Research Article

URF PUBLISHERS
connect with research world

Journal of Petroleum & Chemical Engineering

https://urfpublishers.com/journal/petrochemical-engineering

Vol: 1 & Iss: 1

Involvement in the Extraction of Sediment Layers from the Productive Strata Within the Palchig Pilpilesi Formation, To Create A 3d Geological Model That Distinguishes Various Horizons and Layers

Jabrayil Eyvazov*, Mehri Guliyeva, Ali Rahimli, Shohrat Ahmadov

Azerbaijan State Oil and Industry University, Azerbaijan

Citation: Eyvazov J, Guliyeva M, Rahimli A, Ahmadov S. Involvement in the Extraction of Sediment Layers from the Productive Strata Within the Palchig Pilpilesi Formation, To Create A 3d Geological Model That Distinguishes Various Horizons and Layers. *J Petro Chem Eng* 2025;1(1): 15-21.

Received: 04 February, 2025; **Accepted:** 24 February, 2025; **Published:** 26 February, 2025

***Corresponding author:** Jabrayil Eyvazov, Azerbaijan State Oil and Industry University, Azerbaijan, Email: jabrayil.eyvazov88@gmail.com

ABSTRACT

The analysis of existing geological and geophysical research as well as excavation works reveals that despite the prolonged search and exploration of the Productive Layer (PG) sediments in the South Caspian Basin (SCA), their hydrocarbon reserves remain insufficiently explored. Examination and consolidation of geological-geophysical data, drilling information and the established 3D geological model indicate specific patterns in the distribution of oil and gas deposits within local elevations. These patterns are primarily influenced by tectonic processes. In the 3D geological modeling of the Palchig Pilpilesi deposit, the study accounted for tectonic processes occurring in the sedimentation basin of the sedimentary complex. This included the development of uplifts, their complication due to tectonic disturbances and the impact of changes in the lithological composition and thickness of the horizons and layers constituting the productive layer section on the accumulation of hydrocarbon resources.

Keywords: Palchig Pilpilesi deposit; Hydrocarbon resources; South caspian basin; Productive layer

Introduction

In the development of the 3D geological model for the deposit, three-dimensional modeling was employed to capture the intricacies of the fractures encompassing the structure, leading to the creation of a comprehensive structural model. Subsequent to validating the structural model using well data and trend maps, a 50x50 scale 3D grid was meticulously constructed based on the established structure[1]. Initially, seepage capacity parameter curves, delineated by area and depth, were integrated into the constructed grid.[2]

To ascertain the spatial distribution of rocks within the lithological section of the development horizons, facies modeling was conducted. This process contributed to a nuanced understanding of the field distribution of the various rock types involved in the geological makeup of the deposit[3].

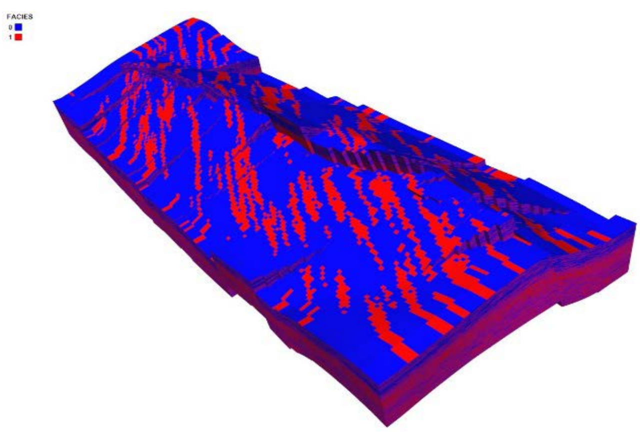

Figure 1: Facies model of Palchig - Pilpilesi field.

The outcomes of the histogram analysis conducted on the facies model, utilizing the calculated parameters, indicate an overall average sandiness value of 0.5 across the horizons of Palchig Pilpilesi[4]. When examined individually, the sandiness values are as follows: QUG-0.26, QUQ-0.34, QD-0.36, QA-0.75 and QaLD-0.58 (**Figure 1**). It is important to note that these parameters are derived from well data. The average values presented were computed based on the data contained within the contour, with information outside the delineation exerting no influence on these statistical measures[5].

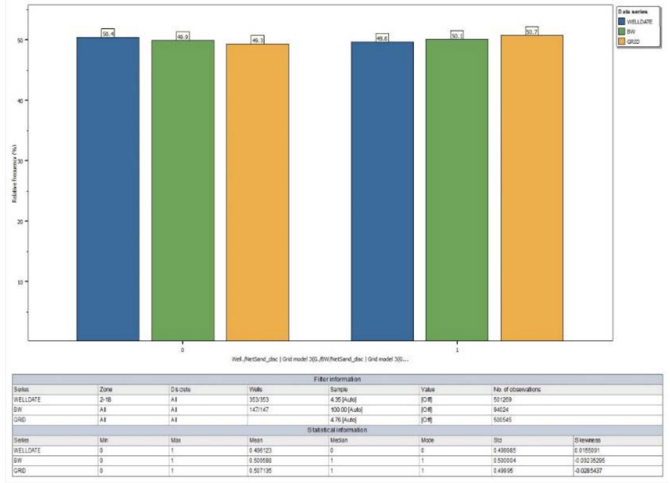

Figure 2: NTG histogram for facial model.

Following the establishment of the facies model, petrophysical modeling was undertaken, encompassing the assessment of porosity, permeability and water saturation. Based on the data derived from petrophysical modeling, the average porosity value across the horizons of the deposit is determined to be 0.183 (**Figure 2**).

When examining porosity values individually, specific averages are identified:

QUG: 0.19

QUQ: 0.20

QD: 0.20 (QD1-0.20, QD2-0.18, QD3-0.19, QD4-0.21, QD5-0.22)

QA: 0.20 (QA1-0.20, QA2-0.216, QA3-0.194)

QaLD: 0.17 (QaLD1-0.17, QaLD2-0.16, QaLD3-0.17, QaLD4-0.18).

These values provide a detailed insight into the porosity characteristics of each specific horizon within the deposit, aiding in a comprehensive understanding of the petrophysical attributes of the geological formation (**Figure 3**).

A 3D porosity (Phie) model was developed utilizing stochastic distribution through kriging simulation under the condition of NTG=1 (where NTG=1 signifies a reservoir and NTG=0 denotes a non-reservoir) following extensive analyses of well data. The variogram model employed for this simulation includes an azimuth with an exponential curve set at 170 degrees, parallel - 150 m, normal - 100 m and vertical direction - 4 m. This modeling approach leverages geostatistical methods to estimate porosity values in three dimensions, providing a spatial representation of porosity distribution within the reservoir (**Figure 4)**.

The porosity coefficient, derived from an analysis of rock samples obtained from 42 wells, is based on a total of 218 samples. This coefficient has been computed for both horizon and bed areas. The accurate calculation of the porosity coefficient by area is intricately tied to variations in lithological composition and reservoir thickness.

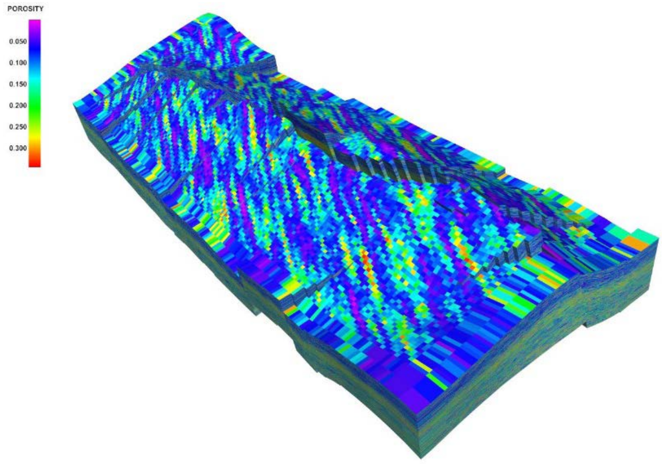

Figure 3: 3D porosity distribution for the Palchig Pilpilesi field (QUG – QaLD).

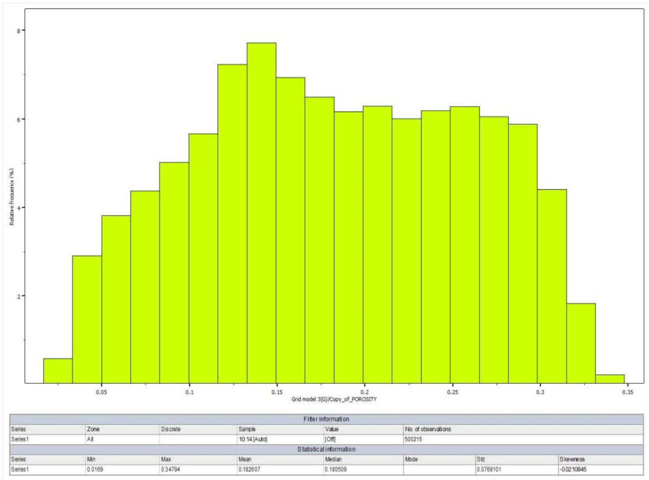

Figure 4: Histogram of porosity distribution.

Among the 218 samples collected from exploratory wells, 184 have been attributed to collectors. The calculated porosity coefficient for these samples falls within the range of 0.15 to 0.26.

It is noteworthy that, consistent with core analysis results and experiences gleaned from other fields in the region, there exists a direct correlation between permeability and porosity. This relationship underscores the importance of understanding and considering both parameters in the assessment of reservoir characteristics[6].

y = 1.4868e+05*x^3 - 24072*x^2 - 2260.2*x^1 + 379.41 (Eq 1)

Permeability was derived from porosity using the formula above, which reflects the increasing relationship between permeability and porosity (Figure 5).

In the subsequent phase, a water saturation model was developed. The average water saturation value calculated within the contour is determined to be 0.31 for the CG - QLD. When categorized by horizons, the water saturation values are as follows: QUG -0.33, QUQ -0.25, QD -0.35, QA-0.28 and QALD -0.32.

The modeling of water saturation (Sw) employed a simplified J-function method, incorporating porosity (Poro), permeability (Perm), height above the free water level (FWL) (H) and petrophysical constants (a, b). This approach enhances the understanding of water saturation dynamics within the reservoir, integrating various key parameters for a comprehensive modeling outcome (**Figure 6**).

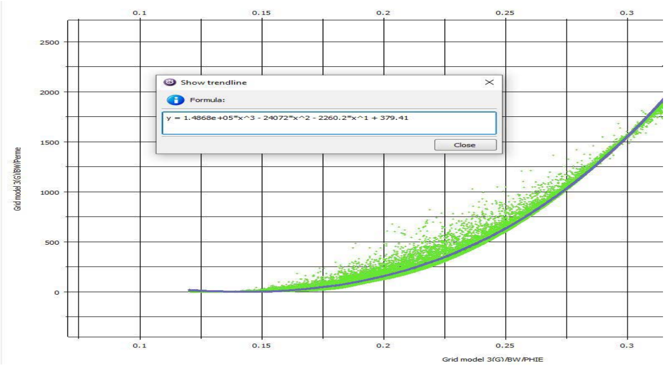

Figure 5: Permeability vs. porosity plot.

$$J = H\sqrt{\frac{Perm}{Poro}}$$

$$S_{wn} = \frac{1}{H_{\text{top}} - H_{\text{bottom}}} \int_{H_{\text{bottom}}}^{H_{\text{top}}} \left(\frac{J}{a}\right)^{\frac{1}{b}} \mathrm{d}H$$

$$S_w = S_{wirr} + (S_{wmax} - S_{wirr})\, S_{wn}$$

Swn – water saturation value by height above free water level

Swirr – saturation value with non-extractable (residual) water

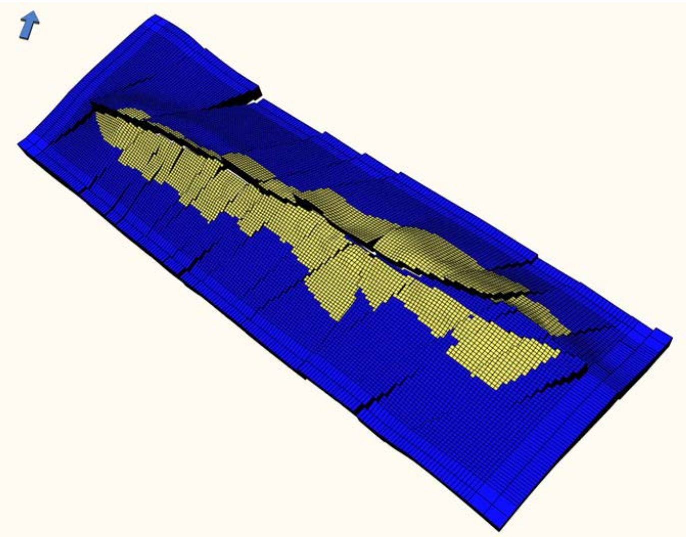

Figure 6: 3D water saturation distribution of Palchig Pilpilesi field.

History Matching: In the realm of reservoir management, the significance of accurate reservoir models cannot be overstated. These models play a pivotal role in forecasting reservoir performance across diverse operating scenarios, thereby mitigating investment risks in field development[7]. The conceptual equivalence of a reservoir model to the actual reservoir is imperative for its precision and reliability.

History matching emerges as a critical procedure in this context, serving to evaluate and validate the similarity between the simulation model and the real reservoir. During history matching, the historical performance of the reservoir is simulated and the model is systematically adjusted to align with observed historical data. The objective is to ensure that the final history-matched model faithfully represents the reservoir's behavior and possesses the capability to reliably forecast its performance in the future[8]. This iterative process enhances the accuracy of the reservoir model, fostering informed decision-making in reservoir management and development endeavors.

The primary objectives of history matching reservoir models include the reduction of uncertainty, enhancement of reservoir understanding, validation of reservoir simulation models and improvement in the accuracy of predictions regarding reservoir performance[9]. The fundamental premise is that, if a reservoir model can faithfully replicate historical reservoir performance, it can reasonably forecast future performance.

The method of "history matching" is employed to align model input with recorded data, encompassing fluid characteristics, geological descriptions and other pertinent information. Recorded data may include phase rates, cumulative production, pressures, tracers, temperatures, salinity and more. Maximizing the alignment of model inputs with historical data contributes to a more effective reduction of ambiguity and a heightened confidence in the current reservoir characterization[10].

It is crucial to recognize, however, that uncertainty can never be diminished beyond the inherent uncertainty present in the historical data itself. Therefore, while history matching serves as a powerful tool for refining reservoir models, it operates within the constraints of the available historical data and associated uncertainties[11].

Precise historical matching of a reservoir model is essential for gaining a thorough understanding of the present conditions within the reservoir, including fluid distribution, fluid movement and validation of the current depletion mechanism[12]. This process not only confirms existing reservoir dynamics but also provides valuable insights into operational issues, such as casing leaks or suboptimal fluid distribution between wells.

By aligning the reservoir model with historical data, it becomes possible to delve into the intricate details of fluid behavior, depletion patterns and potential challenges affecting the reservoir's performance. This historical matching not only serves to validate the accuracy of the model but also offers a practical means to identify and address operational concerns, ensuring a more efficient and effective reservoir management strategy (**Figure 7**).

In summary, accurate historical matching not only enhances our understanding of the reservoir's current state but also serves as a diagnostic tool for uncovering and addressing operational challenges that may impact fluid distribution and overall reservoir performance[13].

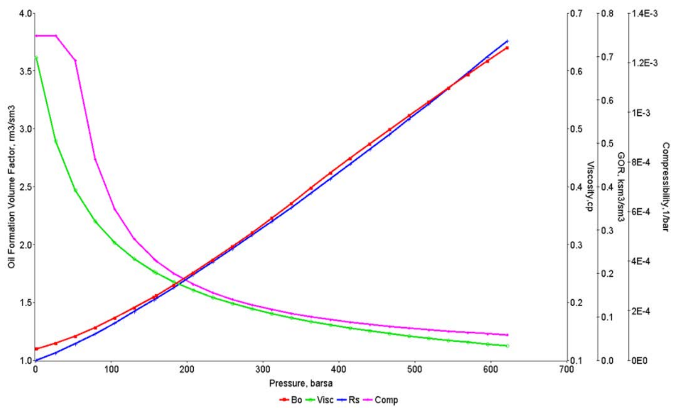

Figure 7: Oil PVT properties versus pressure.

Oil PVT (Pressure-Volume-Temperature) properties encompass the characteristics of petroleum fluids as they respond to changing conditions of pressure, volume and temperature. Understanding these properties is paramount for the exploration, production and processing of oil and natural gas reservoirs[14]. Here's a concise overview of some key oil PVT properties:

Viscosity: Viscosity gauges a fluid's resistance to flow and undergoes variations with changes in temperature and pressure. Accurate viscosity data is crucial for designing pipelines and selecting appropriate pumps, ensuring efficient fluid transportation[15].

Compressibility: The compressibility factor of oil indicates its volume change in response to alterations in pressure and temperature. This property is vital for estimating volume variations during production and injection processes, influencing reservoir behavior.

Bubble Point and Dew Point: These critical points signify the pressure-temperature conditions at which gas begins to dissolve into or separate from the oil phase. Understanding these points is essential for predicting and optimizing reservoir performance, as well as comprehending phase behavior within the reservoir.

A comprehensive grasp of these oil PVT properties is indispensable for making informed decisions in the oil and gas industry, aiding in reservoir management, production optimization and facility design.Saturation

Pressure: Saturation pressure is the pressure at which the first bubble of gas appears in the reservoir oil. It helps in understanding the reservoir's initial conditions[16].

Formation Volume Factor (FVF): FVF relates the volume of oil at reservoir conditions to its volume at surface conditions. It's essential for converting produced volumes to standard conditions.

Understanding and accurately characterizing these oil PVT properties is essential for reservoir engineering, reservoir management and the design of oil and gas production systems[17]. It ensures efficient and safe extraction and processing of petroleum resources (**Figure 8**).

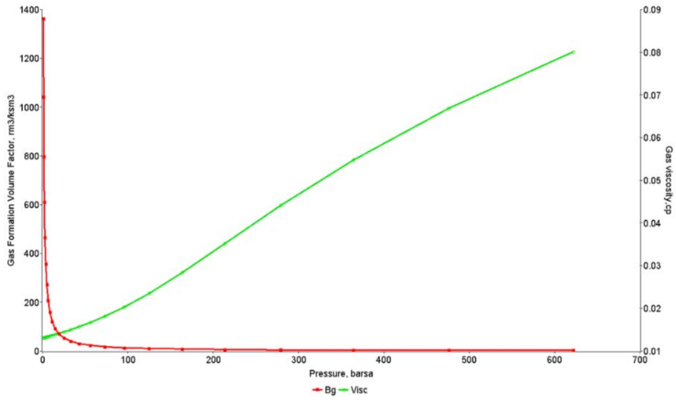

Figure 8: Gas PVT properties versus pressure.

Gas viscosity and gas formation volume factor are pivotal properties in the oil and gas industry, playing crucial roles in various applications. Here's a detailed exploration of their significance:

Gas Viscosity:

Definition: Gas viscosity refers to the resistance of a gas to flow or its internal friction during movement.

Role: It measures how easily a gas can traverse pipelines or porous reservoir rocks.

Applications: Gas viscosity is integral to pipeline design, fluid flow modeling and reservoir engineering.

Impact: It influences pressure drop and flow rate in pipelines, affecting the efficiency of gas production and transportation.

Factors Affecting Gas Viscosity: Temperature and pressure are primary influencers. Generally, viscosity decreases with increasing temperature or pressure.

Gas Formation Volume Factor (FVF):

Definition: Gas FVF represents the ratio of the volume of gas at reservoir conditions to its volume at surface conditions.

Role: It is crucial for converting measured gas volumes at surface conditions to reservoir conditions, aiding in estimating the original gas in place (OGIP) and understanding gas behavior within a reservoir.

Applications: Gas FVF is essential for reservoir management, production optimization and determining efficient gas production and transportation system designs.

Impact: It helps in accurately assessing the behavior of gas under different pressure and temperature conditions.

Factors Affecting Gas FVF: Pressure and temperature are the primary factors. Increasing pressure compresses the gas, reducing volume, while higher temperatures lead to gas expansion and increased volume.

Both gas viscosity and gas formation volume factor are indispensable for ensuring effective reservoir management, optimizing production and designing systems for the safe and cost-effective utilization of natural gas resources (**Figure 9**). Precise measurement and modeling of these properties are essential for informed decision-making in the industry[18].

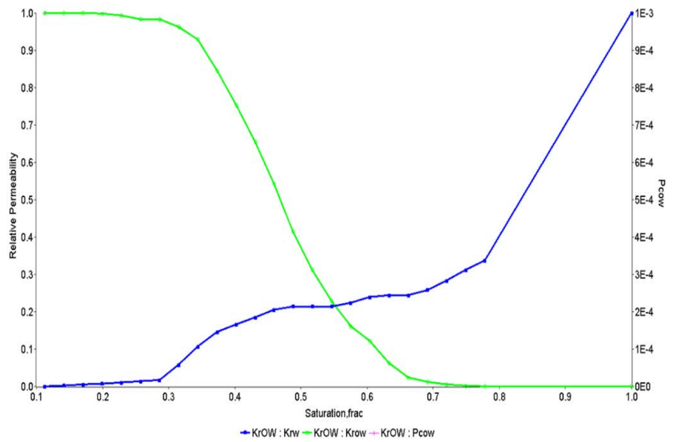

Figure 9: Water-Oil Relative Permeability.

Water-oil relative permeability is a fundamental concept in reservoir engineering and petroleum geology, providing insights into the flow of water and oil through porous rock formations in underground oil reservoirs. Here are key points to understand about water-oil relative permeability:

Relative Permeability Curve: Representation: Relative permeability is typically depicted as a curve or set of curves on a graph, illustrating the relationship between the relative permeability of water and oil and the saturation of each fluid in the porous rock.

Saturation Levels: Saturation levels indicate the fraction of pore space filled with each fluid and the curves demonstrate how the availability of pore space for each fluid changes as saturation levels vary.

Saturation Levels:

Fluid Interaction: Relative permeability curves elucidate how the availability of pore space for each fluid changes as saturation levels fluctuate.

Inversely Proportional: The curves reveal an inversely proportional relationship - as the saturation of one fluid increases, the relative permeability of the other fluid decreases[19].

Understanding water-oil relative permeability is pivotal for optimizing oil recovery strategies in reservoir management. It informs decisions related to well placement, the injection of water or other displacing fluids to enhance oil recovery and overall reservoir development planning. Accurate knowledge of these relative permeability characteristics is instrumental in maximizing the efficient recovery of oil while minimizing water production. This optimization is crucial for achieving cost-effective and sustainable reservoir management practices (**Figure 10**).

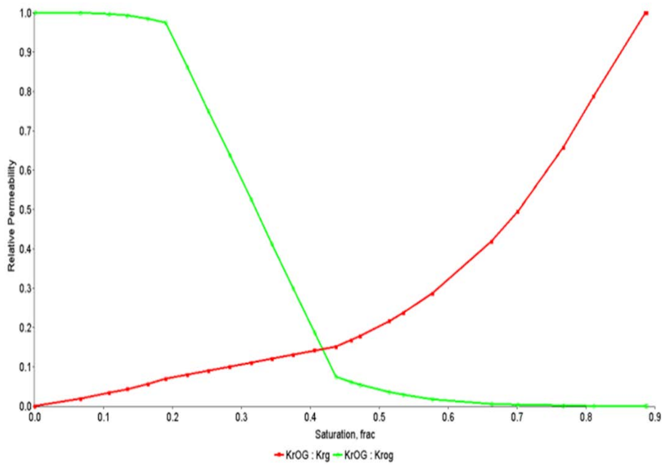

Figure 10: Oil-Gas Relative Permeability.

Understanding oil-gas relative permeability is imperative for making well-informed decisions in reservoir management, especially in scenarios where both oil and gas coexist within the same reservoir. This knowledge is instrumental in optimizing strategies for efficient hydrocarbon recovery, including gas injection, gas cycling and enhanced oil recovery (EOR) techniques. Additionally, it plays a vital role in minimizing unwanted gas breakthrough and ensuring economically viable oil production.

History matching, a critical process in reservoir engineering and oil production, involves adjusting the parameters of a reservoir simulation model to align with observed field data, particularly oil production rates and well performance[20]. The primary goal of history matching is to enhance the accuracy and reliability of the reservoir model, rendering it a valuable tool for reservoir management and production optimization.

Key points about history matching for oil production rate:

Complexity: History matching for oil production rates is a complex and time-consuming process.

Objectives: The process aims to improve the accuracy of the reservoir model and ensure it aligns closely with observed field data.

Necessities: Successful history matching requires a combination of engineering expertise, reservoir modeling software and access to precise field data.

Crucial Step: It is a crucial step in reservoir management, contributing to the optimization of oil production, enhancement of recovery strategies and reduction of operational costs while preserving reservoir integrity.

In summary, understanding oil-gas relative permeability and engaging in effective history matching processes are integral components of successful reservoir management (**Figure 11**).. These practices enable the optimization of hydrocarbon recovery strategies, enhance production efficiency and contribute to cost-effective and sustainable reservoir operations (**Figures 12, 13**).

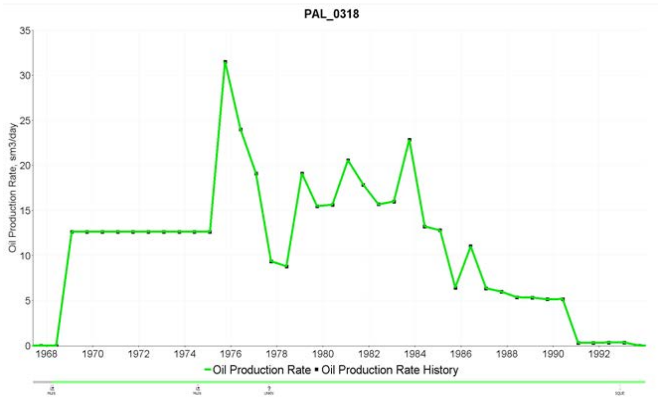

Figure 11: History matching for oil production rate in PAL_0318 well.

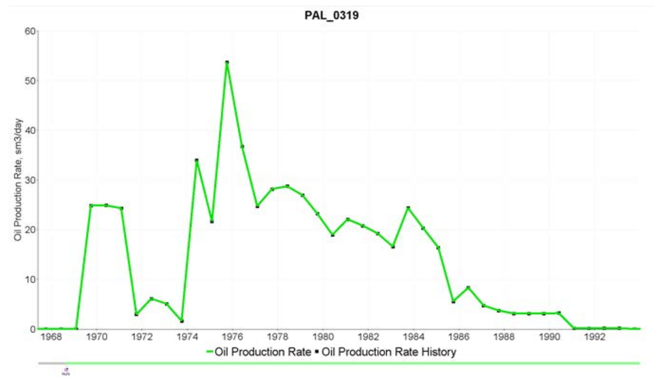

Figure 12: History matching for oil production rate in PAL_0319 well.

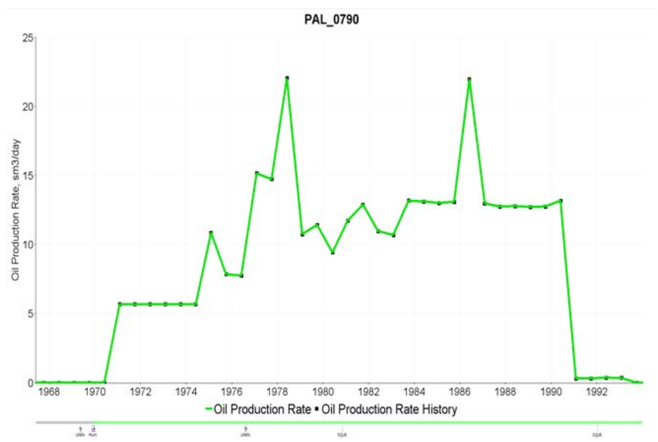

Figure 13: History matching for oil production rate in PAL_0790 well.

Figure 13 showcases the results of a targeted history matching process undertaken specifically for well PAL_0790. The success of this endeavor is clearly evident as the model's predictions now closely correspond with the actual production data observed from the well. This favorable outcome in history matching, a pivotal step in reservoir engineering, indicates that the reservoir model has undergone meticulous adjustments to faithfully replicate real-world conditions. This accomplishment transforms the model into a valuable tool for reservoir management and production optimization.

The alignment between the model predictions and actual production data achieved through history matching enhances the model's accuracy and reliability. It allows for more informed decision-making in reservoir management, enabling the optimization of production strategies, the evaluation of reservoir performance and the reduction of operational uncertainties[21]. This successful history matching process stands as a testament to the refinement and validation of the reservoir model, elevating its utility in guiding effective and efficient reservoir management practices (**Figure 14**).

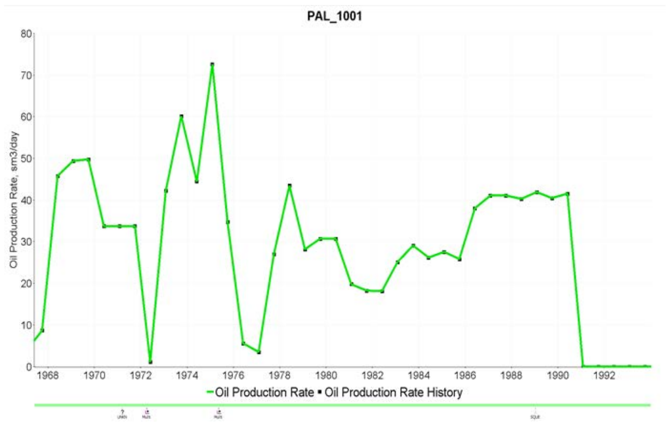

Figure 14: History matching for oil production rate in PAL_1001 well.

(**Figure 14**) provides a visual representation of the history matching process dedicated to well PAL_1001. The outcomes unmistakably demonstrate the successful achievement of this undertaking, with the model's projections closely aligning with the observed production data from the well. This noteworthy accomplishment in history matching, a pivotal phase in reservoir engineering, underscores the meticulous and accurate adjustments made to the reservoir model, ensuring its faithful representation of real-world conditions. Consequently, the refined model emerges as a highly valuable asset, empowering improved reservoir management and the optimization of production processes.

The close alignment between the model's projections and the actual production data achieved through history matching enhances the model's accuracy and reliability. This accomplishment is instrumental in making well-informed decisions for reservoir management, offering insights into production strategies, reservoir performance evaluation and the mitigation of operational uncertainties. The success of the history matching process for well PAL_1001 stands as a testament to the thorough refinement and validation of the reservoir model, elevating its utility as a robust tool for guiding effective and efficient reservoir management practices (**Figure 15**).

Figure 15: History matching results of field oil production rate.

(**Figure 15**) serves as a visual representation of the outcomes stemming from the effort to align the production rates in the oil field. In the subsequent stages of the process, particularly for predictive purposes, the crucial milestone of history matching must be achieved. This integral step involves ensuring that the reservoir model aligns closely with actual production data, faithfully reflecting real-world conditions. It is only through the successful attainment of history matching that the model evolves into a reliable tool for forecasting and optimizing production processes within the oil field.

The importance of history matching lies in its ability to enhance the accuracy and credibility of the reservoir model. When the model closely mirrors observed production data, it becomes a valuable asset for making informed decisions in reservoir management. This includes forecasting future production rates, optimizing recovery strategies and minimizing uncertainties in the production processes. The depiction in (**Figure 15**) signifies the successful alignment of the reservoir model with actual production data, marking a significant step towards the model's reliability and its utility in guiding efficient and effective reservoir management practices (**Figure 16**).

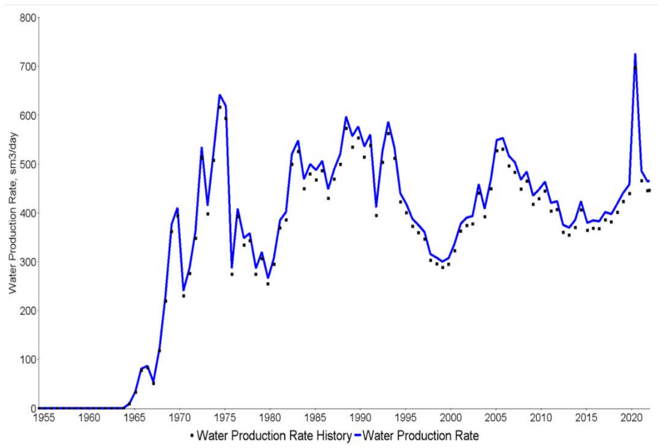

Figure 16: History matching results of field water production rate.

(**Figure 16**) serves as a visual representation of the results pertaining to the matching of water field production rates. In the subsequent stages of the process, particularly for predictive purposes, the critical achievement of history matching becomes imperative. This essential step involves ensuring that the reservoir model aligns closely with actual production data, establishing a faithful representation of real-world conditions. It is only through the successful attainment of history matching that the model becomes a reliable tool for forecasting and optimizing water field production processes.

History matching is pivotal for refining the accuracy and reliability of the reservoir model, allowing it to closely emulate observed production data. This alignment enhances the model's utility in making informed decisions for water field reservoir management, including the prediction of future production rates, optimization of recovery strategies and mitigation of uncertainties in production processes. The depiction in (**Figure 16**) signifies the successful alignment of the reservoir model with actual water field production data, marking a significant stride toward the model's reliability and its role in guiding efficient and effective reservoir management practices.

Conclusion

Here is a refined and structured presentation of the provided information:

3D Geological Modeling: Utilizing the RMS software package from ROXAR, a comprehensive 3D geological model of the Mud Pilpilesi deposit was created.

The process commenced with the establishment of a field database, followed by the construction of a structural model encompassing the development horizons (QUG, QUQ, QD1, QD2, QD3, QD4, QD5, QA1, QA2, QA3, QaLD1, QaLD2, QaLD3, QaLD4).

Facies and petrophysical modeling were conducted and the resulting model enabled the calculation of the initial balance hydrocarbon reserve for the field.

Grid Upscaling for Hydrodynamic Modeling: The 3D geological grid underwent "upscaling" to align with the hydrodynamic grid, a crucial step for forecasting and applying various methods to restore history and enhance processing efficiency.

Sensitivity Analysis and Uncertainty Study: To evaluate the impact of parameters on the calculation of the initial balance hydrocarbon reserve, a sensitivity analysis was performed.

The study also delved into the effect of uncertainties, providing insights into the robustness of the modeling results.

History Matching:

The history matching process involved:

Determining the optimal horizontal section for horizontal wells.

Finding the optimal gas-lift gas injection volumes.

Establishing gravel pack parameters.

Defining parameters for water quifer models.

This comprehensive workflow highlights the systematic approach taken in building, refining and validating the 3D geological model of the Mud Pilpilesi deposit. The integration of sensitivity analysis and uncertainty studies enhances the reliability of the model, while history matching contributes to the optimization of production strategies and reservoir management.

References

1. Baker RO, Chugh S, Mcburney C and Mckishnie R. History Matching Standards; Quality Control and Risk Analysis for Simulation. Paper PETSOC 2006-129 presented at the Petroleum Society's 7th Canadian International Petroleum Conference, Calgary, Alberta, Canada 2006;13-15.
2. Caers J. Petroleum Geostatistics. Richardson, Texas, SPE 2005.
3. Kabir CS and Young NJ. Handling production-data uncertainty in history matching: The Meren reservoir case study, SPE 71621, SPE Annual Technical Conference and Exhibition, Louisiana 2001.
4. Carlson MR. Practical Reservoir Simulation. Tulsa, Oklahoma: PennWell Corporation 2006.
5. Jabrayil Eyvazov. Increase Oil Recovery in Different Surfactant Concentrations on the Basis of Increasing Well Drainage Area.
6. Jafarpour B and McLaughlin DB. History matching with an Ensemble Kalman filter and discreate cosine parameterization. paper SPE 108761 presented at SPE Annual Technical Conference and Exhibition, Anaheim, USA 2007.
7. Aanonsen S I, Aavatsmark I, Barkve T, et al. of Scale Dependent Data Correlations in an Integrated History Matching Loop Combining Production Data and 4D seismic Data, SPE 79665, SPE Reservoir Simulation Symposium, Houston, USA 2003;3-5.
8. Jabrayil Eyvazov. How the Oil Recovery Factor Changes in Different Polymer Concentrations on in the Basis of Increasing Well Drainage Area. Proceedings of the 2022 International Petroleum and Petrochemical Technology Conference.
9. Kleppe J. Reservoir simulation, lecture note 4 and 6, Norwegian University of science and technology, NTNU, Norway 2008.
10. Lepine OJ, Bissell RC, Aanonsen SI and Barker JW. Uncertainty analysis in predictive reservoir simulation using gradient information, SPE 48997, SPE Annual Technical Conference and Exhibition, Louisiana, USA, 1998;27-30.
11. Jabrayil Eyvazov, Natig N.Hamidov. The Effect of Different Hydraulic Fracturing Width to the Well Production. International J Oil Gas and Coal Engineering.
12. Mattax CC and Dalton RL. Reservoir simulation, SPE 20399, Journal of Petroleum Technology 1991;42:692-695.
13. Li R, Reynolds AC and Oliver DS. History matching of three-phase flow production data, SPE Journal 2003;8(4):328-340.
14. Jabrayil Eyvazov, Natig Hamidov. The effect of hydraulic fracturing length to the well production. Journal of Physics Conference Series 2594(1):012022.
15. Bissell R. Calculating optimal parameters for history matching, 4th European Conference on the Mathematics of Oil Recovery, Norway 1994.
16. Dougherty EL and Khairkhah D. A History Matching of Gas Simulation Models Using Optimal Control Theory, SPE 5371, 45th SPE-AIME Annual California Regional Fall Meeting, Venture, California 1975;2-4.
17. Jabrayil Eyvazov. The Effect of Sand Production to the Well Drainage Area. Proceedings of the 2022 International Petroleum and Petrochemical Technology Conference.
18. Harb R. History matching including 4-D seismic - An application to a field in the North Sea, Master thesis, NTNU Norway 2004.
19. Nocedal J and Wright SJ. Numerical Optimization, Berlin: Springer-Verlag 1999.
20. Jabrayil Eyvazov. Sensitivity analysis of oil and gas production as a result of increasing the drainage area within changes in well parameters during different completion of wells. SOCAR Proceedings No.2 2022;19-022.
21. Shah PC, Gavalas GR and Seinfeld JH. Error analysis in history matching: the optimum level of parameterization. Soc Petrol Eng J 1978;18(6):219-228.