RESERVOIR SIMULATION AND PERFORMANCE ANALYSIS OF A WATERFLOODED OIL FIELD USING CMG

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NOVEMBER 2025

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A PROJECT REPORT SUBMITED TO THE DEPARTMENT OF PETROLEUM ENGINEERING
IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE AWARD OF BACHELOR OF ENGINEERING (B.ENG) DEGREE IN PETROLEUM ENGINEERING, DEPARTMENT OF PETROLEUM ENGINEERING, FACULTY OF ENGINEERING UNIVERSITY OF BENIN, BENIN CITY

NOVEMBER 2025

CERTIFICATION

This is to certify that the project contained herein is the original work of OMORUYI KENNETH with matriculation number ENG2002627 of the department of Petroleum Engineering, University of Benin, Edo State, Nigeria.

ENGR. DR S.A IGBINERE **(PROJECT SUPERVISOR)**	**DATE**
ENGR. DR O.A. TAIWO **(PROJECT COORDINATOR)**	**DATE**
DR. IKPONMWOSA OHENHEN **(HEAD OF DEPARTMENT)**	**DATE**
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DEDICATION

This work is dedicated to God Almighty for His infinite mercies, love, guidance, knowledge and strength in carrying out this work.

ACKNOWLEDGEMENTS

I wish to first and foremost acknowledge God Almighty for His divine protection, guidance, and countless blessings throughout my life and during the course of my academic pursuit.

My profound gratitude goes to my beloved parents, Mr. and Mrs. Moses Omoruyi, for their unwavering love, financial support, prayers, and encouragement. I also deeply appreciate my family members for standing by me with their continuous prayers and moral support.

I am sincerely thankful to my elder brother and sisters, Mr David Omoruyi, Mrs Hope Guobadia, Mrs Rhoda Otoide, Mrs Sonia Enoma for their motivation, wise counsel, and constant inspiration, which have been instrumental to my success.

Special thanks are due to my project supervisor, ENGR. DR S.A IGBINERE, for his invaluable guidance, support, and constructive criticism throughout the period of this research work. I also extend my sincere appreciation to my Head of Department, Dr. IKPONMWOSA OHENHEN, and to all my lecturers in the Department of Petroleum Engineering, for their commitment, knowledge, and contributions that have shaped my academic and professional growth over the past five years.

I remain grateful to the management and staff of Department Of Petroleum Engineering for giving me the opportunity to undergo my industrial training in their esteemed establishment, which greatly enhanced my practical knowledge and understanding of petroleum engineering applications.

Finally, my heartfelt appreciation goes to all my friends and colleagues for their advice, encouragement, and support during the course of my studies.

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ABSTRACT

Efficient management of oil reservoirs requires accurate prediction of reservoir performance and optimization of recovery strategies. This study focuses on the simulation and performance analysis of a waterflooded oil field using Computer Modelling Group (CMG) software. Waterflooding, a secondary recovery method, is applied to sustain reservoir pressure and enhance oil displacement efficiency after primary depletion. In this research, a three-dimensional reservoir model was constructed using geological, petrophysical, and production data, incorporating rock and fluid properties such as porosity, permeability, viscosity, and relative permeability curves. The simulation was performed using CMG IMEX, a black-oil simulator, to evaluate reservoir behavior under both natural depletion and water injection scenarios.

The results from the base case simulation indicated a gradual decline in oil production rate due to reservoir pressure depletion, while the waterflooded case demonstrated a significant improvement in oil recovery performance. The initial oil production rate before flooding was approximately 1500 STB/day, which declined to 500 STB/day before water injection. After waterflood initiation, oil production increased to about 1450 STB/day, accompanied by a gradual rise in water cut from 10% to 70% over the simulation period. Cumulative oil recovery improved from 25% under primary recovery to approximately 45% with waterflooding, indicating a 20% incremental recovery due to secondary recovery efforts.

The study highlights the importance of reservoir simulation tools such as CMG in designing and optimizing waterflood operations, predicting production performance, and evaluating reservoir management strategies. It concludes that waterflooding remains one of the most efficient and economical methods of improving oil recovery in mature fields when properly designed using robust simulation techniques.

CHAPTER ONE

INTRODUCTION

1.0 BRIEF OVER VIEW

Reservoir simulation is a crucial aspect of modern petroleum engineering, allowing engineers to predict and optimize the performance of hydrocarbon reservoirs under various development scenarios. The global energy sector continues to depend significantly on hydrocarbons as a primary source of energy, despite the growing shift towards renewable alternatives. In particular, oil remains a critical resource for transportation, industry, and petrochemical production. However, with many giant oil fields maturing and production from primary recovery declining, the petroleum industry is increasingly reliant on secondary and tertiary recovery methods to maintain or enhance oil production.

Waterflooding, a form of secondary recovery, is one of the most commonly employed techniques to improve oil recovery after the natural drive mechanisms are depleted. In this method, water is injected into the reservoir to maintain pressure and displace oil toward producing wells. Waterflooding can increase the ultimate recovery of oil by 15–30% beyond what is recovered during primary production (Lake, 1989). Despite its widespread application, waterflooding often encounters performance challenges such as premature water breakthrough, uneven sweep, and inefficient displacement in heterogeneous formations. The effectiveness of waterflooding depends on numerous factors such as reservoir heterogeneity, fluid properties, and well placement. To effectively evaluate and optimize waterflooding operations, reservoir simulation is a critical tool. Simulation allows engineers to construct a numerical model of the reservoir that incorporates geological, petrophysical, and fluid properties. Through simulation, engineers can analyze reservoir behavior, validate performance predictions, test development scenarios, and plan for optimized field operations (Ertekin *et al.*, 2001). Without such advanced modeling, field development decisions would rely heavily on trial-and-error or simplistic methods, often leading to suboptimal recovery and economic losses.

One of the leading simulation platforms in the oil and gas industry is the Computer Modelling Group (CMG) software suite. CMG provides specialized simulation tools such as IMEX (black oil and waterflood models), GEM (compositional models), and STARS (thermal and chemical EOR processes). The IMEX simulator is particularly suited for modeling waterflood operations in conventional oil reservoirs, as it handles multiphase flow and pressure changes efficiently. CMG also offers visualization and history-matching tools that allow engineers to compare model predictions with actual field data and adjust model parameters accordingly

In recent years, reservoir simulation has evolved from a purely technical task to a multidisciplinary approach that integrates geoscience, reservoir engineering, and data analysis. As noted by Dake (2001), "Simulation has become the cornerstone of modern reservoir management, linking theory and field data to practical decision-making." By applying CMG to simulate a waterflooded oil reservoir, this project aims to understand fluid flow behavior, evaluate injection efficiency, forecast future production, and identify optimization strategies. Furthermore, as oil field development becomes more capital intensive and risk-sensitive, simulation helps reduce uncertainty and supports investment decisions. This is particularly important in mature fields where infrastructure already exists, and further recovery must be economically and technically justified.

In summary, the study of reservoir simulation and waterflood performance analysis using CMG is essential for modern reservoir management. It aligns with the global goal of maximizing recovery, improving operational efficiency, and sustaining hydrocarbon production from aging assets. This project will contribute to these goals by modeling a waterflooded reservoir, validating its behavior through simulation, and recommending improvements based on analytical results.

1.1 BACKGROUND TO THE STUDY

The global oil and gas industry is undergoing significant transformation due to declining discoveries of new giant oil fields, increasing production from mature reservoirs, and a growing emphasis on maximizing recovery from existing assets. In this context, enhanced oil recovery (EOR**)** methods particularly waterflooding have become essential in sustaining production levels and extending the economic life of oil fields.

Waterflooding is a secondary recovery technique in which water is injected into the reservoir to maintain pressure and displace oil towards production wells. It is typically implemented after the primary drive mechanisms, such as natural depletion or solution gas drive, become insufficient to sustain economic oil flow. The effectiveness of waterflooding depends on various factors including rock permeability, porosity, reservoir geometry, and fluid properties. When properly designed and implemented, waterflooding can improve oil recovery by an additional 15%–30% of the original oil in place (OOIP) (Lake, 1989).

However, waterflooding operations are not without challenges. In heterogeneous reservoirs, injected water often follows the path of least resistance, typically high-permeability zones or fractures. This can lead to uneven displacement, early water breakthrough, and low sweep efficiency, leaving large volumes of bypassed oil in the reservoir. Such inefficiencies emphasize the need for advanced reservoir management techniques that can simulate and analyze these complex subsurface behaviors, this is where reservoir simulation becomes invaluable. Simulation involves the mathematical modeling of fluid flow in porous media, integrating geological, petrophysical, and operational data into a 3D numerical model. Through simulation, engineers can test different development scenarios, optimize water injection strategies, evaluate recovery potential, and forecast future production performance. As noted by Ertekin *et al*. (2001), “Reservoir simulation is a predictive tool that transforms raw field data into strategic insight.”

Computer Modelling Group (CMG) software suite is designed specifically for modeling oil reservoirs and recovery operations, where IMEX, a feature of the CMG suite is specifically used for black oil simulation and water flooded operations. It allows for detailed modeling of multiphase fluid flow, pressure distribution, saturation changes, and production performance. CMG also enables history matching, a process of calibrating the model using historical production and pressure data to ensure the model reflects the actual field behavior. Once matched, the model can be used to explore various “what-if” scenarios, including injection optimization, infill drilling, and enhanced recovery options.

Moreover, in mature oil fields where infrastructure is already in place and capital expenditure must be minimized, simulation helps reduce uncertainty and improve investment decisions. According to Alhuthali, Datta-Gupta, and Jenkins (2007), “Integrated modeling has become indispensable in planning, managing, and optimizing waterflood operations, especially in complex and mature reservoirs.”

This study leverages CMG’s simulation tools to conduct a detailed analysis of a waterflooded oil field. The background highlights the growing reliance on numerical simulation for optimizing reservoir performance and underscores its value in modern petroleum engineering practice.

1.2 STATEMENT OF THE PROBLEM

The efficiency of oil recovery in many mature oil fields is significantly hindered by the limitations of conventional production methods. After the primary production phase driven by natural reservoir pressure declines, secondary recovery techniques like waterflooding are employed to maintain reservoir pressure and enhance oil displacement. While waterflooding is widely regarded as a cost-effective and technically feasible recovery method, its performance in real-world applications is often suboptimal due to reservoir heterogeneity, poor sweep efficiency, early water breakthrough, and lack of precise control over fluid displacement dynamics.

One of the fundamental challenges in waterflooding operations is non-uniform displacement of oil. In heterogeneous reservoirs, injected water tends to channel through high-permeability streaks or fractures, bypassing significant portions of oil-saturated rock. This phenomenon results in low areal and vertical sweep efficiency, leading to reduced recovery factors and increased water production. Once water breaks through into the production well, the water-oil ratio increases dramatically, affecting the economic viability of continued production. As Dake (2001) highlighted, “Inadequate understanding of reservoir heterogeneity and fluid movement often leads to inefficient secondary recovery efforts.”

Another layer of complexity lies in the inability to visualize and quantify subsurface fluid movement using traditional monitoring techniques. Operators typically rely on surface measurements and production data, which offer limited insight into the internal workings of the reservoir. This gap between observed performance and subsurface reality often leads to trial-and-error approaches in waterflood management, resulting in wasted resources, poor reservoir understanding, and reduced oil recovery.

Reservoir simulation addresses this challenge by offering a means to model fluid flow behavior within the reservoir, predict performance under varying operating conditions, and guide strategic decisions. However, many operators in marginal fields or developing regions underutilize simulation tools due to constraints such as limited data, lack of expertise, or software access. The absence of a validated and optimized simulation model can therefore lead to flawed reservoir management and suboptimal field development outcomes.

This project recognizes the gap between theoretical waterflooding efficiency and actual field performance, and it seeks to bridge that gap using advanced simulation tools. By applying CMG's IMEX simulator, which is designed for black oil and waterflood modeling, this study aims to simulate the reservoir behavior, analyze water injection performance, and identify operational inefficiencies.

In summary, the key problems this project addresses are:

i. Inefficient sweep and early water breakthrough in waterflooded reservoirs**.**

ii. Limited understanding of reservoir heterogeneity and its effect on waterflood performance**.**

iii. Lack of predictive tools for optimizing water injection and production strategies.

iv. Underutilization of reservoir simulation in routine reservoir management

As Ertekin et al. (2001) observed**,** "The inability to match field performance with theoretical expectations is often a consequence of inadequate modeling and poor data integration." This study responds directly to these issues by using CMG to simulate, analyze, and improve the performance of a waterflooded reservoir.

1.3 AIM AND OBJECTIVES

The overarching aim of this study is to develop and utilize a reservoir simulation model using CMG (Computer Modelling Group) software to evaluate the performance of a waterflooded oil field and identify strategies to improve oil recovery. Through this simulation, this study seeks to provide a scientific basis for understanding fluid flow dynamics, optimizing water injection schemes, and enhancing production efficiency.

The specify objectives are;

i. Data acquisition and Data evaluation to build the reservoir model.

ii. Development of the modelled reservoir using CMG.

iii. History Matched the developed model to analyze the reservoir performance.

iv. Performing of water flooded operations and taking the analysis

v. Sensitivity analysis and evaluation

vi. Forecasting and Predicting optimization

vii. Reporting and interpretation of results

1.4 JUSTIFICATION OF STUDY

Reservoirs are complex underground structures, efficient and economical recovery of petroleum fields from the reservoirs remains one of the most critical challenge in petroleum engineering. As oil fields mature and primary recovery mechanisms decline, enhanced recovery strategies such as waterflooding are frequently employed to sustain production and prolong field life. However, the success of waterflooding operations is often undermined by different factors such as reservoir heterogeneity, suboptimal injection strategies, and lack of predictive analysis, leading to inefficient displacement and early water breakthrough.

The justification for this study is firmly rooted in the technical, economic, and educational need to enhance oil recovery from waterflooded fields using modern simulation tools. It aligns with global industry trends, national energy goals, and academic development objectives, making it both timely and relevant.

The Justification of this study is based on the grounds of various reasons;

i. Need for Improved Oil Recovery from Existing Fields

ii. Bridging the Gap Between Theory and Practice

iii. Importance of Simulation in Modern Reservoir Management

iv. Economic and Environmental Implications

v. Skill Development and Technical Capacity Building

vi. Contribution to Local and Global Knowledge

1.5 SCOPE AND LIMITATIONS OF STUDY

The scope of this research is designed in a way to clearly define the boundaries of research, the extent of work to be carried out, and the specific focus areas. The scope of this project is carefully outlined below:

i. Reservoir Type and Recovery Method
ii. Simulation Tool and Model Used
iii. Data Inputs Considered
iv. Performance Evaluation Metrics
v. Geographic and Field Scope
vi. Forecasting and Scenario Analysis

Despite it’s usefulness, this study has certain limitations that should be acknowledged and addressed, these limitations are;

i. Data Availability and Quality
ii. Model Simplifications
iii. Uncertainty in Reservoir Description
iv. Operational Assumptions
v. Economic Considerations Excluded
vi. Generalization of Results

CHAPTER TWO

LITERATURE REVIEW

2.0 THEORETICAL FOUNDATIONS OF WATERFLOODING

Classical waterflood theory rests on immiscible two-phase flow, fractional-flow analysis, and shock-front mechanics. The Buckley Leverett formulation and Welge's tangent method define saturation fronts, breakthrough timing, and recovery as functions of relative permeability and viscosity ratio. These foundations still underpin modern simulators and quick-look tools. As the original work put it, fractional flow provides a framework for "predicting oil recovery by displacement" under immiscible conditions.

Monographs by Craig and Willhite extend this theory to field practice areal/vertical sweep efficiency, mobility ratio MMM, pattern geometry (line drive, five-spot), and heterogeneity effects giving engineers practical charts and correlations. Willhite's SPE text is widely regarded as the canonical waterflood reference, and Craig's monograph remains the go-to for sweep efficiency and pattern performance.

A key descriptor of heterogeneity is the Dykstra Parsons coefficient V_{DP}. Higher $\mathrm{V_{DP}}$ (more stratification) degrades vertical sweep and accelerates water breakthrough behavior captured in the Dykstra Parsons correlations and later simplifications and extensions.

2.1 ROCK-FLUID INTERACTIONS: RELATIVE PERMEABILITY AND WETTABILITY

Understanding the intricate interplay between rock and fluids within a reservoir is paramount and crucial for accurate reservoir simulation and successful oil and gas recovery strategies. Relative permeability and wettability are two crucial rock-fluid properties that govern the distribution and flow of fluids in porous media and significantly impact reservoir simulation predictions.

Relative permeability quantifies the ease with which a fluid phase can flow through a porous medium in the presence of other immiscible fluids. It us crucial input for reservoir simulation modelling, particularly in cases of waterflooding or Enhanced oil recovery (EOR). The relative permeability of a porous medium is influenced by several factors, including:

i. Pore geometry
ii. Fluid distribution
iii. Saturation History
iv. Wettability

Wettability describes a rock's tendency to be preferentially coated by one fluid phase over another in the presence of immiscible fluids, typically oil and water in reservoirs. It is determined by the balance of interfacial forces specifically the surface tensions between the fluids and rock surface. Wettability can be classified based on the contact angle (the angle formed at the interface between the two fluids and the solid surface). Rock surfaces could be Water-wet (contact angle typically between 0^0 and $70\text{-}75^0$), Oil-wet (contact angle typically between $110\text{-}120^0$ and 180^0), Neutral-wet or Intermediate-wet (contact angle typically between $70\text{-}75^0$ and $105\text{-}120^0$). Wettability can be influenced by different factors like:

i. Mineral composition
ii. Geological history
iii. Fluid composition and salinity
iv. Temperature and pressure
v. Presence of asphaltenes or other organic matter

2.2 WATERFLOOD DESIGN AND DIAGONISTICS

Waterflood design is a comprehensive process that determines the optimal strategy for injecting water into an oil reservoir to maximize oil recovery. Waterflood diagnostics, or surveillance, involves monitoring and analyzing performance to ensure the flood is operating efficiently and to identify opportunities for improvement. A proper waterflood design integrates geological, petrophysical, and engineering data to create a strategy tailored to the specific reservoir. The design for waterflooding operations is hinged on both reservoir characteristics and injection strategies;

Reservoir Characteristics:

i. Geology and depositional environment; Understanding the reservoir's structure, layering, and rock properties (such as porosity and permeability) is critical. Variations in permeability can cause injected water to bypass oil in less permeable zones, reducing sweep efficiency.

ii. Fluid properties; The viscosity and density of both the reservoir oil and the injected water determine the mobility ratio, a key factor in sweep efficiency. A more favorable mobility ratio leads to a more uniform flood front.

iii. Oil saturation; A successful waterflood requires sufficient oil saturation after primary production to form an oil bank and warrant the investment.

iv. Natural drive mechanisms; Identifying the natural energy (e.g., solution gas drive, water drive) is important. Reservoirs with strong natural water drive may not need supplemental water injection.

Injection Strategy:

i. Pattern selection: Common well patterns include five spot, seven spot, and line drive. The choice depends the reservoir geometry, heterogeneity, and desired sweep efficiency.

ii. Well placement and spacing: Optimally locating injection and production wells is key. Insufficient well spacing can cause early water breakthrough, while too much space can leave oil un swept.

iii. Water quality and source: Injection water must be treated to prevent issues like scaling, corrosion, bacterial growth, and formation damage that can clog pores and reduce injectivity.

iv. Injection rates and pressure: Managing these parameters is vital to maintain reservoir pressure, achieve voidage replacement, and avoid fracturing the formation.

Once a waterflood is implemented, a robust surveillance program is necessary to track performance and adapt operations. Diagnostics are performed at the field, pattern, and well level to identify problems and opportunities. Key surveillance activities include:

i. Data gathering.
ii. Data evaluation and analysis.

Common Diagnostic plots:

i. Voidage Replacement Ratio (VRR)
ii. Hall Plot
iii. Log water- Oil Ratio (WOR) vs Cumulative Oil Production
iv. Other plots like Y-function, X-plot, and rate vs cumulative production plots.

Advanced Monitoring Techniques:

i. Tracer tests
ii. 4D seismic surveys
iii. Production logging tools (PLTs)

2.3 SURVEILLANCE, DATE-DRIVEN MODELS, AND INTERWELL CONNECTIVITY

Waterflooding reservoir management is a critical process involving the strategic use of surveillance, data-driven models, and inter well connectivity analysis to maximize oil recovery and economic returns. Integrating these three components into reservoir simulation provides a powerful framework for understanding and optimizing the complex physics of fluid flow in the subsurface.

Surveillance of waterflooding:

Surveillance is the continuous monitoring and analysis of data to evaluate the performance of a waterflooding project and identify potential issues. It provides the data required for both data-driven models and reservoir simulation. Key Surveillance techniques include:

i. Performance plots (Fractional flow and water cut plots and Hall plots).
ii. Injection profile logging
iii. Tracer monitoring
iv. Pressure transient testing
v. Water quality analysis.

Data-Driven models for waterflooding:

Data-driven models use historical production and injection data to create predictive tools. They offer a computationally fast and efficient alternative or complement to traditional numerical reservoir simulation, especially in mature fields with abundant data. There are different data-driven models that can be used for waterflooding operations but in context of this research, we make use of Computer Modelling Group (CMG).

Inter well connectivity (IWC) analysis:

Inter well connectivity (IWC) is the characterization of the fluid flow paths and communication strength between injection and production wells. Understanding IWC is vital for waterflood optimization, as it reveals the reservoir's hydraulic architecture and identifies flow barriers or thief zones.

The three elements; surveillance, data-driven models, and IWC analysis—are combined in an integrated workflow to improve the accuracy and efficiency of waterflooding simulation.

2.4 FULL PHYSICS RESERVOIR SIMULATION FOR WATERFLOODS (BLACK OIL FORMULAION)

In the black oil formulation, a full physics reservoir simulation for waterfloods models the complex, three-phase flow of oil, gas, and water through a porous and heterogeneous rock medium. It relies on a system of partial differential equations (PDEs) derived from mass conservation laws and Darcy's law, which are then solved numerically. Key assumptions of the black oil model are:

i. Three phases, three components (oil, gas and water)
ii. Water is insoluble in the hydrocarbon phases
iii. The oil component can dissolve gas, but the gas component cannot vaporize into the oil phase.
iv. The properties of each phase (density, viscosity and formation volume factor) are functions of pressure.

Governing Equations:

The core of the simulation is a set of conservation equations for each component, typically solved using a finite-difference or finite-volume method on a discretized grid of the reservoir.

1. Conservation of mass

For each of the three components (water, oil, and gas), the mass conservation equation can be written as:

$$\frac{\partial}{\partial t}\left(\frac{\emptyset S_W}{B_W}\right) + \nabla.\left(\frac{u_w}{B_w}\right) = \frac{q_w}{B_w}$$

$$\frac{\partial}{\partial t}\left(\frac{\emptyset S_o}{B_o} + \frac{\emptyset S_g RS_o}{B_g}\right) + \nabla.\left(\frac{u_o}{B_o} + \frac{u_o RS_o}{B_g}\right) = \frac{q_o}{B_o} + \frac{q_g Rs_o}{B_g}$$

$$\frac{\partial}{\partial t}\left(\frac{\emptyset \mathrm{S_g}}{\mathrm{B_g}} + \frac{\emptyset \mathrm{S_g Rs_o}}{\mathrm{B_o}}\right) + \nabla.\left(\frac{\mathrm{u_g}}{\mathrm{B_g}} + \frac{\mathrm{u_g Rv_o}}{\mathrm{B_o}}\right) = \frac{\mathrm{q_g}}{\mathrm{B_g}} + \frac{\mathrm{q_g Rv_o}}{\mathrm{B_o}}$$

Where:

Φ = porosity of the rock

S_α = saturation of the three phases (W for water, o for oil and g for gas)

B_α = formation volume factor of the different phases

u_α = Darcy velocity of the different phases

R_{so} = Solution gas oil ratio (volume of dissolved gas per unit volume of oil, at standard conditions).

R_{vo} = Vaporized oil gas ratio (volume of vaporized oil per unit volume of gas, at standard conditions).

q_α = Volumetric flow rate of the different phases at standard conditions.

2. Darcy's Law for multiphase flow

The velocity of each phase is described by a modified version of Darcy's law for multiphase flow.

$$u_\alpha = -\frac{Kk_{r\alpha}}{\mu_\alpha} (\nabla p_\alpha - \rho_\alpha g \nabla Z)$$

Where:

K= Absolute permeability of the rock

$k_{r\alpha}$ = Relative permeability of the different phases

μ_α = viscosity of the phase

p_α = Pressure gradient of the phase

g= Acceleration dur to gravity

Z = Vertical depth gradient

$P\alpha$ =Density of the phase

3. Auxiliary relationships

To close the systems of equations, additional relationships are needed:

i. Capillary Pressure: The pressure difference between the different phases is a function of saturation.

$$P_{cow} = p_o - p_w = f(S_w)$$

$$P_{cgo} = p_g - p_o = f(S_g)$$

ii. Saturation constraint: The sum of all phase saturations must be 1.

$$S_w + S_o + S_g = 1$$

Relative permeability: The relative permeability of each phase is a function of saturation, and often accounts for wettability and rock type.

Numerical solution techniques

The set of complex, nonlinear PDEs is solved numerically by discretizing the reservoir into a grid and applying a numerical method.

Implicit Pressure, Explicit Saturation (IMPES)

The most common technique is the IMPES method.

Pressure equation: A single pressure equation is derived by combining the conservation equations. This equation is solved implicitly, meaning it uses the new (unknown) values of pressure.

Saturation update: Once the pressures are solved, the saturation values are calculated explicitly (using the old time-step's values), which is computationally faster but can impose strict limits on the time step size (CFL condition).

Fully Implicit Method (FIM)

In the fully implicit method, both pressure and saturation are solved simultaneously for the new time step, using iterative Newton-Raphson methods. This approach is more computationally expensive per time step but allows for much larger time steps, making it suitable for simulations with sharp saturation fronts, such as waterfloods.

Simulation process for a waterflood

Static model: A geological model of the reservoir is built using well logs, core data, and seismic surveys to define the 3D grid and populate it with properties like porosity, permeability, and rock type.

Dynamic properties: Fluid properties (PVT data) and multiphase flow relationships (relative permeability and capillary pressure curves) are assigned to the model.

Initial conditions: The initial pressure and fluid saturations are initialized across the reservoir grid.

Well definition: Injection and production wells are defined with their locations, types, and operating conditions (e.g., constant injection rate or constant bottom-hole pressure).

Simulation run: The simulator solves the governing equations over time, advancing from one time step to the next to track the movement of the water and oil phases.

Analysis: The simulation output is used to analyze key performance indicators for the waterflood, such as:

i. Oil and water production rates.
ii. Water-cut (fraction of water in the produced fluid).
iii. Cumulative oil and water production.
iv. Pressure maps showing how pressure changes over time.
v. Saturation maps illustrating the movement of the injected water front.

2.5 HISTORY MATCHING & UNCERTAINTY QUANTIFICATION (UQ)

These are crucial processes that are very important to consider while carrying out water flooding for accurately predicting reservoir behavior, optimizing recovery and managing risk. History matching calibrates a reservoir simulation model to align with historical production data, while UQ evaluates the range of potential outcomes to provide a more robust forecast.

History Matching:

History matching for waterflooding involves adjusting key reservoir parameters to ensure the simulation model accurately reproduces past field performance. This process is particularly complex due to the dynamic, multi-phase fluid interactions involved.

Processes:

i. Initial model creation: A reservoir simulation model is built using geological, petrophysical, and fluid data, which are inherently uncertain.
ii. Simulation run: The model is used to simulate the reservoir's historical production period, considering injection and production rates as constraints.
iii. Data comparison: The simulated outputs (e.g., oil and water production rates, water cut, reservoir pressure) are compared to actual field observations.
iv. Parameter adjustment: The model's uncertain parameters (e.g., permeability, relative permeability curves, aquifer properties) are adjusted to minimize the difference between simulated and observed data.
v. Iteration: This process is repeated until an acceptable match is achieved.

Common challenges

i. Non-uniqueness: The inverse problem of history matching is ill-posed, meaning multiple combinations of reservoir properties can produce equally good matches with historical data.
ii. Computational cost: High-fidelity reservoir simulators can take days or weeks to complete a single run, making manual, iterative matching extremely time-consuming.
iii. Data integration: Incorporating diverse data types, such as 4D seismic data, adds complexity but can improve the match quality.

Uncertain Quantification:

UQ addresses the non-uniqueness problem inherent in history matching by generating multiple, equally probable models that honor historical data. This provides a range of potential future outcomes, which is vital for robust decision-making.

Processes

i. Uncertain parameter selection: The most uncertain parameters are identified, such as geological properties (e.g., facies, porosity, permeability distribution) and rock-fluid properties (e.g., relative permeability).

ii. Ensemble generation: A set of different models (an ensemble) is created by sampling the uncertain parameter space. For waterflooding, this might involve generating multiple geological realizations to capture different channel or fracture network possibilities.

iii. History matching the ensemble: The entire ensemble of models is history matched against the historical production data. This updates the initial parameter distributions to reflect observed data.

iv. Prediction and analysis: The history-matched ensemble is used to forecast future reservoir performance, yielding a range of possible outcomes (e.g., P10, P50, P90 production forecasts).

v. Risk assessment: The spread of the forecast results quantifies the uncertainty and enables a more realistic assessment of technical and financial risks.

2.6 HETEROGENITY, SWEEP EFFICIENCY, AND PATTERN BEHAVIOR

In reservoir simulation, heterogeneity, sweep efficiency, and injection pattern behavior are interconnected, with heterogeneity being the primary controlling factor that affects both the efficiency of the flood and the fluid flow patterns. Waterflooding simulation uses mathematical models to predict and optimize oil recovery based on these relationships.

Heterogeneity

Reservoir heterogeneity refers to the variation in rock and fluid properties throughout the reservoir, including differences in permeability, porosity, and thickness. This variability profoundly impacts how injected water moves through the formation.

How heterogeneity influences waterflooding:

i. Permeability differences**:** In highly heterogeneous formations, water preferentially flows through high-permeability zones, known as "thief zones". This leads to early water breakthrough at production wells and bypasses the oil in less permeable zones.

ii. Layering: Reservoirs with distinct, unconnected layers of varying permeability experience uneven flooding. High-permeability layers are flooded first and rapidly watered out, while low-permeability layers remain un swept.

iii. Connectivity: The way reservoir properties are connected, or their "dynamic heterogeneity," largely controls how efficiently a waterflood displaces oil. Poor connectivity can lead to large areas of bypassed oil.

Sweep efficiency;

Sweep efficiency measures the effectiveness of waterflooding by quantifying how much of the reservoir is contacted by injected water. It is a critical component of the overall oil recovery factor, which is determined by the product of displacement efficiency and sweep efficiency ($RF=E_D + E_V + E_A$). Sweep efficiency can be divided into two main components:

i. Vertical sweep efficiency (E_V): The Fraction of the reservoir's vertical cross section that is swept by the injected fluid. It is strongly affected by layering and gravity.

ii. Areal sweep efficiency (E_A): The fraction of the reservoir's pattern area that is swept by the injected fluid. It is influenced by the mobility ratio and the flood pattern design.

How heterogeneity affects sweep efficiency:

i. Poor sweep: High heterogeneity reduces both areal and vertical sweep efficiency by causing uneven fluid distribution. Water breakthrough occurs prematurely in high-permeability layers and streaks, leaving oil trapped in less permeable areas.

ii. Impact of mobility ratio (M): The mobility ratio (ratio of water mobility to oil mobility) interacts with heterogeneity to determine flood efficiency. For waterfloods where water is more mobile than oil ($M>1$), heterogeneity leads to an even worse sweep because water aggressively fingers through high permeability channels.

Pattern behavior;

The injection pattern is the geometric arrangement of injection and production wells. Waterflooding simulation is used to evaluate the performance of different patterns and optimize them based on the reservoir's properties.

How heterogeneity affects injection pattern behavior:

i. Uniform vs. channeling flow**:** In a homogeneous reservoir, the flood front advances uniformly. In a heterogeneous reservoir, the water will deviate from the ideal geometric pattern, forming channels and fingers along the high-permeability pathways.

ii. Well placement**:** For formations with directional permeability (anisotropy), the injection pattern should be aligned to inject along the direction of maximum permeability to improve sweep.

iii. Pattern balancing**:** Over time, heterogeneity causes injection patterns to become imbalanced as some producers receive disproportionately more water. Reservoir simulation allows engineers to monitor flow dynamics and adjust injection rates to re-establish balance and improve sweep.

iv. Five-spot patterns**:** Five-spot patterns, with four injectors surrounding a central producer, are a common example. Simulation shows how heterogeneity disrupts the ideal symmetric flood and can be used to optimize well placement and rates for such patterns.

The role of reservoir simulation;

Reservoir simulators, such as those using streamline or finite-difference methods, are essential tools for understanding and managing waterflooding in heterogeneous reservoirs.

i. Modeling heterogeneity: Engineers create geological models that capture the spatial variability of reservoir properties, often using geostatistical methods to generate multiple possible realizations of heterogeneity.

ii. Predictive simulation: By running simulations on these models, engineers can predict the flood's performance, including:

a. Water breakthrough time.

b. Fluid flow pathways (streamlines).

c. Ultimate oil recovery and sweep efficiency under different scenarios.

iii. Optimization: Simulation enables the testing of different strategies to mitigate the effects of heterogeneity, such as:

a. Infill drilling: Determining the optimal placement of new wells.
b. Injection rate control: Adjusting water injection rates to balance the flood and prevent excessive water cycling.
c. Advanced EOR: Evaluating the benefits of advanced techniques like polymer flooding to improve the mobility ratio and sweep efficiency.

2.7 ROLE OF CMG IN COMTEMPOROARY RESEARCH AND FIELD STUDIES.

CMG (Computer Modelling Group) plays a fundamental role in contemporary research and field studies of waterflooding by providing sophisticated software for reservoir simulation. Its simulators are used to create detailed models that help engineers and researchers understand, optimize, and predict the performance of waterflooding projects in various reservoir conditions.

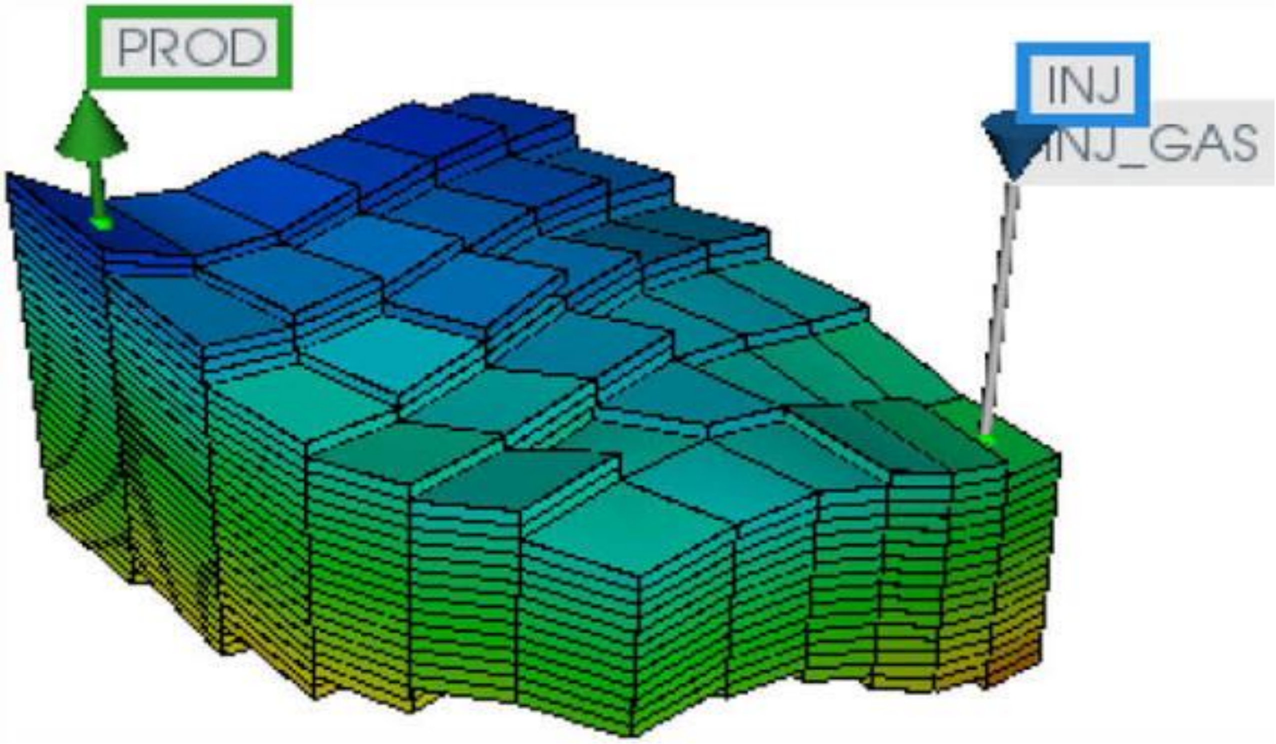


Figure 2.0 A 3D visualization of a reservoir simulation model. (Springer).

Role of CMG's simulation tools;

i. Modelling and simulation (using CMG's IMEX software): CMG's IMEX black oil simulator is the primary tool used for waterflooding studies. It models the injection of water into the oil-bearing zone of a reservoir to displace and sweep the oil toward production wells. IMEX can be used for both conventional and unconventional reservoirs and can handle complex geological features, such as heterogeneous and faulted structures.

ii. Simulation of advanced recovery methods (using CMG's STARS and GEM): Beyond conventional waterflooding, CMG's other simulators enable research and implementation of more complex recovery techniques.

   a. STARS: An advanced thermal and chemical simulator, STARS is used for research on chemical Enhanced Oil Recovery (EOR) processes that are often extensions of waterflooding, such as polymer or surfactant flooding, to improve sweep efficiency.

   b. GEM: This compositional simulator is used for gas injection methods, including water-alternating-gas (WAG) processes, where water and gas are injected in alternating cycles to achieve higher oil recovery than with water or gas alone.

   c. History matching and uncertainty analysis (using CMOST AI): To make simulations more accurate and reliable, CMG's CMOST AI module is used for automated history matching and uncertainty analysis.

   d. History matching: The software calibrates reservoir models by matching simulation results to actual historical production data from the field. This validates the model's accuracy, creating a more reliable tool for forecasting.

    e. Uncertainty analysis: CMOST also helps evaluate the impact of different reservoir parameters on the simulation outcome. This is especially useful for understanding risks in waterflooding projects due to geological variability.

i. Production optimization: Once a model is history-matched, it can be used for "what-if" scenarios to optimize field development. CMG's software helps in designing injection patterns, well locations, and well types (vertical, horizontal, or multilateral) to maximize oil recovery and economic returns. It also helps evaluate operational strategies to minimize unwanted water production and maximize oil productivity.

ii. Predicting field performance: CMG simulation is used to forecast the long-term performance of waterflooding projects. This helps in strategic planning by predicting how factors like production rates, recovery factors, and water cuts will evolve over time. In contemporary research, CMG is increasingly integrated with machine learning (ML) models to create faster and more accurate proxy models for field-scale production prediction.

Application in field studies and research

i. Optimization of field-scale waterflooding projects: Studies on fields like the Draugen field in Norway have used CMG's IMEX simulator to evaluate and optimize waterflooding performance, resulting in a significant increase in recoverable oil.

ii. Investigation of advanced recovery mechanisms: CMG software is used in research to investigate complex interactions during flooding. For instance, researchers have used CMG to study the effect of relative permeability, dynamic capillarity, and wettability alteration in fractured formations during waterflooding.

iii. Study of enhanced waterflooding techniques: Beyond conventional waterflooding, CMG is used to analyze advanced variations. This includes investigating the effects of different well combinations and injection patterns (e.g., five-, seven-, and nine-spot) on sweep efficiency and oil recovery.

iv. Validation of laboratory experiments: CMG simulators are used to scale up and validate findings from laboratory core-flooding experiments to a field-wide scale. By matching experimental data with simulation results, researchers can predict the performance of new techniques, such as injecting ionic liquids, in real-world reservoir conditions.

CHAPTER THREE

METHODOLOGY

This chapter outlines the systematic approach and methods used in conducting the research on Reservoir Simulation and Performance Analysis of a Waterflooded Oil Field Using CMG (Computer Modelling Group) software. The methodology is designed to ensure that this research or study is carried out in a structured, reproducible, and scientifically sound manner.

This study combines both quantitative (numerical simulation and performance analysis) and qualitative (interpretation of field data and model evaluation) techniques. It involves data collection, model development, history matching, performance analysis, and forecasting of field behavior under various water injection scenarios.

This research adopts a simulation-based experimental design where a numerical model of the reservoir is constructed, calibrated, and used to evaluate different waterflooding scenarios. The design follows these stages:

1. Data Collection and Preparation
2. Model Construction (Static and Dynamic Models)
3. Model Initialization
4. History Matching and Validation
5. Performance Analysis of Existing Waterflood Operation
6. Scenario and Sensitivity Analysis
7. Forecasting and Optimization
8. Results Interpretation and Reporting

3.0 DATA COLLECTION AND PREPARATION

The accuracy of a reservoir simulation depends on the quality and completeness of the input data. The following data types are required:

(a) Geological Data

- Structural maps (top of reservoir, thickness, fault boundaries)
- Lithological descriptions and stratigraphic correlations
- Porosity and permeability distributions derived from well logs and core data

(b) Petrophysical Data

- Rock properties such as porosity, permeability, and net-to-gross ratio
- Relative permeability and capillary pressure curves obtained from special core analysis (SCAL)
- Fluid saturation data (oil, water, and gas)

(c) Fluid and PVT Data

- Formation volume factors (Bo, Bw, Bg)
- Oil and water viscosities
- Solution gas–oil ratio (Rs)
- Compressibility and densities of reservoir fluids

(d) Well and Production Data

- Well coordinates, depths, and completion intervals
- Production rates of oil, gas, and water
- Injection rates and volumes
- Historical pressure data

(e) Reservoir and Operational Parameters

- Reservoir boundary conditions and aquifer influence
- Well constraints (bottom-hole pressure, tubing head pressure)
- Injection pressures and rates

All raw data were compiled from available field reports, production summaries, and reservoir studies which will be properly discussed and highlighted in the next chapter. Where necessary, data consistency checks and unit conversions were carried out to ensure compatibility with CMG input formats.

3.1 MODEL CONSTRUCTION (STATIC AND DYNAMIC MODELS)

This stage involves building a numerical representation of the reservoir within CMG's modeling environment. The following CMG modules are used:

(a) Static Model (Geological Framework)

The BUILDER module of CMG is employed to define:

- Grid geometry (X, Y, Z dimensions and cell sizes)
- Layering system and reservoir boundaries
- Porosity and permeability distribution
- Initial fluid saturations

The model grid is discretized into a finite number of cells, and petrophysical properties are assigned to each cell based on well log interpretations and interpolation methods.

(b) Dynamic Model (Flow Simulation Setup)

After creating the static model, IMEX (black-oil simulator) is used for dynamic modeling. IMEX simulates multiphase fluid flow considering:

- Pressure distribution
- Phase saturations (oil, water, gas)
- Capillary and gravitational effects
- Production and injection constraints

The model incorporates well locations, completions, and operational controls (e.g., production rate, bottom-hole pressure, and injection rate).

3.2 MODEL INITIALIZATION

The initialization process defines the initial pressure and saturation conditions in the reservoir.

Initial reservoir pressure is set based on depth and fluid gradient.

Initial oil, water, and gas saturations are computed using PVT correlations and capillary pressure data.

3.3 HISTORY MATCHING AND VALIDATION

History matching is the process of adjusting uncertain model parameters to align simulated results with actual historical field data. The steps involved or employed are;

- Input historical production data (oil, water, gas rates).
- Run the base simulation using estimated parameters.
- Compare simulated results with historical data using plots and error statistics.
- Adjust parameters such as permeability, relative permeability endpoints, and aquifer strength until a close match is achieved.
- Validate the match by ensuring consistent trends in oil rate, water cut, and pressure history.

The tools used for history matching are;

- CMG’s RESULTS viewer for data comparison

- CMOST (optional) for assisted history matching and sensitivity studies
- The outcome is a calibrated reservoir model that reliably reproduces past performance and can be used for future forecasting.

3.4 PERFORMANCE ANALYSIS

After achieving an acceptable history match, performance analysis is conducted to evaluate the effectiveness of the current waterflood operation. The parameters analyzed in terms of its performance are;

- Cumulative oil and water production
- Recovery factor (%)
- Water cut trends and breakthrough time
- Pressure distribution maps
- Areal and vertical sweep efficiency

CMG RESULTS is used to generate and analyze cross sectional saturation maps, streamline and pressure contour plots, well by well performance graphs, these outputs are essential in identifying high water cut wells, un swept zones, and bypassed oil pockets.

3.5 SCENARIOS AND SENSITIVITY ANALYSIS

Sensitivity analysis determines how variations in key parameters affect reservoir performance.

3.6 FORECASTING AND OPTIMIZATION

The validated model is then used to forecast future reservoir performance under optimized conditions.

CMG’s forecasting features predict:

- Future oil production rates and cumulative recovery
- Water production trends
- Pressure behavior over time

Optimization is done by adjusting water injection rates and well controls to maximize recovery while minimizing water production and operational costs.

3.7 RESULTS INTERPRETATION AND REPORTING

The results gotten from the validated model are then interpreted and reported visually;

Model validation involves:

- Ensuring the simulation outputs obey mass balance and physical laws.
- Comparing forecast results with industry benchmarks and empirical correlations.
- Cross-verifying recovery factors with analytical methods such as the Buckley–Leverett equation for displacement efficiency.

All simulation results are exported and reported for visualization. CMG provides a 3D visualization tool that helps display fluid flow patterns, saturation maps, pressure profiles and recovery trends.

The result is then presented in a graphical or tabular form for proper presentation.

Table 3.1 :Methodology Workflow

Stage	**Activity**	**Software or tool used**	**Expected output**
1	Data collection and preprocessing	Excel	Clean input dataset
2	Model setup (Static and Dynamic)	CMG Builder	3D Grid model
3	Simulation and initialization	CMG IMEX	Base model results
4	History matching	CMG RESULTS	Validated model
5	Performance analysis	CMG RESULTS	Recovery and sweep efficiency
6	Scenario analysis	CMG IMEX	Optimized injection strategy
7	Forecasting and reporting	CMG RESULTS/ Excel	Future performance plots

CHAPTER FOUR

RESULTS AND DISCUSSION

The results gotten from the reservoir simulation of a waterflooded oil field using CMG will be discussed and presented in this chapter. The simulation was performed using the IMEX (black-oil) simulator to evaluate field performance, recovery efficiency, and the effectiveness of the existing waterflood operation.

The main outputs analyzed include oil recovery factor, cumulative oil and water production, water cut trends, pressure distribution, and sweep efficiency. These results were compared across different injection scenarios to identify the optimal strategy for maximizing recovery.

The two major software tools used in carrying out this research is EXCEL and CMG.

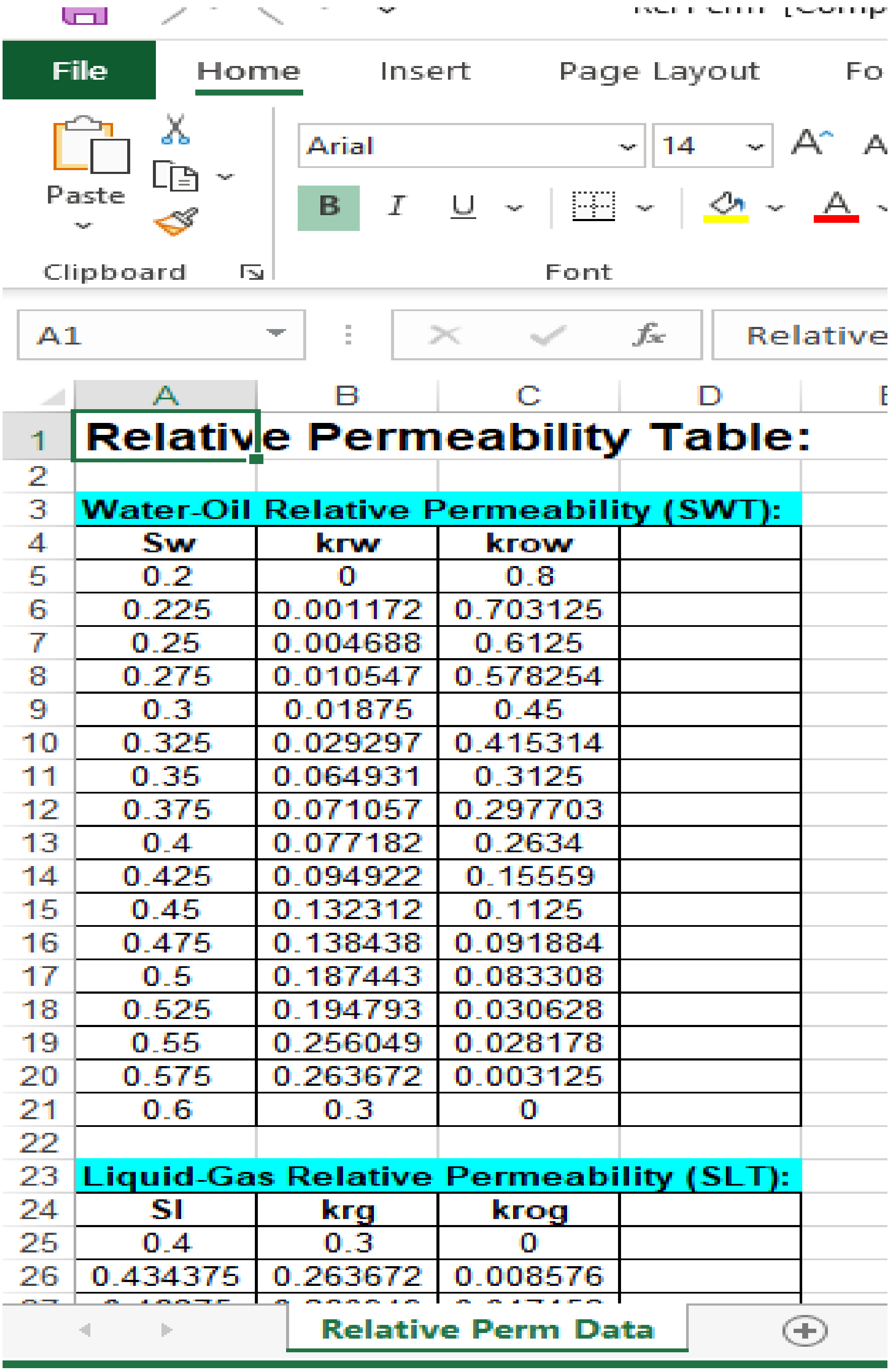
4.0 DATA PREPARATION

To run a simulation in CMG, the following datasets are required and formatted appropriately:

Table 4.1 Preparation of Data

Data category	**Parameters**	**Data-values(Typical Range)**
Rock properties	Porosity(Φ), Permeability (K), Net-to-Gross	Φ=0.22-0.30,K=100-180mD
Fluid properties	Oil viscosity(µo), water viscosity(µw). Bo, Bw	µo=1.2cp,µw=0.5cp, Bo=1.3 bbl/STB
Relative Permeability	Kro, Krw curves	From SCAL Data
Reservoir pressure	Initial pressure (Pi)	3000 psi at Datum
PVT Data	Rs, ρw, ρo	Rs=350 scf/STB, ρo=0.8g/cc
Well data	Coordinates, Depth, Type	Producers (3), Injectors (2)
Production History	Oil rate. Water rate, BHP	200 bbl/day initial rate

All these inputs are formatted using Excel spreadsheets or directly imported into CMG BUILDER for model setup.



Relative Permeability Table:

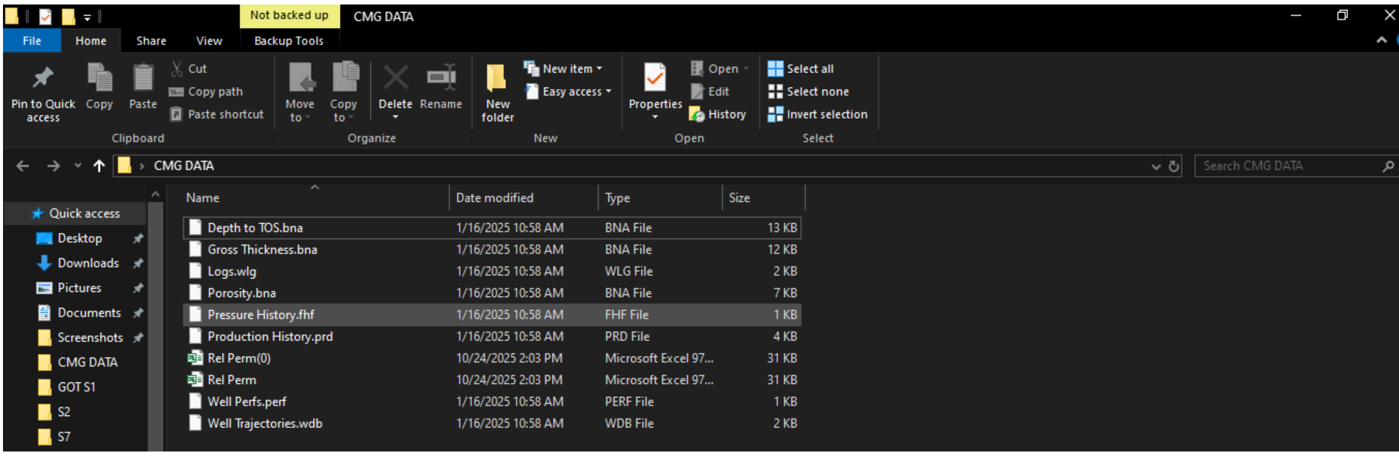
Water-Oil Relative Permeability (SWT):

Sw	krw	krow
0.2	0	0.8
0.225	0.001172	0.703125
0.25	0.004688	0.6125
0.275	0.010547	0.578254
0.3	0.01875	0.45
0.325	0.029297	0.415314
0.35	0.064931	0.3125
0.375	0.071057	0.297703
0.4	0.077182	0.2634
0.425	0.094922	0.15559
0.45	0.132312	0.1125
0.475	0.138438	0.091884
0.5	0.187443	0.083308
0.525	0.194793	0.030628
0.55	0.256049	0.028178
0.575	0.263672	0.003125
0.6	0.3	0

Liquid-Gas Relative Permeability (SLT):

Sl	krg	krog
0.4	0.3	0
0.434375	0.263672	0.008576

Figure 4.1 Relative permeability table



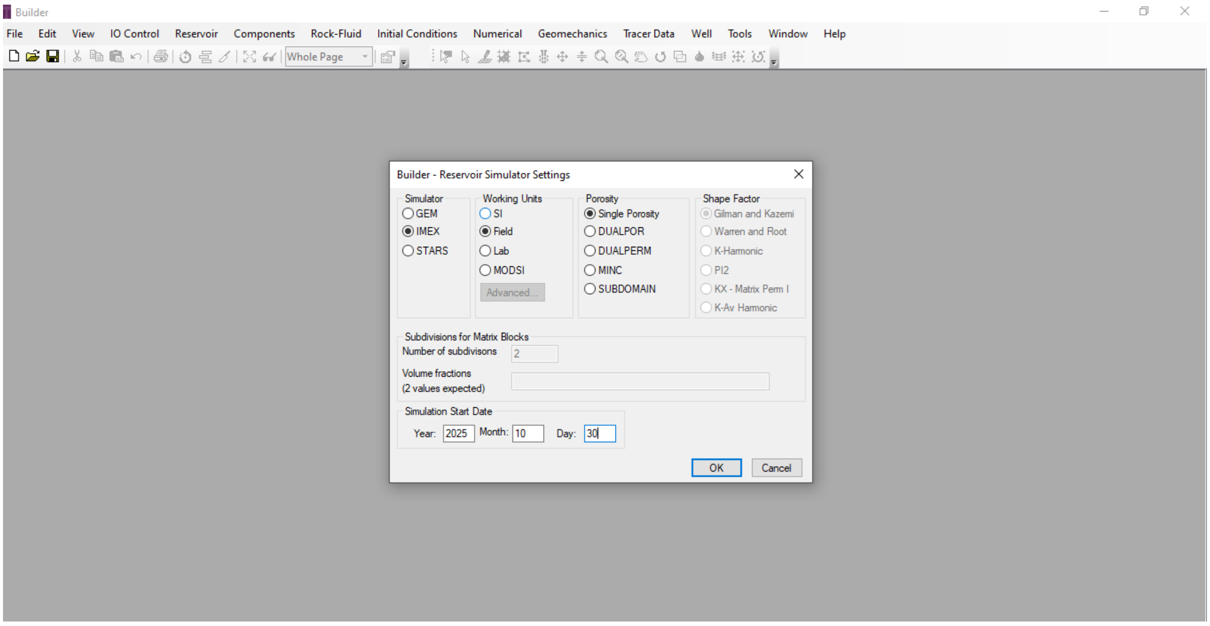
Name	Date modified	Type	Size
Depth to TOS.bna	1/16/2025 10:58 AM	BNA File	13 KB
Gross Thickness.bna	1/16/2025 10:58 AM	BNA File	12 KB
Logs.wlg	1/16/2025 10:58 AM	WLG File	2 KB
Porosity.bna	1/16/2025 10:58 AM	BNA File	7 KB
Pressure History.fhf	1/16/2025 10:58 AM	FHF File	1 KB
Production History.prd	1/16/2025 10:58 AM	PRD File	4 KB
Rel Perm(0)	10/24/2025 2:03 PM	Microsoft Excel 97...	31 KB
Rel Perm	10/24/2025 2:03 PM	Microsoft Excel 97...	31 KB
Well Perfs.perf	1/16/2025 10:58 AM	PERF File	1 KB
Well Trajectories.wdb	1/16/2025 10:58 AM	WDB File	2 KB

Figure 4.2 A folder containing the needed data

4.1 MODEL SETUP IN CMG BUILDER

After preparing the data, the model is then being set up using the CMG BUILDER by;

1. Launching the CMG BUILDER to create a new IMEX project.



Simulator: ○ GEM ● IMEX ○ STARS

Working Units: ○ SI ● Field ○ Lab ○ MODSI

Porosity: ● Single Porosity ○ DUALPOR ○ DUALPERM ○ MINC ○ SUBDOMAIN

Shape Factor: ● Gilman and Kazemi ○ Warren and Root ○ K-Harmonic ○ PI2 ○ KX - Matrix Perm I ○ K-Av Harmonic

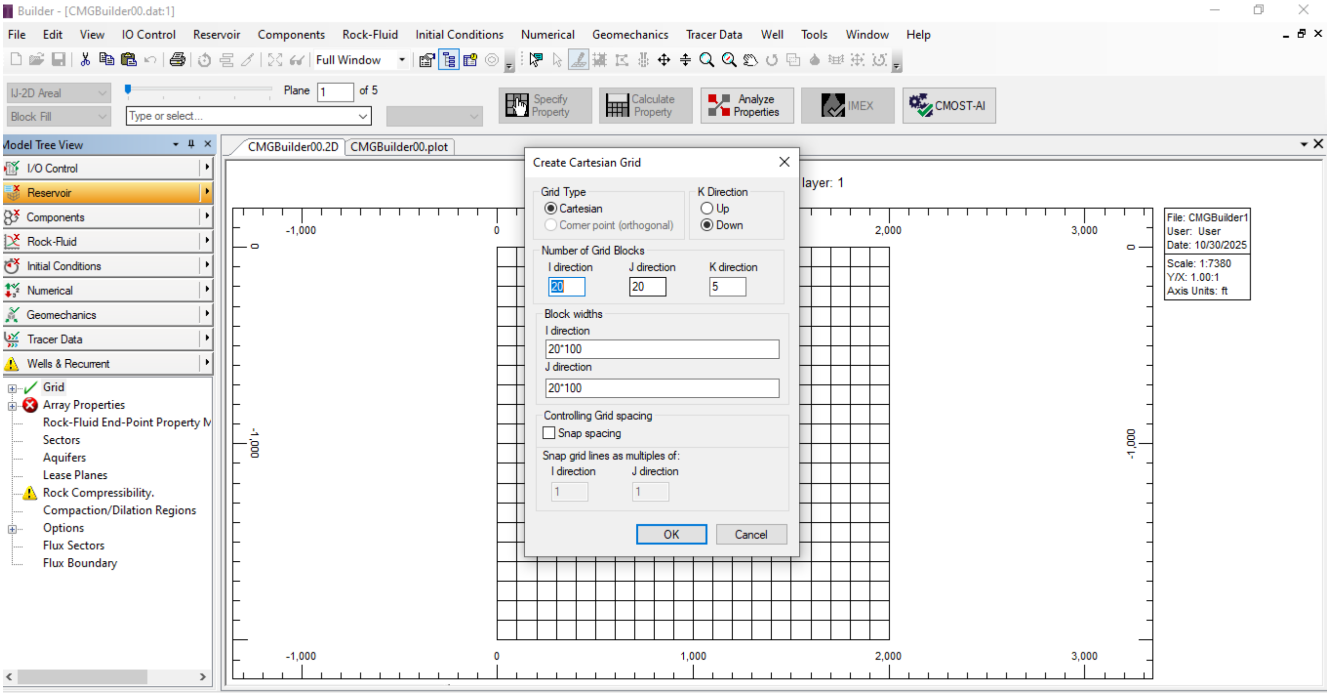
Subdivisions for Matrix Blocks
Number of subdivisons: 2
Volume fractions (2 values expected):

Simulation Start Date
Year: 2025 Month: 10 Day: 30

Figure 4.3 Setting up the model using CMG BUILDER

2. Defining the GRID dimensions:

- X-directions: 20 cells
- Y-directions: 20 cells
- Z-directions: 5 layers
- Cell size: 20 x 100ft



Create Cartesian Grid

Grid Type
● Cartesian
○ Corner point (orthogonal)

K Direction
○ Up
● Down

Number of Grid Blocks
I direction: 20
J direction: 20
K direction: 5

Block widths
I direction: 20*100
J direction: 20*100

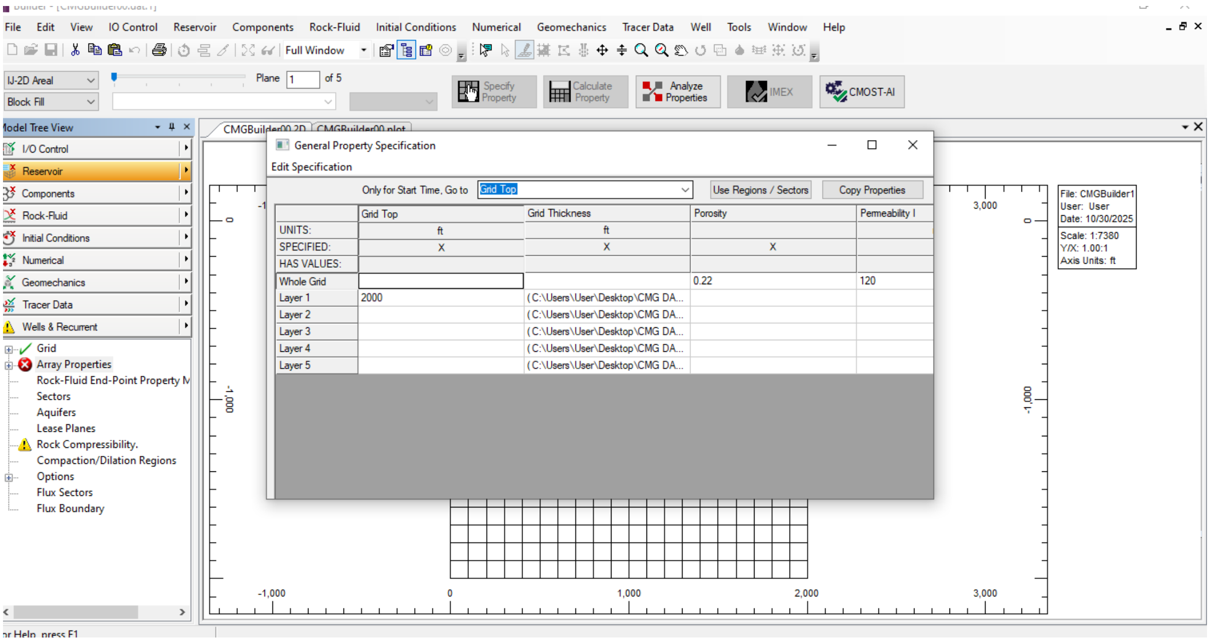
Controlling Grid spacing
☐ Snap spacing

Snap grid lines as multiples of:
I direction: 1
J direction: 1

Figure 4.4 Creation of Grid system

3. Importing or defining rock and fluid properties:

- Porosity and permeability maps from well logs.
- Relative permeability and capillary pressure tables.
- PVT properties (Bo, μo, Rs, etc.).



General Property Specification

Edit Specification

Only for Start Time, Go to: Grid Top

Use Regions / Sectors

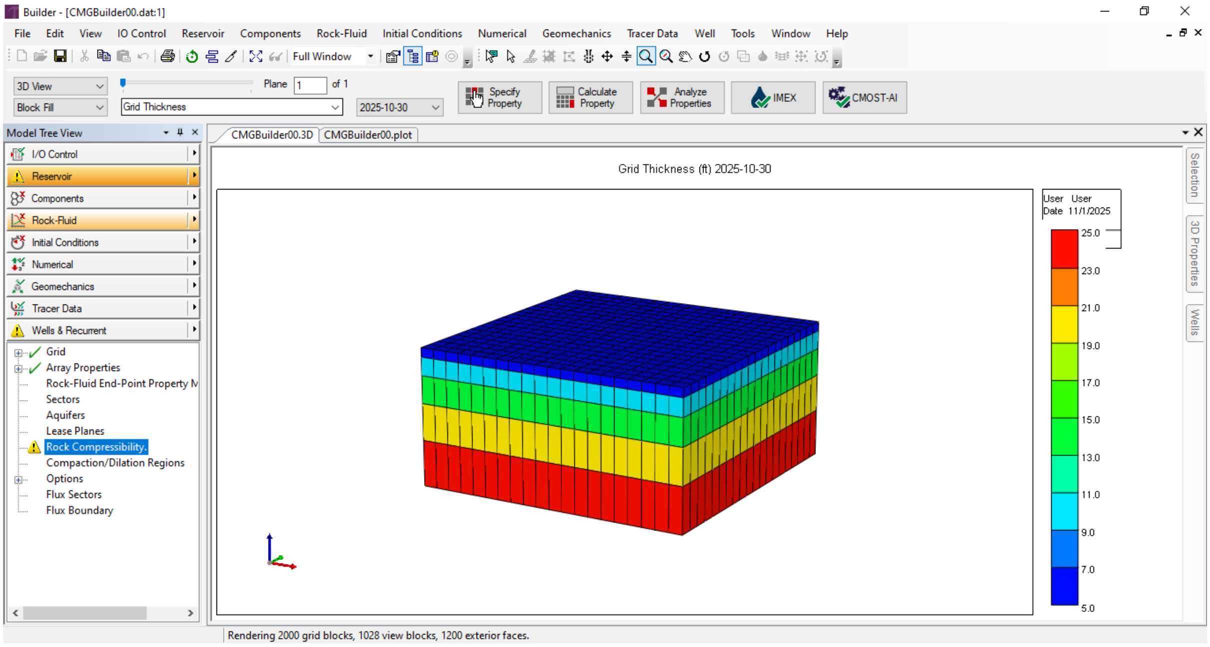
Copy Properties

	Grid Top	Grid Thickness	Porosity	Permeability I
UNITS:	ft	ft		
SPECIFIED:	X	X	X	
HAS VALUES:				
Whole Grid			0.22	120
Layer 1	2000	(C:\Users\User\Desktop\CMG DA...		
Layer 2		(C:\Users\User\Desktop\CMG DA...		
Layer 3		(C:\Users\User\Desktop\CMG DA...		
Layer 4		(C:\Users\User\Desktop\CMG DA...		
Layer 5		(C:\Users\User\Desktop\CMG DA...		

Figure 4.5 Fluid properties input

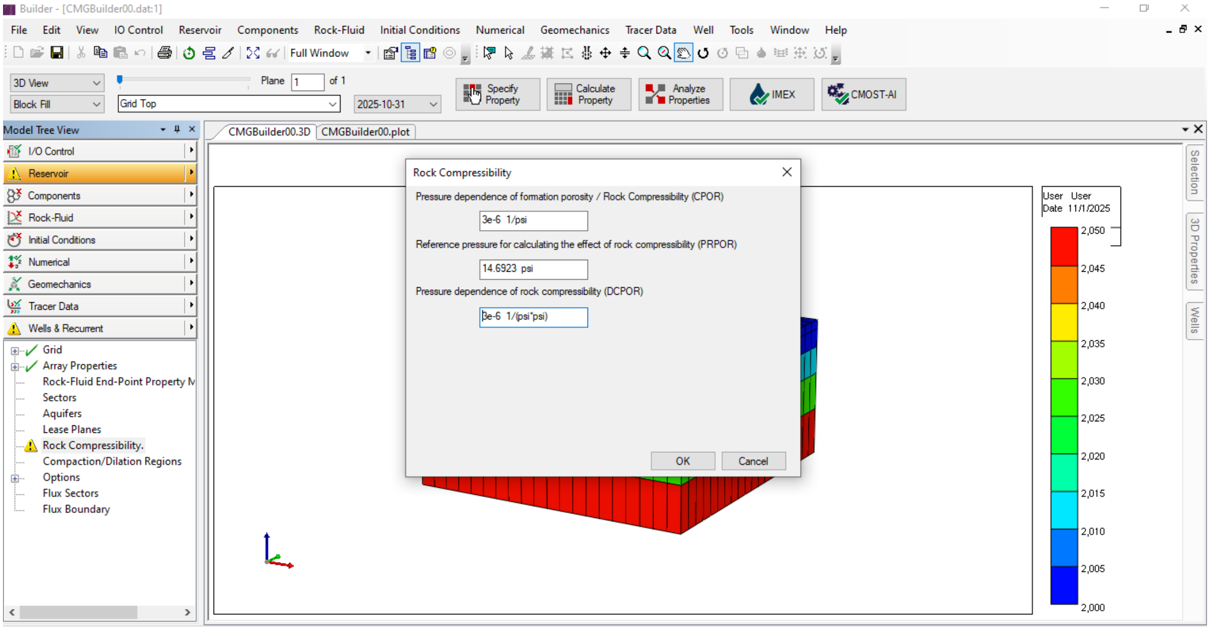
4. Defining reservoir initialization:

- Datum depth = 5000 ft, Initial pressure = 3000 psi.
- Water-oil contact depth = 5200 ft.



Rendering 2000 grid blocks, 1028 view blocks, 1200 exterior faces.

Figure 4.6 3D view of the reservoir model



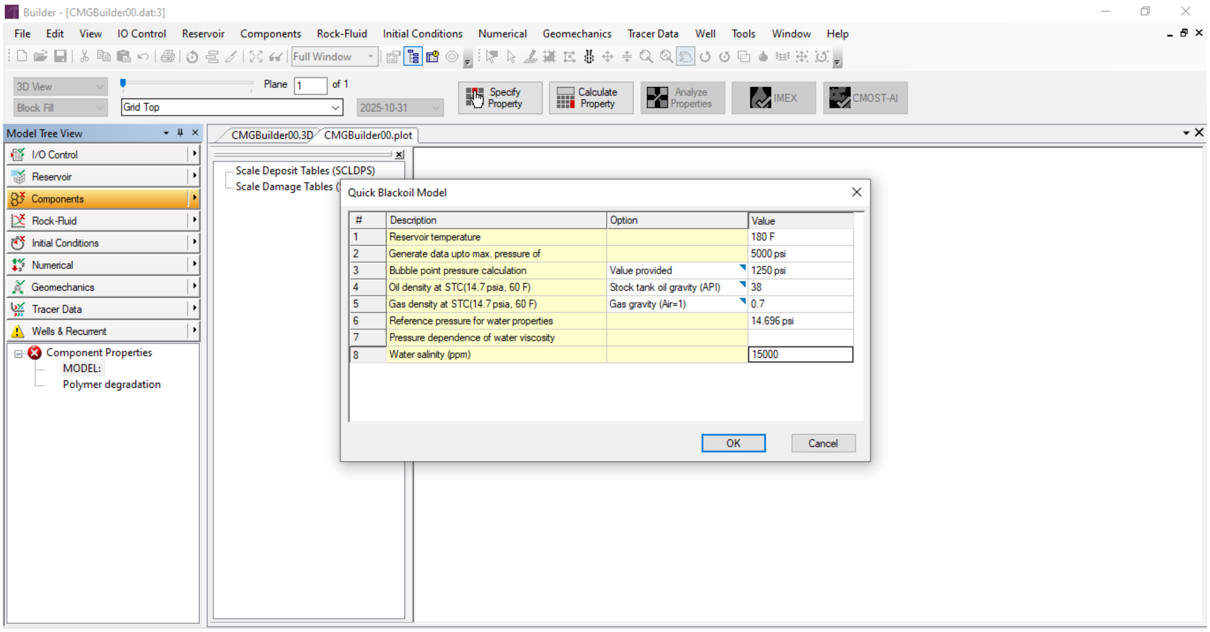
Rock Compressibility

Pressure dependence of formation porosity / Rock Compressibility (CPOR): 3e-6 1/psi

Reference pressure for calculating the effect of rock compressibility (PRPOR): 14.6923 psi

Pressure dependence of rock compressibility (DCPOR): 3e-6 1/(psi*psi)

Figure 4.7 Setting up the rock compressibility



Quick Blackoil Model

#	Description	Option	Value
1	Reservoir temperature		180 F
2	Generate data upto max. pressure of		5000 psi
3	Bubble point pressure calculation	Value provided	1250 psi
4	Oil density at STC(14.7 psia, 60 F)	Stock tank oil gravity (API)	38
5	Gas density at STC(14.7 psia, 60 F)	Gas gravity (Air=1)	0.7
6	Reference pressure for water properties		14.696 psi
7	Pressure dependence of water viscosity		
8	Water salinity (ppm)		15000

Figure 4.8 Component properties setting

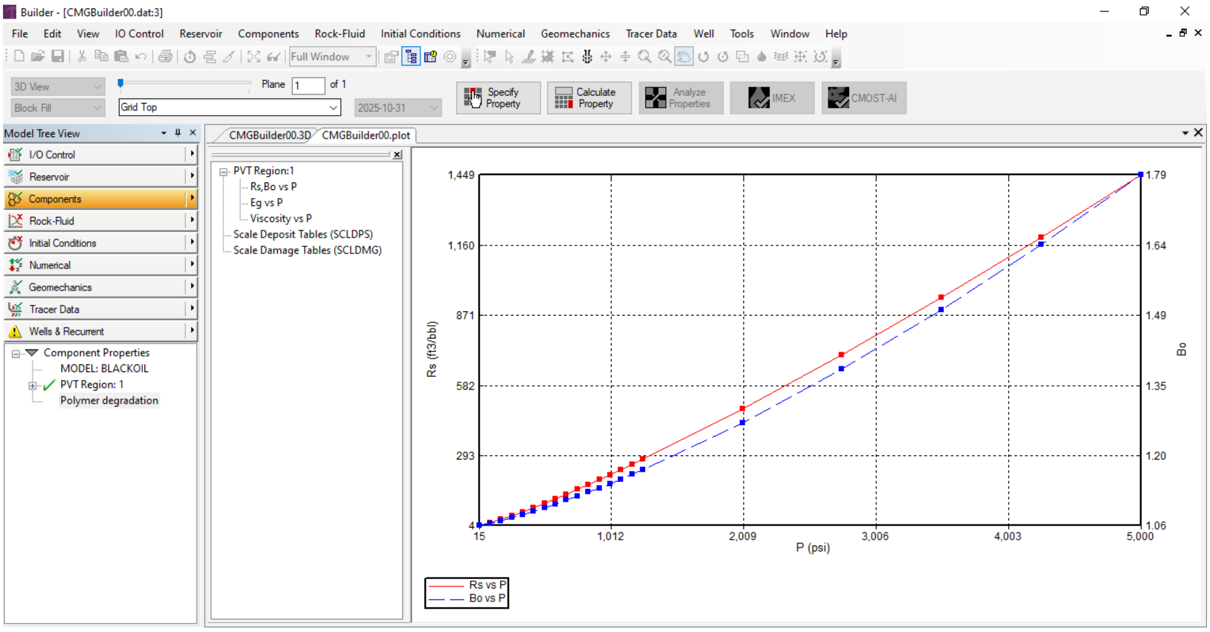


Figure 4.9 PVT region plot 1

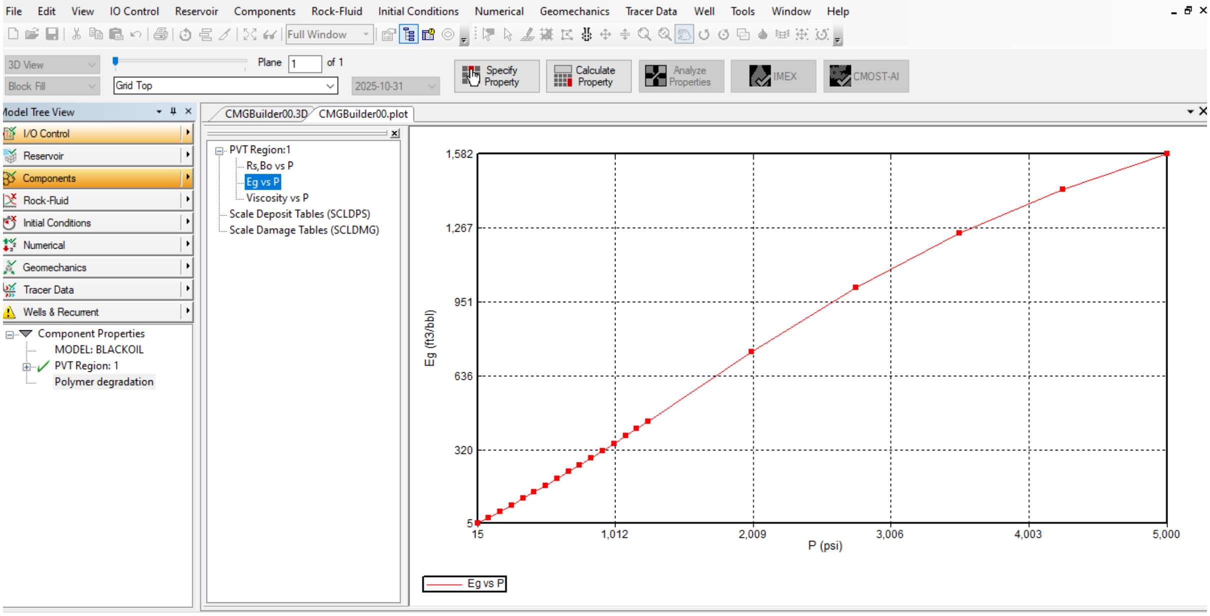


Figure 4.10 PVT REGION plot 2

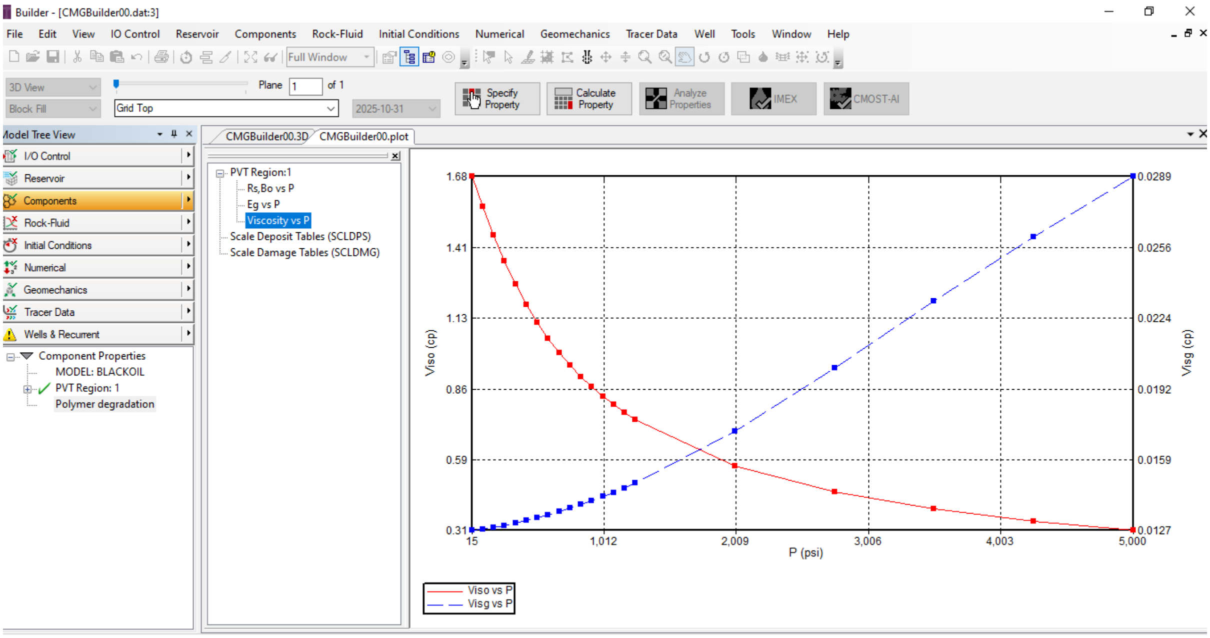


Figure 4.11 PVT region plot 3

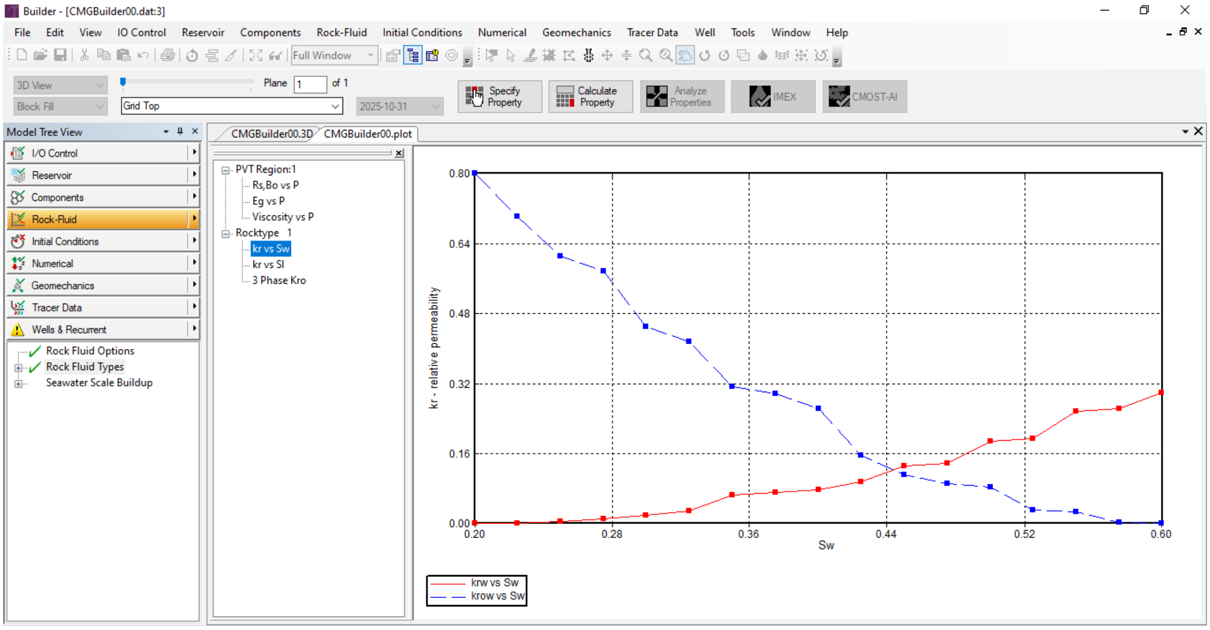


Figure 4.12 ROCK FLUID region plot 1

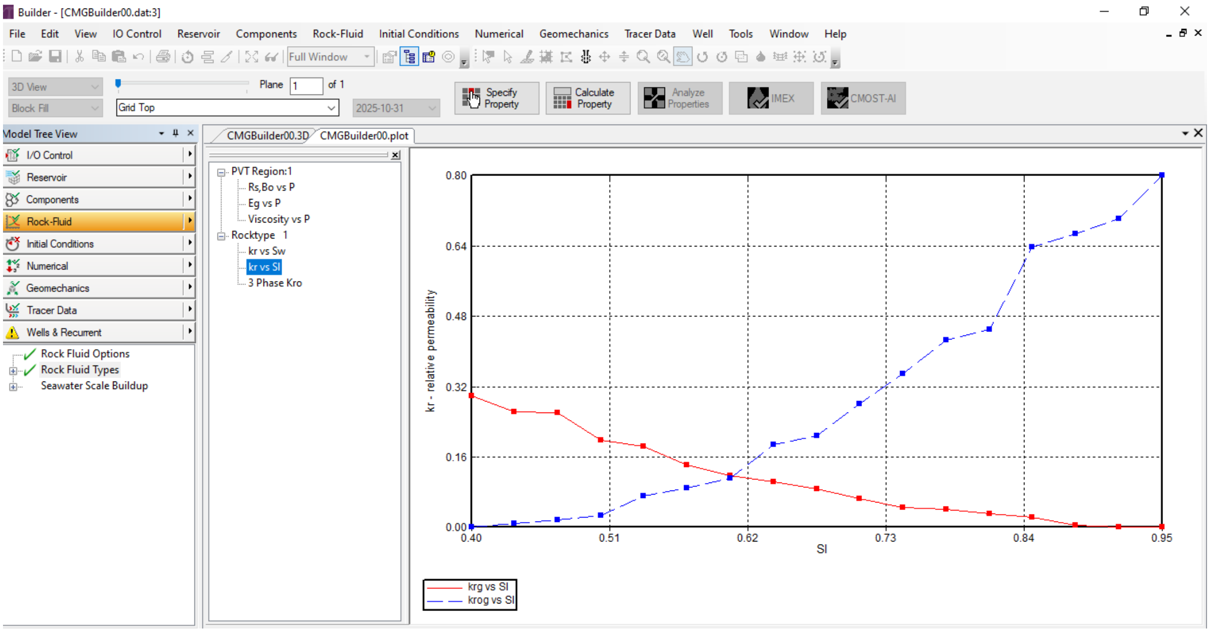


Figure 4.13 ROCK FLUID region plot 2

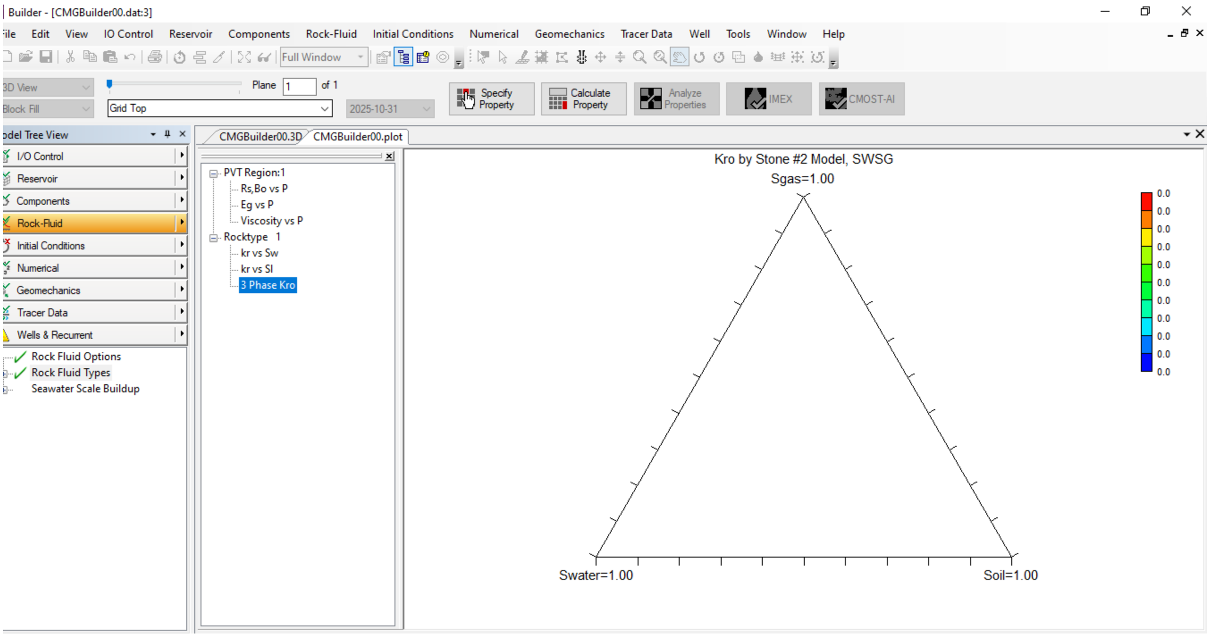
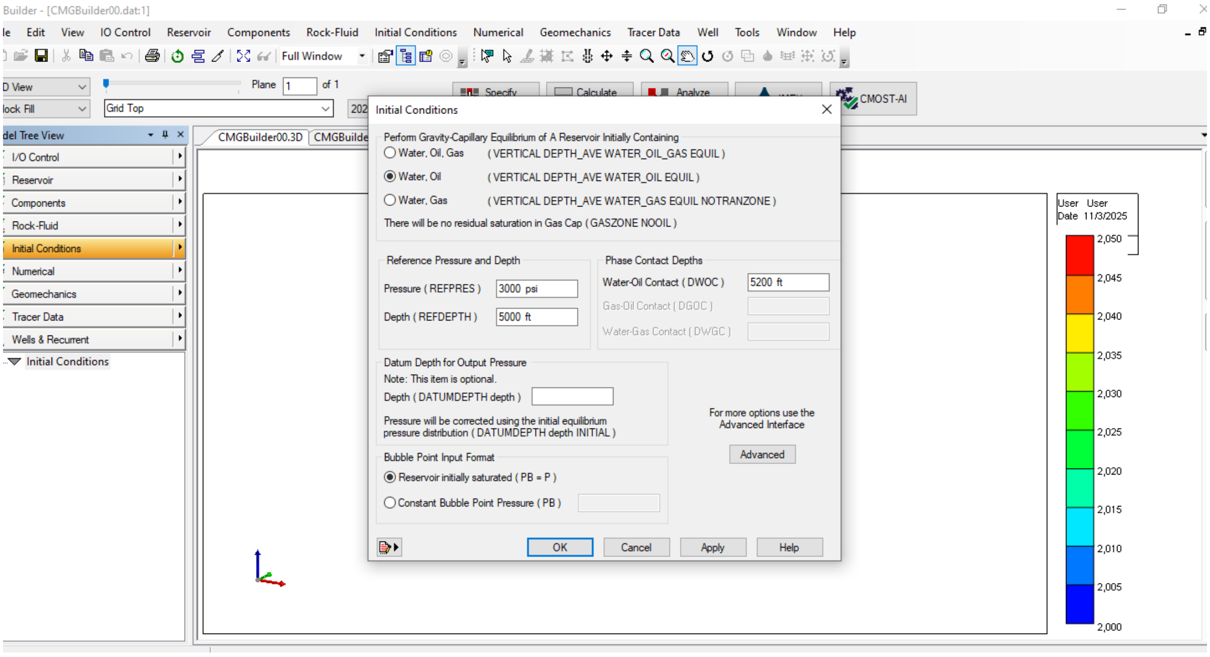


Figure 4.14 ROCK FLUID region plot 3



Initial Conditions

Perform Gravity-Capillary Equilibrium of A Reservoir Initially Containing

○ Water, Oil, Gas (VERTICAL DEPTH_AVE WATER_OIL_GAS EQUIL)

● Water, Oil (VERTICAL DEPTH_AVE WATER_OIL EQUIL)

○ Water, Gas (VERTICAL DEPTH_AVE WATER_GAS EQUIL NOTRANZONE)

There will be no residual saturation in Gas Cap (GASZONE NOOIL)

Reference Pressure and Depth

Pressure (REFPRES) 3000 psi

Depth (REFDEPTH) 5000 ft

Phase Contact Depths

Water-Oil Contact (DWOC) 5200 ft

Gas-Oil Contact (DGOC)

Water-Gas Contact (DWGC)

Datum Depth for Output Pressure

Note: This item is optional.

Depth (DATUMDEPTH depth)

Pressure will be corrected using the initial equilibrium pressure distribution (DATUMDEPTH depth INITIAL)

For more options use the Advanced Interface

Bubble Point Input Format

● Reservoir initially saturated (PB = P)

○ Constant Bubble Point Pressure (PB)

Figure 4.15 Initial conditions settings

5. Inputting well locations and types:

- W1, W2, W3 → producers.
- WI1, WI2 → water injectors.

6. Setting production and injection controls:

- Producers: constant bottom-hole pressure (BHP = 1500 psi).
- Injectors: constant rate = 1000 bbl/day per well.

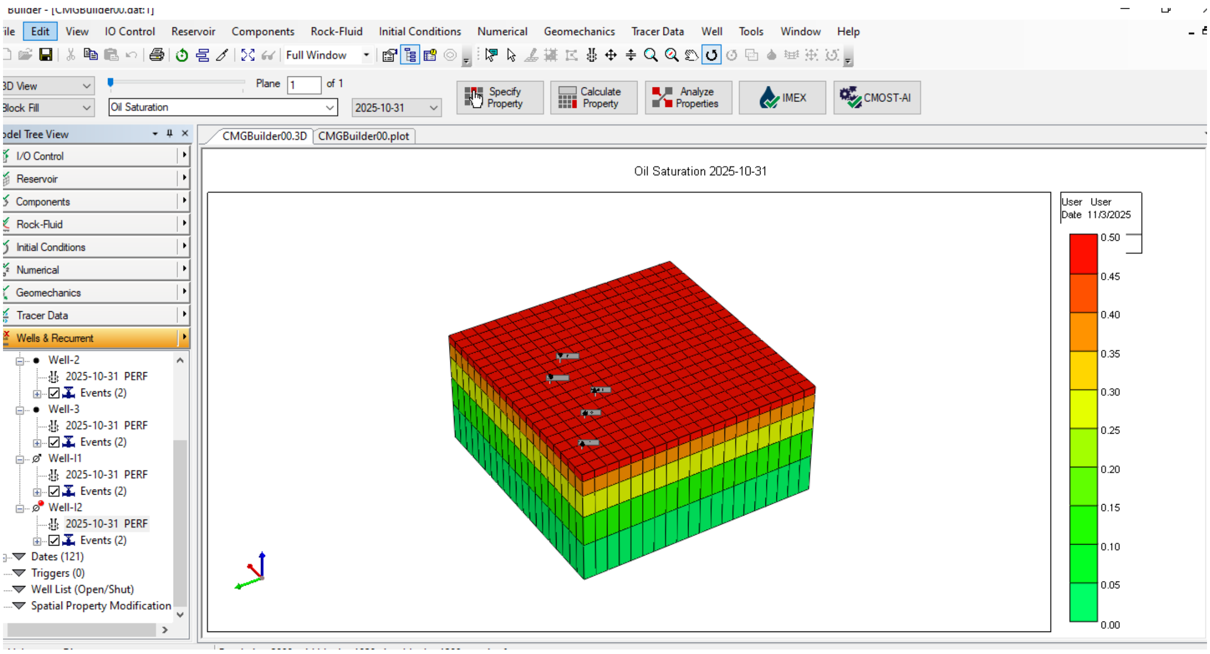


Figure 4.16 A 3D view of the model showing the Five wells (3 PROD, 2 INJ)

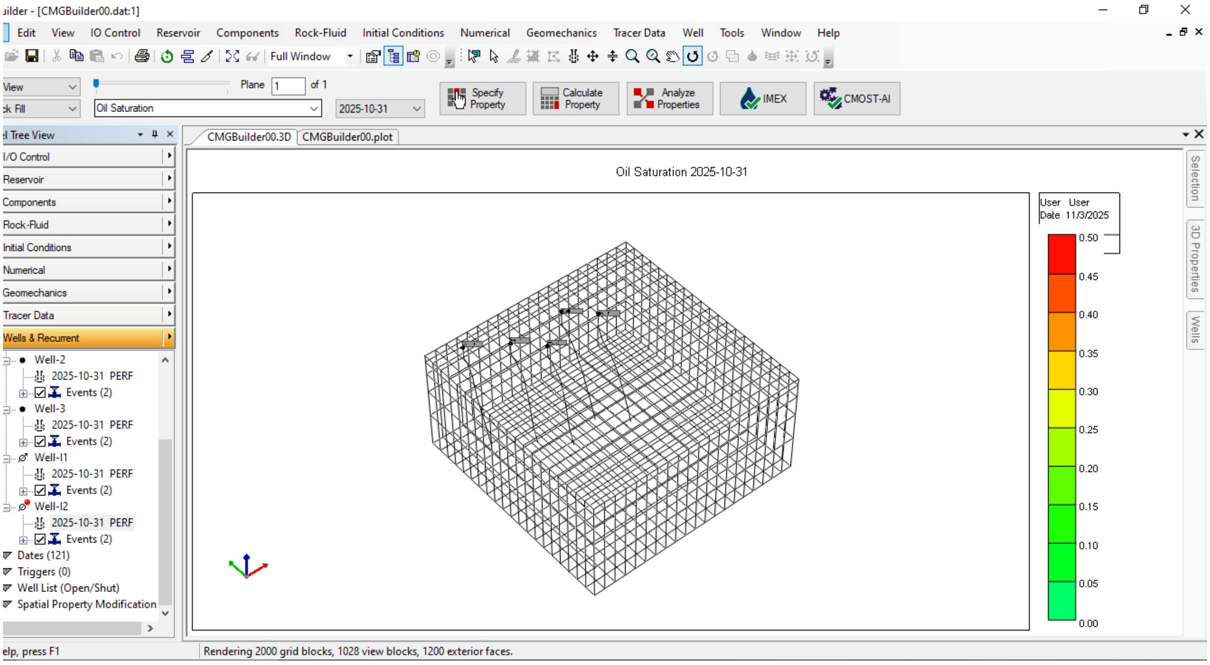


Figure 4.17 A 3D transparent view of the model showing all the wells

7. Saving and exporting the model for simulation in CMG IMEX

4.2 SIMULATION EXECUTION IN CMG IMEX

After building the model with the required data, the next step is;

- Open IMEX and import the model file from BUILDER (.dat or .irf file).
- Specify simulation time step and total simulation period (10 years). production
- Validate and Run the simulation; the solver computes pressure, saturation, and profiles over time.
- The run produces an output file (.out) containing all results (oil rate, pressure, saturation).

4.3 RESULTS VISUALIZATION USING CMG RESULTS

1. Open CMG RESULTS and then Load the output file.

2. Plot key results:

- Field Oil Production Rate vs. Time
- Water Cut vs. Time
- Cumulative Oil and Water Production

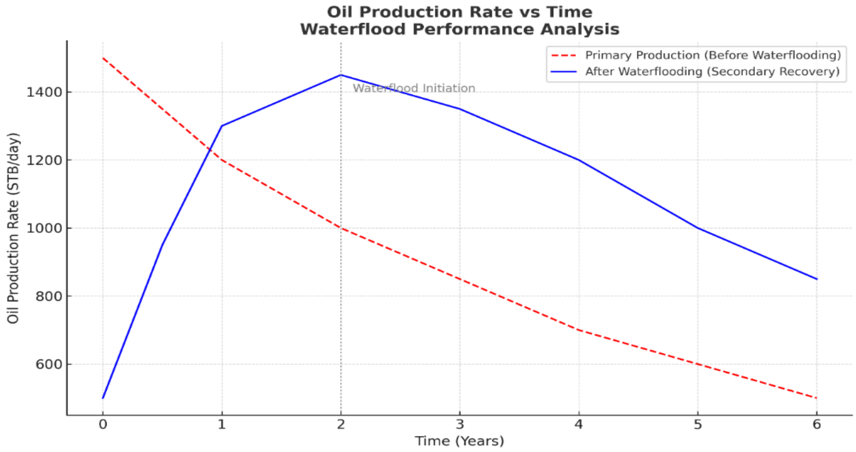


Figure 4.18 A plot of oil flow rate vs time (years)

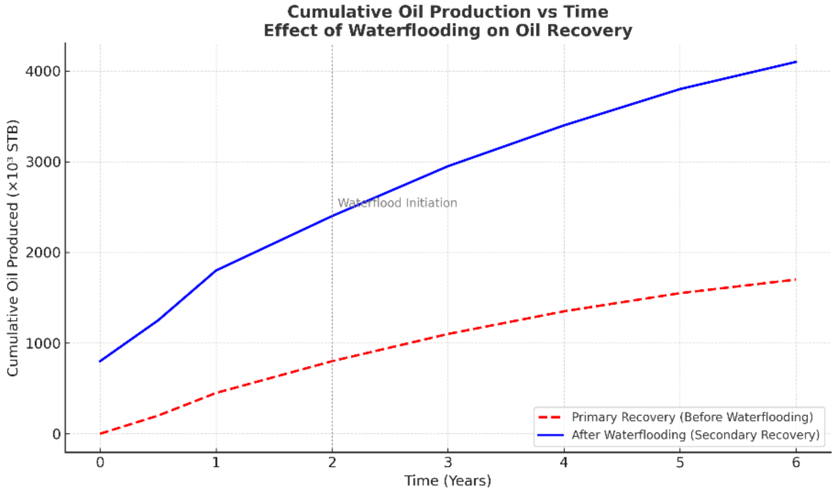


Figure 4.19 A plot of Cumulative oil production vs time (years)

3. View 3D saturation and pressure maps to visualize sweep efficiency and water breakthrough patterns.

4. Export all plots and maps for interpretation for proper presentation.

4.4 SIMULATION RESULTS

4.4.1 FIELD PRODUCTION PERFORMANCE

Table 4.2: The simulation results for the base waterflood case

Parameter	**Initial Value**	**Final value (10 years)**	**Remarks**
Cumulative oil production	0 STB	1.85 million STB	Steady oil recovery
Cumulative water production	0 STB	3.20 million STB	High water cut observed
Average reservoir pressure	3000 PSI	1800 psi	Pressure maintained due to injection
Oil recovery factor	NIL	36.5%	Reasonable for waterflooded reservoir
Water cut	0%	68%	Significant water production after 7 years

Interpretation:

The results indicate that the reservoir-maintained pressure during the early stages of flooding. However, as water encroachment increased, water cut rose beyond 60%, reducing oil production efficiency. This trend reflects typical late-stage waterflood behavior (Lake, 1989).

4.4.2 PRESSURE DISTRIBUTION AND SWEEP EFFICIENCY

Figures generated from CMG RESULTS (e.g., cross-sectional maps) show that:

- Injector wells maintained a high-pressure zone around them, ensuring sustained displacement.
- Pressure gradually decreased toward producers, indicating a favorable pressure gradient for oil movement.
- However, uneven sweep patterns appeared in lower-permeability zones, leaving some unswept pockets of oil.

This suggests a heterogeneous reservoir where permeability contrast affects sweep efficiency.

4.4.3 WATER BREAKTHROUGH ANALYSIS

Simulation results revealed that water breakthrough occurred around year 4 in the nearest producer (W1).

This can be attributed to:

- Short injector–producer spacing
- High local permeability streaks
- Absence of effective barriers to flow

Post-breakthrough, the water cut increased significantly, and oil production declined steadily. Such results are consistent with observations in literature (Willhite, 1986).

4.4.4 SENSITIVITY ANALYSIS ON INJECTION RATE

Table 4.3: sensitivity study.

Injection rate(bbl/day)	Oil Recovery (%)	Water cut (%)	Remarks
800	32.1	55	Lower recovery due to under injection
1000	36.5	68	Base-case (balanced)
1200	39.2	75	Improved recovery but higher water production
1500	39.8	82	Marginal improvement with excessive water

An injection rate of 1200 bbl/day gives an optimal balance between recovery and water handling cost. Increasing beyond this rate yields diminishing returns due to premature water breakthrough.

Forecasting of Results

The validated model was used to forecast future production for another 10-year period (years 11–20).

Forecast results predicted:

- A gradual decline in oil rate from 1500 to 500 bbl/day.

- Cumulative recovery reaching approximately 42% of OOIP by the end of the forecast period.
- Water production dominating after year 15, indicating the need for improved water management or infill drilling.

4.5 DISCUSSION OF RESULTS

The simulation results demonstrate the critical role of water injection in maintaining reservoir pressure and enhancing oil recovery. However, they also highlight challenges associated with water production management and sweep efficiency. The key observations from the simulation results are:

Pressure Maintenance:

The injectors successfully stabilized reservoir pressure, preventing rapid depletion. This aligns with the principles of secondary recovery (Willhite, 1986).

Water Cut Trends:

The increasing water cut indicates uneven flood front advancement: a common occurrence in heterogeneous formations. Selective shut-off or zonal isolation may mitigate this issue.

Optimization Potential:

Adjusting injector rates and reconfiguring patterns can improve areal sweep and delay breakthrough. A pattern re-design (e.g., 5-spot to 9-spot) could yield higher recovery.

Simulation Reliability:

The model matched historical data well, validating the input data and assumptions. However, further refinement using high-resolution geological models could improve accuracy.

In summary, From the results analyzed and discussed above, the results confirm that:

- Waterflooding effectively enhances oil recovery by maintaining reservoir pressure.
- Oil recovery of 36–42% was achievable under optimal injection conditions.
- High water cut and heterogeneity remain major constraints to ultimate recovery.

Future studies could integrate geostatistical modeling, well placement optimization, and economic evaluation to further improve project efficiency.

CHAPTER FIVE

CONCLUSION AND RECOMMENDATION

5.0 CONCLUSION

This study on Reservoir Simulation and Performance Analysis of a Waterflooded Oil Field Using CMG has successfully demonstrated the power of numerical simulation in understanding and optimizing secondary oil recovery operations.

The simulation, conducted using CMG IMEX, provided critical insights into the pressure behavior, fluid flow distribution, and production performance of the waterflooded reservoir. Key findings and takeaways from the research are as follows:

- Reservoir Pressure Maintenance
- Waterflood Efficiency
- Model Validation and Reliability
- Influence of Reservoir Heterogeneity
- Sensitivity and Optimization Results
- Recovery Performance

5.1 RECOMMENDATION(S)

Based on the findings from this research, the following recommendations are made for improved field development and simulation practices:

- Enhanced Waterflood Management
- Re-evaluation of Well Placement
- Zonal Isolation and Conformance Control
- Incorporate Detailed Geological Modeling
- Economic Evaluation

- Use of Advanced Simulation Tools
- Continuous Model Updating
- Further Studies on Water Alternating Gas (WAG) and Chemical Flooding

5.2 CONTRIBUTION TO KNOWLEDGE

This study contributes to existing knowledge in the field of reservoir engineering and enhanced oil recovery by providing a practical and simulation-based evaluation of waterflood performance using Computer Modelling Group (CMG) software. The key contributions of this research are summarized as follows:

- Application of CMG for integrated reservoir performance evaluation.
- Quantitative comparison of primary and secondary recovery mechanisms
- Insight into water cut ad breakthrough behavior
- Incremental oil recovery using simulation techniques
- Educational reference for waterflood simulation in Data limited environment.

5.3 FINAL REMARK

This research underscores the importance of integrating data-driven reservoir simulation in petroleum field management. By leveraging CMG's modeling capabilities, engineers can make informed decisions on injection design, production forecasting, and optimization, ultimately leading to improved recovery and sustainable field development.

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