and traps • Well-characterized reservoir systems • Economically viable for EOR, EGR	• Often distant from CO2 emission sites • Limited storage capacity
Deep saline aquifers	• Widespread with high CO2 storage potential • Easily locatable storage sites for emitters	• Limited characterization of sites • Potential CO2 leakage after injection
Un-mineable coalseams	• Proximity to CO2 emission sites • Economically viable for methane recovery	• Injection challenges due to coal's low permeability • Limited storage capacity

Table 2.2: Potential storage reservoirs with their advantages and disadvantages

2.2 Challenges Linked to Carbon Capture and Storage

An essential benefit of CCS lies in the availability of all necessary technology for its widespread implementation. The oil and waste disposal industries boast significant experience in injecting gases and liquids into deep subsurface formations, thus negating the requirement for new technological advancements. However, enhancing process efficiency, developing low-cost capture techniques, and implementing new technologies for long-term monitoring of injection systems remain essential for CCS advancement(20).

The large-scale implementation of CCS encounters substantial challenges, which can be categorized into six main areas as listed below, each with a brief summary of its complexities(5).

- **Cost complexity**

  Difficulty in estimating and expressing actual CCS costs due to lack of empirical data, currency variations, and diverse operating conditions.

- **Geo-storage uncertainty**

  Uncertainty in estimating global CO2 storage capacity, with varying regional estimates and classification systems, leading to a lack of clarity on ultimate potential.

- **Storage capacity constraint**

  Limited understanding of the impact of storage capacity constraints on CCS deployment, particularly in the long term, and potential limitations on commercial viability.

- **Supply chain limitations**

  Challenges in the availability of equipment, skilled labor, and regulatory frameworks, particularly regarding geological appraisal, workforce availability, and regulatory uncertainty.

- **Policy and market barriers**

  Absence of effective mechanisms to support CCS deployment, including lack of market incentives, regulatory frameworks, and investment support, hindering widespread adoption.

- **Public acceptance and perceptions**

  Public perception challenges, including insufficient knowledge, concerns about sustainability, and competition with renewable alternatives, affecting acceptance and support for CCS initiatives.

Therefore, it is essential to understand a secure injection process thoroughly to build investor confidence and promote global collaboration for effective solutions.

This research targets a significant technical obstacle related to safety concerns during the initial injection phase. It tackles this challenge by employing CMG to simulate the dynamic changes occurring throughout the process.

2.3 Previous Studies on CO2 Injection

2.3.1 Advancements from Historical Foundations to Current Innovations

- **Pioneering Efforts in CO2 Wellbore Research**

  The study of CO2 flow in wellbores initially emerged from research focused on oil and gas extraction, particularly enhanced oil recovery (EOR). Early investigations, such as those conducted by Cronshaw and Bolling (1982), employed simplified thermodynamic models to analyze quasi-steady flows.

  These foundational models provided essential insights into CO2 behavior under steady-state conditions in wellbores but were limited in their ability to address transient flow effects, which are crucial during operations like well start-up and shut-in. Further research was necessary to develop models that could accurately simulate these transient conditions and handle complex phase transitions of CO2, ensuring more reliable predictions for practical CCS applications.

- **Key Milestones in CO2 Wellbore Dynamics: Pre-2015**

  Before 2015, several researchers made significant contributions to the study of CO2 flow in wellbores, each addressing different aspects of the problem.

  Afanasyev (2013) developed a compositional modeling approach for sub- and super-critical three-phase flows, focusing on the thermodynamic potential of CO2 mixtures. However, his model primarily addressed the thermodynamic properties and did not fully capture transient flow dynamics.

  Lu Connell (2014) proposed a novel modeling scheme specifically for transient CO2 wellbore hydraulics, integrating rigorous thermodynamic principles. Despite its advancements, their model still faced challenges in accurately predicting the complex interactions during transient operations like start-up and shut-in.

  These studies laid the groundwork for future research but highlighted the need for more comprehensive models that could address both the thermodynamic complexities and the dynamic flow behaviors in wellbores.

- **Advancements in CO2 Wellbore Technology: 2015-2020**

  Li et al. (2015) conducted a comprehensive analysis of parameters influencing transient CO2 operations, particularly within the Goldeneye CCS Project in the UK. Utilizing a 1D+1D model in the OLGA software, they simulated wellbore dynamics, incorporating mass, momentum, and energy conservation equations.

  The model accounted for radial heat transfer between the fluid and surrounding rock, described by the radial transient heat conduction equation:

$$\rho_W c_{p_W} \frac{\partial T_W}{\partial t} = \frac{1}{r}\frac{\partial}{\partial r}\left(k_W r \frac{\partial T_W}{\partial r}\right) \tag{2.1}$$

  Where the subscript W refers to the wall layer, c_p denotes the specific heat capacity, T represents the temperature, r is the radial coordinate, and k signifies the heat conductivity.

  They also used a quadratic inflow equation to describe the pressure differential between the bottom-hole and the reservoir:

$$A + B \times M + C \times M^2 = P_{BHF}^2 - P_{res}^2 \tag{2.2}$$

  where A,B, and C are constants, and M represents the mass flow rate at the bottom-hole. The Span Wagner EoS was applied for CO2 density and specific heat calculations, while the K.S.P EoS was used for viscosity and thermal conductivity. Although this model provided valuable insights into temperature and phase behavior during transient CO2 injection, its limitations include the simplification of heat transfer by neglecting axial conduction, dependence on specific assumptions that may limit broader applicability, and the absence of experimental validation to support the accuracy of the simulation results under real-world conditions(16).

  In the following year,Linga et al. (2016) developed an advanced model for CO2 injection that utilizes a physically consistent two-fluid model to describe flow dynamics, with the Span-Wagner Equation of State accurately representing CO2 thermodynamics.

The model accounts for friction and heat transfer across different flow regimes, such as bubbly, annular, and mist flows, and includes a heat conduction model for the well's layers (tubing, casing, cement, and rock). The heat conduction in radial geometry is expressed as:

$$\rho(r)c_p(r)\frac{\partial T(r,t)}{\partial t} = \frac{1}{r}\frac{\partial}{\partial r}\left(k(r)r\frac{\partial T(r,t)}{\partial r}\right) \tag{2.3}$$

where k(r), (r), and cp(r) represent the thermal conductivity, density, and specific heat capacity (at constant pressure) at radius r, respectively. This formulation neglects axial heat conduction along the pipe but considers heat transported by the fluid inside the well.

However, the model assumes that the outflow from the reservoir is at reservoir temperature, potentially overlooking significant temperature drops due to the Joule-Thomson effect. The model also predicts a water hammer effect during shut-in scenarios, though further refinement is needed to accurately capture thermodynamic behavior under varying conditions(18).

Subsequently, Acevedo and Chopra (2017) examined the effects of transient operations on CO2 injection wells, specifically in the Goldeneye project.

Their study revealed that brief temperature drops occur at the top of the well during operations like closing-in and restarting injection, mainly due to reduced friction from lower injection rates. They used OLGA software to simulate these operations, focusing on how different durations affect well components. However, the study's limitations include assumptions that may not fully represent real-world scenarios and a lack of long-term impact analysis on well integrity and CO2 management(1).

- **Recent Innovations in CO2 Injection and Wellbore Dynamics:2021 Onwards**

  Recent advancements in CO2 injection modeling have incorporated sophisticated tools like OLGA 2022, T2WELL-ECO2M, and CMG STARS. These updates enhance simulations of complex CO2 behaviors, particularly supercritical phase transitions, and improve accuracy in modeling transient operations, including start-ups and shut-ins, by incorporating detailed thermal effects, phase behavior, and fluid dynamics within wellbores and reservoirs.

Pan and Oldenburg (2020) developed a two-dimensional radial model to simulate CO2 injection into a subsurface reservoir.

This model, which extends over a 10 km radius, includes a 20-meter-thick permeable reservoir capped by a 50-meter-thick impermeable layer. The system, initially saturated with water, is subjected to dry CO2 injection through the wellbore. The model is divided into grids to accurately capture the complex flow and thermal dynamics.

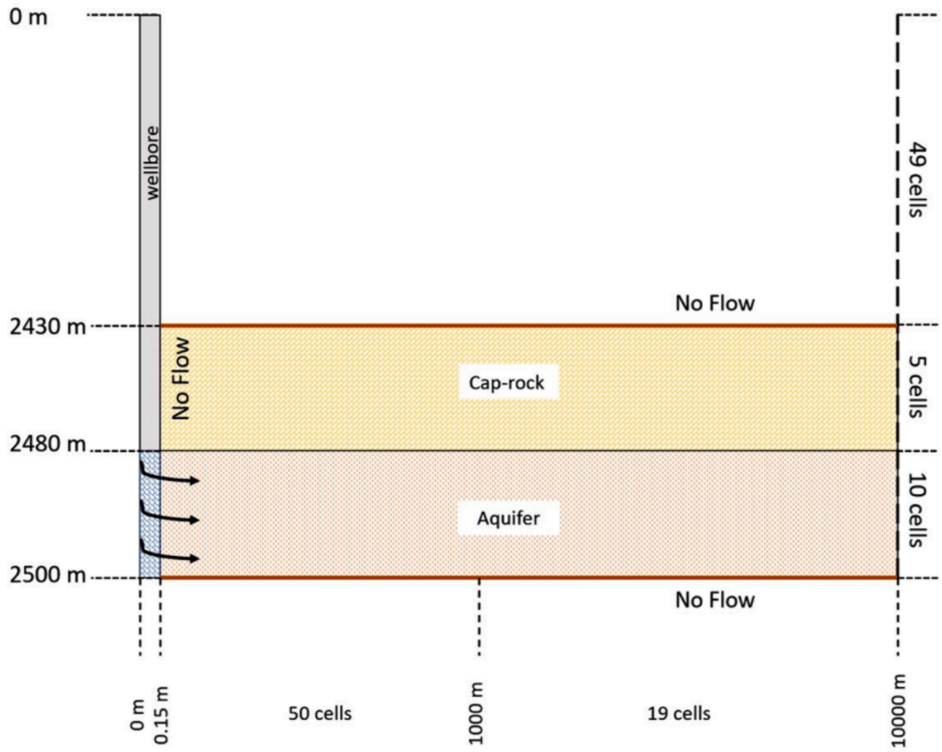


Figure 2.2: Schematic of the Wellbore, Reservoir, and Cap Rock Model

The research utilized T2WELL-ECO2M software, which excels at integrating wellbore and reservoir simulations. This integration allows for precise modeling of thermal processes and CO2 phase transitions. The software's semi-analytical approach also boosts computational efficiency, making it ideal for large-scale carbon capture and storage (CCS) projects. However, T2WELL-ECO2M has limitations, including a sensitivity to initial conditions, which can be difficult to define accurately, and it is restricted to simulating CO2–NaCl-water systems, limiting its application to scenarios involving other gases.

Smith et al. (2022) used OLGA 2022 software to model CO2 injection in the Peterhead CCS project, focusing on accurately predicting temperature and pressure changes. The study stresses the importance of managing CO2 phase behavior in depleted gas reservoirs, especially due to the Joule-Thomson cooling effect, which can cause dangerously low temperatures in the wellbore. These low temperatures could threaten well integrity and safety. The researchers carefully validated their simulations with real-world data to ensure accurate predictions. They also explored various strategies to control CO2 injection and avoid problems from phase changes, ultimately improving the safety and effectiveness of CCS operations(28).

Previous research were primarily theoretical and required validation through real-world cases. However, recent studies have shifted their focus towards validating these methods using real-world data, now accessible due to the implementation of more CCS projects. Ensuring that these findings are consistent with actual data is essential for successfully scaling up these methods for wider application.

2.4 Joule-Thomson cooling effect under adiabatic conditions

When CO2 is injected at high pressure into a well with a lower pressure at the wellhead, it resembles the expansion of a real gas transitioning from a high-pressure zone to a low-pressure area. This transition inevitably causes the gas to cool as it enters the lower pressure region, a process driven by the Joule-Thomson cooling effect(16; 20). Thus, it is essential to have a comprehensive understanding of this effect.

Figure 2.3 illustrates the phase diagram of CO2, highlighting why the supercritical region is considered the most optimal for geological storage. At supercritical conditions, CO2 has a much higher density compared to its gaseous state, which allows for a larger amount of CO2 to be stored within a given volume. Additionally, in its supercritical state, CO2 behaves like a liquid but with lower viscosity, making it easier to flow through porous rock formations. Geological storage typically occurs at depths where temperature and pressure naturally bring CO2 into a supercritical state—specifically, at depths greater than approximately 800 meters, where temperatures exceed 31°C and pressures surpass 7.38 MPa, corresponding to CO2's critical point. These conditions make supercritical CO2 ideal for efficient and secure long-term storage.

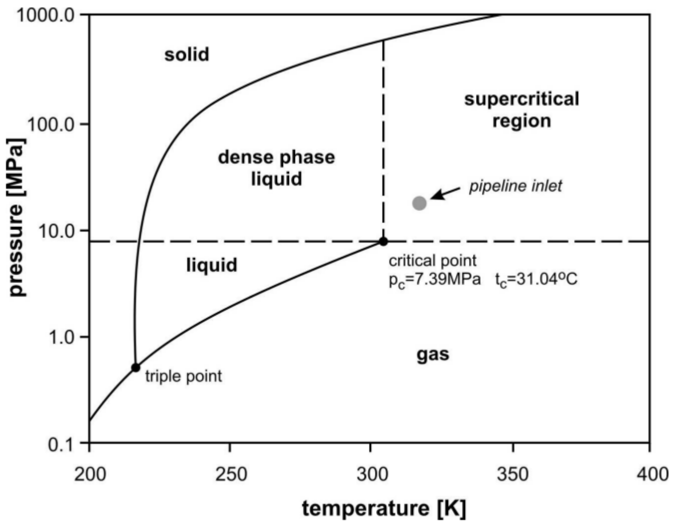


Figure 2.3: CO2 phase diagram showing various regions

the Joule-Thomson cooling effect accompanies "CO2 injection from the injection well to the reservoir, especially in the two of the most common situations, a decrease in wellhead temperature during well start-up operations and a decrease in temperature at the inlet of the reservoir in cases of CO2 storage in depleted gas fields with low pressure"(16).

The Joule-Thomson coefficient in this process is defined by equation (2.4), which is a fundamental thermodynamic property of real gases. This coefficient can be determined using the thermodynamic relationship that involves the basic parameters of pressure (P), volume (V), and temperature (T), along with the specific heat at constant pressure (CP), as illustrated in the second part of equation.(27; 16).
The equation is expressed as:

$$\mu_{JT} = \left(\frac{\partial T}{\partial P}\right)_H = \frac{T\left(\frac{\partial V}{\partial T}\right)_P - V}{C_P} \tag{2.4}$$

Where μ_{JT} is the Joule-Thomson coefficient, C_P is the heat capacity at constant pressure, H is enthalpy, P is pressure, T is temperature, and V is the volume of the fluid.

$$H_{\text{out}} - H_{\text{in}} = \frac{Q}{M} + g(h_{\text{in}} - h_{\text{out}}) \tag{2.5}$$

Equation (2.5),describes the change in enthalpy between the inner and outer boundaries of a section in the downward flow direction. In this context, "out" refers to the section's outer boundary, while "in" refers to the inner boundary. The variables M and Q represent the mass flow rate and heat transfer coefficient, respectively, and g stands for gravity.

According to this equation, the enthalpy change in CO2 is linked to heat exchange with the surrounding rocks and the loss of potential energy. Consequently, during transient operations, CO2 expands from high to low pressure at the wellhead under isenthalpic conditions in adiabatic tubing(16). This expansion process results in a drop in CO2 temperature.
The adiabatic temperature change can be computed using equation (2.6):

$$\Delta T_{\text{adiabatic}} = \int \mu_{JT}(P, T)\, dP \tag{2.6}$$

2.4.1 Simulation Framework Overview

In recent years, the impact of temperature fluctuations resulting from production, injection, or shut-in operations has become a focus of attention, whereas they were largely overlooked in the past. Traditionally, the temperature at the sand-face was assumed to be equivalent to the reservoir temperature, typically estimated using the geothermal gradient (approximately 3°C per 100 meters). However, with advancements in surveillance technology, it is now possible to measure these temperature variations, which have been found to be affected by factors such as well bottom-hole pressure and the rate of fluid injection.

This thesis explores the phase transition of CO2 during its injection from the wellbore into the reservoir. The simulations were carried out using STARS, a Thermal and Advanced Processes Reservoir Simulator created by Computer Modelling Group Ltd. (CMG). STARS is specifically designed for thermal and chemical enhanced oil recovery processes such as steam, solvent, air, and chemical injections as well as other advanced recovery methods, enabling the integration of wellbore and reservoir dynamics..

In my thesis, I employed the Flexible Well bore (FLX-WELLBORE) option within the CMG STARS simulator to accurately model the CO2 injection process and the interaction between the well bore and the reservoir.
The FLX-WELLBORE feature is specifically designed to handle complex well bore behaviors that are beyond the capabilities of traditional Sink/Source wells.This advanced option offers a detailed and versatile approach to simulating the thermal and fluid flow dynamics within well bores, especially in scenarios involving varying well bore configurations, multi-tubular systems, and intricate thermal interactions between the well bore and the surrounding geological formation.

The FLX-WELLBORE tool allows for the detailed definition of a wellbore, which can include multiple components such as regular tubing, concentric tubing, instrumentation tubing, and annular. It can also model variations in tubular diameters, thermal properties, and heat capacities along the length of the wellbore. Additionally, this feature enables the simulation of complex phenomena such as phase segregation, frictional pressure drops, and other critical factors that occur during fluid injection or production(19).

This approach was crucial in my research for capturing the intricate thermal and fluid dynamics associated with CO2 injection, particularly in relation to phase transitions and heat exchange processes as CO2 moves from the wellbore into the reservoir.
By utilizing the FLX-WELLBORE feature, I was able to simulate the effects of wellbore conditions on reservoir behavior with a high degree of precision, ensuring that the complexities of wellbore-reservoir coupling were thoroughly and accurately addressed in my study.
This comprehensive modeling approach provided deeper insights into the behavior of CO2 during injection, contributing to a more robust understanding of the overall process.

Chapter 3

Research Methodology and Results

For the injection of CO2 into gas reservoirs under depleted conditions, it's crucial that the simulation accurately captures the relevant thermal processes, phase transitions, and allows for the coexistence of multiple non-aqueous phases. Given that the phase behavior of CO2 is highly sensitive under these depleted conditions, it readily undergoes phase changes, which have a substantial impact on its thermophysical properties. In fact, phase transitions throughout the reservoir during sequestration are unavoidable(7).

3.1 Numerical Modelling

To investigate the strongly coupled effects near the wellbore, the STARS simulator from the Computer Modelling Group (CMG) is employed. This module is capable of conducting non-isothermal compositional multi-phase simulations, which include processes such as salt precipitation and phase transitions. However, salt precipitation is not covered in this research. The simulation package and the specific options utilized are discussed in more detail in the subsequent sections.

3.1.1 CMG STARS

As outlined briefly in the Simulation Framework Overview section, CMG STARS is a comprehensive reservoir simulator that integrates thermal, K-value (KV) compositional, chemical reaction, and geomechanics capabilities. It is specifically designed for modeling recovery processes that involve the injection of steam, solvents, air, and chemicals(7).

The simulator's strong reaction kinetics and geomechanics features make it both versatile and complete. Unlike other simulators, STARS does not require a separate thermal option to be activated, as it was developed to handle processes such as Steam Assisted Gravity Drainage (SAGD), Expanding-Solvent SAGD (ES-SAGD), steam, hot water, and hot solvent injection, cyclic Steam Stimulation (CSS), thermal VAPEX, in-situ combustion (air injection), and both High and Low Temperature Oxidation (HTO LTO), among others(7).

3.1.2 Flexible Wellbore Option

The Flexible Wellbore (FLEXWELL) model used in CMG STARS is a sophisticated tool designed to simulate complex wellbore conditions by fully coupling an independently solved wellbore model with a thermal reservoir simulator. This model allows for the representation of wellbores containing up to three tubing strings, which can run in any orientation—vertical, horizontal, slanted, or undulating—and can include laterals. The model is versatile, handling injectors and producers under various operational conditions, with no restrictions on tubing lengths or how the wellbore intersects the reservoir grid(7; 19).

In the FLEXWELL model, tubing strings can vary in length, insulation, and diameter, while the annulus may include casing, cement, and varying diameters. Radial heat flow is influenced by factors such as wall thickness, insulation, and cement. The flow regime within each tubing string, which is determined by liquid and gas velocities, governs the calculation of frictional pressure drops and heat transfer in both axial and radial directions. Additionally, the model is capable of simulating transient wellbore behavior, which is crucial for accurately modeling cyclic processes(7; 19).

One of the key features of FLEXWELL is its ability to solve equations corresponding to all streams and sections of the wellbore simultaneously. Each wellbore's equation set is solved independently, but the wellbore remains fully coupled to the reservoir through an annulus-reservoir flow term that accounts for fluid and heat exchange along the entire wellbore length. This allows for accurate modeling of cross flow, phase segregation, and transient behavior, which are vital in certain well and reservoir configurations(7; 19).

Moreover, while CMG offers another wellbore modeling option known as CO-FLOW, which is designed for steady-state conditions, FLEXWELL is specifically engineered for transient conditions. This capability provides a significant advantage over other wellbore models on the market, allowing for a dynamic and accurate simulation of wellbore behavior over time(19).

The non-linearity of equations in the FLEXWELL option often requires many iterations, leading to convergence challenges. To improve numerical performance, the model uses over-relaxation of accumulation terms in the Jacobian matrix, controlled by the *FW-RELAX-ACC keyword. This can be enabled, disabled, or managed adaptively with the *STEP option, which helps reduce time step cuts and enhance convergence, even if it requires more iterations(19). Generally the Flexible Wellbore model is best utilized when the wellbore flow is complex and has a substantial effect on reservoir dynamics.

Table 3.1 compares the features of the Sink/Source well model available in modules like IMEX and GEM with those of the Flexible Wellbore model found in STARS (24).

	Sink/Source well	**FLEXWELL**
Gravity	Explicit head	Implicit
Friction-heatloss	Optional	Automatic
Cross flow Wellbore-Reservoir	Optional (simple)	Automatic
Trajectory	Optional	Optional
Multilaterals	Optional	Optional
Transients	Not possible	Automatic
Fluid Segregation	Not possible	Automatic
Tubing	Not possible	Maximum 3
Wellbore heatloss and friction, wellhead to pay top	Optional	Optional
Orifice flow Annulus-Reservoir	Optional	Optional
Orifice flow Tubing-Annulus	Not possible	Optional
Well plugging by solids	Not possible	Optional

Table 3.1: Capabilities of Sink/Source and Flexible Wellbore models

In summary, the FLEXWELL model in CMG STARS is a robust and flexible tool for simulating intricate wellbore dynamics, ensuring accurate representation of both fluid and thermal interactions between the wellbore and the reservoir, and offering advanced numerical techniques to handle convergence challenges. Its capability to handle transient conditions makes it a superior choice compared to other wellbore models, such as the steady-state CO-FLOW option(7; 19).

3.2 Conservation Equations Overview

In reservoir simulation, conservation equations are essential for accurately modeling the behavior of fluids and energy within a reservoir. These equations ensure that fundamental physical principles, such as the conservation of mass, momentum, and energy, are upheld throughout the simulation process. Most simulators, including CMG, Eclipse, and others, rely on the same principles of energy balance. However, in CMG STARS, the equations governing thermal processes differ from those used in compositional simulations in three key ways: the inclusion of an energy variable and corresponding energy equation, the presence of water not only in the liquid phase but also in the gas phase, and the temperature-dependent nature of various properties. These distinctions make STARS particularly effective in simulating thermal recovery processes(19; 7).

Below is a brief overview of the key conservation equations relevant to flow, thermal, and energy processes in the CMG STARS simulator(19).

3.2.1 Flow Conservation Equation

The flow conservation equation is constructed for each fluid phase (e.g., water, oil, and gas) within the reservoir. It balances the rate of change in the fluid's mass within a control volume against the net inflow of mass from adjacent regions and any sources or sinks (such as wells) within the system. Mathematically, it can be expressed as:

$$\frac{\partial}{\partial t}\left(\phi \rho_j S_j\right) = \nabla \cdot \left(\rho_j \mathbf{u}_j\right) + q_j \tag{3.1}$$

Where:

- ϕ represents the porosity,
- ρ_j denotes the density of phase j,
- S_j indicates the saturation of phase j,
- $\mathbf{u}_j$ corresponds to the Darcy velocity,
- q_j accounts for the source or sink terms for phase j.

Equation 3.1 guarantees that the mass of each fluid phase within the reservoir is conserved.

3.2.2 Thermal Conservation Equation

The thermal conservation equation governs the distribution of temperature within the reservoir, accounting for the energy associated with fluid flow and heat transfer. This equation considers conductive and convective heat transport mechanisms and is essential in simulations involving thermal processes, such as steam injection or in-situ combustion.
It is described by the following equation:

$$\frac{\partial}{\partial t}\left(\phi \rho_j S_j u_j\right) = \nabla \cdot (\lambda \nabla T) + \nabla \cdot \left(\rho_j u_j h_j\right) + q_T \tag{3.2}$$

Where:

- u_j is the internal energy per unit mass of phase j,
- λ is the thermal conductivity,
- T is the temperature,
- h_j is the enthalpy of phase j,
- q_T is the source/sink term for energy.

This equation ensures the conservation of thermal energy in the reservoir and is critical in scenarios where temperature variations significantly impact fluid properties.

3.2.3 Energy Conservation Equation

The energy conservation equation integrates both the flow and thermal conservation equations to account for the overall energy balance in the reservoir. It includes contributions from internal energy, kinetic energy, and potential energy due to pressure and temperature gradients.

The general form of the energy conservation equation is:

$$\frac{\partial}{\partial t}\left(\phi \rho_j S_j U_j\right) = \nabla \cdot \left(q_j U_j\right) + Q_j \tag{3.3}$$

Where:

- U_j represents the total internal energy of phase j,
- q_j denotes the heat flux,
- Q_j includes contributions from work done by pressure and any external heat sources.

The energy conservation equation ensures that the total energy within the system is balanced, accounting for the interactions between fluid flow and thermal processes.

To summarize, these conservation equations are essential to reservoir simulation models like CMG STARS, enabling precise predictions of fluid and energy behavior across various conditions. By ensuring the conservation of mass, momentum, and energy, these equations facilitate the accurate modeling of complex processes such as multiphase flow, heat transfer, and chemical reactions within the reservoir(19).

3.3 Overview of Simulations and Workflow

To thoroughly investigate the occurrence and extent of near wellbore effects, this research follows a structured approach with several simulation studies. Initially, the depletion phase is simulated to replicate the conditions of a depleted reservoir. Following this, the injection scenario is modeled. Finally, a realistic geological model is applied to analyze the near wellbore effects on a larger scale.

3.3.1 Depletion phase

Model Setup

This study simulates a reservoir initially filled with natural gas (methane) at around 250 Bar, with pressure variations depending on depth and the type of fluid present in the pore spaces. The simulation spans from the surface down to a depth of 2800 meters. The sections from the surface to 2490 meters and from 2529 to 2800 meters are water-bearing, so a water gradient is applied for pressure calculations in these zones. For the reservoir itself, which is specifically located between 2490 and 2529 meters in depth, a gas gradient is used for calculating pressure.

The input parameters for this base case model are detailed in Table 3.2.

Parameter	**Value**
Temperature Gradient (°C/Km)	28.6
Surface Temperature (°C)	16.85
Pressure Gradient of Water (kPa/m)	9.8
Pressure Gradient of Gas (kPa/m)	1.81
Surface Pressure (kPa)	101

Table 3.2: Pressure and Temperature input parameters

Figure 3.1 shows the pressure profile versus depth, with a red rectangle highlighting a section with a distinct pressure gradient indicating gas-containing reservoir layers, contrasting with surrounding areas where the pressure follows a water gradient.

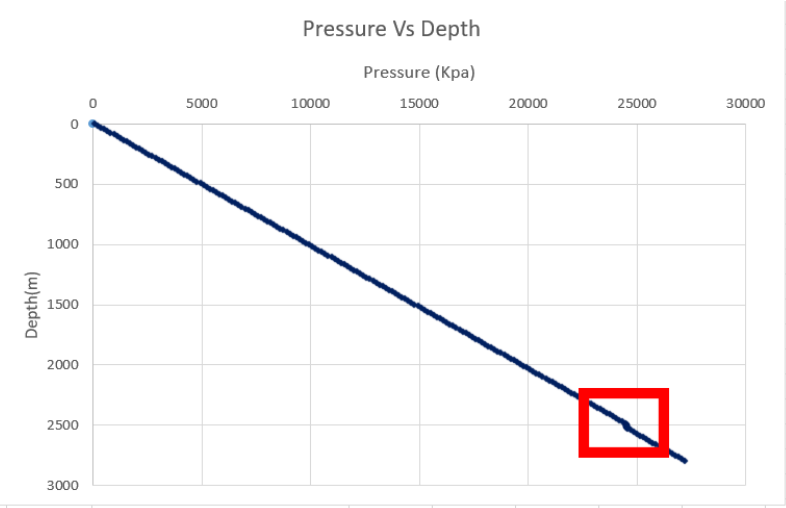


Figure 3.1: Initial Condition Profile: Pressure vs Depth for the Reservoir Model

The simulation encompasses an area of 0.2 km by 0.2 km, with the reservoir extending vertically for approximately 40 meters. The model is divided into a 9x9x198 grid, and depletion is simulated through four wells located at the grid's corners.(23).

The table below, along with the relative permeability curves for the reservoir layers, outlines the reservoir and fluid properties accounted for in the model formulation.

Property	**Value**
Porosity	0.2
Permeability	Varies by reservoir and water sections
Reservoir Temperature	Non-Isothermal Behavior
Irreducible Water Saturation	0.2
Water/Gas Cap	Not present

Table 3.3: Reservoir properties and conditions

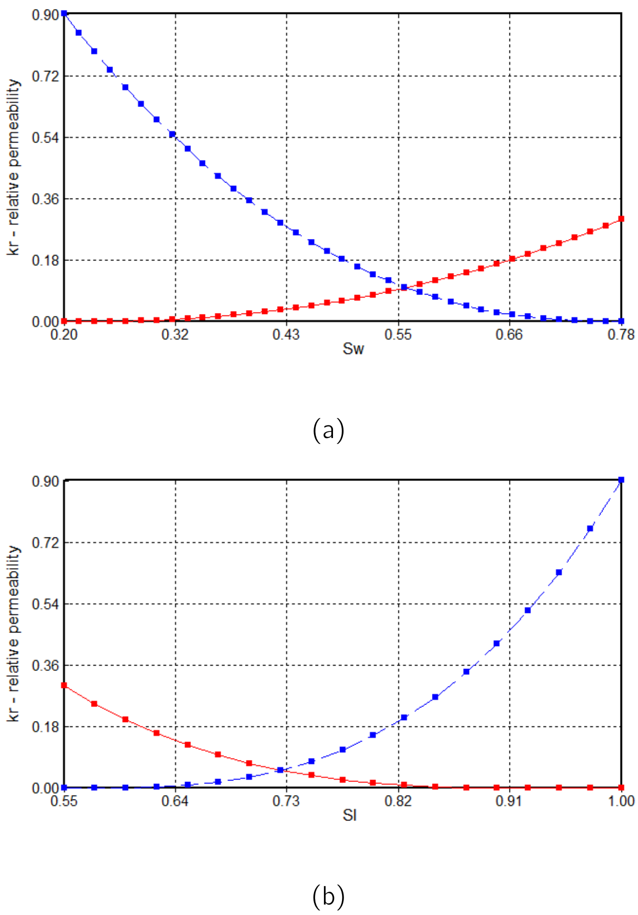


Figure 3.2: Relative permeability curves for water (a) and liquid (b)

Presented below is a configuration illustrating the well locations from a top-down perspective.

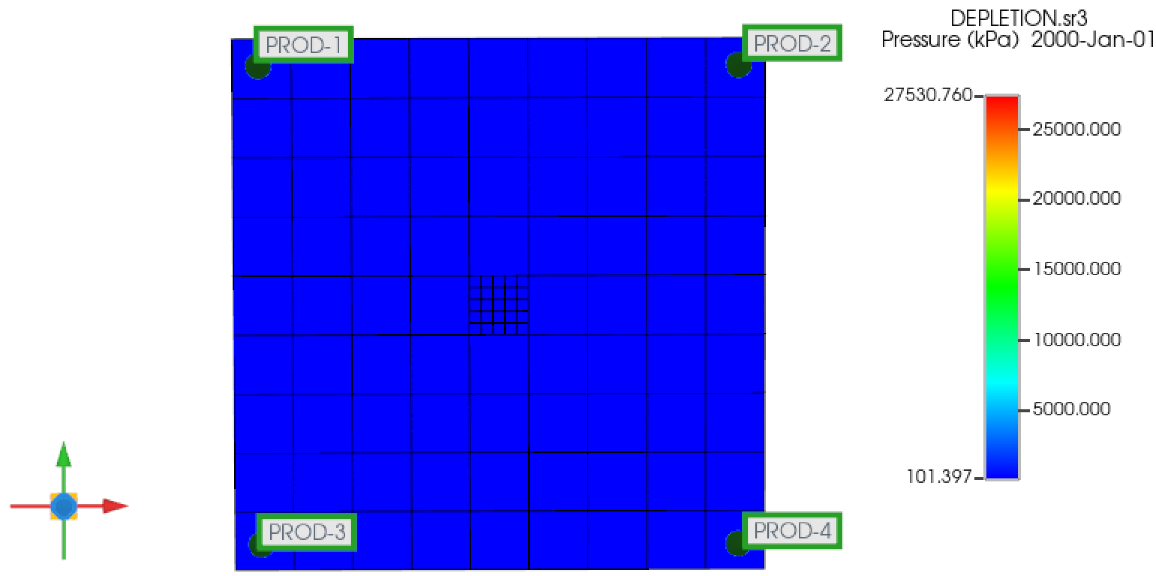


Figure 3.3: Top-down view of well locations within the reservoir grid

Result

Upon completing the depletion process according to the constraints set for the production wells, the results can be analyzed using 2D graphs.

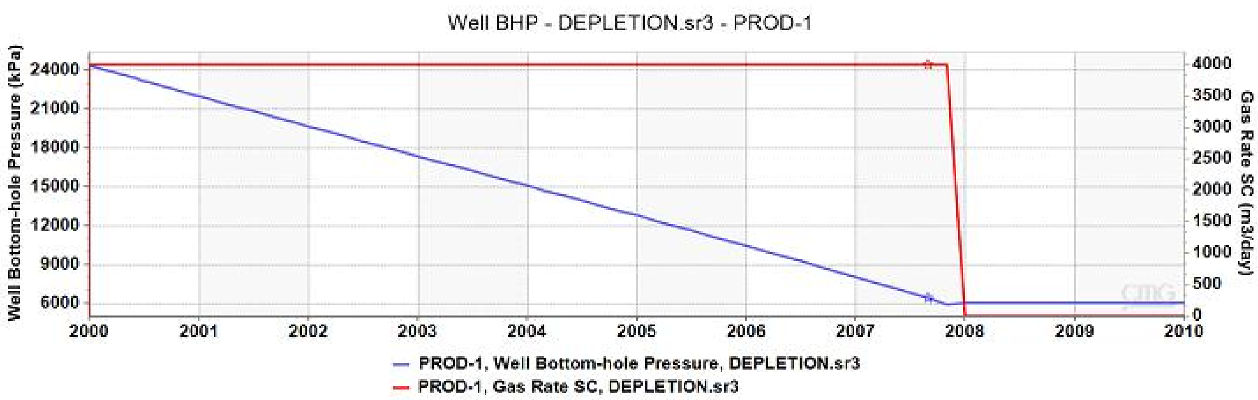


Figure 3.4: Bottom-Hole Pressure and Corresponding Flow Rate

The production continued until 2008, as constrained by the defined conditions for the four wells. By 2008, the well bottom-hole pressure dropped to 6000 kPa, signaling the point at which production ceased. This is further confirmed by the gas production rate(methane) shown in the same figure, which also drops to zero at the same time (2008), indicating the end of production as the pressure limit was reached.

3.3.2 Injection Phase

For CO2 injection into gas reservoirs under depleted conditions, it is crucial that the simulator accurately accounts for thermal processes, phase transitions, and supports the coexistence of multiple non-aqueous phases. Since the phase behavior of CO2 is highly sensitive at these low-pressure conditions, CO2 can easily undergo phase changes, which notably affect its thermophysical properties. In fact, phase transitions throughout the reservoir during the sequestration process are unavoidable.(7).

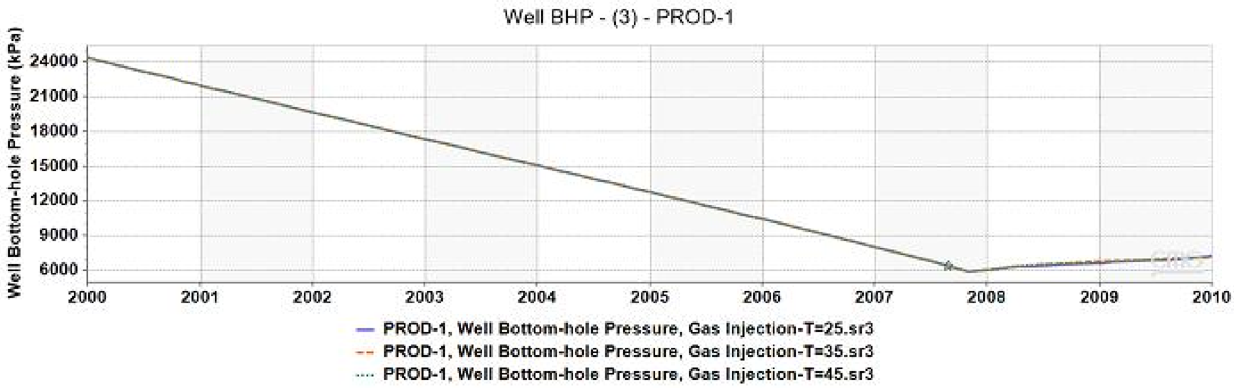
Following reservoir depletion, the injection phase begins, which is divided into two stages: CO2 injection in liquid form and CO2 injection in gaseous form. This distinction allows for a detailed examination of the Joule-Thomson effect during the injection process, as phase changes along the reservoir significantly influence the thermodynamic and physical properties of CO2.

Understanding these transitions is essential for optimizing the sequestration process and ensuring accurate simulation of reservoir behavior.

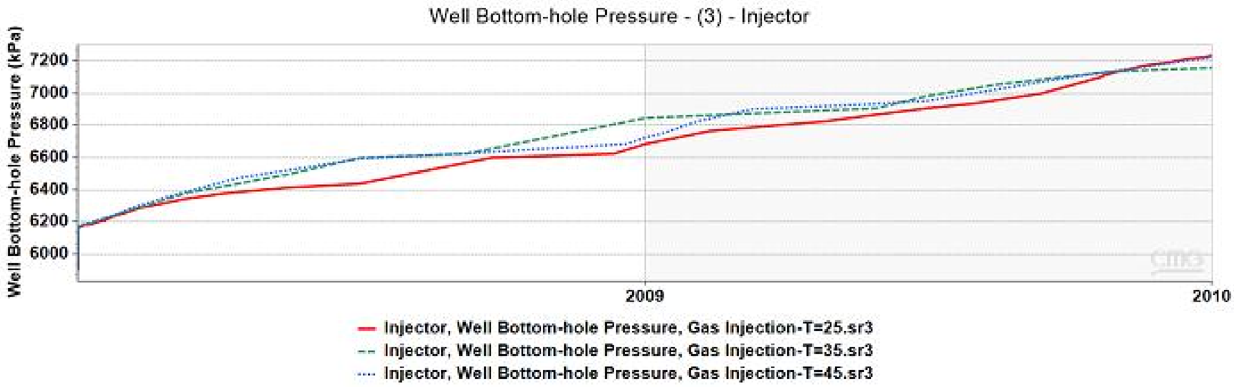
- Injection of Gaseous CO_2 into the Reservoir:

  The injection of gaseous CO2 into the reservoir began in 2008 and lasted for two year, as evident from the increase in pressure shown in the graph.

  The injection phase was scaled up, and a sensitivity analysis was conducted on the temperature of the injected fluid. Although the variation in temperature did not significantly affect the bottom-hole pressure, it led to noticeable differences in the temperature profile along the wellbore, which, in turn, influenced the density profile of the CO2 in the reservoir.



(a) Bottom-Hole Pressure vs Time During Production and Injection

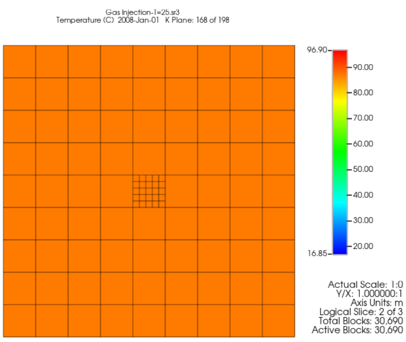


(b) Bottom-Hole Pressure Comparison During CO2 Injection with Temperature Sensitivity

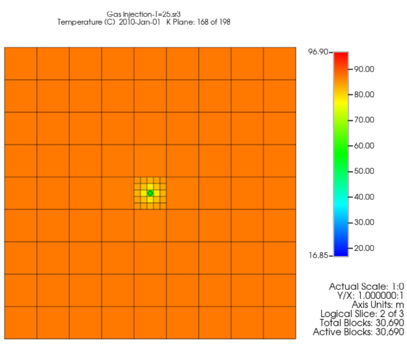
Figure 3.5: Bottom-Hole Pressure Over Time

The following figures show the temperature decline during two years of injection.

Local grid refinement was applied around the injection well to improve the simulation's accuracy in capturing the Joule-Thomson effect. This increased resolution allows for better observation of temperature and pressure changes near the wellbore during CO_2 injection.



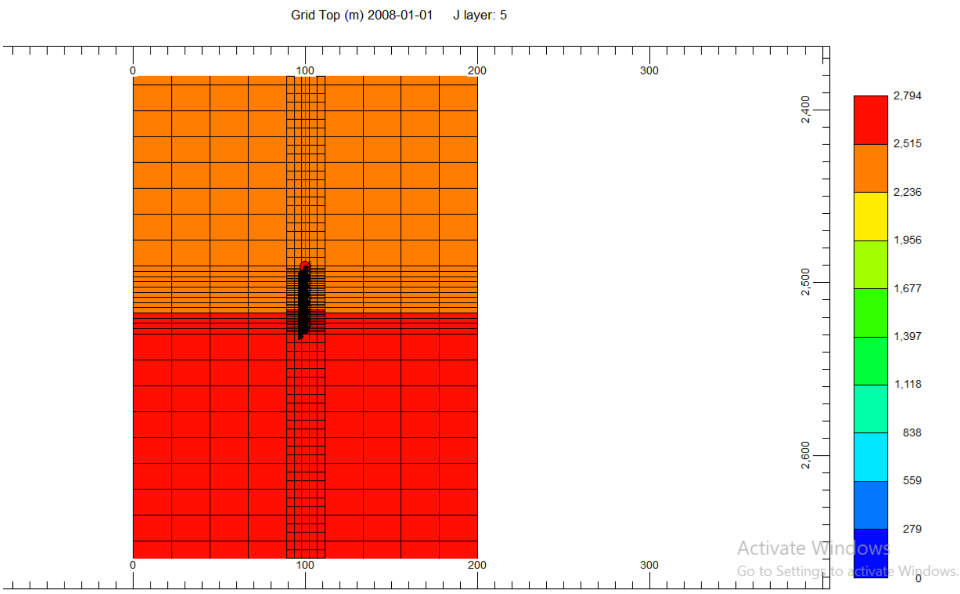
(a) Temperature Profile Prior to Injection



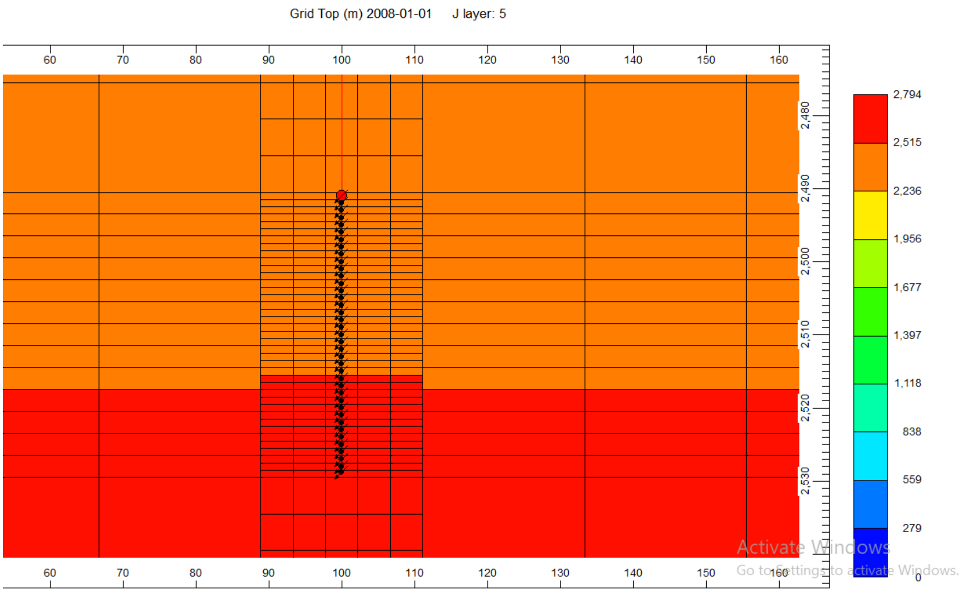
(b) Temperature Profile After One Year

Figure 3.6: Temperature Profile Before and After Injection

Before presenting the temperature and density profiles at various times, it's important to specify the thickness being referred to. CO2 was injected into a reservoir layer with a thickness of approximately 39 meters. A flexible well was then connected to these sections to monitor and verify the temperature and density profiles within the wellbore.



(a)



(b)

Figure 3.7: Depth Referenced in Profile Demonstration

- **Temperature and Density Profiles at Different Time Instances:**

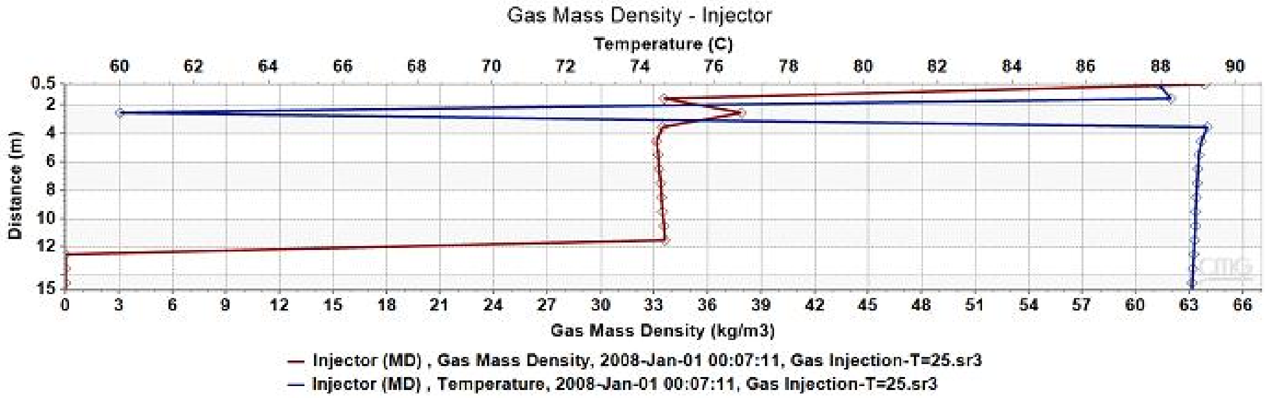


Figure 3.8: Temperature and Density Profiles 7 Minutes Post-Injection

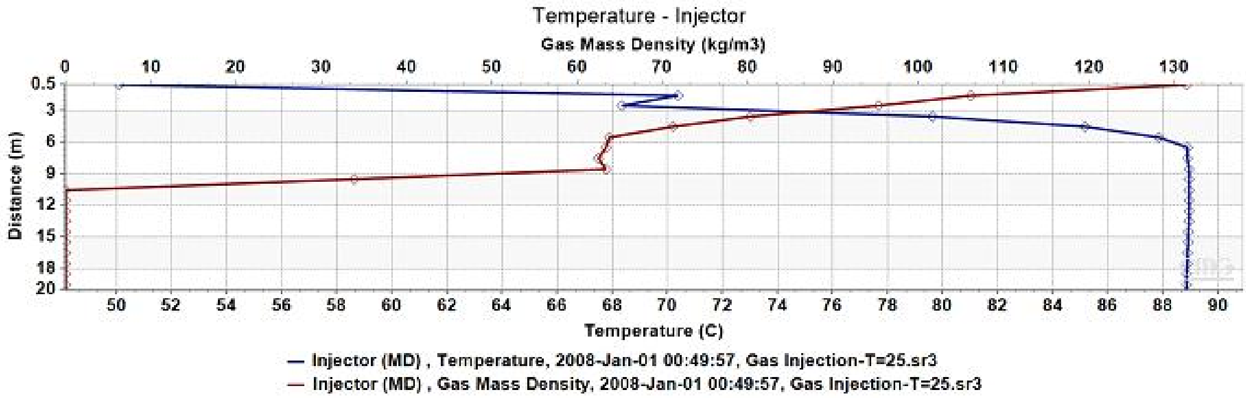


Figure 3.9: Temperature and Density Profiles 50 Minutes Post-Injection

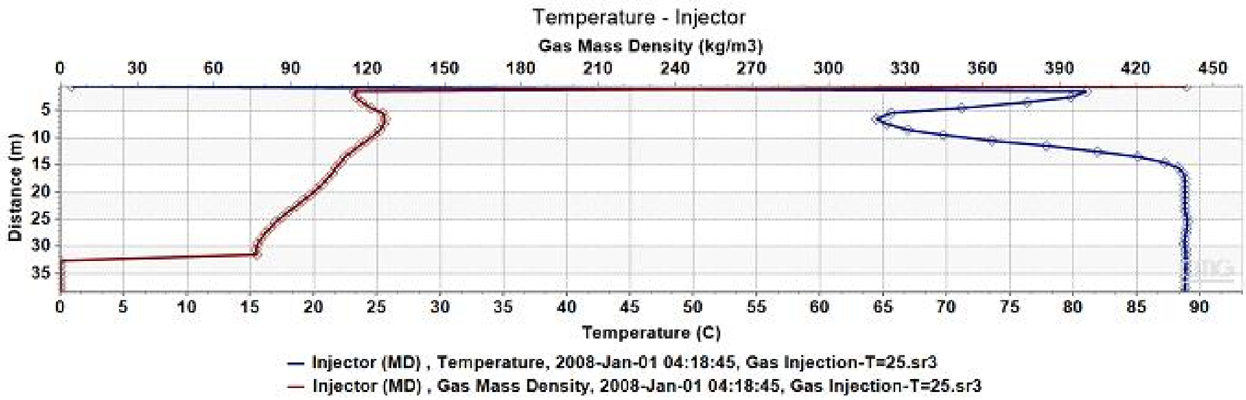


Figure 3.10: Temperature and Density Profiles 4 hours Post-Injection

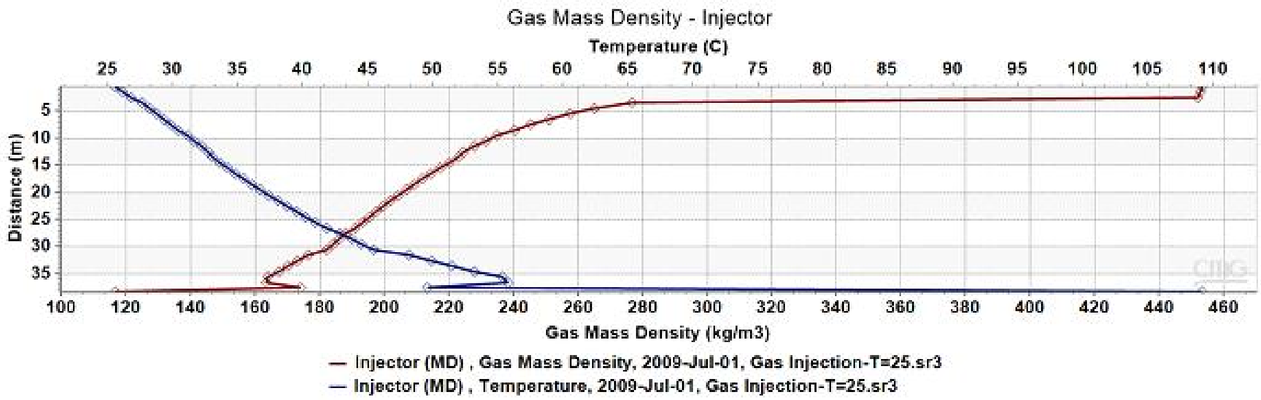


Figure 3.11: Temperature and Density Profiles one-year Post-Injection

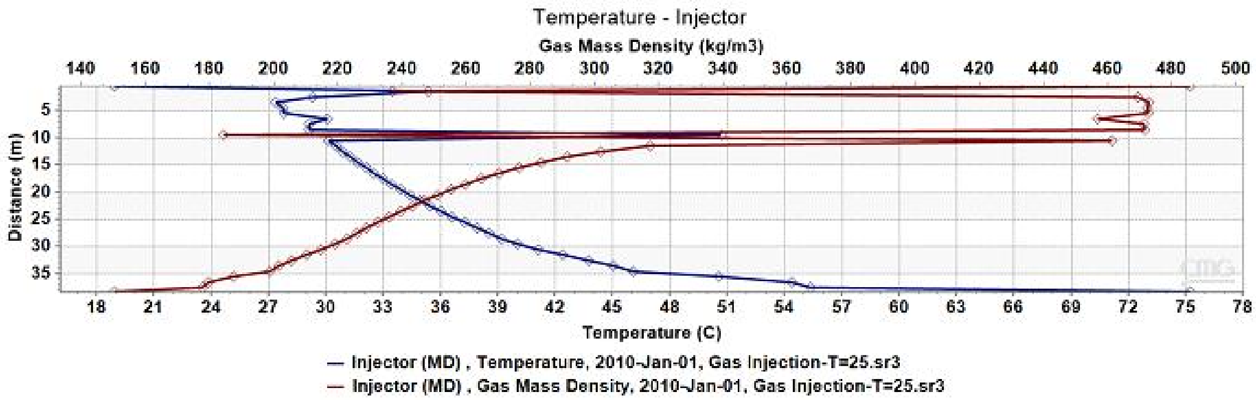


Figure 3.12: Temperature and Density Profiles 2 years Post-Injection

The variation in profiles over time is primarily caused by the open perforations within the depleted reservoir layer. When the injected gas enters these low-pressure zones, it undergoes rapid expansion, which leads to a significant drop in temperature due to the Joule-Thomson effect. As the gas cools, its density increases, further altering its behavior within the wellbore. Additionally, this cooling effect is influenced by the thermal properties of the surrounding rock, creating further variations in the temperature and density profiles. The interaction between the expanding gas and the low-pressure layers introduces complexities in predicting how the fluid behaves over time, as the wellbore dynamics are continually changing(14).

Before proceeding with the temperature demonstration during injection, it is essential to clarify how the Joule-Thomson coefficient behaves with respect to temperature for CO2.

For CO2, the coefficient is positive at lower temperatures, meaning it cools as it expands, but as the temperature rises, the Joule-Thomson effect becomes less pronounced. This relationship plays a crucial role in predicting temperature changes during CO2 injection into the reservoir, where variations in pressure and temperature significantly influence the cooling effect.

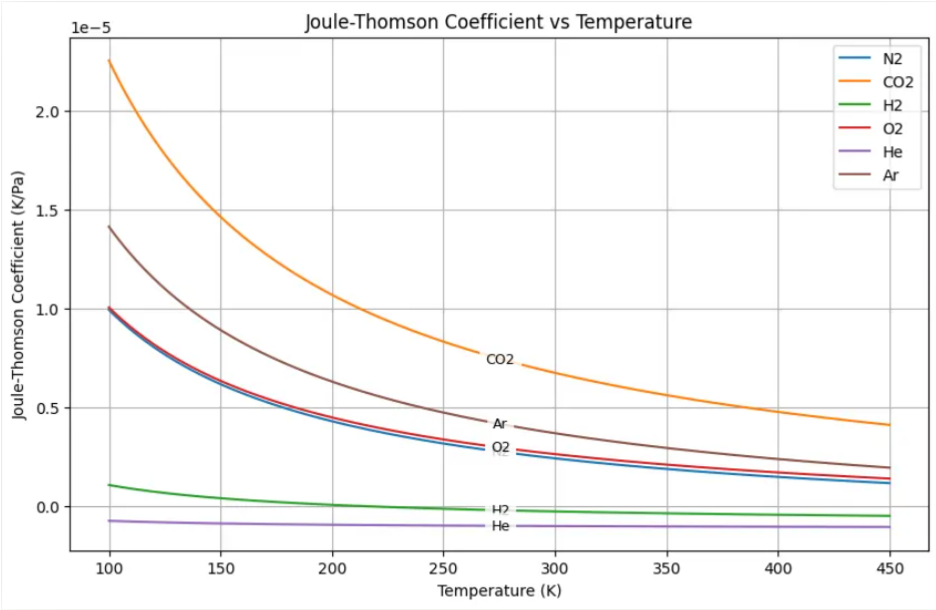


Figure 3.13: Joule-Thomson Coefficient vs. Temperature for Different Components

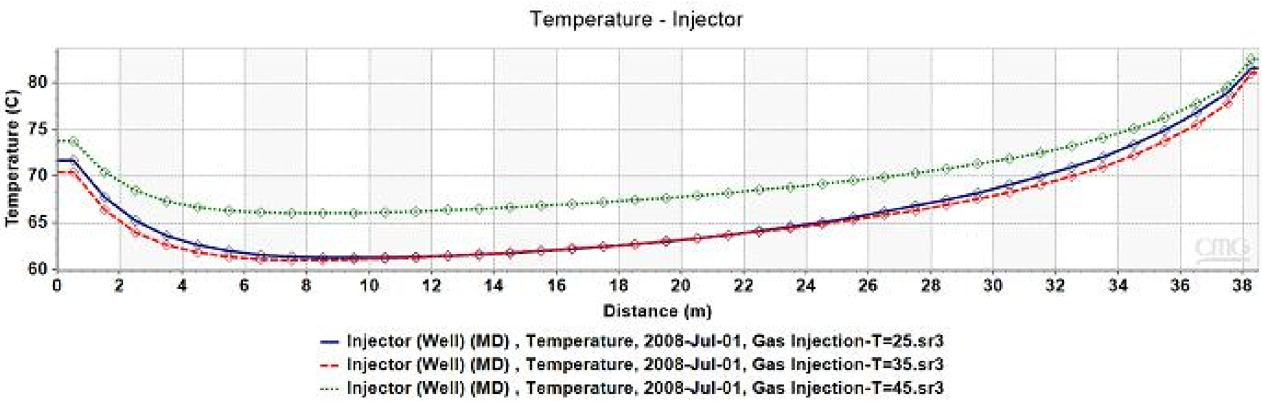


Figure 3.14: JT Cooling Effect on Wellbore Temperature - Jul 2008

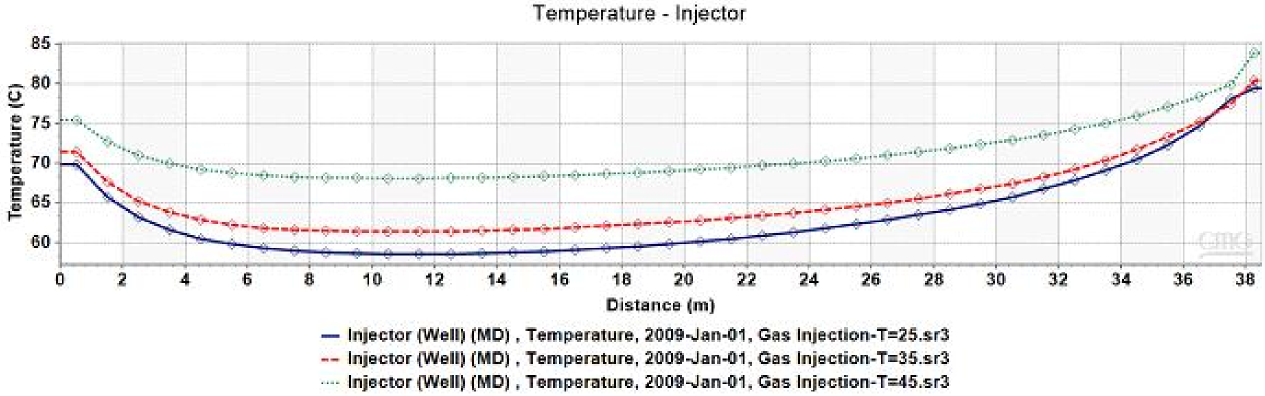


Figure 3.15: JT Cooling Effect on Wellbore Temperature - Jan 2009

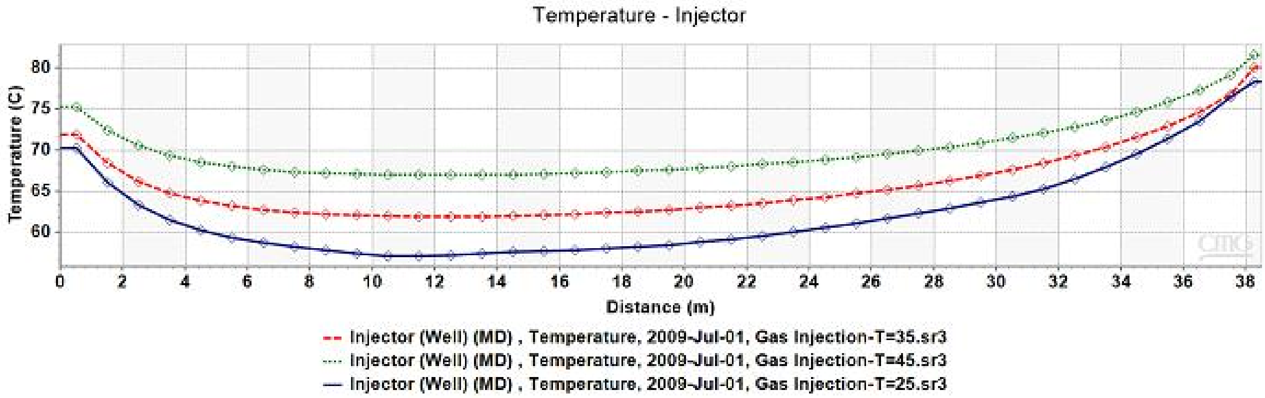


Figure 3.16: JT Cooling Effect on Wellbore Temperature - Jul 2009

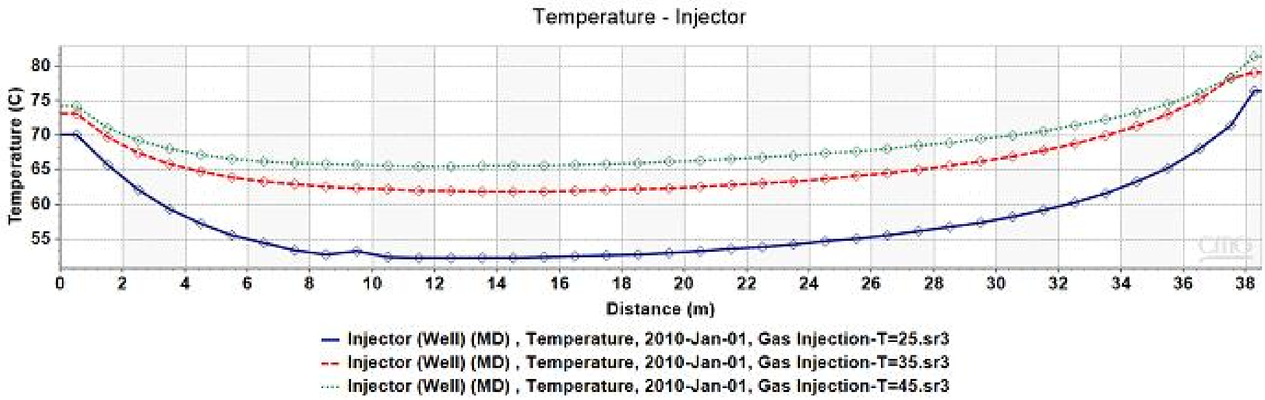


Figure 3.17: JT Cooling Effect on Wellbore Temperature - Jan 2010

From the graphs, it is clear that higher injection temperatures result in a smaller Joule-Thomson cooling effect during CO2 injection. As the injection temperature increases, the amount of cooling along the wellbore decreases, reducing the overall temperature drop caused by the Joule-Thomson effect.

- Injection of liquid CO_2 into the Reservoir:

After reservoir depletion, the injection of liquid CO2 for two years commenced.

The liquid CO2 undergoes phase changes, which are illustrated in the following figures.

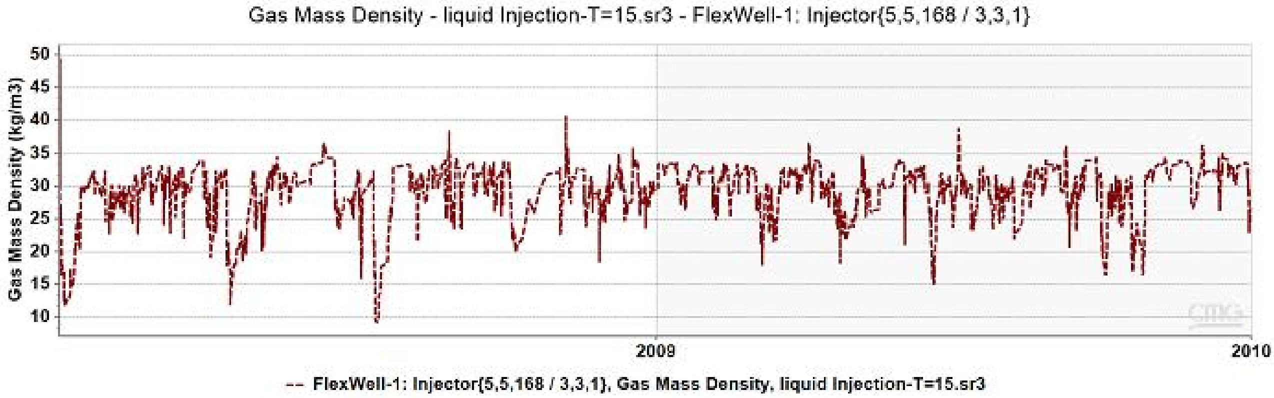


Figure 3.18: Gas Mass Density at 15°C

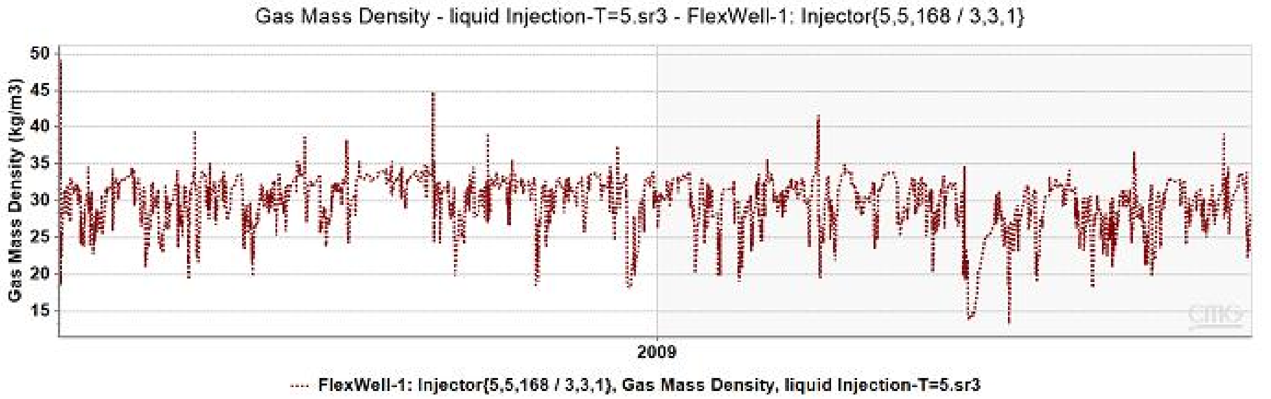


Figure 3.19: Gas Mass Density at 5°C

The two figures demonstrate the occurrence of phase changes during the injection of liquid CO2 into the reservoir. While the primary phase remains liquid, variations in gas mass density indicate the presence of gas within the wellbore. These changes highlight the phase transition, as indicated by the presence of gas.

The following figures confirm the presence of the Joule-Thomson (JT) cooling effect.

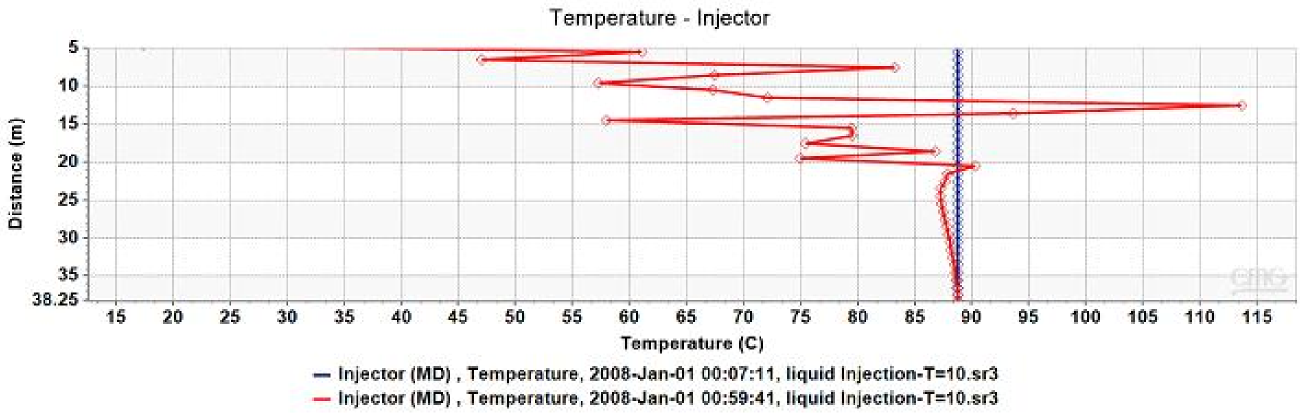


Figure 3.20: Temperature Variation from JT Cooling Effect One Hour After Injection

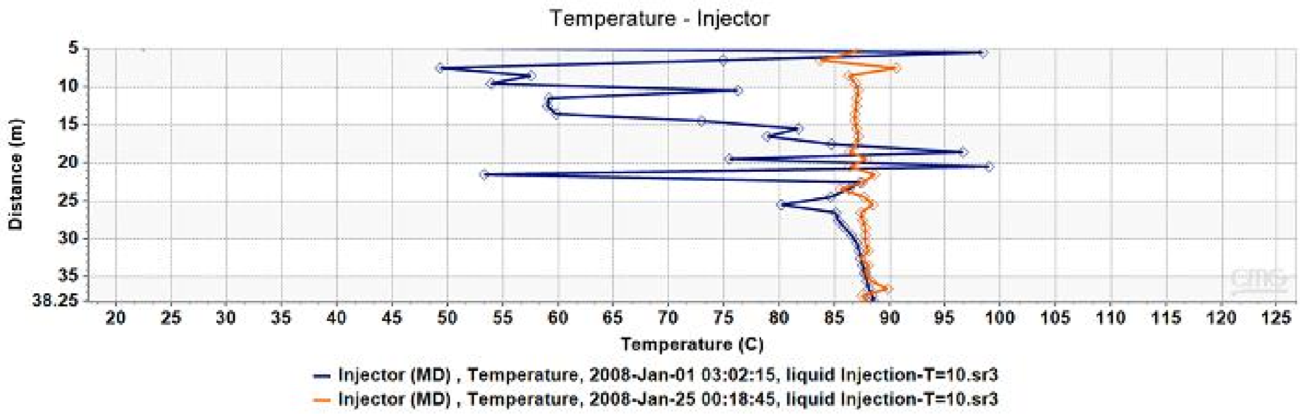


Figure 3.21: Temperature Variation from JT Cooling Effect 25 days After Injection

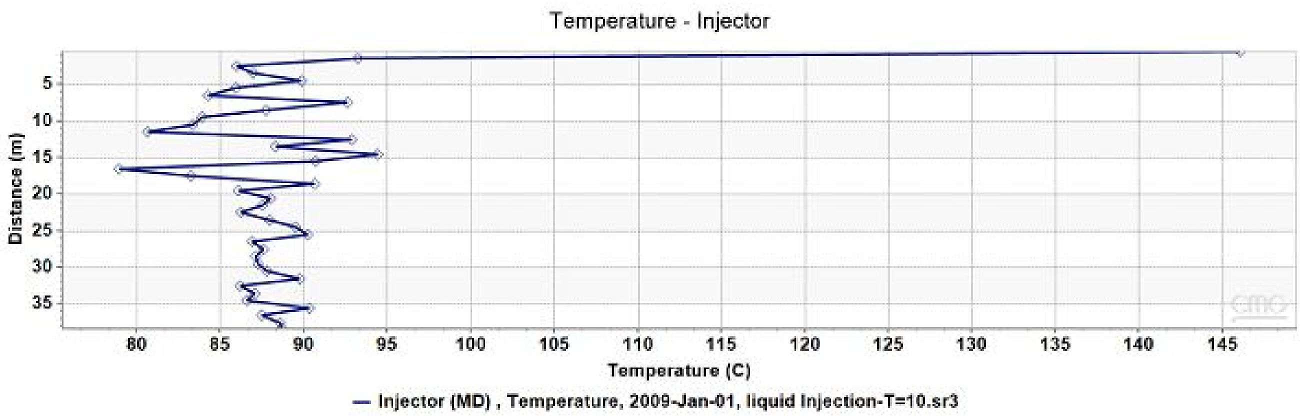


Figure 3.22: Temperature Variation from JT Cooling Effect One year After Injection

It is evident that the JT effect is more pronounced during the initial stages of CO2 injection, as the larger pressure and temperature differences between the injected fluid and the reservoir create a stronger cooling effect. As time progresses, the system stabilizes, reducing the pressure differential, which in turn weakens the JT effect and results in less cooling as the injection continues.

Analyzing the temperature profile within the wellbore at various time intervals provides insights into the thermal behavior of the fluid during injection. Monitoring these variations helps to optimize injection strategies and predict potential impacts on wellbore integrity and reservoir performance.

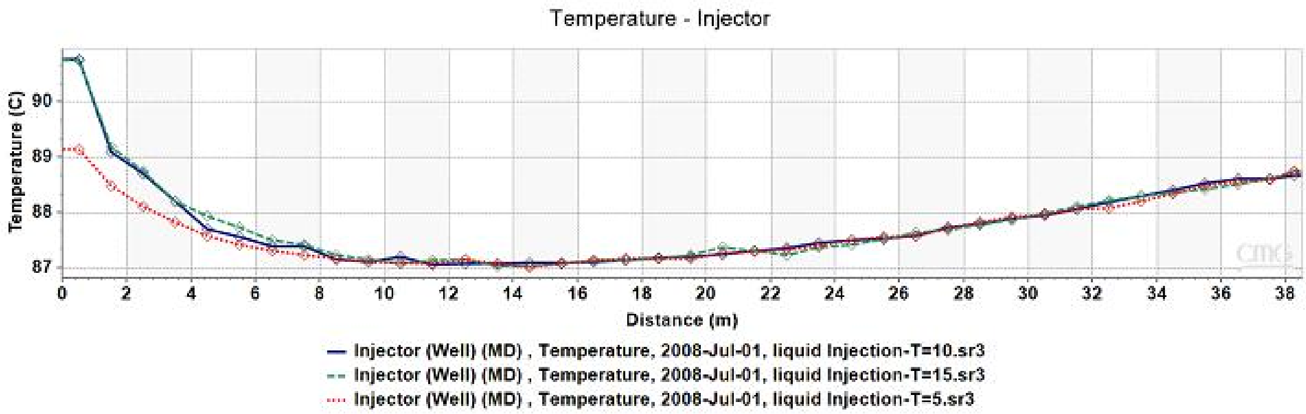


Figure 3.23: JT Cooling Effect on Wellbore Temperature - Jul 2008

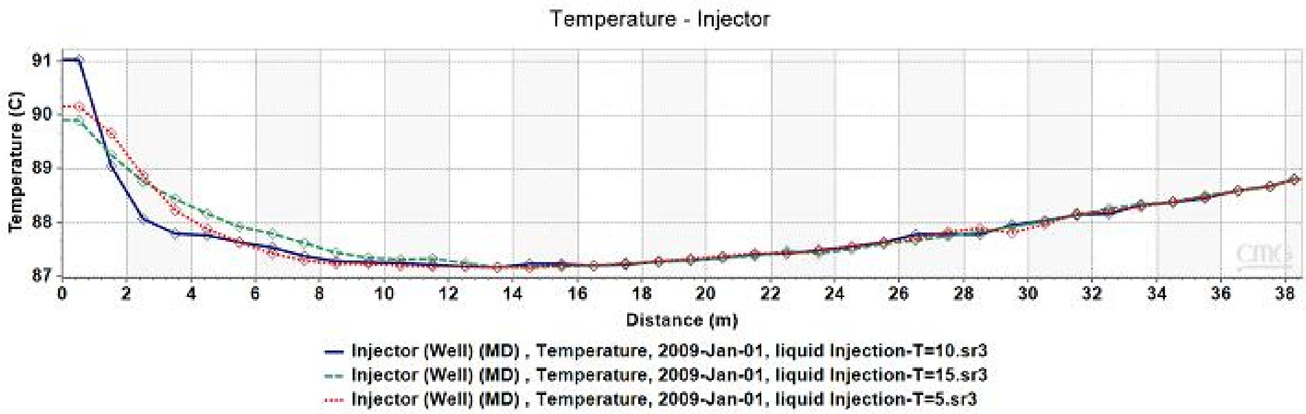


Figure 3.24: JT Cooling Effect on Wellbore Temperature - Jan 2009

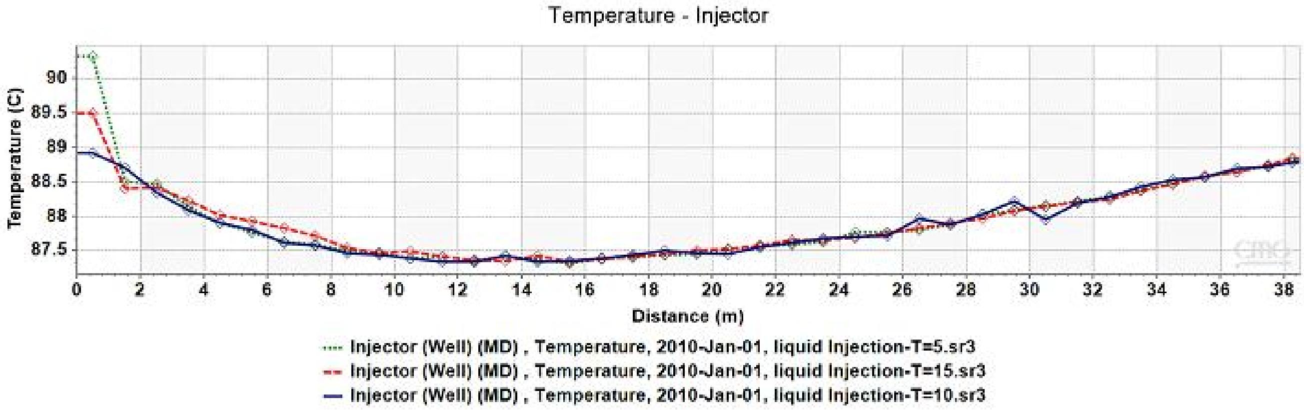


Figure 3.25: JT Cooling Effect on Wellbore Temperature - Jan 2010

The Joule-Thomson (JT) cooling effect is typically weaker during liquid CO2 injection compared to gas injection at the same flow rate. This happens because liquids are much less compressible than gases, so a pressure drop leads to only a small change in volume, and therefore less cooling. In contrast, gases, which are more compressible, experience greater cooling during expansion, making the JT effect more noticeable in gas injection than in liquid injection under similar conditions.

By comparing the figures showing the JT cooling effect on wellbore temperature during gaseous CO2 and liquid CO2 injection, it is clear that the Joule-Thomson effect is less significant for liquid injection. This confirms that the cooling effect during liquid injection is weaker than in gas injection at the same time intervals.

Chapter 4

Conclusions and Suggestions for Future Research

4.1 Conclusions

This thesis has explored the Joule-Thomson effect caused by CO_2 injection into gas reservoirs at depleted conditions, focusing on transient behavior through simulations using CMG STARS. The study integrates both the reservoir and wellbore models.

The following conclusions can be drawn from this research:

- The cooling effect is initially more intense during the early stages of injection, but it gradually weakens as the system stabilizes over time.
- Simulations show that the Joule-Thomson effect is less significant during liquid CO_2 injection compared to gas injection, primarily due to the lower compressibility of liquids. These insights are essential for improving CO_2 injection efficiency and mitigating thermal stresses in the reservoir.

4.2 Suggestions for Future Research

- Near-wellbore effects, including the Joule-Thomson effect, have been successfully demonstrated through simulations using CMG STARS. However, these simulations often focus on isolated conditions, and the flow rates and parameters applied typically differ from those in realistic injection scenarios in depleted gas fields. As a result, it is crucial to validate simulation results at high injection rates on a field scale to more accurately capture the behavior of these effects in real-world conditions.

- The cooling effects observed in the simulations suggest that significant thermal stresses may develop near the wellbore, which could increase the likelihood of fractures forming in the reservoir. However, this thesis did not examine the impact of cooling on stress or how it might lead to the initiation and spread of fractures. Future research could focus on understanding how temperature changes influence these geomechanical effects and their potential impact on the wellbore and reservoir stability.

- Geochemical effects near the wellbore should be further investigated, including salt precipitation, hydrate formation, and reactions involving carbonic acid and its interaction with rock minerals. While these reactions are less significant in depleted gas reservoirs, they could be critical in more reactive carbonate reservoirs. Studying these interactions may provide valuable insights into how precipitation and dissolution reactions impact injectivity.

- This thesis has been limited to studying pure CO2; however, in real-world applications, the injected stream often contains various impurities. These impurities can significantly influence the phase behavior of CO2, which in turn affects its injectivity. Further investigation is needed to assess how different impurities impact CO2 properties during injection and how they alter the overall performance of the reservoir.

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Appendix A

Analytical Solution for Joule-Thomson Cooling(21)

- **Mathematical Model**

  The constant-rate injection of CO_2 into a homogenous, isotropic, and confined formation is described by the following simplified heat transport equation:

$$[\phi(1-S_r)\rho_{CO_2}C_p+\phi S_r\rho_w C_p+(1-\phi)\rho_r C_p]\frac{\partial T}{\partial t}=-q\rho_{CO_2}C_p\left(\frac{\partial T}{\partial r}-\mu_j t\frac{\partial p}{\partial r}\right) \quad \text{(A-1)}$$

  where the boundary conditions are:

$$T=T_0,\quad r\geq r_w,\quad t=0$$

$$T=T_w,\quad r=r_w,\quad t>0$$

- **Pressure Distribution**

  The pressure gradient is derived from Darcy's law, assuming steady-state single-phase flow:

$$\frac{\partial p}{\partial r}=\frac{q_{inj}\mu_{CO_2}}{2\pi r h\phi k_r CO_2} \quad \text{(A-2)}$$

  Integrating this provides the pressure distribution:

$$P=P_w+\frac{q_{inj}\mu_{CO_2}}{2\pi h\phi k_r CO_2}\ln\left(\frac{r}{r_w}\right) \quad \text{(A-3)}$$

- **Temperature Profile**

  The transient heat equation, coupled with Darcy's law, leads to the following dimensionless form of the temperature equation:

$$\frac{\partial T_D}{\partial t_D} = \frac{1}{r_D}\left(\frac{\partial T_D}{\partial r_D} + \frac{1}{r_D}\right) \tag{A-4}$$

  where T_D, r_D, and t_D are the dimensionless temperature, radial distance, and time, respectively, as defined by:

$$T_D = \frac{2\pi hk_r CO_2 K(T - T_0)}{\mu_j q_{inj} \mu_{CO_2}}$$

$$r_D = \frac{r}{r_w}, \quad t_D = \frac{q_{inj} t}{\pi h r_w^2}$$

- **Analytical Solution**

  To solve this, apply Laplace transformations. The final form of the dimensionless temperature can be written as:

$$T_D(r_D, t_D) = \frac{1}{2}\ln\left(1 - \frac{2t_D}{r_D^2}\right), \quad t_D < \frac{r_D^2 - 1}{2} \tag{A-5}$$

  and

$$T_D(r_D, t_D) = \frac{1}{2}\ln(1 + T_{wD}), \quad t_D \geq \frac{r_D^2 - 1}{2} \tag{A-6}$$

- **Minimum Temperature**

  The minimum temperature reached in the reservoir, $T_{\min}$, occurs at the discontinuity and is given by:

$$T_{\min} = \frac{\mu_j q_{inj} \mu_{CO_2}}{4\pi hk_r CO_2 K}\ln\left[\frac{C_p}{\phi(1 - S_r)\rho_{CO_2} C_p}\right] \tag{A-7}$$

Appendix B

Derivation and Implementation of K-Value Equation(8)

The K-value, or equilibrium ratio, is a fundamental parameter in phase equilibrium calculations, particularly in reservoir simulation and thermodynamic modeling. It represents the ratio of the mole fraction of a component in the vapor phase to its mole fraction in the liquid phase.

This appendix outlines the derivation of the K-value equation, with a focus on the implementation of the Wilson and Whitson-Torp equations, commonly used in compositional reservoir simulations particularly for PVT simulation used in STARS.

- **Derivation of the K-Value Equation**

  The K-value for a given component i is defined by the following relationship:

  $$K_i = \frac{y_i}{x_i} \tag{B-1}$$

  where y_i is the mole fraction of component i in the vapor phase, and x_i is the mole fraction of component i in the liquid phase. Several correlations are used to estimate K-values under varying pressure and temperature conditions. A widely used correlation is the Wilson equation, which is applicable for systems at moderate pressures.

Wilson's equation for estimating the equilibrium ratio is expressed as:

$$\ln K_i = \ln\left(\frac{P_{ci}}{P}\right) + 5.37\,(1+\omega_i)\left(1-\frac{T_{ci}}{T}\right) \tag{B-2}$$

where:

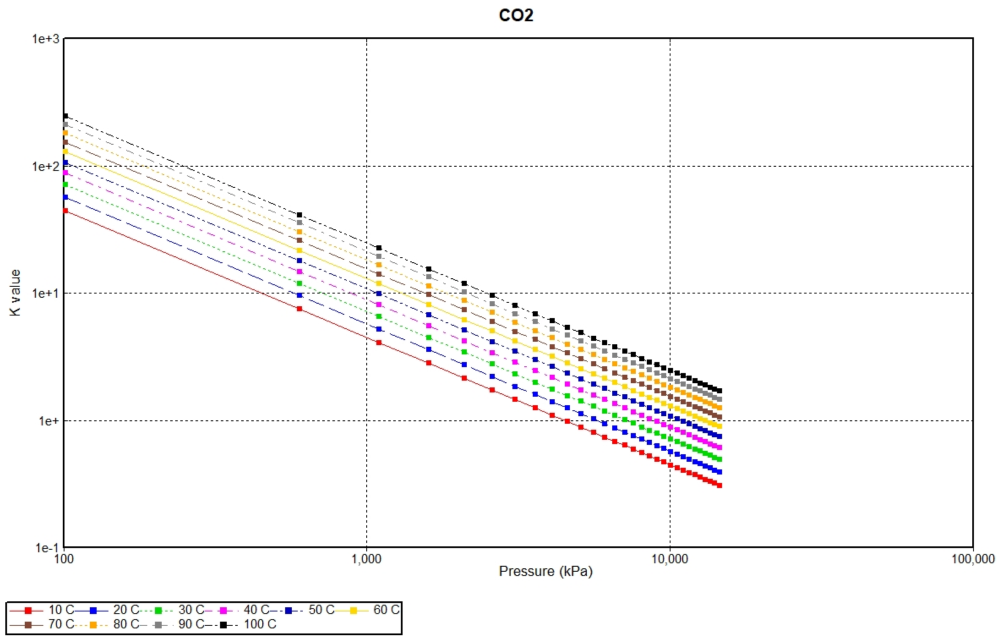
- P_{ci} is the critical pressure of component i,
- T_{ci} is the critical temperature of component i,
- ω_i is the acentric factor of component i,
- P is the system pressure, and
- T is the system temperature.

The term $\frac{T_{ci}}{T}$ accounts for the temperature effect, while the term $\frac{P_{ci}}{P}$ represents the pressure effect on the equilibrium ratio.

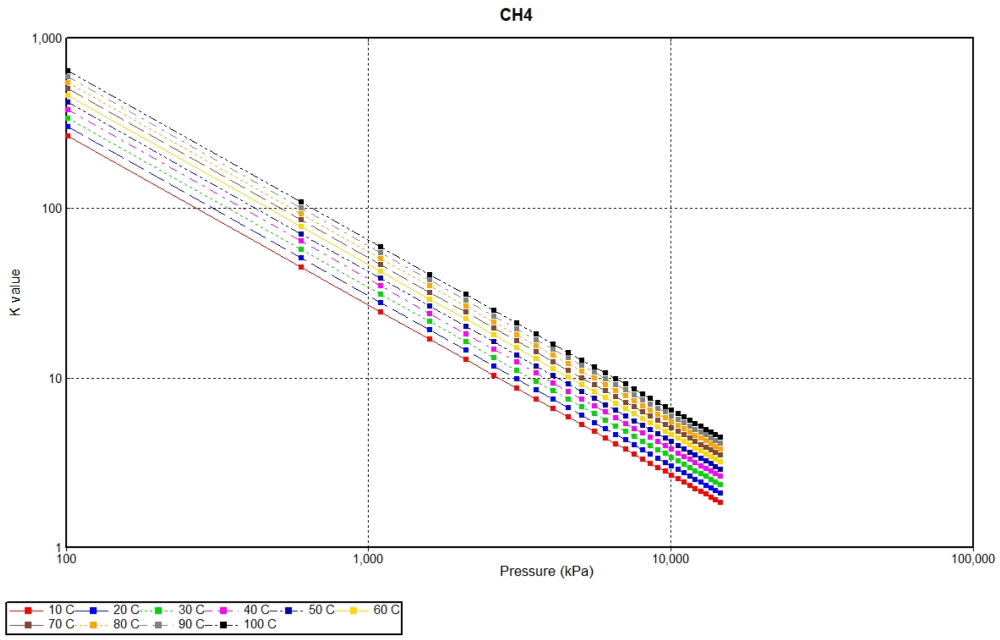
The K-value equations derived above are implemented within reservoir simulators to dynamically calculate phase equilibria during simulations. The simulator utilizes key input parameters such as critical pressure, critical temperature, the acentric factor, and the system's prevailing pressure and temperature to compute the K-values for each component in the system. These K-values are essential for determining the partitioning of components between the vapor and liquid phases. At each simulation timestep, the calculated K-values enable the accurate allocation of components across the phases, ensuring that the phase behavior is properly modeled under varying reservoir conditions.

The figures below illustrate the K-values calculated by WINPROP as a function of both pressure and temperature.

- Gas-Liquid K values

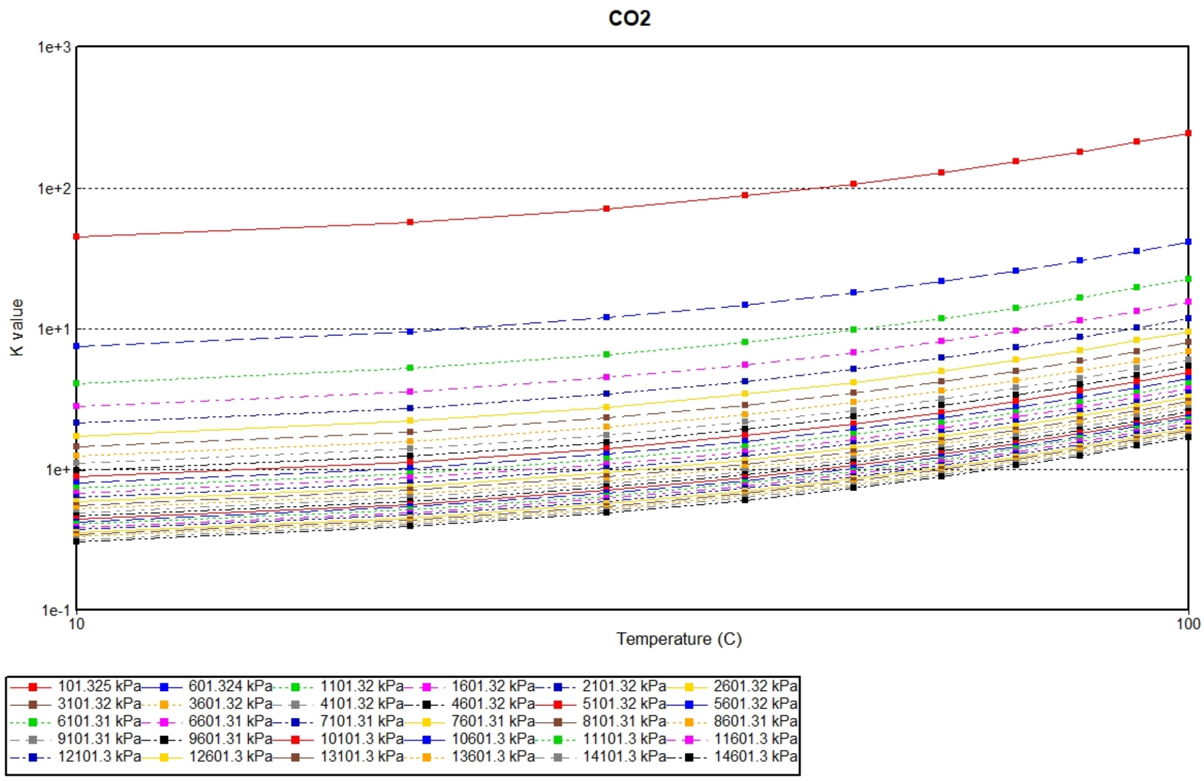


(a) CO_2 K-Values vs Pressure at Various Temperatures

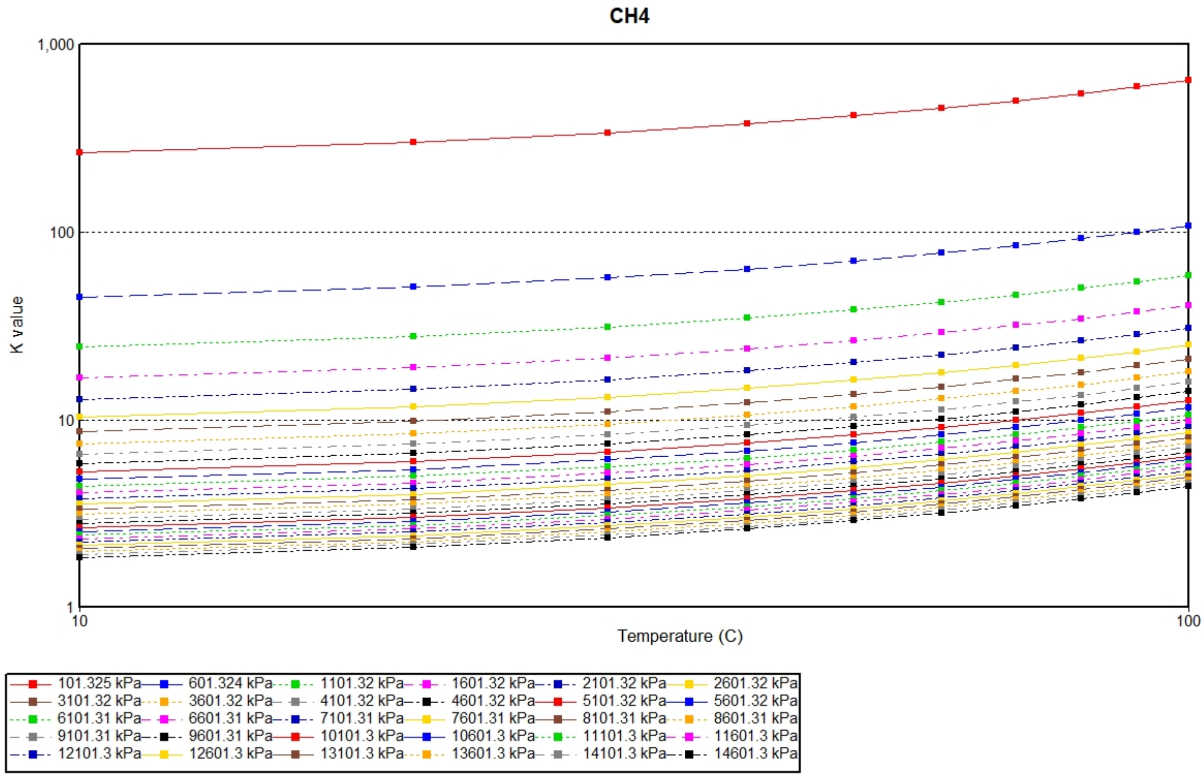


(b) CH_4 K-Values vs Pressure at Various Temperatures

Figure 1: Gas-Liquid K-Values as a Function of Pressure at Various Temperatures



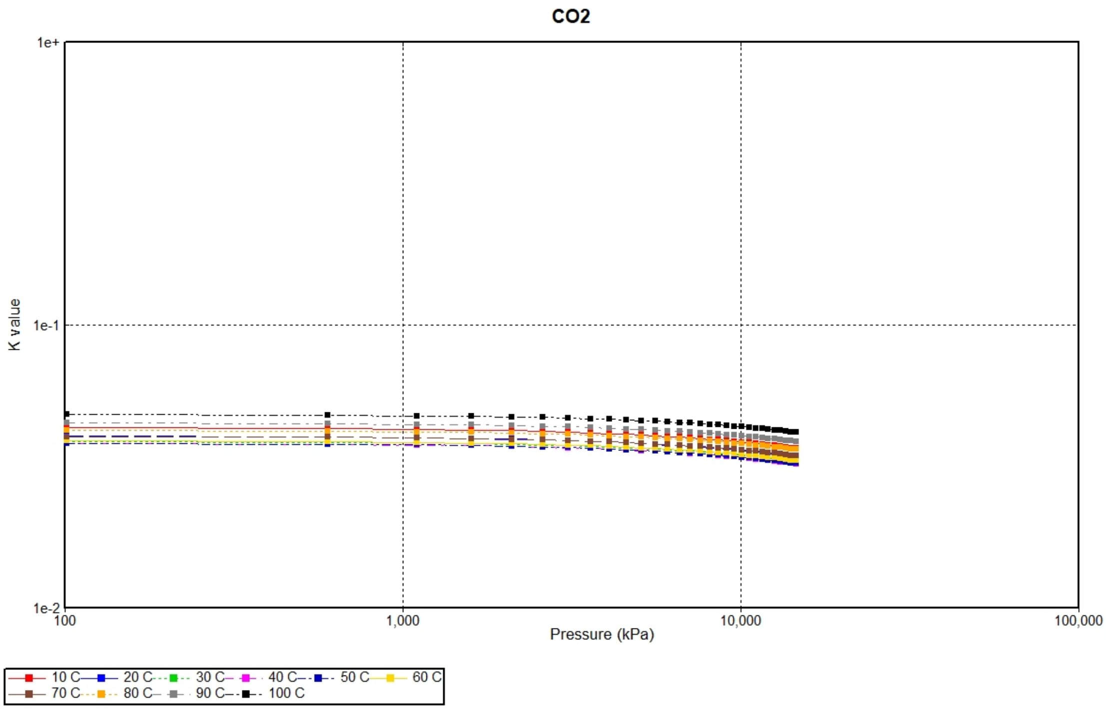
(a) CO2 K-Values vs Temperatures at Various Pressure



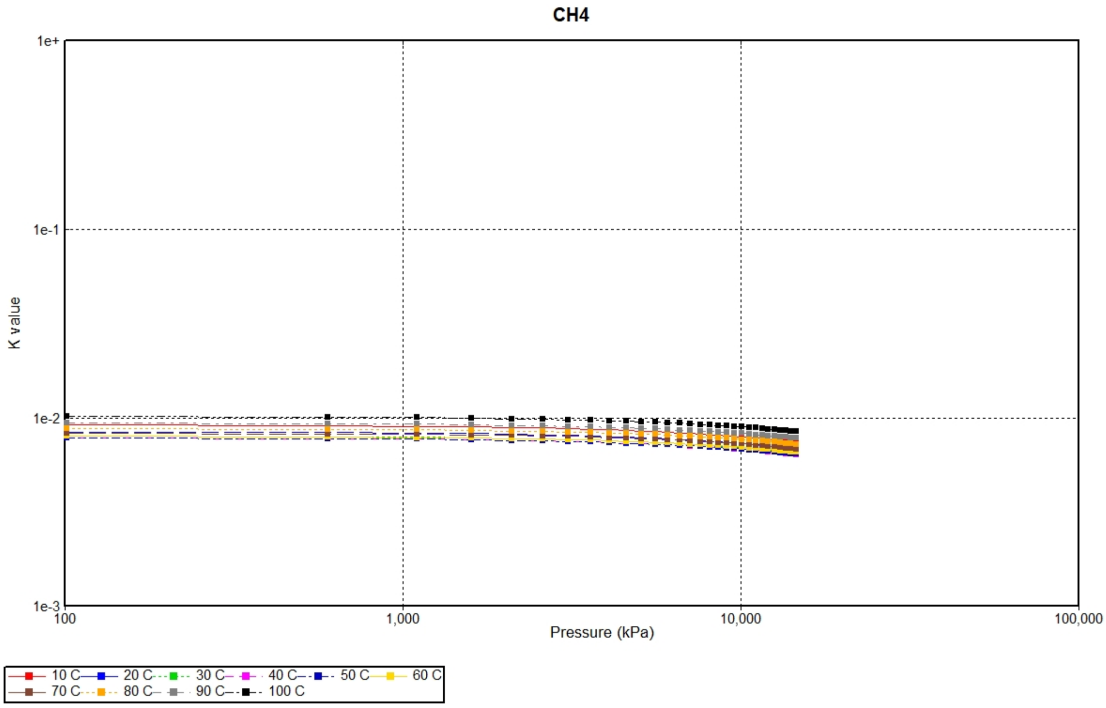
(b) CH4 K-Values vs Temperatures at Various Pressure

Figure 2: Gas-Liquid K-Values as a Function of Temperatures at Various Pressure

- Liquid-Liquid K values

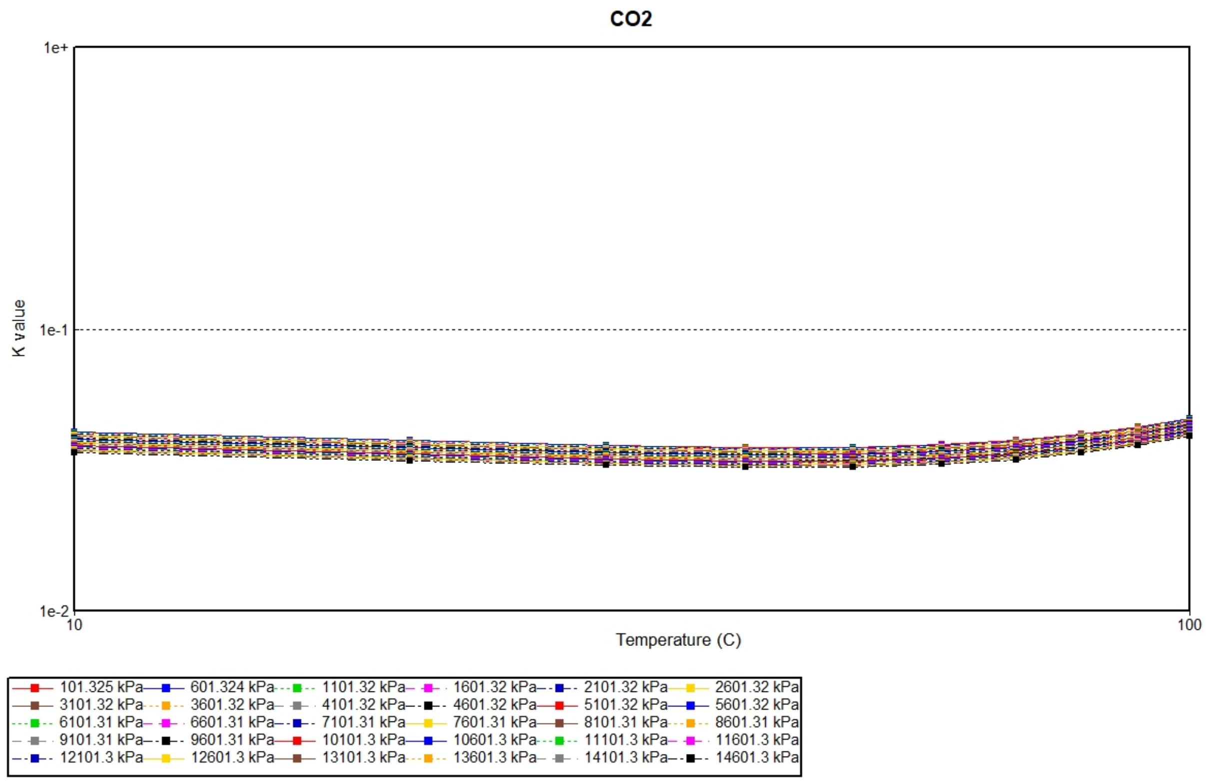


(a) CO2 K-Values vs Pressure at Various Temperatures

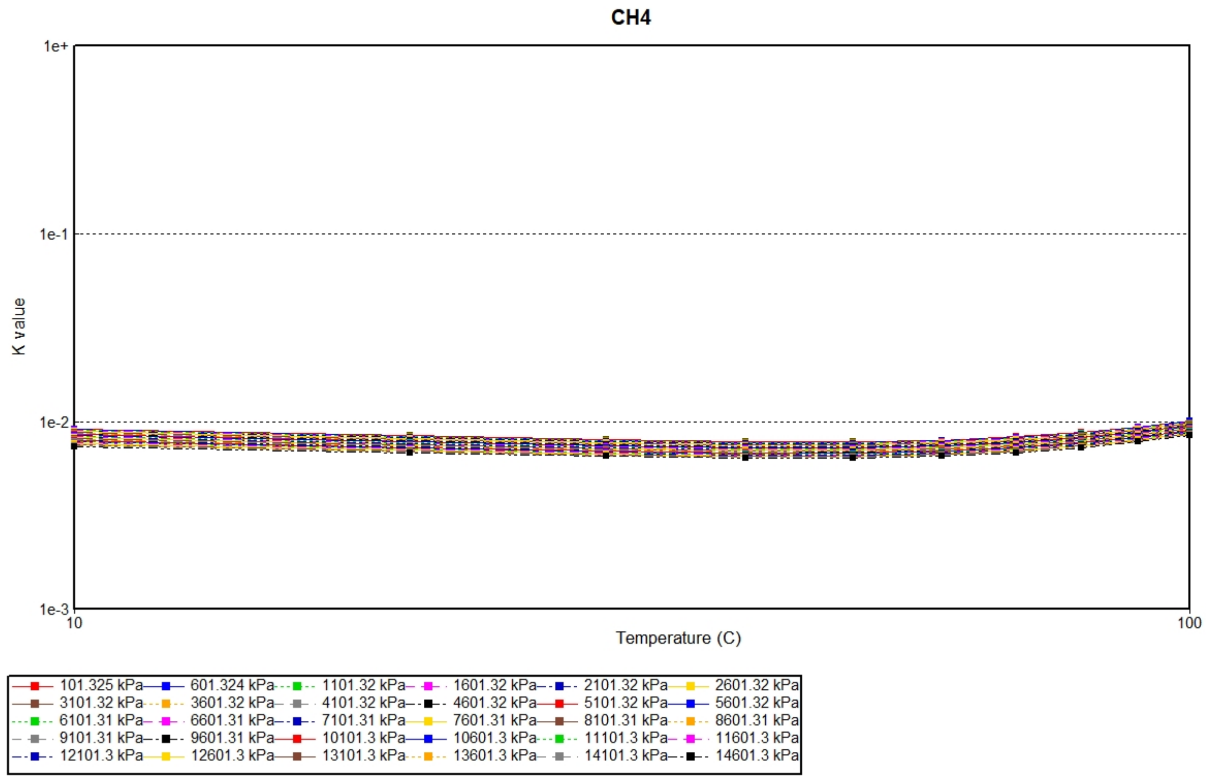


(b) CH4 K-Values vs Pressure at Various Temperatures

Figure 3: Liquid-Liquid K-Values as a Function of Pressure at Various Temperatures



(a) CO_2 K-Values vs Temperatures at Various Pressure



(b) CH_4 K-Values vs Temperatures at Various Pressure

Figure 4: Liquid-Liquid K-Values as a Function of Temperatures at Various Pressure