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Dynamic Modeling of Hydrocarbon Reserves and Estimating Optimal Well Placement in Mature Oil Fields

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Abstract

I Development of mature oil reservoir blocks strategy in optimizing hydrocarbon production from mature oil fields. Using dynamic modeling techniques together with subsurface interpretations that were based on sharply adjacent well data, the study has presented new development well placements. Production data studies, pressure surveys, and detailed subsurface studies will be integrated in improving the understanding of the reservoir behavior to predict reservoir performance. The key findings indicate high increments in oil production on account of the implementation of new development wells. The current research provides not only empirical evidence supporting the efficacy of strategic drilling but also lends a structured workflow applicable for similar mature oil fields, thus providing practical means for increasing production and betterment in field life. Opportunities that deliver high value yet have limited associated risks and costs are typically characterized in general by short payout periods and reinvestment of savings. Unlock residual potential from low-productivity or shut-in wells, maximizing asset value, and information driving decisions on optimizing is an asset development strategy. These strategies can only be effectively implemented if inter-disciplinary teams work together to ensure that data is comprehensively analyzed and all solutions are formulated in line with these analyses.

This work discusses the efficiency of developing non drained oil reservoir blocks strategy in optimizing hydrocarbon production from mature oil fields. Using dynamic modeling techniques together with subsurface interpretations that were based on sharply adjacent well data, the study has presented new development well placements. The study of the Abu Rudeis oil field has laid the foundation for long-term optimization, integrating production data, pressure surveys, and geological studies into a comprehensive reservoir management strategy. The interdisciplinary approach ensured well-informed and targeted decisions, resulting in enhanced hydrocarbon recovery and improved field performance. Results from three-dimensional grid that captured heterogeneity in the reservoir, the assignment of reservoir properties like porosity and permeability and fluids distribution helped to leveraging data-driven strategies and advanced technology, the field's sustainability and efficiency have been significantly improved, providing a strong foundation for future optimization efforts.

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Introduction

Mature oil fields, generally characterized by decline in production rates and complex conditions of the reservoir, constitute a significant fraction of the world's petroleum industry [1,2]. Generally, a mature oil field will mean any field that has been heavily exploited during regimes that stretch for decades; hence, this diminishes the chances of maintaining optimal production levels and maximizes hydrocarbon recovery [3,4]. The identification of no drained reservoir blocks and the strategic placement of development wells form a critical approach for rejuvenating such mature fields and extending productive life [5]. Unless advanced modeling tools and multidisciplinary expertise are brought to bear, traditional approaches to reservoir management, typically based on simplistic static models and built from historical data, are more likely to overlook the dynamic nature of reservoir behavior and the potential for optimum well placement. There is, hence, substantial opportunity for tapping these reserves and maximizing field-wide production rates [6,7].

Traditional static modeling techniques are foundational methods used in field development to characterize subsurface reservoirs and plan production strategies. These techniques rely on geological and engineering data to create static representations of the reservoir's physical properties, without accounting for changes over time Traditional approaches in field development, particularly static modeling techniques, face significant limitations when it comes to capturing dynamic field behavior [7,8].

Dynamic modeling techniques in the context of oil field development refer to sophisticated computational methods used to simulate the time-dependent behavior of reservoirs and optimize production strategies. Unlike static modeling, which provides a snapshot of reservoir conditions at a specific point in time, dynamic modeling considers the fluid flow dynamics, pressure changes, and production history over the entire life cycle of the reservoir [2,7,9].

Dynamic modeling offers several significant advantages over traditional static models when it comes to optimizing field development and reservoir management [10,11]. Accurate Representation of Time-Dependent Processes: Dynamic models simulate the evolution of reservoir conditions over time, capturing changes in reservoir pressure, fluid movement, and production rates [11]. Unlike static models that provide a snapshot of reservoir properties at a single point in time, dynamic modeling accounts for the dynamic behavior of fluids and reservoirs, leading to more accurate predictions of reservoir performance [12]. Improved Reservoir Characterization: Dynamic modeling incorporates detailed reservoir characterization, including variations in permeability, porosity, and fluid properties across the reservoir. This comprehensive understanding allows for better identification of reservoir compartments, fluid flow pathways, and geologic heterogeneities that impact reservoir behavior and production strategies [13].

This paper deals with mature oil fields that still have significant amounts of hydrocarbons remaining, either in erosional or otherwise tight geological formations or simply in under-exploited reservoir compartments. The placing of development wells in undrained blocks of the reservoir in a meaningful way is the emphasis, and hence does not encompass themes of petroleum engineering such as new drilling technologies or how to optimize surface facilities [12,13]. The major emphasis is on the interaction of dynamic modeling and subsystem analysis in achieving optimized reservoir management and well placement [14]. The main objective of the study is to evaluate the effectiveness of applying dynamic modeling techniques in conjunction with detailed subsurface interpretations toward optimizing hydrocarbon recovery in mature oil fields. Particular emphasis has been placed on the optimization of well placement in undrained reservoir blocks to help unlock remaining reserves.

Methodology

Study Area

This study focuses on Abu Rudeis Field, Fig., it is centrally located in the Gulf of Suez, more precisely along the shoreline of the Sinai Peninsula. Hydrocarbons were first discovered in this field in 1957 when Abu Rudeis Well-02 was drilled and tested for oil within the Lower Miocene AB Formation. The primary area of interest for this study lies within the NW-SE trending El Qaa half-graben located on the eastern margin of the central Suez Rift, within the Sinai Peninsula. This approximately 40 km-long and 15-20 km-wide basin was developed as a consequence of eastward tilting of the Nezzazat fault block during Early Miocene. This structural subsidence, because of normal faulting during the Miocene, gradually gave way to a number of sub-basins that were subsequently flooded by marine waters, allowing the deposition of various sedimentary facies. As much as 1-kilometer-thick Miocene syn-rift deposits built up, ranging from shallow marine limestones and sandstones on the structural highs to shales and marls in deeper parts of the basin.

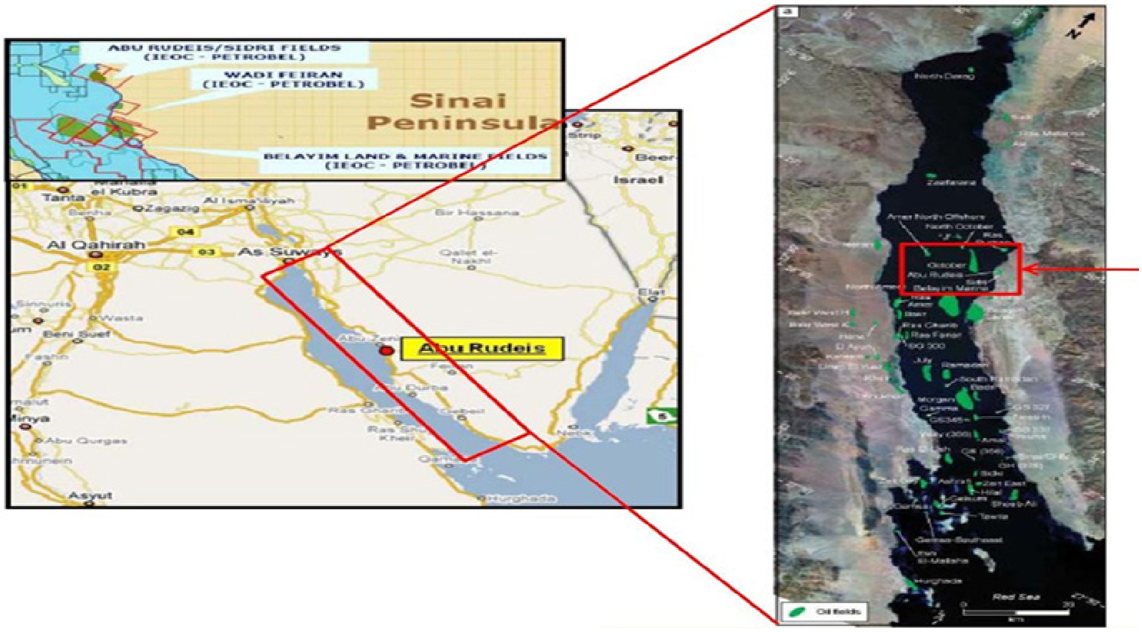

Figure 1: Location of Abu Rudeis Field [2]

A simplified, integrated workflow used in this study to enhance hydrocarbon recovery from undrained blocks in mature oil reservoir of AbuMadhi oil field, Nile Delta, Egypt. The workflow initiates with the gathering of data related to historical production, pressure surveys, and detailed subsurface studies like well log interpretations and geological data, as shown in Fig. 2. The acquired data will be analyzed properly for identifying major reservoir characteristics and any probable undrained blocks. Next, dynamic modeling methods will be used to simulate the behavior of the reservoir, to calibrate models on historical data, and to run simulations to determine optimal well placements [15,16]. Simulation results from these studies provide a basis for the strategic placement of new development wells supported by in-depth risk assessment, which aims at evaluating the associated costs and risks. This is then followed by an implementation phase where the new wells are drilled, their performance monitored, and necessary changes made in line with real-time data. This methodology is underscored by interdisciplinary collaboration among geologists, engineers, and data scientists to guarantee a deep understanding of the reservoir and informed decision-making [17,18]. Economic evaluations shall be carried out on the proposed strategies for their financial benefits through cost-benefit analysis and considerations of return on investment.

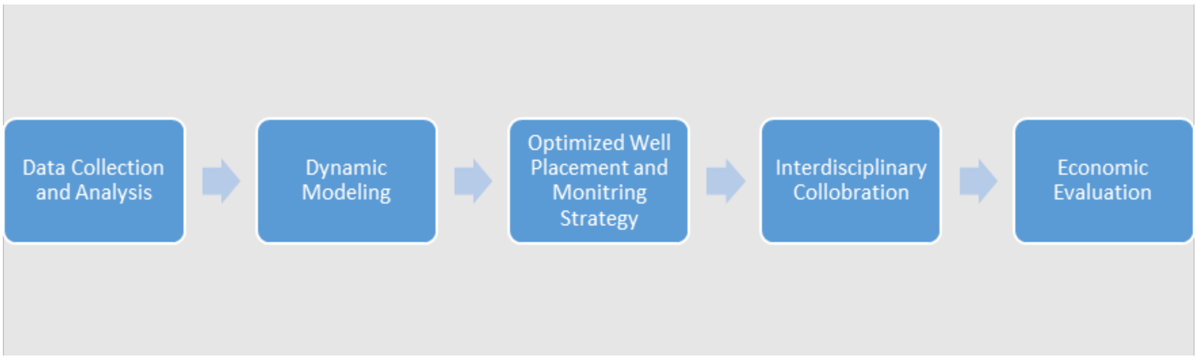

Figure 2: Streamlined, Integrated Workflow, [17]

This approach will now be applied to the mature oil field in order to prove its practical effectiveness. This field, in particular—the main original oil in place with respect to the AB formation—represents a very good case study for the validation of this workflow. The research does not only target the improvement of hydrocarbon recovery and elongation in productive life of mature oil fields, but is also directed towards setting up a new benchmark for field optimization. It will provide valuable insight and establish a replicable model under similar situations within the industry [19-21].

Production Data

The source and interpretation of production data are important activities in seeking a deep understanding of an oil field and how it can be optimized. This involves gathering all available production rates, cumulative recovery data, water cut trends, and any other abnormalities that can be retrieved from historical records [22-24]. Compiling this comprehensive dataset is essential as it forms the basis for detailed analysis. Such analysis is vital for identifying trends, comparing well performance across different wells, and investigating any production anomalies that may arise. Interpreted data like this is invaluable as it allows for the projection of future production, optimal well placement, and the formulation of strategies aimed at enhancing recovery [25-27]. Ensuring that field management decisions are made based on accurate and factual data is paramount, as it directly influences the effectiveness of the optimization strategies implemented. Fig. 3 illustrates production from the AB Formation began in July 1957, and the history of fluid production was simulated from that time until September 2014, top curve is production rate, middle curve is water cut, and bottom curve represents cumulative production. Monthly intervals were used in the simulation model to provide a detailed understanding of production rates, pressures, and water-cut trends. The history match phase involved adjusting certain parameters, such as transmissibility, to achieve a close match between simulated and actual production. The field was confirmed to have three distinct producing levels, which communicated via sand-to-sand contact along fault planes. Water encroachment from the aquifer was identified as affecting production, particularly in the southwest and northeast regions of the field.

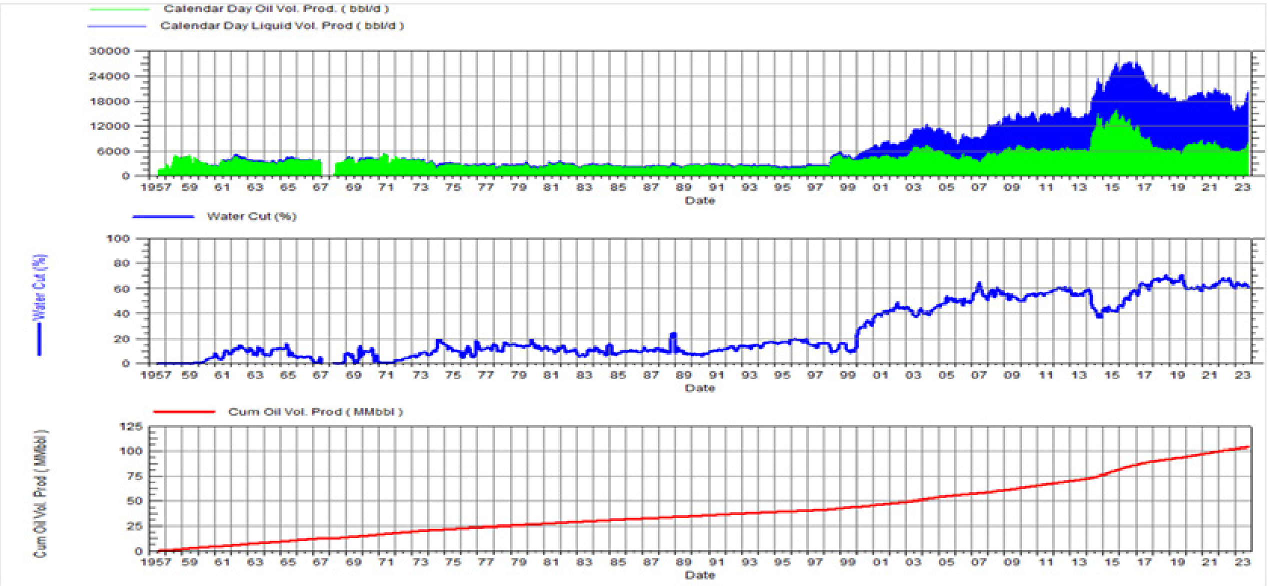

Figure 3: Production Rate, Water Cut and Cumulative Oil Production.

Figure 4 presents production decline analysis. Understanding and interpreting production data is crucial for fully grasping how an oil field like the N field operates and identifying opportunities for improvement. It all starts with carefully collecting as much production data as possible, including production rates, cumulative recovery, water cut trends, gas-oil ratios, and any anomalies that could point to hidden issues within the reservoir. This data is typically gathered from historical records, production logs, well reports, and other operational documents, giving a detailed view of how the field has performed over time. However, it's not just about gathering numbers. Each piece of data needs to be thoroughly checked for accuracy and consistency, as even small errors can lead to incorrect conclusions about the reservoir's behavior. Ensuring the data is reliable is essential for analyzing it effectively and uncovering trends that might otherwise go unnoticed. For example, analyzing production rates over time can help identify drops in performance, which might point to problems like water breakthrough, compartmentalization of the reservoir, or mechanical issues in the wells

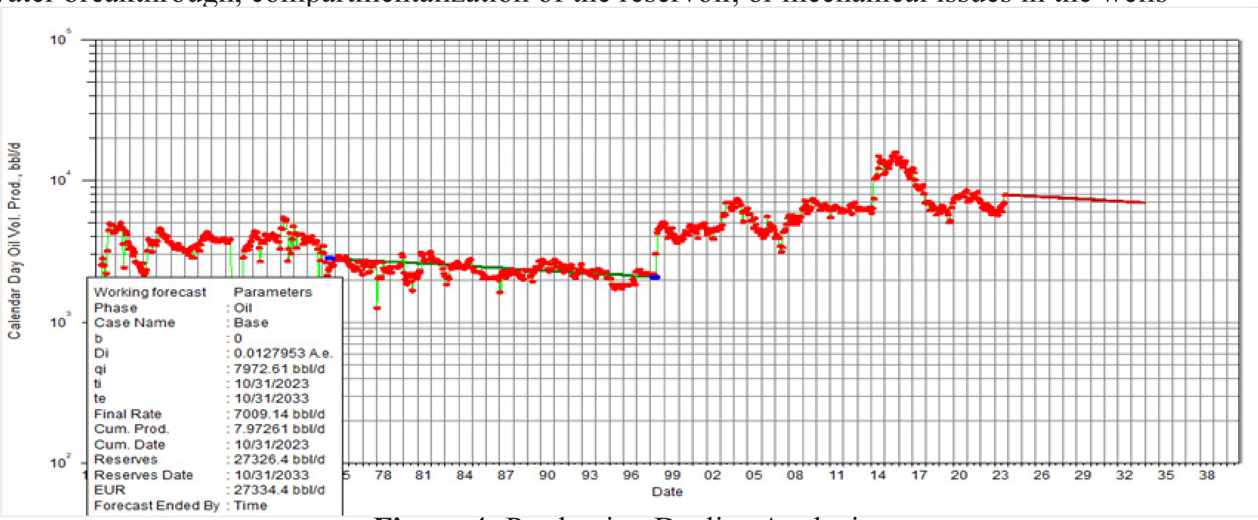

Figure 4: Production Decline Analysis.

Pressure Surveys

Pressure data acquisition and interpretation were necessary to have a good understanding of the reservoir pressure distribution and related repercussions on this reservoir's performance. This will be very important in refining well placement and, equivalently, in building reservoir management strategies. Detailed pressure surveys were done with state-of-the-art techniques such as wireline formation testing and downhole pressure gauges, Fig. 5. These data were carefully interpreted for pressure-depth and pressure-time plots in order to assess some of the key properties of the reservoir, such as its permeability and drainage area. From these assessments, high and low-pressure zones could be distinguished, indicating areas that were highly productive or else potential flow barriers. This pressure information was combined with geological data to give a comprehensive picture of the entire reservoir. There were some significant pressure drops and anomalies observed, which gave invaluable information regarding possible locations for further drilling and helped predict the behavior in the future of the reservoir and the operations of its recovery. This procedure incorporates a comprehensive and detailed analysis of the pressure data needed to build dynamic models and strategies for enhanced recovery and field life extension.

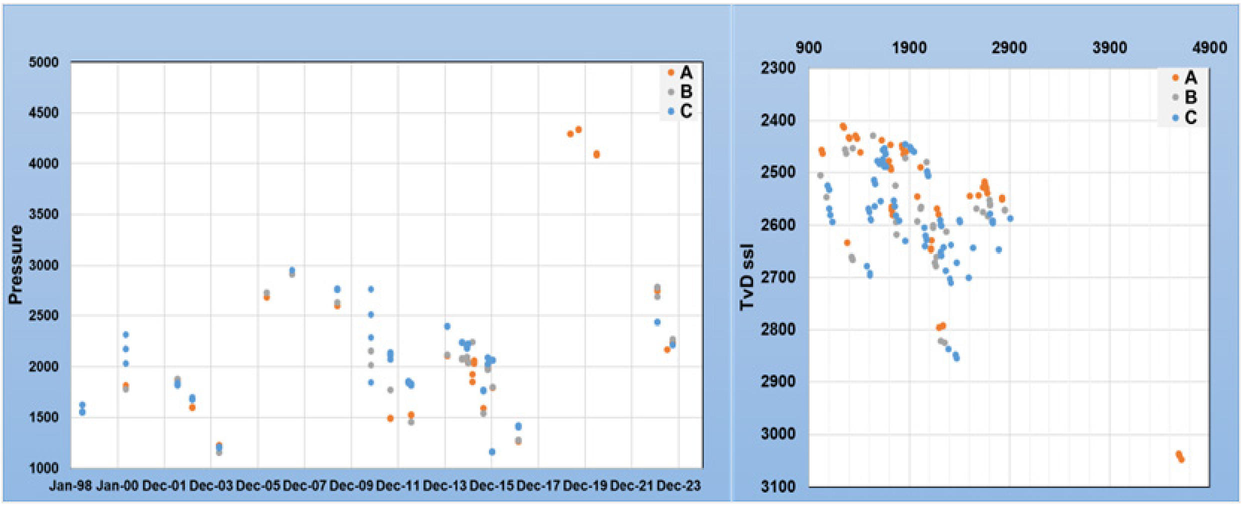

Figure 5: Reservoir Pressure from RFT.

Additionally, this detailed pressure data analysis was crucial for developing dynamic models of the reservoir. These models simulate how the reservoir will respond to different production and injection strategies, offering insights into future reservoir performance. For example, the models can predict how reservoir pressure will change over time, helping to optimize well placement, set production rates, and design effective water or gas injection strategies. By incorporating pressure data into these models, operators can make better decisions that maximize recovery and extend the productive life of the reservoir. In short, acquiring and interpreting pressure data is a key part of managing a reservoir. This analysis not only helps identify important reservoir properties like permeability and drainage areas but also guides well placement and production strategies. By integrating pressure data with geological insights, operators can gain a deeper understanding of the reservoir, optimize recovery, and ensure long-term success in the field. This integrated approach, supported by dynamic modeling, is essential for making informed decisions that boost reservoir performance and maximize the value of the N field. Regarding the sealing potential of the fault system shown in Fig. 6 there were two different trends can be highlighted after water injection started up in 1999. This figure shows depletion of reservoir pressure until December 2001 and then water injection program was resumed which led to change in reservoir pressure adding more energy to reservoir driving forces until December 2024. Water injection program started in December 01 and followed by no injection activity until April 21 and after that water injection program was resumed which led to change in reservoir pressure.

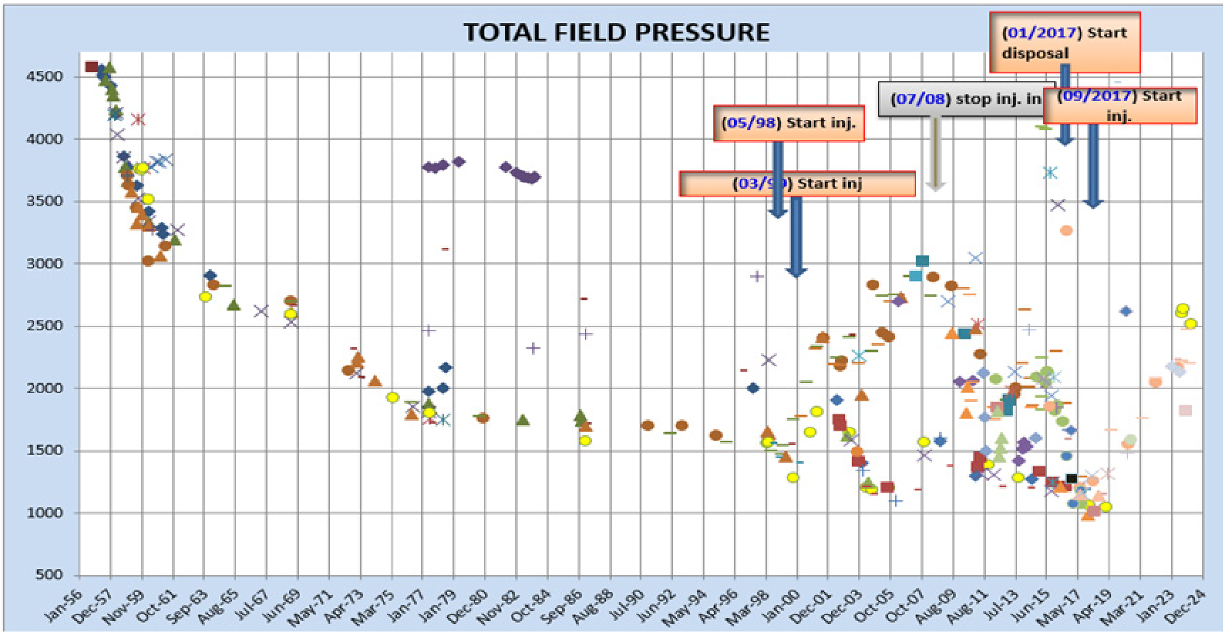

Figure 6: Reservoir Pressure Trend.

Discussion

Dynamic Model of AB Formation

Reservoir engineering efforts within the Abu Rudeis Field focused on evaluating reservoir performance and dynamic behavior to optimize production. Through history matching, reservoir simulations were calibrated to match historical data, providing insights into future production trends. These efforts helped establish recovery factors and identify areas for further optimization, such as new well placements and water injection strategies. Dynamic model of the reservoir was built to simulate how it behaves, bringing together geological, petrophysical, and production data into one framework. The process started by creating a 3D grid that captured the reservoir's natural variations. Each grid cell was assigned specific properties like porosity and permeability, reflecting the differences within the reservoir. The model was set up with initial conditions, such as pressure and fluid distribution, to prepare for the simulations. This approach made sure the model could accurately represent the reservoir's complex nature.

Subsurface Studies

Surface study will further allow an in-depth study of the geology and petrophysics of field N through subsurface studies for an insight into the architecture of this reservoir, its rock properties, and fluid distributions—information that is important for informed well placement and, hence, reservoir management decisions. In these studies, major concern was devoted to the process of well log interpretation, which was based on the analysis of the gamma ray, resistivity, neutron porosity, and density logs to differentiate the shale from the sandstone formations, identification of the hydrocarbon-bearing zones, and evaluation of the porosity and lithology,[25,26]. The well logs were integrated with core samples and seismic data to develop a detailed geological model, based on which the major structural features that control fluid flow were underpinned, such as faults and fractures. It allowed for accurate reservoir zonation and mapping of fluid distribution, understanding the interaction of structural features with fluid migration.

Key ingredients in these subsurface studies were the interpretation of gamma ray logs to identify intervals containing sandstones with potential hydrocarbon content, followed by the cross-plot of neutron porosity with density logs. Highlighted were those high porosity zones important for hydrocarbon storage, Fig. 7 demonstrates well logging analysis of AB Formation. It is possible to recognize three different sub-layers. The upper one (highlighted in green) is more arenaceous. The middle one (highlighted in blue) shows low porosity,

, usually less than 10%, while the lower one (highlighted in light blue) is usually the most calcareous. Further, the geological data—core samples and seismic surveys—formed a robust structural interpretation that delivered fault and fracture analysis, stratigraphic correlation, and reservoir characterization. The main reservoir zonation of AB formation which has been divided in five main levels: AB A: Shoreline System deposits (Facies Associations A), AB B: Shoreline System deposits (Facies Associations A-B), AB C: Fluvial-Deltaic System deposits (Facies Associations C-D), AB D: Alluvial System deposits (Facies Association E) and AB A, B and C are divided by two shaly interlayers, AB D is usually tight. These zones are characterized by certain permeability- porosity heterogeneity as shown in Fig. 8, different correlations of permeability as a function of porosity were generated by using core data from different wells for AB formation.

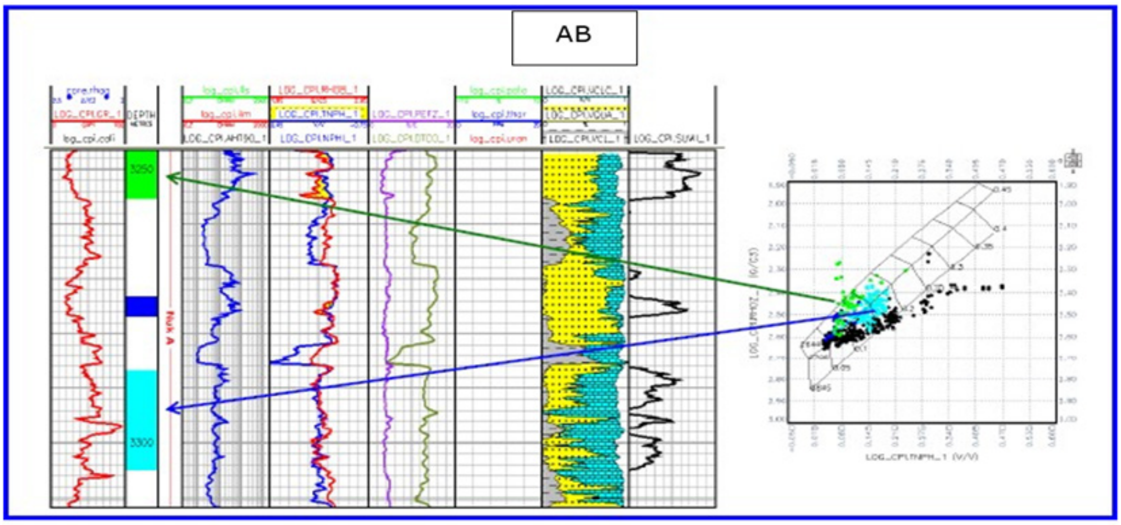

Figure 7: Well Logs Response and Lithofacies Distribution on Density- Neutron Cross-Plot, AB Formation.

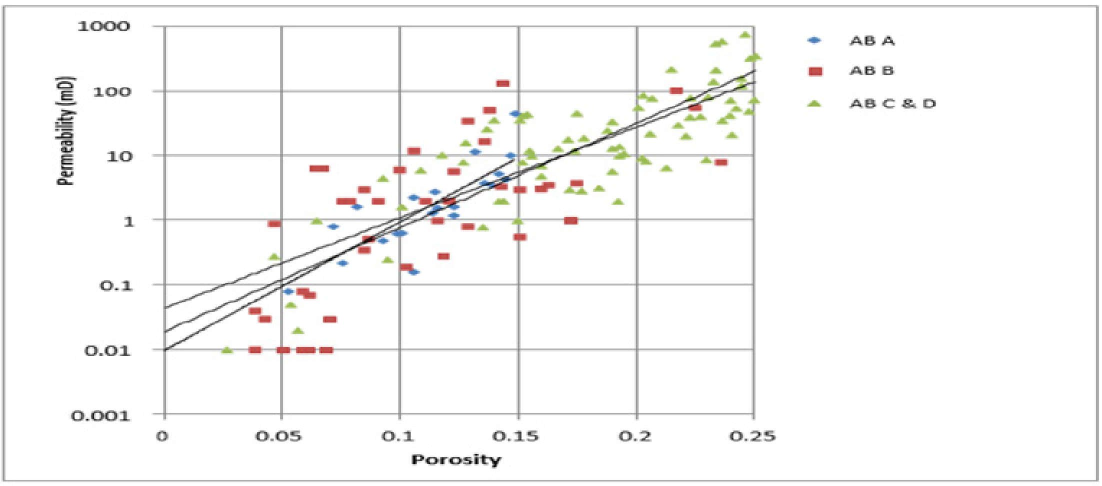

Figure 8: Porosity-Permeability Function of AB Zonation.

Results

Dynamic Model of AB Formation

Dynamic model of the reservoir was built model its behavior based on geological, petrophysical, and production data combined in one framework. This involved the construction of a three-dimensional grid that captured heterogeneity in the reservoir, the assignment of reservoir properties like porosity and permeability to grid cells, and the definition of initial conditions such as pressure and fluid distribution. Various production and injection scenarios were simulated in an attempt to establish their interactions with the performance of the reservoir, including the optimum well placement and proper production strategies. Fig. 9 visualizes the constructed grid of the reservoir, highlighting its heterogeneity, such as variations in porosity, permeability, and fluid saturation. The model was calibrated using historical data so that it is representative of reality. This is because simulation takes place through iterative adjustments of parameters validated with independent data sets. Finally, an uncertainty analysis was performed that yields confidence in the model predictions, enabling the delivery of reliable guidance on management and optimization of the reservoir

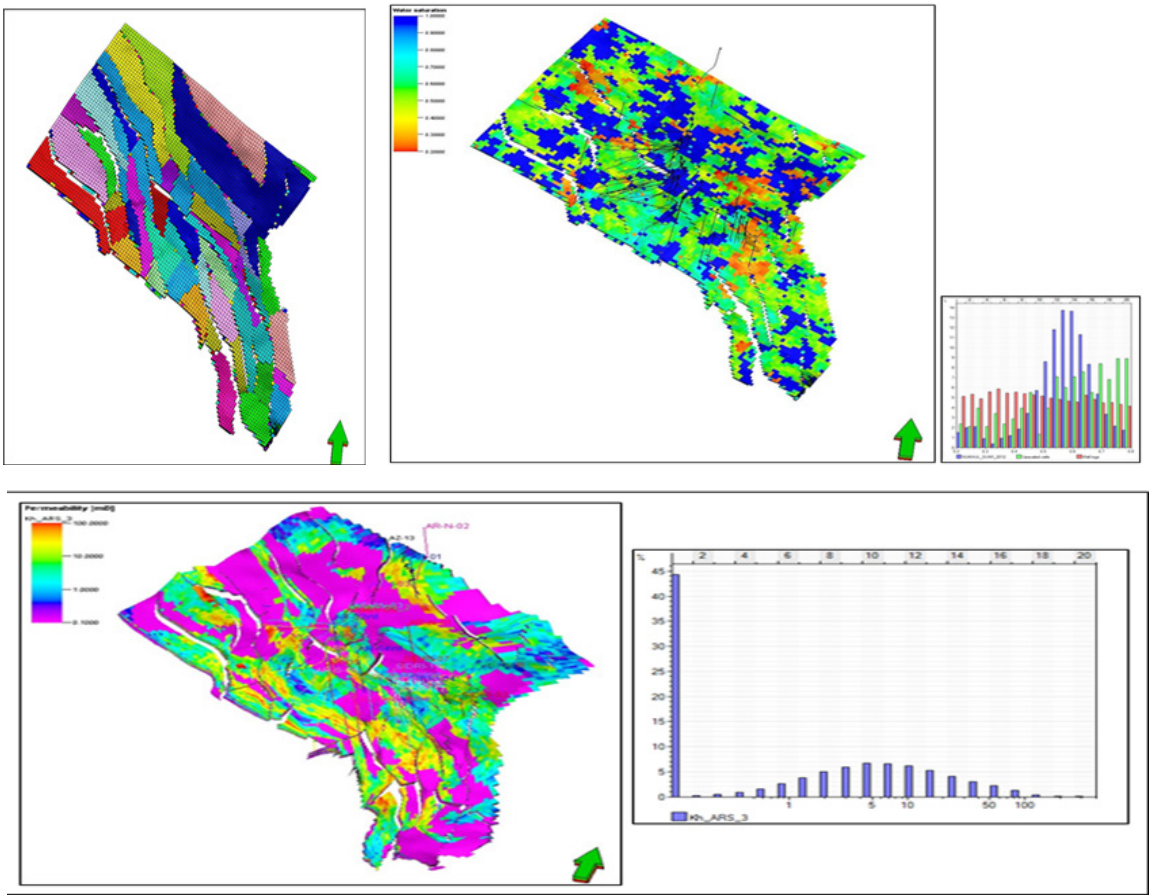

Figure 9: Three-Dimensional Grid Representation, AB Formation

Optimized Well Placement and Monitoring Strategy

This well placement strategy was designed to identify areas not drained properly and to model the optimal placement of new development wells in order to enhance recovery. A number of areas with relatively higher pressures, high hydrocarbon saturation, and considered to be the potential non-drained areas were identified from the dynamic modeling results. In search of optimum placements, different well configurations like horizontal, vertical, and deviated wells were tried. The production rates had also been assessed, and proper economic analysis had been performed to ensure cost-effectiveness. Elaborate assessment was done for the geological, operational, and economic risks related to the new well placements.

Well placement strategy implementation and monitoring used to give knowledge about the developments in the behavior and performance of this reservoir. New wells drilled in the non-drained blocks that have been identified substantially improve hydrocarbon recovery and, thereby, field production. With continuous monitoring and evaluation, timely adjustments have been made to ensure optimum production and reduce risks. Positive trends in well performance real-time data include increased rates and stable reservoir pressure. Reservoir pressure varies from of high pressure, indicating potential non-drained zones to low pressure in drained areas.

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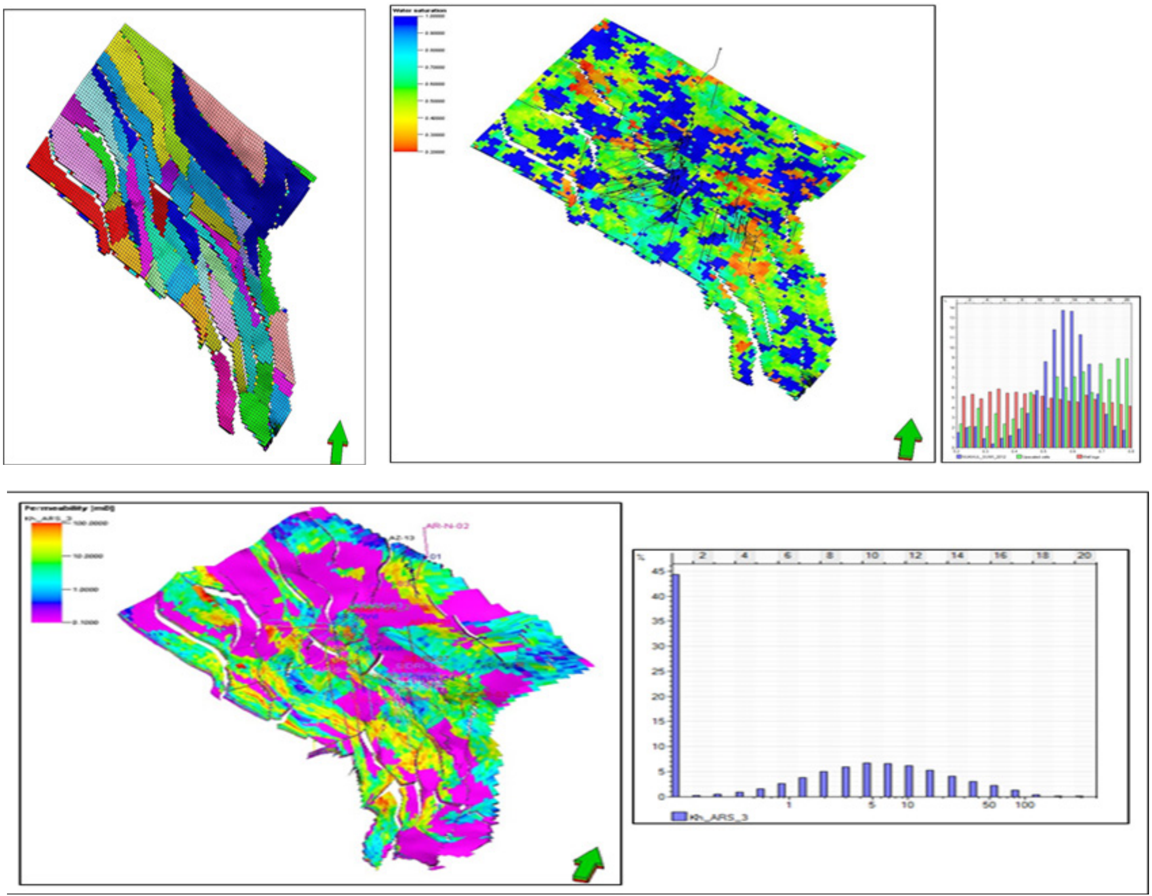

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Fig. 10 illustrates the distribution of hydrocarbons within the reservoir, identifying areas with significant hydrocarbon saturation that have not been effectively drained.

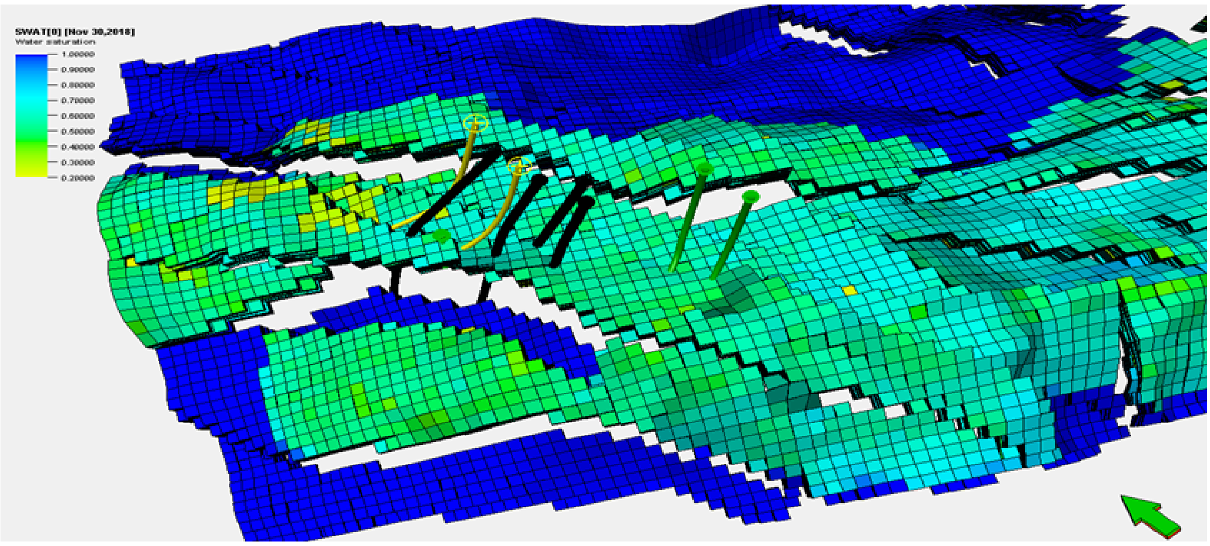

Figure 10: Hydrocarbon Saturation Distribution Map, AB Formation

Interdisciplinary Collaboration

The integration of geologists, engineers, and data scientists increased the understanding of the reservoir and allowed good decision-making. The team came up with more accurate and reliable models by integrating geological, production, pressure, and well log data. Regular meetings, workshops, and jointly working on data analyses kept up good communication and teamwork—hence, a unified effort. This integrated approach to well placement strategies and reservoir management enabled the team to gain some important insights and make very well-informed decisions. Teamwork insured that those decisions are based on correct and reliable insights to optimize production while mitigating risks. This then enabled the team to manage the reservoir much more effectively and achieve enhanced results. The interdisciplinary collaboration was core to strategic decisions, right from well placement strategies to improved reservoir performance.

Economic Evaluation of Study

The economic evaluation of Abu Rudeis field optimization, from a monetary value standpoint, was relative: it compared the costs related to new development wells. This analysis demonstrated that actual pay-out time realized was within 2 years from the production start date. In 5 years, the cash flow generated amounted to $15 million, which is a tremendous return considering the $5 million spent in drilling and operational costs. This positive cash flow indicates that the project is financially viable, capable of substantial returns within a relatively short period. The economic analysis also addressed the efficiency of the optimization strategies that were implemented and how well they work in enhancing production to ensure financial sustainability. These results show the potential for further investment and development in the N-field, providing a strong base for future economic planning and decision-making.

Conclusion

Study of the Abu Rudeis field has significantly enhanced the understanding of its performance and optimization potential. Analysis of production data identified key trends and anomalies, aiding future production forecasts. Pressure surveys provided crucial insights into reservoir pressure distribution, essential for optimal well placement and management strategies. Integration of geological and pressure data helped define structural features critical to fluid flow and hydrocarbon recovery. Subsurface studies refined the geological model, supporting effective reservoir zonation and fluid distribution mapping. The combination of continuous monitoring, real-time data analysis, and an interdisciplinary, data-driven approach ensured improved hydrocarbon recovery, sustained field production, and a strong foundation for future optimization.

Data-driven approach for Abu Rudeis field helped to pinpoint areas of concern and opportunities for improvement, ensuring well-informed and targeted strategies. The detailed analysis of production data revealed patterns crucial for understanding reservoir behavior over time, allowing for better planning to maximize hydrocarbon recovery while minimizing risks. The key findings indicate high increments in oil production on account of the implementation of new development wells. The current research provides not only empirical evidence supporting the efficacy of strategic drilling but also lends a structured workflow applicable for similar mature oil fields, thereupon; providing practical means for increasing production and betterment in field life.

This study of Abu Rudeis oil field has laid the foundation for similar mature oil fields 1) long-term optimization, integrating production data, pressure surveys, and geological studies into a comprehensive reservoir management strategy, 2) The interdisciplinary approach ensured well-informed and targeted decisions are resulting in enhanced hydrocarbon recovery and improved field performance, 3) By leveraging data-driven strategies and advanced technology, the field's sustainability and efficiency have been significantly improving and providing a strong foundation for future optimization efforts and 4) An interdisciplinary approach combining expertise from geologists, engineers, and data scientists was essential in refining reservoir management strategies.

Declarations

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This study did not receive any fund.

Competing Interests Statement

The authors declare no competing financial, professional, or personal interests.

Consent for publication

The authors declare that they consented to the publication of this study.

Authors' contributions

All the authors made an equal contribution in the Conception and design of the work, Data collection, Drafting the article, and Critical revision of the article. All the authors have read and approved the final copy of the manuscript.

Availability of data and material

Authors are willing to share data and material according to the relevant needs

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