VALIDATION OF GEOLOGICAL STOIIP ESTIMATES USING MBAL; A CASE STUDY IN RESERVOIR MANAGEMENT.

BY

ESEKHAIGBE QUEEN AIWANOSE

(ENG1905774)

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CERTIFICATION

This is to certify that this work was carried out by **ESEKHAIGBE QUEEN AIWANOSE,** identified with matriculation number **ENG1905774,** ESEKHAIGBE QUEEN AIWANOSE is currently enrolled in the petroleum engineering program offered by the Faculty of Engineering at the University of Benin, located in Edo State, Nigeria.

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DR. OLUWASEUN TAIWO   Date

(PROJECT SUPERVISOR)

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DR. OLUWASEUN TAIWO

(PROJECT COORDINATOR)   Date

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DR. IK OHENHEN

(HEAD OF DEPARTMENT)   Date

------------------------   -------------------------------

PROF. S. O. ISEHUNWA

(EXTERNAL SUPERVISOR)   Date

DEDICATION

I dedicate this work to God Almighty, whose guidance has supported me through my time at the University of Benin. I also extend my heartfelt gratitude to my parents, Deacon, and Deaconess Isaac Esekhaigbe, friends, and coursemates, thank you all.

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ABSTRACT

Accurate estimation of Stock Tank Oil Initially in Place (STOIIP) is essential for effective reservoir management and production planning. This study validates geological STOIIP estimates through the Material Balance (MBAL) method, comparing it with the volumetric approach to evaluate their reliability. The research focuses on Reservoir Q, which spans 1,000 acres, has a thickness of 75 feet, and an estimated oil volume of 105 million stock tank barrels (MMSTB). A comparative analysis of both methods showed no significant differences, with STOIIP estimates of 102 MMSTB and 105 MMSTB, respectively, being nearly identical. This consistency enhances confidence in the accuracy of geological reserve assessments and supports improved reservoir performance optimization and hydrocarbon recovery strategies. The study underscores the importance of MBAL as a validation tool to reduce uncertainties and enhance resource estimation. These findings contribute to the advancement of petroleum engineering methodologies by demonstrating the effectiveness of MBAL in verifying geological STOIIP estimates. The research also highlights the necessity for ongoing reservoir monitoring and data integration to enhance decision-making in field development and maximize hydrocarbon recovery.

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CHAPTER 1

INTRODUCTION

1.1 BACKGROUND OF STUDY

Petroleum is formed through the decomposition of organic matter found in sedimentary layers. The type and quantity of petroleum generated in a basin are influenced by the characteristics and abundance of the organic matter, the level of maturity it reaches during burial, and the environmental conditions in which it accumulates. The amount of organic matter present in the source rock determines the potential volume that can be converted into petroleum, although not all of this volume may migrate to a reservoir for trapping. Petroleum engineers often face difficulties in accurately estimating both the total volume of hydrocarbons available and the portion that can be recovered economically.

A key metric in petroleum engineering and geology is STOIIP, or Stock Tank Original Oil in Place, which represents the total volume of oil present in a reservoir before any production activities.

Several factors influence STOIIP estimates:

1. Reservoir Characteristics: The geological attributes of a reservoir, such as porosity, permeability, and rock type, play a vital role in determining STOIIP. Generally, higher porosity and permeability are associated with larger volumes of oil.

2. Geological Models: Various geological modeling techniques are utilized to estimate STOIIP. These models integrate data from geological surveys, seismic studies, and well logs to simulate the subsurface environment.

3. Fluid Properties: The characteristics of the fluids present, including the properties of oil and gas, impact the estimation of STOIIP. Factors such as viscosity and density are important for understanding the recoverable oil volume.

Accurate measurement of fluid volume in a reservoir is crucial for resource estimation and for selecting appropriate production methods and rates. This information is also essential for effective reservoir planning and management over time. However, reservoir estimates are often accompanied by uncertainties, which depend on the quality of the geological and production data available. Since direct observation of subsurface geology is not possible, indirect methods must be employed to estimate the size and recoverability of resources. These methods include volumetric analysis, the Material Balance Equation (MBE), reservoir simulation, and decline curve analysis.

This paper will focus on the Material Balance Equation and the use of MBAL software for estimating STOIIP. The Material Balance Equation is based on the principle of mass conservation, which asserts that the mass of a closed system remains constant over time. In the context of oil reservoirs, the MBE considers various components, including oil, gas, and water, along with their respective phase behaviors. The main goal is to correlate changes in reservoir pressure, volume, and fluid production with the initial hydrocarbon volume.

The Material Balance approach is a volumetric balance that states that, since the volume of a reservoir (defined by its initial boundaries) is constant, the cumulative observed production, represented as an underground withdrawal, must equal the expansion of the fluids in the reservoir resulting from a finite pressure drop.

1.2 PROBLEM STATEMENT

Accurate estimation of fluid volumes is essential for the exploration and development of reserves; however, uncertainties and complexities often complicate this process. Poor reservoir management can result in suboptimal production techniques and rates, disrupted timelines, and ultimately lead to significant revenue losses, wasted resources, and economic challenges. Therefore, a comprehensive study is necessary to derive values that facilitate comparative analysis, pinpoint factors that hinder precise reserve quantification, and propose solutions to these challenges.

1.3 AIM AND OBJECTIVES

The primary aim of this paper is to validate geological estimates of Stock Tank Oil Initially In Place (STOIIP) using the Material Balance (MBAL) method. The specific objectives include:

1. Analyzing a geological model of a particular reservoir to determine the estimated STOIIP using a defined method, such as the volumetric method.

2. Validating the accuracy of the geological STOIIP estimate through the application of the MBAL method in the selected reservoir.

3. Comparing production performance analysis plots for the specific reservoir.

4. Evaluating the results obtained.

5. Identifying the challenges encountered.

1.4 SIGNIFICANCE OF THE STUDY

This study is significant for several reasons. It ensures reliable estimates of oil reserves, which are crucial for informed planning and investment decisions. The validation process enhances reservoir management by supporting effective strategies for optimizing oil extraction and improving recovery rates. Additionally, it helps mitigate risks by identifying discrepancies in estimates, thereby reducing financial uncertainties. Accurate validation leads to better production forecasting, which aids in resource allocation and operational planning. It promotes cost efficiency by directing efforts toward accurately assessed reservoirs and contributes to sustainability by encouraging efficient resource use while balancing economic and environmental considerations. Overall, this study plays a vital role in advancing reservoir engineering and effective resource management.

1.5 SCOPE OF THIS STUDY

The scope of this study encompasses several key areas. It begins with data collection, focusing on gathering geological, reservoir, and production data for a selected case study. This is followed by geological modeling to estimate STOIIP based on rock properties and reservoir characteristics. The MBAL method will then be employed to analyze production data, allowing for a comparison with geological predictions to assess accuracy and identify discrepancies.

CHAPTER TWO

LITERATURE REVIEW

2.1 INTRODUCTION

Researchers have made substantial advancements in the development of various methods for reserve estimation. Their work has also included the analysis of different formation types to determine the most effective approach for specific situations. This study seeks to review their contributions, with a particular emphasis on the comparisons made between methods and the factors that influence variations in results during standard reserve estimation processes. The widely accepted and scientifically validated theory regarding the origin of hydrocarbons posits that the decomposition of marine organisms and vegetation, influenced by heat, pressure, bacteria, and time, leads to the formation of organic matter within bedrock.

Numerous studies advocate for the use of the volumetric method during the initial delineation and development phases of exploratory fields. This method estimates the volume of hydrocarbons present in the reservoir by relying on geological data to ascertain the reservoir's physical dimensions, the volume of the rock matrix, and the distribution of fluids. Calculating oil in place primarily involves assessing fluid pressure regimes and identifying fluid contacts within the reservoir. The discussion of primary recovery highlights the significance of the isothermal compressibility of reservoir fluids. The principles of volumetric reservoir engineering exemplify the process of estimating recovery factors while incorporating a time scale. Geological estimates of Stock Tank Oil Initially in Place (STOIIP) are essential for evaluating the potential of oil reservoirs. These estimates represent the total volume of oil that can theoretically be recovered from a reservoir under standard conditions, taking into account various geological factors.

This literature review delves into the methodologies, influencing factors, challenges, and applications of STOIIP estimates, drawing on current research and practices.

Cockcroft. (1989) highlighted the significance of accounting for wettability effects in hydrocarbon estimation, especially in oil-wet or water-wet reservoirs, for both static and dynamic methods. Wettability plays a crucial role in determining key parameters such as oil saturation (So) and net pay thickness (h), which are essential for calculating hydrocarbon volumes. These parameters are typically obtained from log and core analyses, making them critical for volumetric estimation techniques. The study pointed out that neglecting wettability effects could lead to inaccuracies in reserve calculations, underscoring the necessity for a comprehensive assessment of reservoir characteristics.

Petter. (1992) addressed the difficulties associated with sparse and potentially unreliable data often encountered during the appraisal phase of reservoir evaluation. They proposed a stochastic approach to create probability distributions for reservoir characteristics, utilizing Bayesian statistics to effectively integrate these distributions. This method provided a more systematic alternative to previous analytical techniques, which were deemed overly complex and time-consuming. To tackle these challenges, the Monte Carlo Simulation technique was introduced, enabling the generation of probability plots for corrected petrophysical parameters. This approach facilitated the calculation of hydrocarbons in place and recoverable reserves with varying levels of certainty. Furthermore, the study recommended employing Kriging as a data-enhancement technique to reduce inaccuracies, emphasizing that improving theoretical and practical tools was more beneficial than drilling additional exploratory wells during the early exploration phase.

Holtz (1993) introduced the concept of Reserve Variability Potential (RVP), focusing on cumulative errors in reserve analysis and the impact of advancements in production technology. Conducted on several oil reservoirs in Texas, the study utilized Monte Carlo Simulation with 1,000 iterations to establish reserve probability distributions. By analysing volumetric parameters, statistical measures such as mean, standard deviation, skewness, and kurtosis were calculated. The study detailed how uncertainty ranges for original oil-in-place (OOIP) were determined, including the 10th, 50th, and 90th percentiles. These distributions were applied at various stages of reservoir development to calculate average OOIP per acre, illustrating how reserve variability evolves throughout the reservoir's lifecycle and providing critical insights into the uncertainties inherent in reserve analysis.

Elliott (1995) investigated several key aspects of reserve determination, including its importance in financial decision-making, field development through new well planning, and strategic reservoir lifecycle management. The study presented a reserve estimation methodology that employed linear regression on production decline curves. By utilizing a best-fit technique, Elliott estimated reserves with a 50% confidence level, corresponding to the arithmetic mean of the data. This method provided a reliable estimate of reserve volumes, facilitating more accurate planning and decision-making.

Hefner. (1996) conducted an in-depth case study on the Bugle field in Adams, analyzing five production phases across five wells. This research involved a team of 12 estimators who initially applied deterministic methods, such as volumetric and decline curve analyses, as a foundation for a probabilistic approach. Key reserve metrics, including P90, P50, and P10 values, were calculated alongside the hyperbolic decline exponent "b" for each well. The study revealed significant variability among evaluators, particularly for P10 values, highlighting disparities in estimation methods. The results indicated that P90 estimates were simplified with an increase in the "b" value, while lower "b" values simplified P10 estimates, emphasizing the sensitivity of reserve calculations to this parameter.

Avi. (1997) proposed a methodology that combined deterministic and probabilistic approaches for reserve and resource estimation. The study underscored the complementary nature of these methods, suggesting that their combined use offers a more comprehensive understanding of recoverable hydrocarbon volumes. The authors began by calculating P1 and P2 values deterministically, followed by Monte Carlo Simulation for random sampling, which produced cumulative probability distributions. This dual approach enabled predictions of potential hydrocarbon volumes with associated certainty levels. Additionally, the mean value derived from these distributions represented the ultimate recovery (UR), providing a reliable metric for future predictions. The authors noted that this methodology could be effectively applied at any stage of the reservoir lifecycle, enhancing its versatility.

Kelly. (1998) analysed the E-M field offshore South Africa using three distinct approaches: deterministic, probabilistic, and parametric methods. In the deterministic approach, the field was divided into polygons, and a simple volumetric equation was employed to calculate Gas Initially in Place (GIIP), accounting for inherent uncertainties in the estimation process. The probabilistic approach utilized Monte Carlo Simulation with triangular distributions, offering a more robust analysis of uncertainty. The parametric method, which focused solely on P50 values, assumed a normal distribution for simplicity. The study highlighted the strengths and limitations of each method, emphasizing the probabilistic approach as the most effective for managing uncertainty.

Palke. (2001) explored the integration of reservoir simulation techniques into reserve estimation processes, particularly for predicting recoverable hydrocarbon volumes and future production rates. The study emphasized that reservoir simulation provides a balanced perspective between "proved" and "probable" reserves, yielding a more realistic estimate of hydrocarbon accumulations. Sensitivity analysis was identified as a crucial step in refining predictions and addressing uncertainties in parameter estimates. The authors concluded that reservoir simulation is a more accurate method for reserve estimation, provided that high-quality geological and engineering data are available.

Truong (2002): This study compared two statistical methods for estimating oil reserves using the same dataset. The first method employed Monte Carlo Simulation alongside Spearman’s rank-order correlation, resulting in reserve estimates ranging from 10.78 to 118.2 MMSTB. The second method, known as the box method, produced estimates between 8.1 and 144.5 MMSTB. The author recommended the box method for reservoirs with geological complexity and heterogeneity, as it provided greater confidence and efficiency in reserve estimation.

Worthington (2005): This research addressed the inherent uncertainties in reserve estimation techniques, particularly during the early phases of reservoir development when data is limited. The study underscored that accurate reserve values can only be established at the end of a reservoir's lifecycle, post-abandonment. Worthington reviewed various reserve estimation methods, including volumetric analysis, reservoir simulation, material balance, and decline-curve analysis. The study differentiated between deterministic and probabilistic approaches, emphasizing the latter's capacity to incorporate uncertainty through probability distribution curves, although it noted limitations in meeting strict proved reserve criteria.

Wadsley (2005): This work introduced the Markov Chain Monte Carlo (MCMC) method, which integrates material balance and volumetric reserve estimation into a cohesive distribution. By merging results from volumetric and material balance methods using a Simple Merge Algorithm, the study achieved a reliable triangular distribution for reserve estimates. This approach created a "zone of consistency" in parameter estimation, thereby enhancing the reliability of reserve predictions.

Ferruh (2007): This comprehensive study analyzed 15 major oil fields in the Norwegian Continental Shelf from 1974 to 2004, examining both pre- and post-production data. The research highlighted fluctuations in ultimate recovery (UR) over time, influenced by changes in reservoir conditions and production technologies. Ferruh advocated for a stochastic approach, emphasizing its ability to generate expectation curves for reserve probabilities. Additionally, the study recommended incorporating the probability of economic success (Pes) into reserve probability density functions to enhance accuracy in economic assessments.

2.2 Material Balance Theory

The concept of material balance for reservoir estimation was first introduced by Schillthuis in 1936. Material balance is a volumetric approach that asserts the volume of a reservoir remains constant, meaning the cumulative observed production, represented as underground withdrawal, must equal the fluid expansion in the reservoir due to finite pressure drop. The development of material balance methods established a framework for tracking materials entering and exiting a system. This approach treats the reservoir as a large storage tank, relying on measurable quantities to estimate unmeasurable amounts. These measurable quantities include cumulative production volumes of oil, water, and gas, as well as precise reservoir pressure data and fluid property information obtained from produced fluid samples.

In his journal, Petris Williams J. Engle noted that statistical methods can be employed for general studies and large-scale planning, provided the uncertainties remain within an acceptable range. However, for specific projects beyond the initial exploratory phase, a minimum amount of physical data is essential. The material balance method utilizes computer simulations to describe fluid flow within the reservoir.

Brian E. Ausburu. (1998) pointed out that factors such as tectonic variations, depositional environments, rock type and quality, reservoir fluid characteristics, well drainage areas, and recovery per well significantly influence the selection of the most appropriate reserve estimation method.

Frick, C. M. (1998) suggested that volumetric estimation is generally reliable for sandstone reservoirs and certain non-carbonate reservoirs characterized by massive formations with porous production intervals, which often occur in non-correlative or discontinuous positions within the section. John R. Fenchi (2001) argued that while the volumetric method provides a measure of the reservoir's quantity, it relies on static information that does not change over time, rendering it inadequate for quantifying reserves.

Fair Jr. (1994) presented statistical approaches to various material balance methods, aiming to optimize material balance equation (MBE) analysis through comparison. Research by Eugene. (2004) demonstrated that the material balance method improved the quality of history-matched results obtained during 3D reservoir simulation studies of a Niger-Delta field. This was accomplished by establishing connected hydrocarbon in-place volumes, understanding reservoir compartmentalization, identifying potential hydrocarbon-water contacts, and revealing historical reservoir drive mechanisms and evidence of undetected aquifer support.

Brian E. Ausburu. (1998) emphasized that since the material balance technique utilizes dynamic data to achieve results comparable to the volumetric method, which relies on static data, thorough reservoir characterization should yield consistent fluid volume estimates regardless of the chosen method.

Lisa (2007) also highlighted that combining various estimation techniques produces more reliable results than relying on a single method.

Rafael Osam Simpe (2011) stressed that reservoir estimates should include recovery factor adjustments to account for changes in fluid properties, which necessitates high production rates, significant time intervals, or both. He also noted that inaccuracies in estimates using the material balance method could arise from prevailing drive mechanisms in the reservoir or a combination of mechanisms such as solution gas drive, gas cap expansion, or water pushing.

Justina. (2005) conducted material balance evaluations on a Niger-Delta field and found that geometry significantly influences material balance calculations. Their findings provided a new method for tracking pressure decline causes in the absence of production and confirmed that two different leases could be draining from the same pool.

Turhan. (2007) introduced a novel analytical model aimed at predicting water influx from finite bottom water drive aquifers. This model has been utilized for aquifer representation in both reservoir simulation and material balance analysis. McEwen (1961) explored pressure uncertainties in water influx reservoirs, concluding that the material balance method is unreliable even with minor pressure uncertainties. Wang. (1997) investigated the impact of drive mechanisms on original oil in place (OOIP) estimates, determining that estimating OOIP is more challenging in reservoirs with water influx compared to volumetric reservoirs. They observed similar findings in reservoirs with substantial initial gas caps. Walsh (1999) analyzed the effects of pressure uncertainty on various material balance methods, revealing that the Havlena-Odeh graphical method for reservoirs with initial gas caps is particularly sensitive to pressure uncertainty. Baker. (2003) studied PVT uncertainties and their influence on material balance estimates, discovering that these effects can be significant, especially when pressure decline is minimal or when PVT correlations are applied without adjustments to field data.

2.3 RESERVOIR SIMULATION: This essential technique in petroleum engineering and subsurface geology is employed to forecast the behavior of fluids—oil, gas, and water—within a reservoir. It is a computational method that integrates physics, mathematics, and geology to model fluid flow under various conditions. Reservoir simulation allows engineers and decision-makers to optimize hydrocarbon extraction, predict production, evaluate reservoir management strategies, and make informed decisions regarding field development. Advanced modelling techniques simulate reservoir behaviour across different production scenarios, making this method increasingly favoured for its capacity to accommodate complex geological features (Moeck., 2020).

Components of Reservoir Simulation:

A reservoir model encapsulates the physical characteristics of the reservoir, including porosity, permeability, fluid properties, and geological structures. It incorporates data from seismic surveys, which provide structural insights, well logs that reveal rock and fluid properties, and core samples that offer detailed geological information. This data forms the basis for accurate simulations.

The flow equations that govern reservoir simulations are derived from Darcy's law for porous media. These equations encompass mass conservation to monitor fluid quantities, momentum conservation for fluid movement, and energy conservation to account for thermal effects. Collectively, these equations constitute the foundation of the simulation process.

To facilitate computations, the reservoir is divided into a grid, with each grid cell representing a small section of the reservoir and assigned properties such as porosity, permeability, and fluid saturation. Grids can be Cartesian (with regular-shaped cells), corner-point (with irregular cells for complex geometries), or unstructured (for fractures or unconventional reservoirs).

Numerical methods, including finite-difference, finite-volume, or finite-element techniques, are employed to solve the flow equations, approximating solutions to ensure accuracy and stability. Additionally, boundary conditions define interactions with surrounding formations and surface facilities, such as pressure boundaries and injection/production rates.

Simulation software is crucial for implementing these components. Common tools include Eclipse, widely used for black oil and compositional simulations; CMG (Computer

Modelling Group) for thermal and unconventional reservoir modelling; and Petrel RE, which integrates geological and simulation workflows.

Types of Reservoir Simulations:

Reservoir simulations can be categorized into several types based on their complexity and application. The Black Oil Model assumes three fluid phases—oil, gas, and water—with simplified interactions, making it suitable for reservoirs with minimal compositional variations. In contrast, the Compositional Model tracks individual hydrocarbon components, such as methane, ethane, and heavier fractions, making it ideal for gas-condensate and volatile oil reservoirs.

Thermal simulations model heat transfer within reservoirs, which is vital for enhanced oil recovery (EOR) methods like steam injection or in-situ combustion. Dual-porosity and dual-permeability models are tailored for fractured reservoirs, where the matrix and fractures exhibit distinct properties. Furthermore, unconventional reservoir simulations address the complexities of tight formations like shale, incorporating hydraulic fracturing and adsorption phenomena.

Applications of Reservoir Simulation:

Reservoir simulation has a broad spectrum of applications. It is integral to field development planning, determining optimal well placement and spacing, and assessing the impact of secondary and tertiary recovery methods, such as water flooding or CO_2 injection. Simulations also facilitate production forecasting, enabling predictions of reservoir performance over time and aiding in the planning of facilities, pipelines, and storage.

Enhanced oil recovery (EOR) strategies are evaluated through simulations, allowing for the optimization of techniques like polymer flooding, gas injection, or thermal recovery. Reservoir management benefits from simulations by monitoring fluid flow, minimizing water and gas breakthrough, and adjusting production strategies in real time. Additionally, reservoir simulations are essential for economic evaluations, assisting in the comparison of development scenarios based on net present value (NPV) and recovery factors.

Challenges in Reservoir Simulation

Challenges in Reservoir Simulation

Reservoir simulation encounters numerous challenges, with data uncertainty being a primary concern. Incomplete or inaccurate geological and fluid data can significantly affect simulation outcomes. To mitigate this issue, stochastic methods and sensitivity analyses are frequently utilized. Another challenge is the computational demand; high-resolution models and intricate simulations require extensive computational resources. However, advancements in parallel computing and cloud-based technologies are helping to alleviate this burden.

Modeling complex geological formations, such as heterogeneous reservoirs with faults, fractures, and unconventional structures, presents additional difficulties. The use of unstructured grids and sophisticated algorithms is becoming more common to navigate these complexities. Moreover, integrating real-time production and monitoring data into simulations is crucial for effective dynamic reservoir management, although it can be challenging.

Recent Advances in Reservoir Simulation

In recent years, there have been notable advancements in reservoir simulation. The application of machine learning and artificial intelligence has enhanced predictive analytics, accelerated simulation processes, and facilitated automated history matching and optimization. High-performance computing (HPC), particularly GPU-based simulation, has significantly sped up processing times, allowing for larger and more intricate models.

Integrated reservoir management, which merges geological, geophysical, and production data in real-time, supports adaptive strategies. There have also been significant improvements in modeling unconventional reservoirs, especially in simulating hydraulic fractures and multi-phase flow in tight formations. Additionally, simulations are increasingly being utilized for carbon capture and storage (CCS), assessing the viability of injecting CO_2 into depleted reservoirs for storage and enhanced recovery.

Future of Reservoir Simulation

The future of reservoir simulation looks promising, with emerging technologies such as quantum computing and digital twin concepts set to transform the field. These innovations aim to reduce uncertainties, enhance accuracy, and make simulations more cost-effective. As the energy sector evolves, the integration of renewable energy and carbon storage into reservoir studies is anticipated to broaden the applications of reservoir simulation beyond traditional hydrocarbon production.

Influencing Factors

1. Reservoir Properties: Essential characteristics like porosity, permeability, and fluid properties (such as viscosity and density) play a crucial role in influencing estimates of Stock Tank Oil Initially in Place (STOIIP) (Bourgogne., 1991).

2. Geological Complexity: Heterogeneities, including faults, fractures, and stratigraphic variations, introduce uncertainties that complicate estimations. Research indicates that integrating geological modeling with STOIIP calculations can enhance accuracy (Chen., 2019).

3. Data Quality and Availability: The reliability of STOIIP estimates is heavily reliant on the quality and comprehensiveness of available data, including well logs, core samples, and seismic information (Tucker., 2021).

Challenges

1. Uncertainty and Variability: Variations in reservoir data can lead to significant discrepancies in estimates. It is advisable to employ sensitivity analyses and probabilistic modeling to quantify uncertainty (Zhou., 2022).

2. Dynamic Reservoir Behavior: As reservoirs are produced, changes in pressure and saturation levels can affect STOIIP. Continuous monitoring and updating of estimates are crucial (Dake, 2001).

3. Technological Advancements: The rapid evolution of exploration and production technologies necessitates ongoing updates to methodologies to improve estimation accuracy (Hossain., 2020).

Applications

1. Resource Assessment: STOIIP estimates are critical for making strategic decisions regarding exploration and development investments, influencing assessments of economic viability (Dusseault ., 2015).

2. Field Development Planning: Accurate estimates are essential for designing extraction methods and planning infrastructure, optimizing recovery strategies (Hossain., 2020).

3. Environmental Impact Studies: Understanding STOIIP is vital for evaluating the environmental implications of oil extraction, contributing to sustainable development practices (Benson., 2013).

STOIIP estimates are crucial for effective oil resource management. The integration of advanced modeling techniques, combined with a solid understanding of geological characteristics, is essential for enhancing the accuracy of these estimates. Future research should focus on improving data integration methods and incorporating machine learning techniques to better predict reservoir behavior and minimize uncertainty.

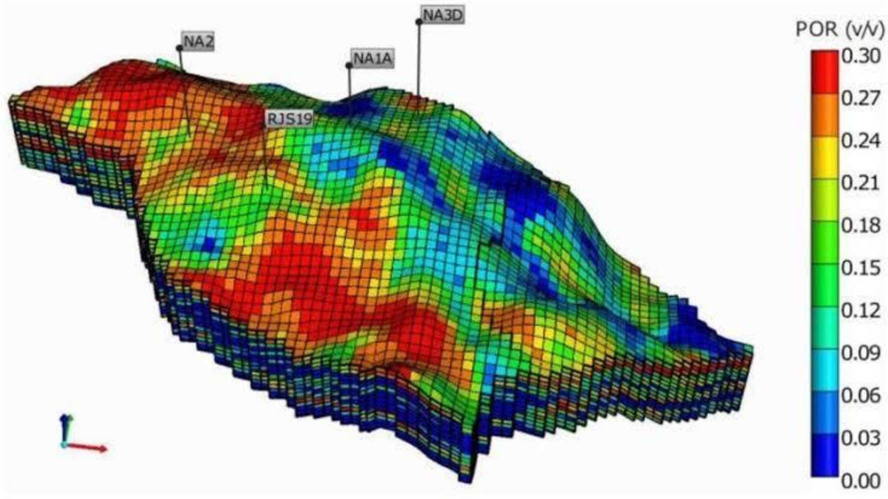


Figure 2. 1 Geological model of a Reservoir

CHAPTER 3

METHODOLOGY

Volumetric and material balance assessments were performed using reservoir data from fields within a known reservoir Q, with the oil in place determined through both approaches. The material balance estimation utilized MBAL, a specialized software for material balance analysis, to estimate the volumes of fluids present in the reservoir.

3.1 VOLUMETRIC METHOD

The volumetric method leverages geological data to ascertain the physical dimensions of the reservoir, including the volume of the rock matrix and fluid contact. This method, often referred to as the "geologist's method," is the most widely used technique for estimating reserves in the early stages of production, prior to the availability of pressure and production data for performance analysis. It involves calculating the reservoir's physical size, estimating the volume of hydrocarbons contained within the reservoir rock, and determining the ultimate recoverable hydrocarbons. The fundamental volumetric equation for estimating oil in place is presented below:

Volumetric estimates of OOIP (Original Oil in Place) are based on a geological model that interprets the hydrocarbon volume within the reservoir and are typically compared with other estimation methods, such as reservoir simulation. This approach relies on geological and petrophysical parameters, each of which carries its own uncertainties. When combined, these uncertainties can result in inconsistent or erratic estimation outcomes.

The ultimate recoverable hydrocarbons are then calculated by multiplying the estimated volumetric OOIP by the appropriate recovery factor:\

Recoverable=OOIP×R.F.

It is essential to recognize that the recovery factor is the most challenging variable to estimate, as it is influenced by natural drive mechanisms, fluid properties, and the interactions between the reservoir and its fluids.

Geological STOIIP (Stock Tank Oil Initially in Place) estimates are vital for evaluating the potential of oil reservoirs. They represent the total volume of oil that can theoretically be recovered from a reservoir under standard conditions, taking into account various geological factors. Understanding geological STOIIP estimates is fundamental for assessing the recoverable resources in oil reservoirs.

1. Estimation Methodologies

Volumetric Method: This approach calculates STOIIP using the formula:

$$OOIP = \frac{7758Ah\emptyset(1-Swi)}{Boi}$$

Where

- Ah = Bulk (rock) volume (acre-feet or cubic meters)
- Ø= Fluid-filled porosity of the rock (fraction)
- Sw= Water saturation - water-filled portion of this porosity (fraction)
- Boi = Formation volume factor (dimensionless factor for the change in volume between reservoir and standard conditions at surface)

The volumetric method uses geological data to determine the physical size of the reservoir, the volume with the rock matrix and fluid contact. Volumetric Method for Estimating OOIP (Original Oil in Place)

The volumetric method is a widely used and essential technique for estimating the Original Oil in Place (OOIP) in a reservoir. This method provides a static estimate of the total amount of hydrocarbons present in the reservoir before production. It is based on geological, petrophysical, and fluid property data, making it a fundamental step in reservoir characterization and field development planning. By utilizing reservoir geometry, rock properties, and fluid saturation data, the volumetric method offers a clear picture of the hydrocarbon volumes that could potentially be extracted. However, it is important to note that this method does not directly account for production performance or recovery efficiency, focusing instead on the initial hydrocarbon volume in place.

Each component of this formula represents a key parameter in understanding the reservoir. The term A refers to the areal extent of the reservoir, typically measured in acres. Reservoir boundaries are delineated using geological and geophysical tools, such as seismic surveys and structural maps. The parameter h, the net pay thickness, represents the effective thickness of the reservoir rock capable of storing and producing hydrocarbons. Accurate determination of net pay requires well log analysis and sometimes core sample evaluation to identify zones meeting specific porosity and permeability criteria.

Porosity (φ) is another critical input and measures the percentage of void space in the rock available to store fluids. Porosity values can be derived from core analysis and well log interpretation, with typical tools including neutron, density, and sonic logs. Another important parameter, water saturation (Sw), is the fraction of pore space filled with water. It is usually calculated from resistivity logs and core tests, as understanding water saturation is crucial to estimating the hydrocarbon-filled pore space. Finally, the formation volume factor (Bo) accounts for the volumetric difference between oil at reservoir conditions and oil at surface conditions. This parameter is obtained through Pressure-Volume-Temperature (PVT) analysis, reflecting the expansion and phase behavior of hydrocarbons under changing pressure and temperature conditions.

3.1.1 STEPS IN ESTIMATING OOIP USING THE VOLUMETRIC METHOD

The volumetric method follows a systematic workflow, beginning with the collection of reservoir data. Geological and geophysical studies provide information about reservoir boundaries and structure, while well log and core analyses offer insights into petro physical properties like porosity, permeability, and saturation. Seismic data and structural maps are used to define the areal extent of the reservoir, while isopach maps help estimate the net pay thickness.

Once the necessary data is collected, the next step involves calculating each parameter in the OOIP formula. Porosity and water saturation are obtained from log interpretation and laboratory tests, while net pay thickness is determined through well data and mapping techniques. PVT analysis provides values for the formation volume factor. After all the inputs are gathered, they are substituted into the formula to compute the OOIP. This process may be repeated for different reservoir zones to obtain a comprehensive estimate of the total oil in place.

3.1.2 ASSUMPTIONS AND LIMITATIONS OF THE VOLUMETRIC METHOD

While the volumetric method is straightforward, it operates under several assumptions that may not hold true in all reservoirs. One key assumption is that the reservoir properties, such as porosity and saturation, are uniformly distributed or their variations can be accurately mapped. This assumption may not be valid in heterogeneous or complex reservoirs with significant lateral and vertical variations. Furthermore, the volumetric method assumes that the reservoir boundaries are well-defined, an ideal scenario that can be challenging to achieve, especially in reservoirs with uncertain geological structures.

Another limitation lies in the method's static nature. The volumetric approach provides an initial estimate of OOIP without considering dynamic processes such as pressure changes, fluid movement, or recovery mechanisms during production. Additionally, the accuracy of OOIP estimates is highly sensitive to input data quality. Errors in determining porosity, saturation, or net pay thickness can significantly impact the final calculation, leading to over- or underestimation of oil volumes.

3.1.3 ADVANTAGES OF THE VOLUMETRIC METHOD

Despite its limitations, the volumetric method offers several advantages, particularly in the early stages of field exploration and appraisal. It is a quick and efficient way to estimate OOIP when production data is unavailable, making it a valuable tool for newly discovered reservoirs. Its reliance on measurable geological and petro physical properties allows for straightforward calculations, making it accessible to engineers and geologists with adequate data.

Additionally, the volumetric method provides a baseline estimate of oil volumes that can be refined with further data collection and advanced analysis techniques. It is particularly effective when combined with modern technologies, such as 3D seismic data, which enhances the accuracy of reservoir mapping and parameter estimation.

3.1.4 ENHANCING THE VOLUMETRIC METHOD WITH ADVANCED TECHNIQUES

To improve the accuracy of OOIP estimates, the volumetric method can be integrated with advanced tools and methodologies. Geostatistical modeling allows for better characterization of reservoir heterogeneity, capturing variations in properties like porosity and saturation. 3D seismic data and reservoir imaging techniques provide detailed insights into reservoir geometry and structure, reducing uncertainties in areal extent and thickness estimates.

Incorporating reservoir simulation models can also enhance the volumetric method by combining static estimates with dynamic data. This integration enables engineers to evaluate the impact of reservoir behavior over time, providing a more comprehensive understanding of hydrocarbon recovery potential. Furthermore, the use of probabilistic methods, such as Monte Carlo simulations, allows for the quantification of uncertainties, giving a range of possible OOIP values rather than a single deterministic estimate.

The volumetric method remains a cornerstone of reservoir engineering, offering a robust framework for estimating OOIP. Its simplicity, reliance on readily available data, and applicability in the early stages of reservoir development make it indispensable in the petroleum industry. However, to maximize its effectiveness, high-quality data and careful interpretation are essential. While it provides a static estimate of hydrocarbons in place, combining the volumetric method with dynamic models, advanced seismic data, and probabilistic approaches can offer a more holistic view of reservoir potential. This integration ensures that reservoir management strategies are based on the most accurate and comprehensive information available.

3.2 MATERIAL BALANCE METHOD:

Material Balance Method for Estimating OOIP

The Material Balance Method (MBM) is a fundamental technique in reservoir engineering for estimating the original oil in place (OOIP) within a hydrocarbon reservoir. Grounded in the principle of mass conservation, it analyzes how reservoir pressure, production data, and fluid influx interact to determine the volume of hydrocarbons initially present in the subsurface. Unlike purely volumetric or seismic approaches, MBM integrates historical reservoir performance data to provide a more dynamic and comprehensive view of reservoir behavior.

It is particularly valuable for evaluating mature reservoirs or reservoirs with substantial production history, as it relies heavily on accurate measurements of fluid withdrawal, pressure decline, and changes in fluid properties over time.

The MBM is built on the principle that any change in the reservoir's hydrocarbon and fluid content must correspond to changes caused by production, fluid expansion, or external influxes such as aquifer support. The general material balance equation (MBE) is expressed as:

$$F = Eo + mEg + Ew$$

Here, represents the underground withdrawal, which quantifies the fluids removed from the reservoir, while, and account for the volumetric expansions of oil, gas, and water (or water influx), respectively. This equation, when rearranged, allows engineers to calculate the OOIP by analyzing the cumulative effects of these components. By applying the MBE systematically, engineers can evaluate reservoir drive mechanisms, validate production forecasts, and optimize recovery strategies.

3.2.1 STEPS IN ESTIMATING OOIP USING THE MATERIAL BALANCE METHOD

The application of the MBM to estimate OOIP involves several systematic steps. First, it is critical to identify the reservoir's primary drive mechanisms. These mechanisms—whether solution gas drive, water drive, gas cap drive, or a combination thereof—dictate the dominant terms in the material balance equation. For instance, a solution gas drive reservoir primarily depends on the expansion of oil and dissolved gas, while a water drive reservoir is dominated by water influx from an aquifer. Accurate identification ensures that the analysis reflects the reservoir's unique characteristics and leads to reliable OOIP estimates.

The next step involves collecting comprehensive reservoir data. This includes pressure measurements, typically obtained through well testing or bottom-hole surveys, and production data, such as oil, gas, and water production rates. Additionally, PVT (pressure, volume, temperature) properties of the reservoir fluids must be measured to determine parameters like the oil formation volume factor (Bo), gas-oil ratio (Rs), and fluid compressibility. These parameters are critical for modeling fluid behavior under changing reservoir conditions.

Once sufficient data is gathered, the material balance equation is formulated to account for the relevant reservoir forces. In its most basic form, the equation is adapted to the specific drive mechanism. For example, in a gas cap drive reservoir, the term representing free gas expansion () becomes more significant. Conversely, in water drive reservoirs, the water influx term () requires careful modeling, often using analytical aquifer models like the van Everdingen-Hurst or Fetkovich models. The adapted equation is then used to calculate the cumulative fluid withdrawal () and the energy contributions from fluid expansions and influxes.

Finally, engineers typically plot and analyze the data to estimate OOIP. A common approach is to plot against to check for linearity. If the plot yields a straight line, the slope provides an estimate of the OOIP. This graphical method is not only intuitive but also serves as a validation tool for the consistency and reliability of the input data and the chosen reservoir model.

3.2.2 ADVANTAGES OF THE MATERIAL BALANCE METHOD

The MBM offers several advantages that make it a valuable tool for reservoir engineers. First, it provides a comprehensive evaluation of reservoir performance by integrating production, pressure, and fluid property data. Unlike static volumetric methods, MBM accounts for dynamic reservoir behavior, offering insights into reservoir drive mechanisms and energy sources. This makes it particularly useful for optimizing recovery strategies and evaluating the effectiveness of secondary recovery methods, such as water flooding or gas injection.

Another advantage of the MBM is its versatility. It can be applied to reservoirs with various drive mechanisms, including solution gas drive, water drive, gas cap drive, and combinations of these. Additionally, it is a non-intrusive method that does not require new field operations or seismic surveys, relying instead on historical production and pressure data. This makes it cost-effective and practical for long-term reservoir management.

3.2.3 CHALLENGES AND LIMITATIONS

Despite its benefits, the MBM has certain limitations. One of the most significant challenges is its reliance on high-quality data. Accurate pressure measurements, production rates, and PVT properties are essential for reliable OOIP estimation. Errors in any of these inputs can lead to significant inaccuracies in the results. Moreover, the method assumes homogeneous reservoir conditions, which may not hold true in highly heterogeneous or fractured reservoirs. In such cases, advanced modeling techniques or simulation tools may be required to complement the MBM.

Another limitation is the complexity of aquifer modeling in water drive reservoirs. Accurately quantifying water influx requires detailed knowledge of the aquifer’s size, connectivity, and response to pressure changes. These parameters are often difficult to measure, leading to uncertainties in the results. Additionally, the MBM is less effective in the early stages of reservoir development when limited production and pressure data are available.

The Material Balance Method is a cornerstone of reservoir engineering, providing a systematic and reliable approach to estimating OOIP. By applying the principles of mass conservation and integrating production, pressure, and fluid property data, the MBM offers valuable insights into reservoir dynamics and energy sources. While it has limitations, advancements in data acquisition and modeling techniques have enhanced its accuracy and applicability. As a result, the MBM remains an essential tool for optimizing hydrocarbon recovery and managing reservoirs effectively.

Utilized primarily in cases with production data, this method assesses the relationship between oil production, pressure decline, and reservoir fluid characteristics (Aadnoy ., 2018). Aadnoy emphasize the material balance method as a fundamental tool in reservoir engineering. He explained that it is used to estimate hydrocarbon reserves and evaluate reservoir performance by tracking the flow of fluids in and out of a reservoir. The method relies on the conservation of the mass principle, allowing engineers to analyze changes in pressure and saturation over time.

3.3 THE MATERIAL BALANCE AS AN EQUATION OF A STRAIGHT LINE

An understanding of the general Material Balance Equation (MBE), specifically Equation 4.3.15,

can be gained by considering the physical significance of the following term groups:

- **Np[Bo + (Rp − Rs)Bg]** represents the total volume of oil and gas produced from the reservoir.
- **[We − WpBw]** indicates the net water influx retained in the reservoir.
- **[GinjBginj + WinjBw]**, the pressure maintenance term, represents the cumulative fluid injection into the reservoir.
- **[mBoi(Bg/Bgi − 1)]** represents the net expansion of the gas cap that occurs as Np stock-tank barrels of oil are produced (measured in bbl/STB of original oil-in-place).

There are essentially three unknowns in Equation (4.3.15):

1. The original oil-in-place (N)
2. The cumulative water influx (We)
3. The original size of the gas cap compared to the oil zone (m)

To solve for these unknowns, Havlena and Odeh (1963, 1964) restructured Equation 4.3.15 as follows:

$$Np(Bo + (Rp - Rs)Bg) + WpBw$$
$$= N\big((Bo - Boi) + (Rsi - Rs)Bg\big) + mNBoi\left(\frac{Bg}{Bgi} - 1\right)$$
$$+ N(1 + m)Boi\left(\frac{cwSwi + cf}{1 - Swi}\right)\Delta p + We + WinjBw + GinjBginj$$

Havlena and Odeh further simplified this equation into a more condensed form:

$$F = N(Eo + mEg + Ef,w) + We + WinjBw + GinjBginj$$

For simplicity, if no pressure maintenance through gas or water injection is considered, the equation simplifies to:

$$F = N(Eo + mEg + Ef,w) + We$$

Where the terms **F**, **Eo**, **Eg**, and **Ef,w** are defined as follows:

- **F** represents the underground withdrawal and is given by:

$$F = Np(Bo + (Rp - Rs)Bg) + WpBw$$

In terms of the two-phase formation volume factor **Bt**, the underground withdrawal **F** can be written as:

$$F = Np(Bt + (Rp - Rsi)Bg) + WpBw$$

- **Eo** describes the expansion of oil and its initially dissolved gas and is expressed in terms of the oil formation volume factor as:

$$Eo = (Bo - Boi) + (Rsi - Rs)Bg$$

Or equivalently, in terms of **Bt**:

$$Eo = Bt - Bti$$

- **Eg** represents the expansion of the gas cap gas and is defined by:

$$Eg = Boi\left(\frac{Bg}{Bgi} - 1\right)$$

In terms of the two-phase formation volume factor **Bt**, where **Bti = Boi**, this becomes:

$$Eg = Bti\left(\frac{Bg}{Bgi} - 1\right)$$

- **Ef,w** represents the expansion of initial water and the reduction in the pore volume and is given by:

$$Ef, w = (1 + m)Boi\left(\frac{cwSwi + cf}{1 - Swi}\right)\Delta p$$

Havlena and Odeh examined different reservoir types using Equation 4.4.2 and noted that the equation could be rearranged into the form of a straight line. For example, in a reservoir with no initial gas cap (**m = 0**) or water influx (**We = 0**), and negligible formation and water compressibilities (**cf** and **cw = 0**), Equation 4.4.2 simplifies to:

$$F = NEo$$

This suggests that if **F** is plotted as a function of **Eo**, the resulting plot would form a straight line with a slope of **N** and an intercept of 0.

The straight-line method involves plotting one group of variables against another, with the selection of variables depending on the production mechanism of the reservoir. The key aspect of this method is that the sequence of points and the direction in which they plot are significant, as is the shape of the resulting plot.

The straight-line approach is valuable because if the plotted data deviates from this line, there may be an underlying reason. Such deviations provide crucial insights that help in determining the following unknowns:

- Initial oil-in-place (N)
- Size of the gas cap (m)
- Water influx (We)
- Driving mechanism
- Average reservoir pressure

The straight-line form of the MBE can be applied in various reservoir engineering scenarios. The following cases illustrate its utility:

1. Determination of **N** in volumetric undersaturated reservoirs
2. Determination of **N** in volumetric saturated reservoirs
3. Determination of **N** and **m** in gas cap drive reservoirs
4. Determination of **N** and **We** in water drive reservoirs
5. Determination of **N**, **m**, and **We** in combination drive reservoirs
6. Determination of average reservoir pressure (**p**)

3.3.1 CASE 1: VOLUMETRIC UNDERSATURATED OIL RESERVOIRS

The linear form of the MBE, as shown in Equation 4.4.2, can be written as:

$$F = N(Eo = mEg + Ef,w) + We$$

Assuming no water or gas injection, certain terms in this equation may disappear based on the driving mechanism assumed for the reservoir. For a volumetric and undersaturated reservoir, the following conditions hold:

- **We = 0** (since the reservoir is volumetric)
- **m = 0** (since the reservoir is undersaturated)
- **Rs = Rsi = Rp** (since all produced gas is dissolved in the oil)

Applying these conditions to Equation 4.4.9 gives:

$$F = N(Eo + Ef,w)$$

Or:

$$N = \frac{F}{Eo + Ef,w}$$

Where:

$$F = NpBo + WpBw$$

$$Eo = (Bo - Boi)$$

$$Ef,w = Boi\left(\frac{cwSwi + cf}{1 - Swi}\right)\Delta p$$

Here, **N** is the initial oil-in-place (in STB), **pi** is the initial reservoir pressure, and **pr** is the average reservoir pressureHere's a rephrased version of the provided text:

3.4 THE MBAL SOFTWARE TOOL (M-BAL™ 10.5) USED FOR THE STUDY

The M-BAL™ 10.5 software package, developed by Petroleum Experts, was utilized as a material balance tool for this evaluation. M-BAL™ is a comprehensive software application featuring a variety of tools that assist reservoir engineers in better understanding reservoir behavior. The MBAL software includes several sections:

- **Input Section**: This allows the analyst to enter data describing the reservoir's properties, such as known and estimated reservoir parameters, aquifer types and their properties, pore volume fractions versus depth (optional), relative permeability curves, transmissibility parameters (optional), and the production and injection history on a well-by-well basis or total tank production. The software also includes validation features.
- **History Matching Section**: Here, a graphical method (e.g., p/z, Havlena Odeh) is used to quantify missing reservoir and aquifer properties.
- **Production Prediction Section**: This section simulates reservoir performance based on production and constraint schedules, gas contracts, relative permeabilities, well performance definitions, and well schedules or drilling programs.

While entering production history data is not strictly necessary to run production predictions, it is highly recommended to fine-tune reservoir and aquifer models if any production history data is available. If such data is not available for model calibration, the 'Production History' and 'History Matching' sections can be left blank. Relative permeability curves are used for tanks, transmissibility, and wells during prediction; however, their use in history matching is limited to calculating transmissibility rates.

3.5 METHOD/PROCEDURE

3.5.1 MATERIAL BALANCE WORKFLOW FOR OIL IN PLACE DETERMINATION

The process flow for determining oil in place using MBAL™ is summarized as follows:

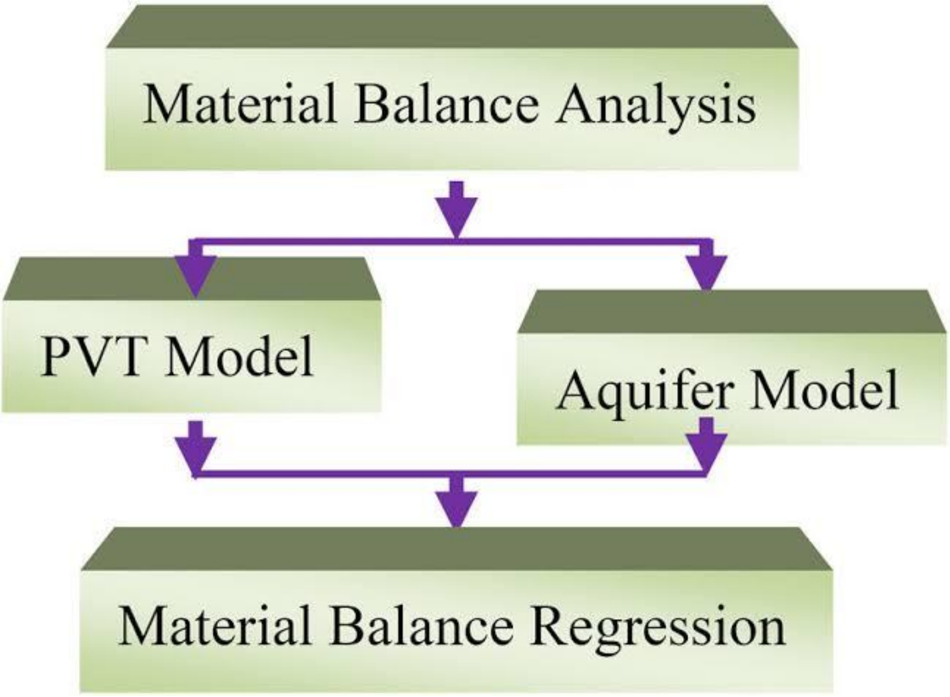


Figure 3. 1 Work flow of MBAL

Material Balance Process:

- Match data tables
- Input tank data and PVT parameters
- Incorporate well production allocation and relative permeabilities
- Use history matching, including energy and analytical plots

- Perform regression to estimate oil in place, aquifer permeability, and other parameters

3.6 DATA REQUIREMENTS AND INPUT

For material balance analysis using the MBAL® software, the following data is required:

1. PVT Data
2. Initial Reservoir Pressure
3. Reservoir Average Pressure History
4. Production History
5. Available Reservoir and Aquifer Parameters

3.7 HISTORY MATCHING

History matching is a trial-and-error approach to comparing observed and calculated data on a zero-dimensional level. This includes graphical methods, analytical methods, simulation tests, and pseudo-relative permeability matching techniques. History matching is used to identify sources of reservoir energy, their magnitude, and to determine parameters like OOIP, OGIP, aquifer type, and strength.

3.7.1 ANALYTICAL METHOD

The analytical method employs regression on all reservoir model parameters to minimize the discrepancy between observed and model production. It is particularly useful for adjusting parameters like formation compressibility that cannot be easily assessed using graphical methods. The regression quality is evaluated using the standard deviation between measured and model values. Analytical plots help compute parameters like oil in place, encroachment angle, and aquifer permeability.

3.7.2 GRAPHICAL METHOD

The first step involves plotting $(F - W_e)/E_t$ versus F (withdrawal), known as Campbell's plot, initially assuming no aquifer is present. A horizontal straight line in this plot suggests that fluid expansion is the only energy source, while any deviation (turn-up) indicates another energy source, such as aquifer influx or injector contributions.

3.7.3 ENERGY PLOT

The energy plot illustrates the predominant energy systems present in the reservoir over time, such as water influx, pore volume compressibility, and fluid expansion. It shows the fractional contributions of these energy systems and identifies the most significant energy sources at various dates.

3.8 ASSUMPTIONS

Material balance calculations are particularly vulnerable to assumptions early in the depletion process, especially when fluid movement is limited and pressure changes are small. The following assumptions are made in the Material Balance Evaluation (MBE):

1. **Constant Temperature**: Reservoir pressure-volume changes occur without significant temperature variations.
2. **Pressure Equilibrium**: The entire reservoir is assumed to have uniform pressure, with fluid properties constant throughout. Minor variations near the wellbore are ignored.
3. **Constant Reservoir Volume**: The reservoir volume is considered constant except for rock and water expansion or water influx. It is assumed that the formation is sealed, preventing significant volume changes due to overburden pressure reduction.

CHAPTER 4

RESULT AND ANALYSIS

4.1 VOLUMETRIC METHOD FOR ESTIMATING STOIIP OF RESERVOIR Q

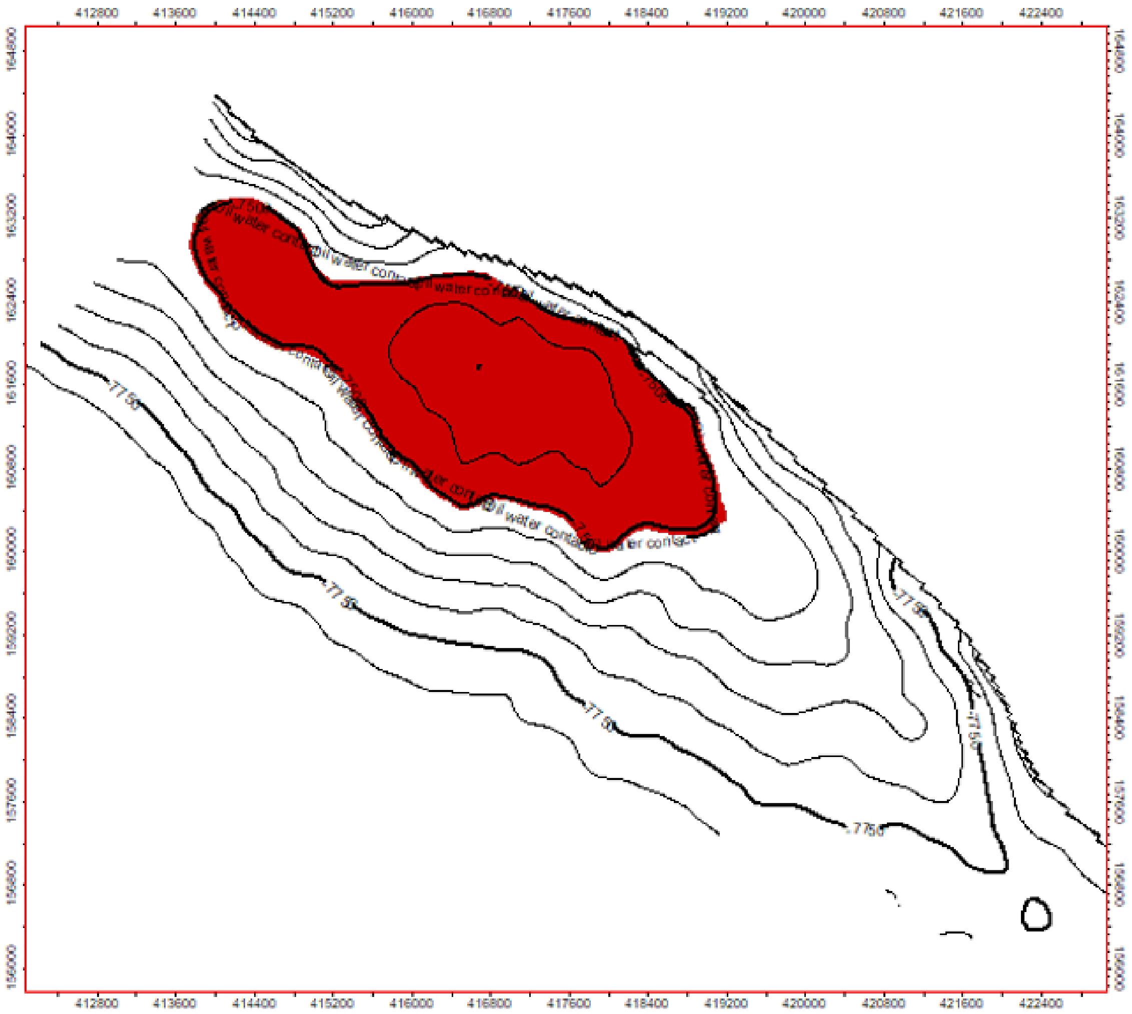


Figure 4. 1 Geological model of Reservoir Q

DATA OBTAINED FROM GEOLOGICAL MODEL

1. Area
2. Thickness

OTHER DATA GIVEN

1. Porosity
2. Water saturation
3. Oil formation volume factor

Therefore,

FIELD	Area(acres)	Thickness(ft)	porosity	Water saturation	Oil formation volume factor
Reservoir Q	1000	75	0.22	0.15	1.063

Table 4. 1 Data for volumetric calculation

$$OOIP = \frac{7758Ah\emptyset(1 - Swi)}{Boi}$$

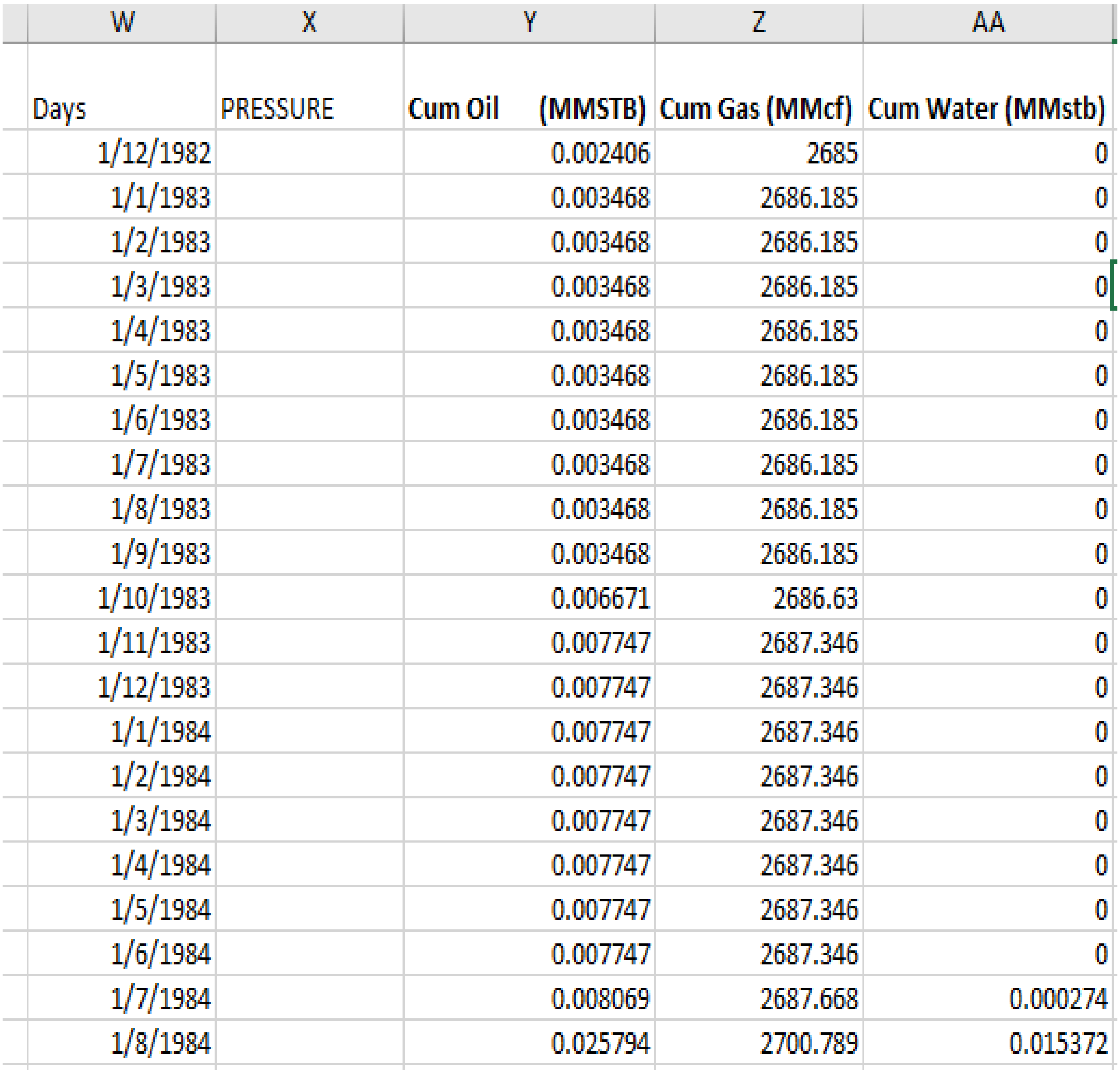
OOIP= 102MMSTB from volumetric calculation.

4.2 MATERIAL BALANCE METHOD FOR ESTIMATING STOIIP IN RESERVOIR Q.

Reservoir Q is an active oil-producing reservoir that is currently yielding oil from six operational well. The oil within this reservoir is under saturated. Based on the provided API gravity, the oil is classified as heavy, indicating a higher density and viscosity compared to lighter crude oils.

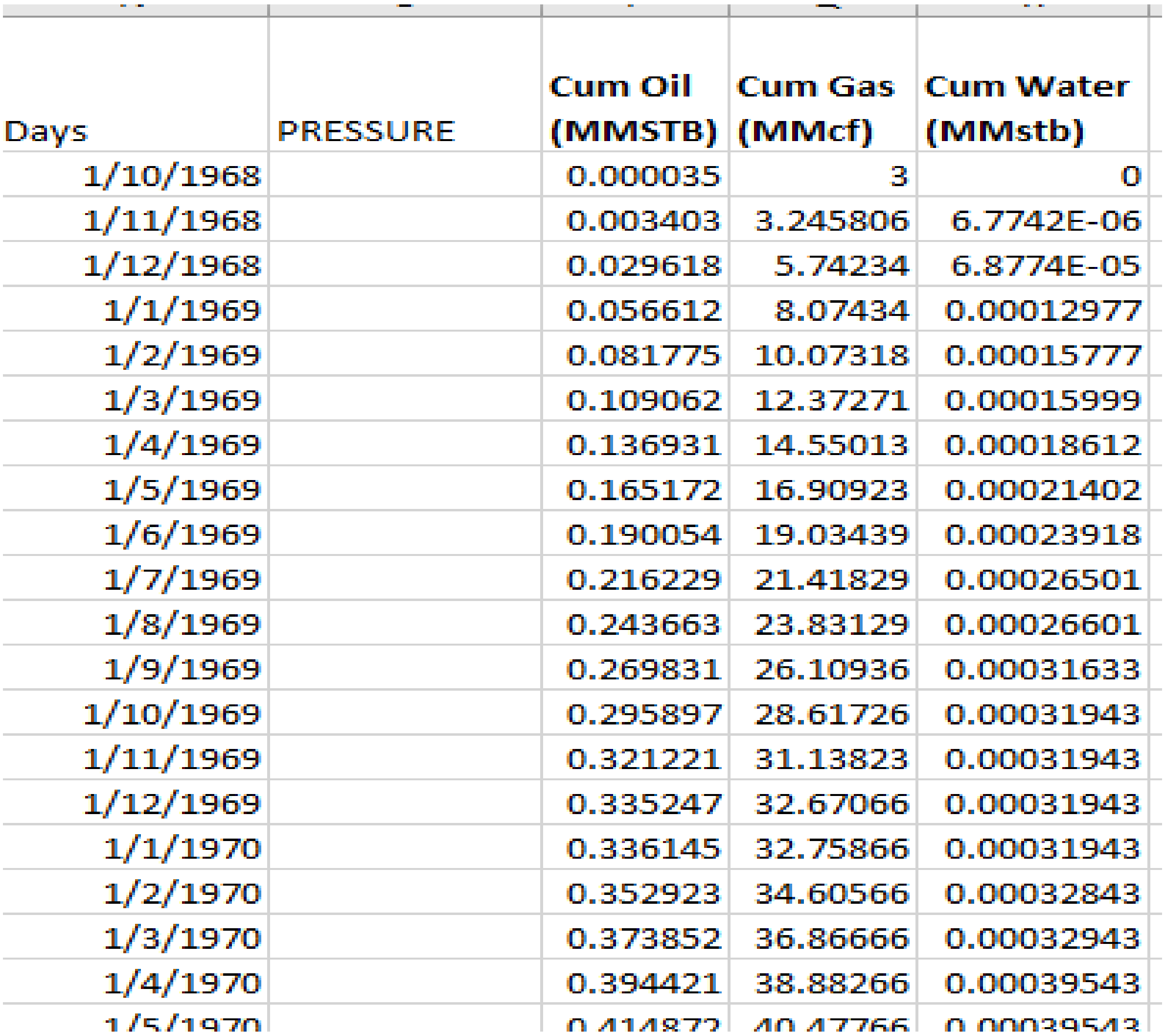
Data from six producing wells, along with provided PVT data, history matching data and reservoir data, were used to estimate the STOIIP and perform the material balance analysis using MBAL software.

Well data



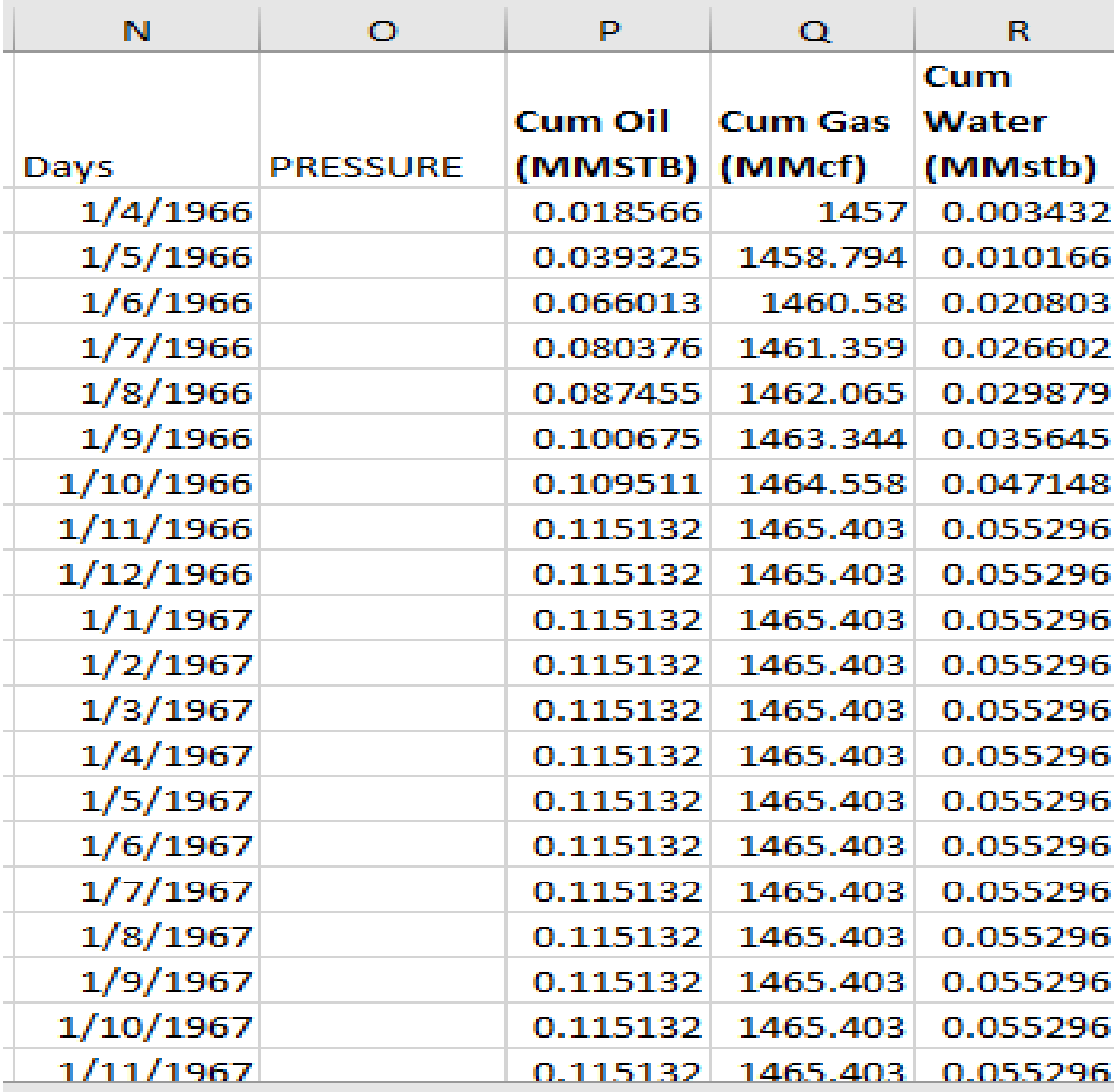
W	X	Y	Z	AA
Days	PRESSURE	Cum Oil (MMSTB)	Cum Gas (MMcf)	Cum Water (MMstb)
1/12/1982		0.002406	2685	0
1/1/1983		0.003468	2686.185	0
1/2/1983		0.003468	2686.185	0
1/3/1983		0.003468	2686.185	0
1/4/1983		0.003468	2686.185	0
1/5/1983		0.003468	2686.185	0
1/6/1983		0.003468	2686.185	0
1/7/1983		0.003468	2686.185	0
1/8/1983		0.003468	2686.185	0
1/9/1983		0.003468	2686.185	0
1/10/1983		0.006671	2686.63	0
1/11/1983		0.007747	2687.346	0
1/12/1983		0.007747	2687.346	0
1/1/1984		0.007747	2687.346	0
1/2/1984		0.007747	2687.346	0
1/3/1984		0.007747	2687.346	0
1/4/1984		0.007747	2687.346	0
1/5/1984		0.007747	2687.346	0
1/6/1984		0.007747	2687.346	0
1/7/1984		0.008069	2687.668	0.000274
1/8/1984		0.025794	2700.789	0.015372

Figure 4. 2 Data for Well 3S for Reservoir Q



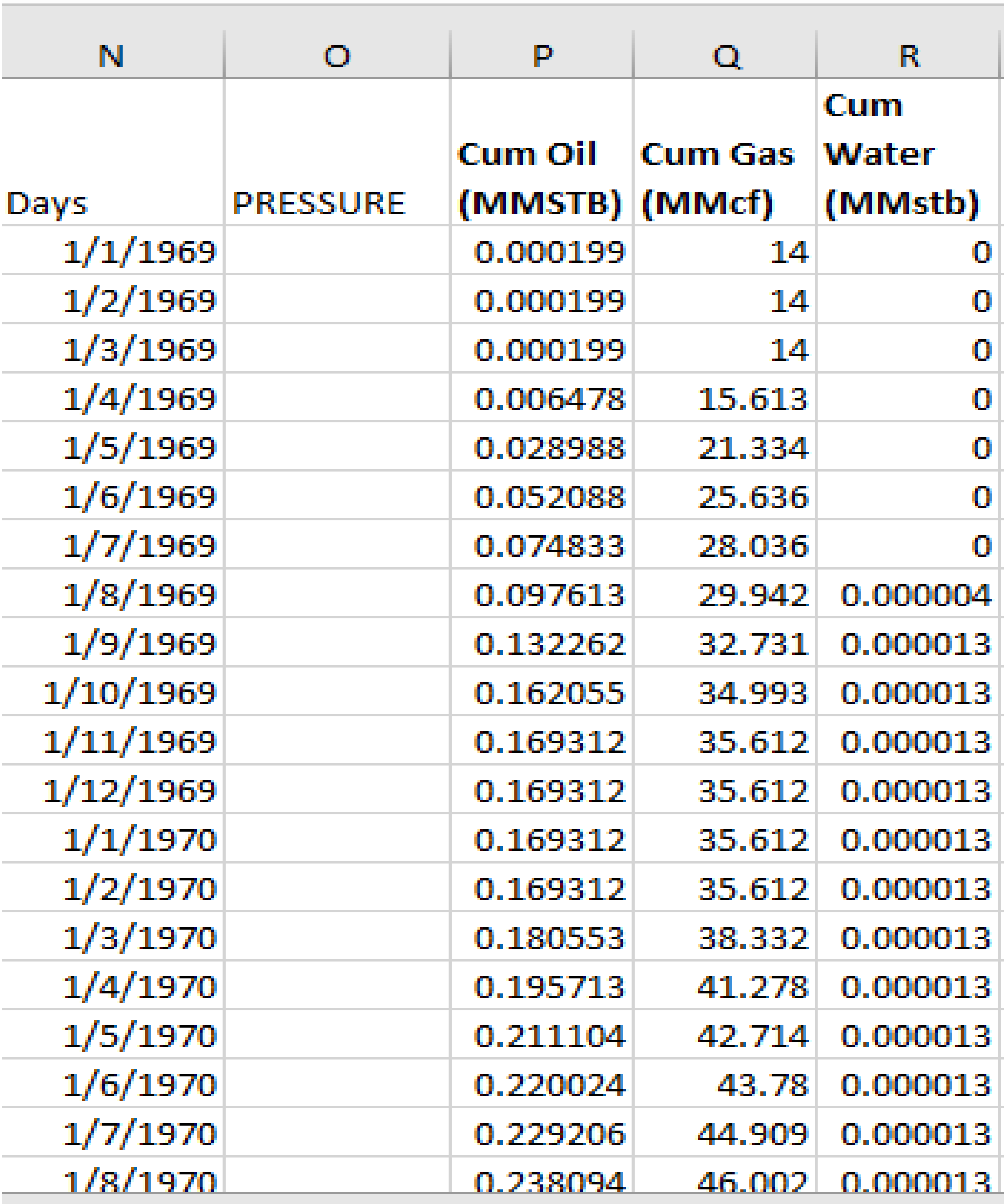
Days	PRESSURE	Cum Oil (MMSTB)	Cum Gas (MMcf)	Cum Water (MMstb)
1/10/1968		0.000035	3	0
1/11/1968		0.003403	3.245806	6.7742E-06
1/12/1968		0.029618	5.74234	6.8774E-05
1/1/1969		0.056612	8.07434	0.00012977
1/2/1969		0.081775	10.07318	0.00015777
1/3/1969		0.109062	12.37271	0.00015999
1/4/1969		0.136931	14.55013	0.00018612
1/5/1969		0.165172	16.90923	0.00021402
1/6/1969		0.190054	19.03439	0.00023918
1/7/1969		0.216229	21.41829	0.00026501
1/8/1969		0.243663	23.83129	0.00026601
1/9/1969		0.269831	26.10936	0.00031633
1/10/1969		0.295897	28.61726	0.00031943
1/11/1969		0.321221	31.13823	0.00031943
1/12/1969		0.335247	32.67066	0.00031943
1/1/1970		0.336145	32.75866	0.00031943
1/2/1970		0.352923	34.60566	0.00032843
1/3/1970		0.373852	36.86666	0.00032943
1/4/1970		0.394421	38.88266	0.00039543
1/5/1970		0.414872	40.47766	0.00039543

Figure 4. 3 Production Data of Well 6s



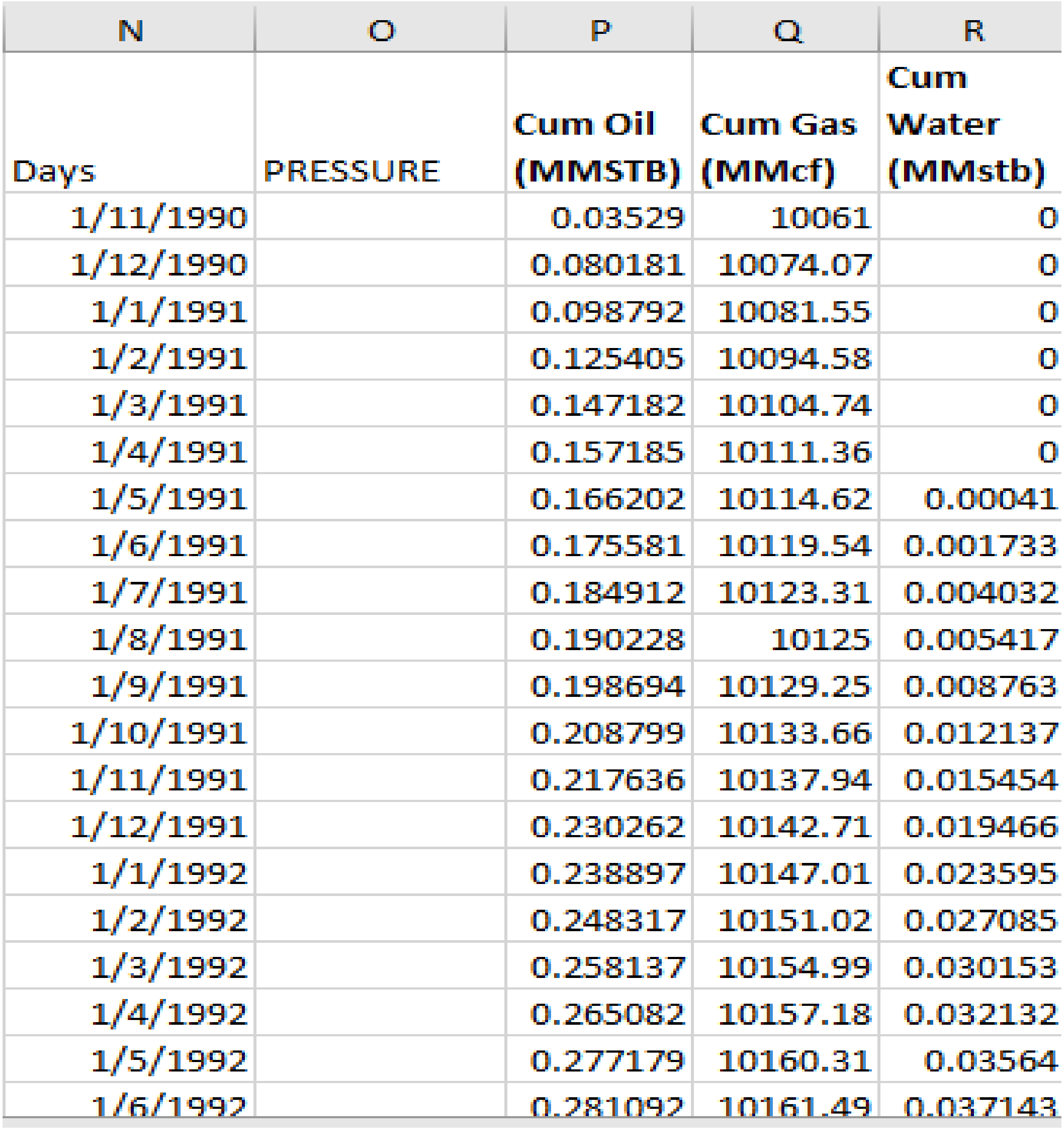
N	O	P	Q	R
Days	PRESSURE	Cum Oil (MMSTB)	Cum Gas (MMcf)	Cum Water (MMstb)
1/4/1966		0.018566	1457	0.003432
1/5/1966		0.039325	1458.794	0.010166
1/6/1966		0.066013	1460.58	0.020803
1/7/1966		0.080376	1461.359	0.026602
1/8/1966		0.087455	1462.065	0.029879
1/9/1966		0.100675	1463.344	0.035645
1/10/1966		0.109511	1464.558	0.047148
1/11/1966		0.115132	1465.403	0.055296
1/12/1966		0.115132	1465.403	0.055296
1/1/1967		0.115132	1465.403	0.055296
1/2/1967		0.115132	1465.403	0.055296
1/3/1967		0.115132	1465.403	0.055296
1/4/1967		0.115132	1465.403	0.055296
1/5/1967		0.115132	1465.403	0.055296
1/6/1967		0.115132	1465.403	0.055296
1/7/1967		0.115132	1465.403	0.055296
1/8/1967		0.115132	1465.403	0.055296
1/9/1967		0.115132	1465.403	0.055296
1/10/1967		0.115132	1465.403	0.055296
1/11/1967		0.115132	1465.403	0.055296

Figure 4. 4 Production Data for Well 18S



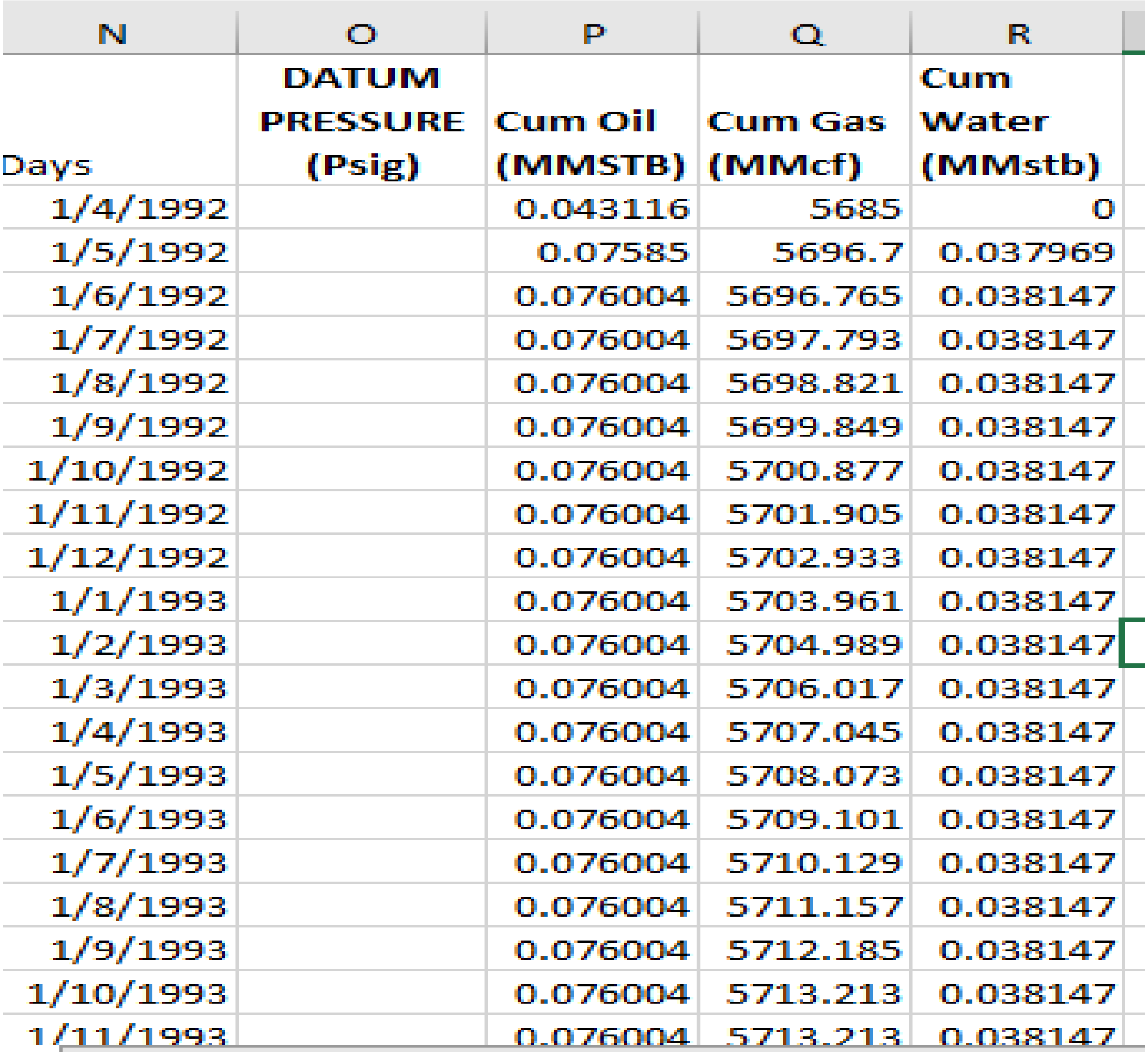
N	O	P	Q	R
Days	PRESSURE	Cum Oil (MMSTB)	Cum Gas (MMcf)	Cum Water (MMstb)
1/1/1969		0.000199	14	0
1/2/1969		0.000199	14	0
1/3/1969		0.000199	14	0
1/4/1969		0.006478	15.613	0
1/5/1969		0.028988	21.334	0
1/6/1969		0.052088	25.636	0
1/7/1969		0.074833	28.036	0
1/8/1969		0.097613	29.942	0.000004
1/9/1969		0.132262	32.731	0.000013
1/10/1969		0.162055	34.993	0.000013
1/11/1969		0.169312	35.612	0.000013
1/12/1969		0.169312	35.612	0.000013
1/1/1970		0.169312	35.612	0.000013
1/2/1970		0.169312	35.612	0.000013
1/3/1970		0.180553	38.332	0.000013
1/4/1970		0.195713	41.278	0.000013
1/5/1970		0.211104	42.714	0.000013
1/6/1970		0.220024	43.78	0.000013
1/7/1970		0.229206	44.909	0.000013
1/8/1970		0.238094	46.002	0.000013

Figure 4. 5 Production Data for Well 29L



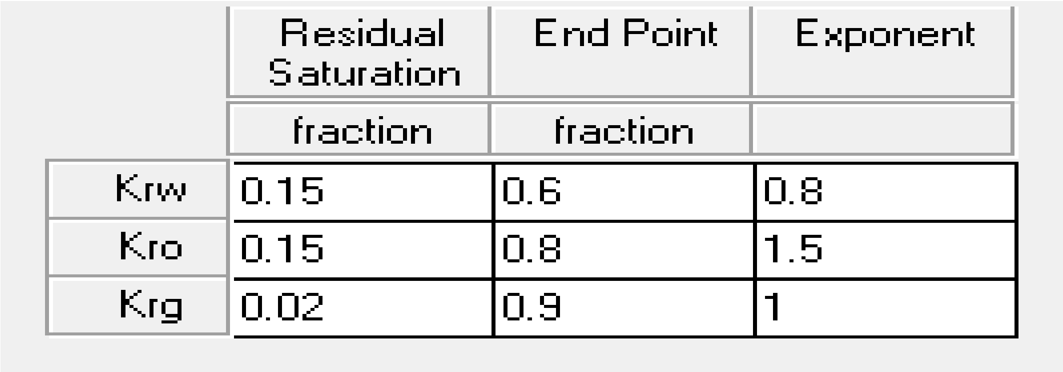
N	O	P	Q	R
Days	PRESSURE	Cum Oil (MMSTB)	Cum Gas (MMcf)	Cum Water (MMstb)
1/11/1990		0.03529	10061	0
1/12/1990		0.080181	10074.07	0
1/1/1991		0.098792	10081.55	0
1/2/1991		0.125405	10094.58	0
1/3/1991		0.147182	10104.74	0
1/4/1991		0.157185	10111.36	0
1/5/1991		0.166202	10114.62	0.00041
1/6/1991		0.175581	10119.54	0.001733
1/7/1991		0.184912	10123.31	0.004032
1/8/1991		0.190228	10125	0.005417
1/9/1991		0.198694	10129.25	0.008763
1/10/1991		0.208799	10133.66	0.012137
1/11/1991		0.217636	10137.94	0.015454
1/12/1991		0.230262	10142.71	0.019466
1/1/1992		0.238897	10147.01	0.023595
1/2/1992		0.248317	10151.02	0.027085
1/3/1992		0.258137	10154.99	0.030153
1/4/1992		0.265082	10157.18	0.032132
1/5/1992		0.277179	10160.31	0.03564
1/6/1992		0.281092	10161.49	0.037143

Figure 4. 6 Production Data for Well 34S



N	O	P	Q	R
Days	DATUM PRESSURE (Psig)	Cum Oil (MMSTB)	Cum Gas (MMcf)	Cum Water (MMstb)
1/4/1992		0.043116	5685	0
1/5/1992		0.07585	5696.7	0.037969
1/6/1992		0.076004	5696.765	0.038147
1/7/1992		0.076004	5697.793	0.038147
1/8/1992		0.076004	5698.821	0.038147
1/9/1992		0.076004	5699.849	0.038147
1/10/1992		0.076004	5700.877	0.038147
1/11/1992		0.076004	5701.905	0.038147
1/12/1992		0.076004	5702.933	0.038147
1/1/1993		0.076004	5703.961	0.038147
1/2/1993		0.076004	5704.989	0.038147
1/3/1993		0.076004	5706.017	0.038147
1/4/1993		0.076004	5707.045	0.038147
1/5/1993		0.076004	5708.073	0.038147
1/6/1993		0.076004	5709.101	0.038147
1/7/1993		0.076004	5710.129	0.038147
1/8/1993		0.076004	5711.157	0.038147
1/9/1993		0.076004	5712.185	0.038147
1/10/1993		0.076004	5713.213	0.038147
1/11/1993		0.076004	5713.213	0.038147

Figure 4. 7 Production Data of Well 40S



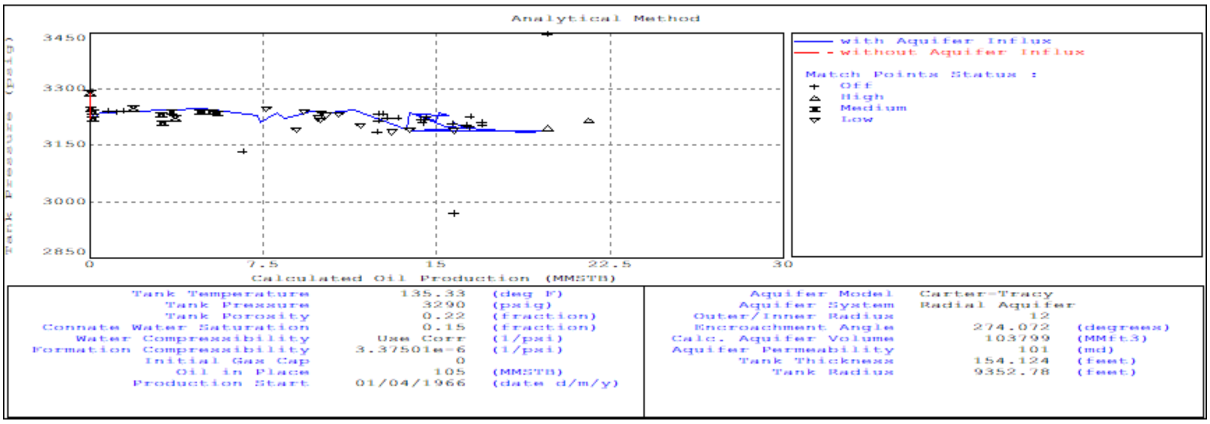
	Residual Saturation	End Point	Exponent
	fraction	fraction	
Krw	0.15	0.6	0.8
Kro	0.15	0.8	1.5
Krg	0.02	0.9	1

Figure 4. 8 Relative permeability Data

NO	PARAMETER	VALUE
1	OOIP	105MMSTB
2	Average porosity	0.22
3	Initial gas cap	0
4	Average water saturation	0.15
5	Initial pressure	3290psig
6	Temperature	135^{0}F
7	GOR	79.5 scf/stb
8	API	16.9API
9	Gas gravity	0.6
10	Water salinity	20000ppm

Table 4. 2 Parameters for MBAL calculation

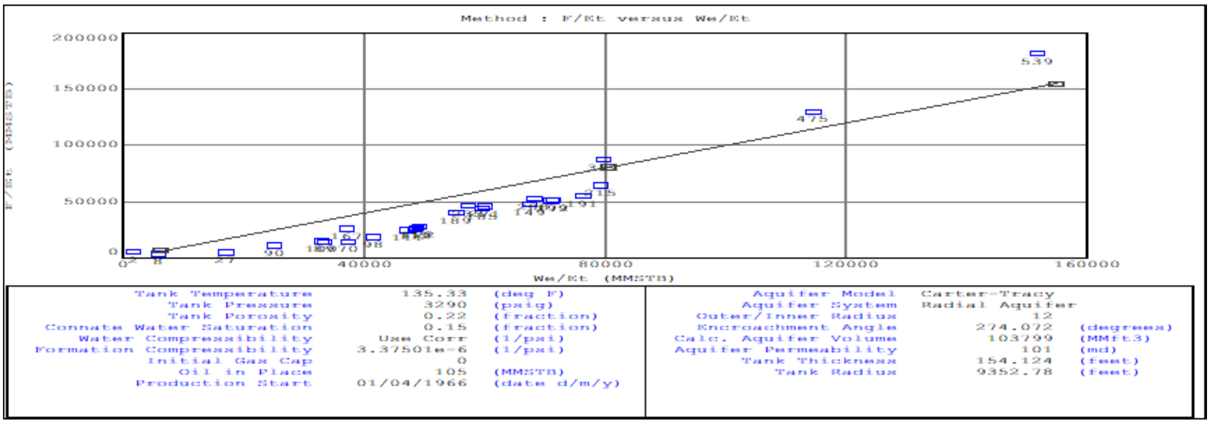
RESULT ON HISTORY MATCHING



```
     Tank Temperature      135.33   (deg F)        Aquifer Model   Carter-Tracy
        Tank Pressure        3290   (psig)        Aquifer System   Radial Aquifer
        Tank Porosity        0.22   (fraction)  Outer/Inner Radius            12
Connate Water Saturation     0.15   (fraction) Encroachment Angle        274.072   (degrees)
 Water Compressibility   Use Corr   (1/psi)   Calc. Aquifer Volume       103799   (MMft3)
Formation Compressibility 3.37501e-6 (1/psi)  Aquifer Permeability          101   (md)
      Initial Gas Cap           0                  Tank Thickness       154.124   (feet)
         Oil in Place         105   (MMSTB)           Tank Radius       9352.78   (feet)
     Production Start  01/04/1966   (date d/m/y)
```

Figure 4. 9 Analytical plot of MBAL software of Reservoir Q

Figure 4.9 presents the analytical approach for Reservoir Q. The red line represents the simulator running without aquifer influx, while the blue line indicates the simulator running with water influx support, showing an almost perfect match. From the analytical plot, it can be understood that water influx serves as the primary energy source supporting the reservoir.

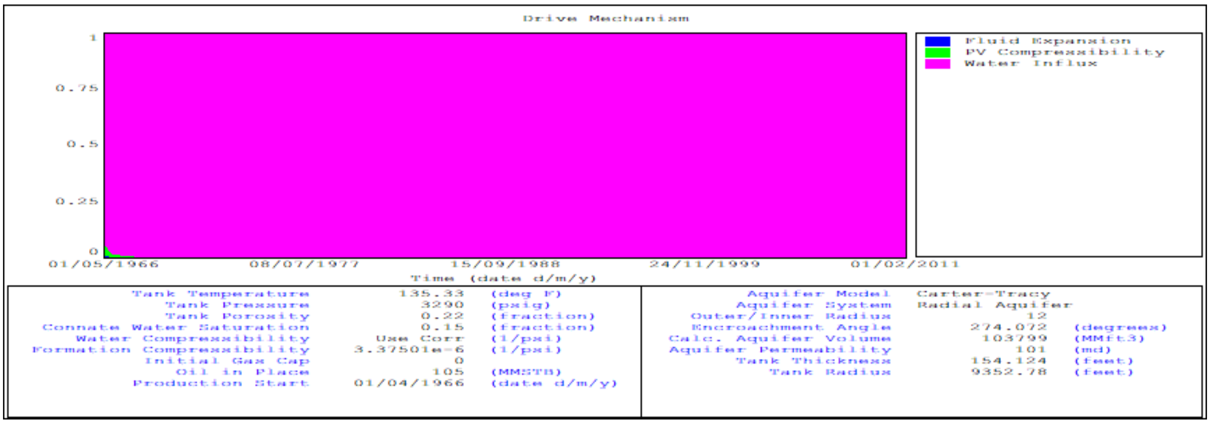


Tank Temperature 135.33 (deg F)
Tank Pressure 3290 (psig)
Tank Porosity 0.22 (fraction)
Connate Water Saturation 0.15 (fraction)
Water Compressibility Use Corr (1/psi)
Formation Compressibility 3.37501e-6 (1/psi)
Initial Gas Cap 0
Oil in Place 105 (MMSTB)
Production Start 01/04/1966 (date d/m/y)

Aquifer Model Carter-Tracy
Aquifer System Radial Aquifer
Outer/Inner Radius 12
Encroachment Angle 274.072 (degrees)
Calc. Aquifer Volume 103799 (MMft3)
Aquifer Permeability 101 (md)
Tank Thickness 154.124 (feet)
Tank Radius 9352.78 (feet)

Figure 4. 10 Graphical Plot of MBAL software of Reservoir Q

The F/Et versus We/Et method is a graphical approach used in MBAL software to analyse reservoir drive mechanism and estimate oil in place. This method is based on the havlena and odeh material balance equation, which transforms the traditional material balance equation into a linear form. The oil initially in place from this plot is 105MMSTB. The straight line trend has a slope approximately 1, suggesting a strong water drive.



Tank Temperature 135.33 (deg F)
Tank Pressure 3290 (psig)
Tank Porosity 0.22 (fraction)
Connate Water Saturation 0.15 (fraction)
Water Compressibility Use Corr (1/psi)
Formation Compressibility 3.37501e-6 (1/psi)
Initial Gas Cap 0
Oil in Place 105 (MMSTB)
Production Start 01/04/1966 (date d/m/y)

Aquifer Model Carter-Tracy
Aquifer System Radial Aquifer
Outer/Inner Radius 12
Encroachment Angle 274.072 (degrees)
Calc. Aquifer Volume 103799 (MMft3)
Aquifer Permeability 101 (md)
Tank Thickness 154.124 (feet)
Tank Radius 9352.78 (feet)

Figure 4. 11 Energy Plot

Figure 4.11 illustrates the fractional contributions of various drive mechanism in the recovery of Reservoir Q. the plot highlights three primary energy sources influencing oil recovery: water influx, shown in pink; pore volume compressibility, represented in green; and fluid expansion, depicted in blue. Among these, water influx is the dominant energy source in the reservoir, aligning with the results of the water influx simulation approach.

CHAPTER 5

CONCLUSION AND RECOMMENDATION

CONCLUSION

This study sought to validate geological estimates of Stock Tank Oil Initially in Place (STOIIP) using the Material Balance (MBAL) method, comparing it with the volumetric method to evaluate the accuracy of reservoir estimations. Precise reserve estimation is vital in petroleum engineering, as it significantly influences field development planning, production forecasting, and economic decision-making. The findings revealed that both the volumetric method and MBAL produced nearly identical STOIIP estimates of 102 MMSTB and 105 MMSTB, respectively, indicating a strong consistency and reliability in the results. This alignment suggests that the reservoir characteristics, including porosity, permeability, fluid saturation, and pressure behavior, were effectively characterized and accurately represented in both approaches.

The volumetric method, which relies on static geological data, offers an initial estimate of hydrocarbons in place, while MBAL utilizes dynamic production and pressure data to account for reservoir depletion and fluid movement. The agreement between the two methods reinforces the robustness of the geological model and the reliability of the input data. This outcome demonstrates that MBAL can effectively validate volumetric estimates, especially when high-quality petrophysical and production data are available. Additionally, it underscores the importance of employing multiple estimation techniques to ensure a thorough reservoir evaluation and reduce uncertainties in hydrocarbon volume predictions.

The results also highlight the necessity of ongoing reservoir monitoring and data refinement to enhance the accuracy of reserve estimations. While the consistency observed between the two methods in this study is encouraging, it is essential to recognize that reservoirs are dynamic systems that change over time due to pressure depletion, fluid migration, and potential water or gas influx. Regular reassessment using MBAL, volumetric calculations, and other advanced techniques, such as reservoir simulation and decline curve analysis, will improve predictive accuracy and optimize recovery strategies. Furthermore, ensuring high-quality well log interpretation, core sample analysis, and pressure data collection will further enhance the reliability of reserve estimates in future studies.

In summary, this research confirms that combining static and dynamic reservoir estimation methods offers a more dependable approach to evaluating hydrocarbons in place. The identical estimates derived from both MBAL and the volumetric method validate the accuracy of the geological model and bolster confidence in reservoir assessment techniques. These findings provide a solid foundation for optimizing production planning, enhancing hydrocarbon recovery, and minimizing financial risks in reservoir management. Future research should investigate the use of probabilistic models and advanced simulation tools to further mitigate uncertainties and improve the accuracy of STOIIP estimation in complex reservoirs.

RECOMMENDATIONS

1. Integration of Multiple Estimation Methods – Given the close alignment of results from the volumetric and MBAL methods, future studies should incorporate additional techniques such as reservoir simulation and decline curve analysis for further validation of estimates.

2. Continuous Reservoir Monitoring – Implement regular updates to reservoir parameters, including pressure and production data, to refine estimates and enhance predictive accuracy.

3. Data Quality Enhancement – Focus on collecting high-quality geological and petrophysical data to minimize uncertainties and improve the reliability of reserve estimations.

4. Advanced Software Utilization – Employ more sophisticated reservoir modeling tools and probabilistic approaches (e.g., Monte Carlo simulation) to conduct a more comprehensive uncertainty analysis.

5. Field-Specific Validation – While this study demonstrated consistency in estimates, applying the same validation framework to different reservoirs with varying geological complexities would further evaluate the robustness of the methodology.

By adhering to these recommendations, reservoir engineers can improve oil recovery efficiency, enhance decision-making, and ensure sustainable hydrocarbon production.

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