Methods Used to Estimate Reservoir Pressure Performance: A Review

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ABSTRACT

Reservoir pressure plays a significant role in all reservoir and production engineering studies. It is crucial to characterize petroleum reservoirs: by detecting fluid movement, computing oil in place, and calculating the recovery factor. Knowledge of reservoir pressure is essential for predicting future production rates, optimizing well performance, or planning enhanced oil recovery strategies. However, applying the methods to investigate reservoir pressure performance is challenging because reservoirs are large, complex systems with irregular geometries in subsurface formations with numerous uncertainties and limited information about the reservoir's structure and behavior. Furthermore, many computational techniques, both numerical and analytical, have been utilized to examine reservoir pressure performance. This paper summarizes the concepts and applications of traditional and novel ways to investigate reservoir pressure changes over time. It provides a comprehensive review that assists the reader in recognizing and distinguishing between various techniques for obtaining an accurate description of reservoir pressure behavior during production, such as the reservoir simulation method, material balance equation approach, time-lapse seismic data, and modern artificial intelligence methods. Thus, the central concept of these procedures and a list of the authors' research are discussed.

Keywords: Reservoir pressure, Reservoir simulation, Material balance equation, Time-Lapse seismic data.

الطرق المستخدمة في تحديد ادائية الضغط المكمني : مراجعة

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الخلاصة

يلعب الضغط المكمني دورًا مهمًا في جميع دراسات هندسة المكمن والإنتاج. فهو بالغ الأهمية في توصيف الخزانات البترولية من خلال : اكتشاف حركة السوائل ، وحساب النفط الابتدائي في المكمن ، وحساب عامل الاسترداد. تعد معرفة ضغط المكمن أمرًا بالغ الأهمية للتنبؤ بمعدلات الإنتاج المستقبلية ، أو تحسين أداء البئر ، أو التخطيط لاستراتيجيات محسنة لاستخراج النفط. ومع ذلك ، فإن تطبيق الطرق المستخدمة لفحص أداء ضغط المكمن يمثل تحديًا. ويرجع ذلك إلى أن المكامن هي أنظمة كبيرة ومعقدة ذات أشكال هندسية غير منتظمة توجد في التكوينات الجوفية مع العديد من أوجه عدم اليقين والمعلومات المحدودة حول هيكل المكمن وسلوكه. علاوة على ذلك ، تم استخدام العديد من التقنيات الحسابية ، العددية والتحليلية ، لفحص أداء ضغط المكمن. تلخص هذه الورقة مفاهيم وتطبيقات الطرق التقليدية والجديدة للتحقيق في تغيرات ضغط المكمن بمرور الوقت. كما تقدم هذه الورقة البحثية مراجعة شاملة تساعد القارئ في التعرف والتمييز بين التقنيات المختلفة للحصول على وصف دقيق لسلوك ضغط المكمن أثناء الإنتاج ، مثل طريقة محاكاة المكامن ، ونهج معادلة توازن المواد ، والبيانات الزلزالية ذات الفاصل الزمني، وأساليب الذكاء الاصطناعي الحديثة. وبالتالي ، فأن المفهوم المركزي لهذه الإجراءات مع قائمة بأبحاث المؤلفين تمت مناقشتها.

الكلمات المفتاحية: الضغط المكمني ، محاكاة المكامن ، معادلة توازن المواد ، البيانات الزلزالية بفاصل زمني.

1. INTRODUCTION

The most crucial parameter in effectively controlling field development strategies, which describes the reservoir energy and must be continuously investigated, is reservoir pressure (**Galkin et al., 2021**). Since reservoir pressure varies as fluids are produced, it should be identified by a name specific to the measurement period. The reservoir pressure for a brand-new field at the moment of discovery when no production is taking place is referred to as the initial reservoir pressure, whereas for a field with prior production history, it is referred to as the average reservoir pressure (**Gyan et al., 2019**). The average reservoir pressure indicates how much gas, oil, or water remains in a reservoir at any particular moment during the production stage. It represents the reservoir energy that drives these fluids toward the wellbore (**Ghanavati et al., 2014**). It is essential to estimate the average reservoir pressure and its variations as a function of time or accumulative production to calculate the oil initially in place (OIP) or gas initially in place (OGIP) as well as estimate the reserves, improve the performance of the wells, plan and assess water flooding processes and multiple enhanced oil recovery operations, and ensure that an efficient pressure management scheme is implemented and maintained (**Mohammed et al., 2014; Al- Obaidi and Al-Jawad, 2020; Al-Mudhafar et al., 2021**).

Developing any reservoir requires great wariness and interest in pressure and fluid flow, particularly investigating the variation of reservoir pressure with time and space during production. An effective hydrocarbon recovery strategy involves taking natural reservoir energy into account. However, many reservoir engineers have adopted strategies to

investigate the reservoir performance and enhance its recovery factor: the ratio of the produced hydrocarbons to the original oil in place (**Gyan et al., 2019**). Based on the preceding information, estimating the pressure behavior under the present and anticipated future strategies is necessary to acquire a more accurate knowledge of the reservoir's behavior and thus aid in constructing a comprehensive field development plan. Since one of the leading reservoir engineer's responsibilities is to monitor the reservoir constantly, gather pertinent data, and evaluate them to examine the reservoir's current status, predict future conditions, and control the flow of fluids through the reservoir to increase the recovery factor and improve oil recovery (**Sylvester and Onyekonwu, 2015**). Consequently, it attracted numerous scholars' attention and was their study's primary subject.

This paper provides an exhaustive overview that assists the reader in recognizing and differentiating various techniques for obtaining a precise description of reservoir pressure behavior during production. It also demonstrates each method's limitations and the range of implementation to achieve an adequate degree of precision and run time. The approaches and published research that have been utilized to examine and predict reservoir pressure behavior as part of overall reservoir performance are described in this study.

2. METHODS USED TO ESTIMATE RESERVOIR PRESSURE PERFORMANCE

2.1 Reservoir Simulation Method

Reservoir simulation combines mathematics, physics, reservoir management, and computer programming to mimic and visualize an actual reservoir performance and forecast future performance. Simulation has become the unsurpassed approach for describing multiphase, complicated heterogeneous reservoirs (**Jemeel et al., 2020**). Reservoir simulators are essential tools for carrying out early development plans, history matching, improving reservoir performance, and planning and assessing the performance of the reservoir system (**Sapale et al., 2019**). It offers a deep insight into a reservoir's flow mechanisms. By specifying the hydrocarbon recovery process, reservoir modeling can evaluate and reduce the risks involved with the recovery strategy. Due to its computational capacity and high accuracy, reservoir simulation is being employed at all stages, from well testing to enhanced oil recovery prediction (**Hashan et al., 2018**).

Reservoir engineers can use reservoir modeling to understand how a reservoir would produce under a wide range of hypothetical scenarios. Including geology and reservoir data into a unified reservoir model assist in understanding fluid dynamics and characteristics of rocks and their impact on the reservoir's prospective performance (**Mohammed et al., 2020; Al-Obaidi et al., 2023; Majeed and Al-Rbeawi, 2022**). Typical simulation studies predict well production rates, WORs, and GORs with time. Reservoir pressure and fluid saturation are also indicated as functions of both space and time, as shown in **Fig. 1**.

Developing a simulation model requires collaboration between the technical, operating, and management departments for petroleum assets to succeed. Additionally, to reduce the effects of uncertainties in reservoir characterization and flow processes, an integrated methodology is required to develop this insight, so drilling, logging, geochemistry, seismic, geophysics, geology, petrophysical analysis, reservoir engineering, and reservoir management are all covered for this purpose (**Sylvester et al., 2015**). The workflow for general reservoir studies is described in **Fig. 2**.
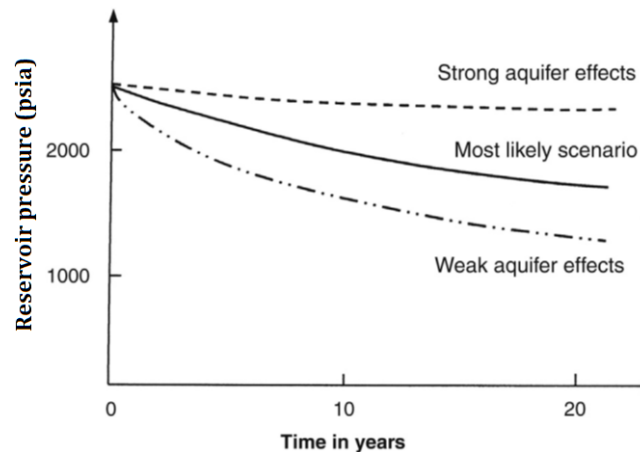
Figure 1. Simulation of likely scenarios of reservoir pressure over time due to varying degrees of water influx (**Satter and Iqbal, 2015**).

To accurately predict future reservoir performance and accomplish effective management, 3-D static models must be built accurately (**Asad and Hamd-Allah, 2022**). The results of building a 3D reservoir grid model significantly impact the modeling of reservoir attributes and numerical simulation based on geostatistics. How the reservoir's macroscopic homogeneity is characterized is a key consideration in the gridding process of geostatistical reservoir modeling. The grid's shape and resolution impact the simulation's precision and speed when applied to a reservoir (**Jassam and Al-Fatlawi, 2023**).

Developing a comprehensive reservoir model of big oil fields necessitates the upscaling of geological models, ultimately reducing the inevitable level. Yet, this upscaling may introduce extra inaccuracies in the simulation process (**Shamkhi and Aljawad, 2020**). Therefore, it is challenging to understand and visualize the reservoirs perfectly because they are enormous and complicated, with large heterogeneity in subterranean formations, multiple unknowns, and scant details about reservoir structure and behavior (**Sylvester and Onyekonwu, 2015**). The construction of a reservoir model is regarded as the fundamental stage for implementing field development plans. Initialization findings and history matching can be used to evaluate the model before it is used for field development planning, ensuring that the model is representative of the reservoir and its performance (**Al-Mozan and Al-Jawad, 2020**). Typically, in history matching, an inverse problem entails modifying model parameters (e.g., permeability, porosity, and other flow attributes) until the reservoir model's simulation outcomes match the observed data, such as pressure and production (**Baker and Awad, 2017**). Generally, a particular history-matched model is used to anticipate future reservoir performance. Since the history match is not unique, the predicted scenarios are uncertain (**Subbey et al., 2004**). As more and improved geoscience, engineering, and production data are available, there should be less uncertainty in the appraisal (or the possible outcomes). Consequently, it is important to recognize these ambiguities (**Sylvester et al., 2015**).

Predicting reservoir pressure behavior from history to the future got the attention of many researchers. (**Acharya, 1987**) conducted a reservoir simulation study to investigate the reservoir performance and aquifer response using the unsteady state water influx and material balance equations. This work was done to describe reservoir behavior and aquifer response and verify the accuracy of the fundamental geological and engineering information; this aided in laying the groundwork for the comprehensive simulation investigations.
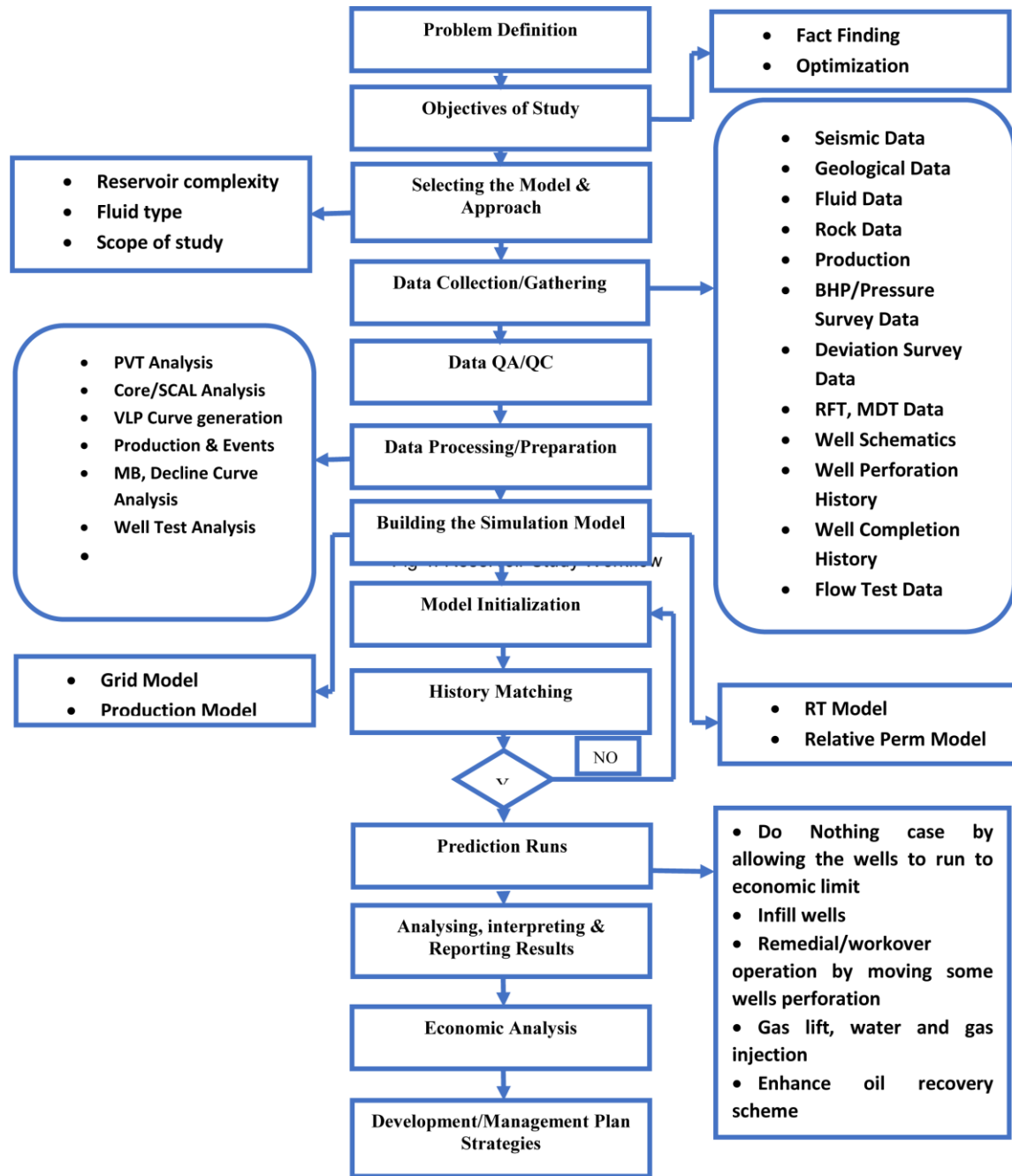
Figure 2. Reservoir study workflow (**Sylvester et al., 2015**).

The critical finding from this material balance analysis is that the reservoir initially behaves like a depletion drive reservoir and that the aquifer only becomes active after a significant pressure differential between the oil zone and the aquifer. While permeability or other variables may cause this phenomenon, the black oil model's historical match indicated that some elements may have served as a barrier to water inflow before eventually collapsing to permit increased inflow. According to this study, the researcher noted that the simulation model could not match the actual pressure behavior with any other assumption besides tarmat breakdown. **(Cagle, 1990)** Used computer reservoir simulation to reevaluate the secondary gas recovery project in a relatively active water drive reservoir. After being

developed as an oil reservoir, gas was injected into the reservoir from 1960 until 1975 to support reservoir pressure for oil production. The blowdown of the gas cap started right after the injection operations. The reservoir pressure dropped to its lowest level during the blowdown period mid-1979, as shown in **Fig. 3.**
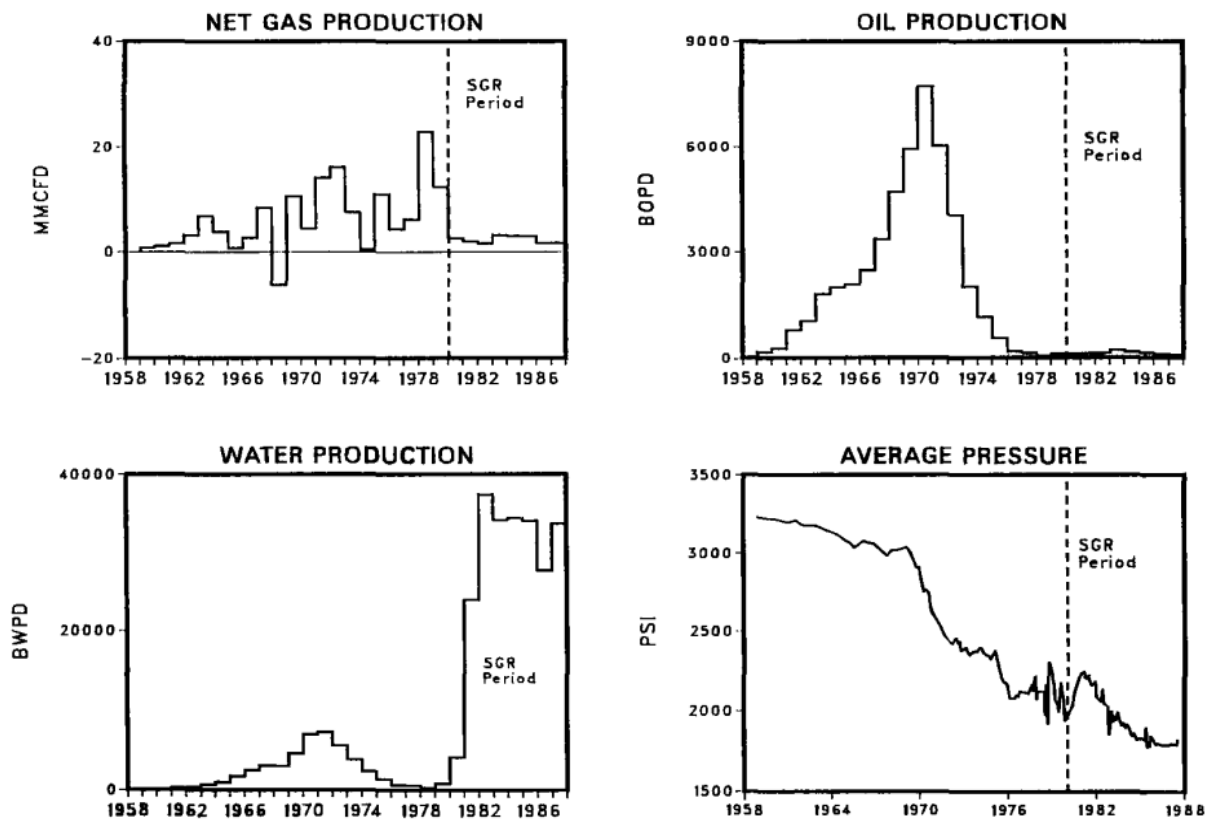

Figure 3. Production and pressure history **(Cagle, 1990).**

The gas cap began to collapse rapidly until the mid-1980s when the gas wells were watered-out. The project aimed to reduce reservoir pressure, allowing trapped gas to expand and restore gas productivity. The simulation model in this study is three-dimensional and three-phase, with a dissolved gas present in both the water and oil phases. The previous models did not account for the addition of gas dissolved in the water of the reservoir and aquifer region. During the history matching, Cagle acquired good match results from the start of production in 1958 under primary recovery to the beginning of the SGR project in 1980. However, beginning in 1985, the history match started to face difficulties. Measured pressures leveled off and indicated a slight increase, whereas the model pressure continued to decrease from 1985 onward see **Fig. 4**.

The investigation revealed no communication with the surrounding reservoir, but it was determined that two water wells of the SGR project were the root of the issue. One of these wells, number 143, had been inactive for over two years; the casing leak of this well was the principal cause of pressure matching problems. Water sands from a depth of 2023 feet to a depth of 6228 feet could enter the reservoir. The other well was number 407, which was active, and had parting casing, causing the communication. On the other hand, the prediction cases examined the effect of varied water withdrawal rates on pressure performance. A withdrawal rate of 60,000 bbl./day would be necessary to reduce reservoir pressure in an acceptable amount of time, as seen in **Fig. 5**.
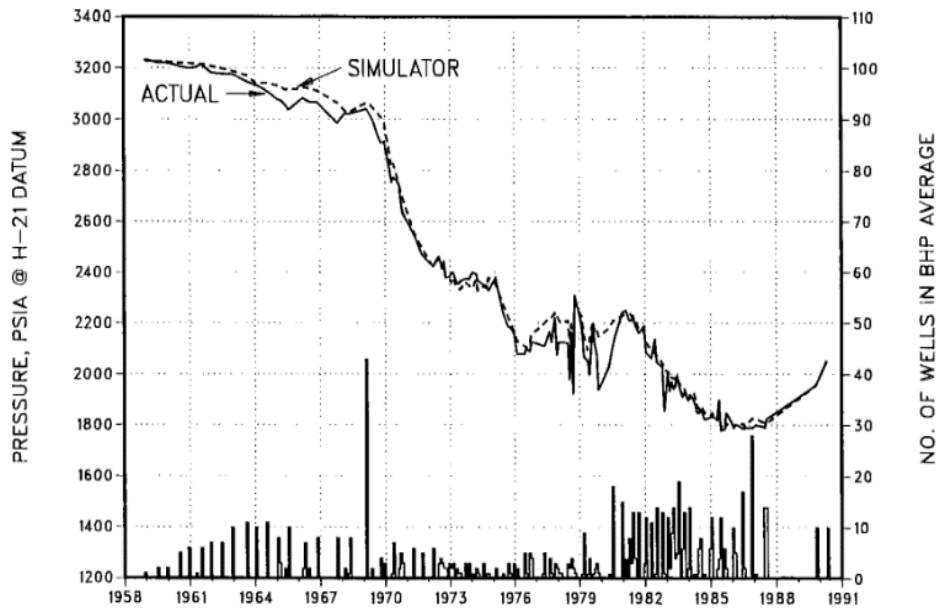
Figure 4. Reservoir simulation history match **(Cagle, 1990).**
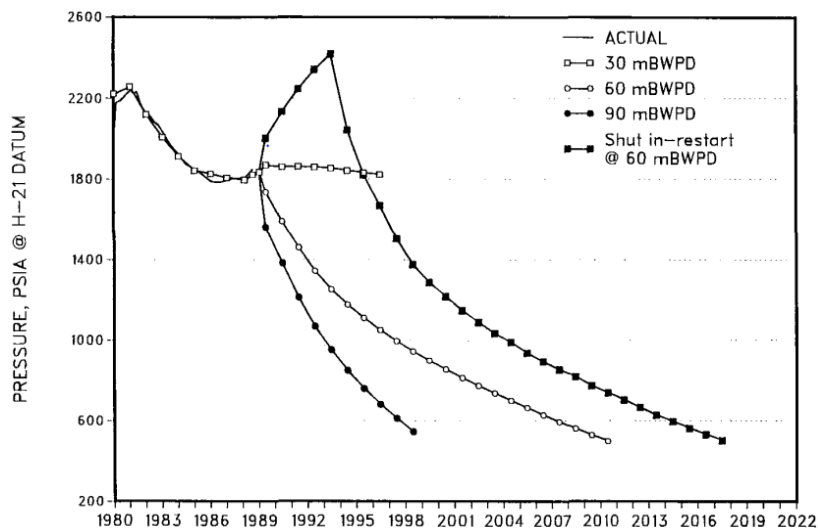

Figure 5. Actual and predicted pressure vs. time **(Cagle, 1990).**

(Sibey et al., 1997) conducted a reservoir simulation study to predict reservoir performance under various scenarios and assess the effects of infill wells and pressure maintenance plans. The proposed model served as the framework for a great history match. Several changes to the geologic model were made during the production and pressure history-matching process, including the vertical permeability of the diagenetic barrier and the horizontal permeability of the deepest layer (much below the OWC); this led to a successful match of the 38-year production and pressure history (1956–94).

(Sibley et al., 1997) found that the field-wide rapid pressure depletion and the delayed influx of water are caused by the diagenetic barrier (DB), which is located close to the base of the reservoir and poses a severe obstacle to fluid flow and pressure support from the underlying aquifer. For the pressure-maintenance strategy, they observed that neither a

typical peripheral flood, in which injection wells are drilled around the edges of the oil accumulation, nor injecting water beneath the oil column to sustain the aquifer would be particularly beneficial. This is because these choices would produce injection beneath the DB, where pressure is already high, and prevent overlying productive intervals from receiving pressure support. The answer was to create a redesigned periphery flood in which injectors are drilled outside the main producing regions and above the DB, as shown in **Fig. 6**. The field-margin areas above the DB will experience pressure support and improved sweep efficiency because of this design. However, there is a delayed pressure response in the center of the field, where pressure support is most required.
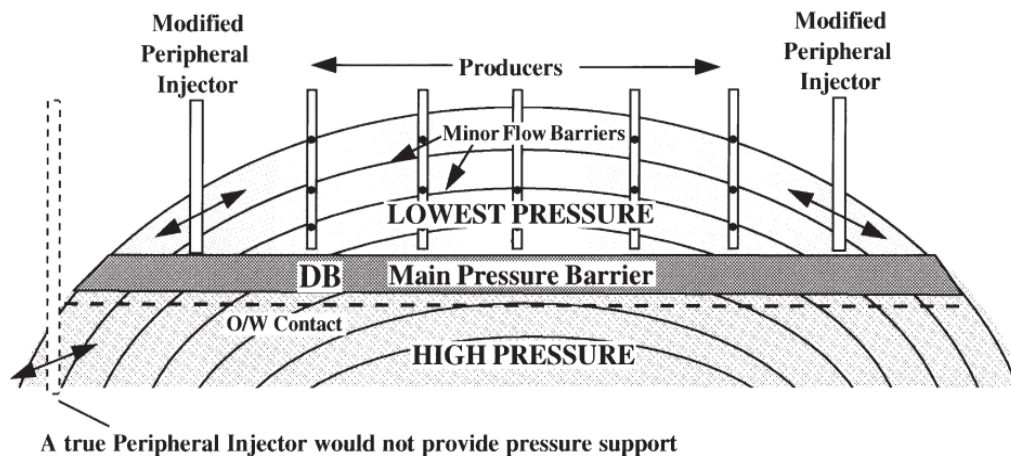

Figure 6. Structural cross-section diagram displaying where the modified peripheral injectors are located **(Sibey et al., 1997).**

 (Grover et al., 2008) used the Tough + Hydrate reservoir simulator to evaluate the observed production data from a Gas Hydrate Reservoir. Single-well two-dimensional cross-sectional models were constructed to mimic gas production and reservoir pressure reports during the primary producing and shutting-in durations. They observed an increase in the average reservoir pressure during shut-in and suggested that the increased reservoir pressure after the well was shut in was because of the reduced intrinsic permeability; namely, the hydrate layer disassembling, not water influx into the reservoir, caused the pressure to rise. They came up with this conclusion by the comparison of the modeling results for different strength aquifers with the observations of previous studies that there has been no movement in the gas-water contact, leading to the assumption that the aquifer has a weak impact on the production of gas from the field. Additionally, many sensitivity cases were conducted to evaluate how the pressure would respond to different permeability levels in the hydrate layer; the results showed that the ongoing gas hydrate disassociation was the cause of the pressure increase.

(Koutsabeloulis and Zhang, 2009) created a coupled reservoir geomechanical model using the VISAGE geomechanics simulator and ECLIPSE reservoir simulator to investigate and calculate pore pressure changes and the status of stress, reservoir characteristics progression, possible fractures development, and present faults rejuvenation. The main idea of this study is that changes in pore pressure brought on by both depleting and injecting processes were first modeled by ECLIPSE and then utilized to calculate the variation in effective stress and the resulting disfigurements in the reservoir by VISAGE.

(Mohammed et al., 2010) utilized a reservoir simulator named "SimBest II" to examine fluid flow in the reservoir and forecast the reservoir's future performance for a sector of the South Rumaila oil field's main pay that has been producing under the natural drive mechanisms for more than 20 years with depletion and water drive mechanisms. Then, for the aim of maintaining pressure, a water injection program was implemented. According to the study, an aquifer and a no-flow border are the two sorts of boundary conditions that can occur in the reservoir. The Carter-Tracy method treats Natural water influx boundaries to the east and west.

A comparison between the model's findings and the actual reservoir performance has been made to evaluate the validity of the current model. So the pressure matching was carried out in two stages: average reservoir pressure matching and well block pressure matching. Several runs have been made to match the average reservoir and well block pressure. Several adjustments are made to achieve the best pressure match, including modifying the reservoir's and aquifer's properties and the eastern flank's transmissibility. After history matching, three different types of contour maps were generated for the sector's layers, one of which was the Pressure Contour Map (known as the Isobaric Map), which shows high pressure for the layers on the western side; this indicates that the quantity of water influx on the west flank is substantially greater than the amount of water influx in the eastern flank, which was caused by injection wells as well as water influx. All of the layers of the low-pressure system were primarily located on the east flank. In light of this, it is possible to conclude that the water encroachment from the western side more quickly increases pressure, as illustrated in **Fig. 7**. The better (kh) in the west than on the east contributes to the western flank's greater water intake.
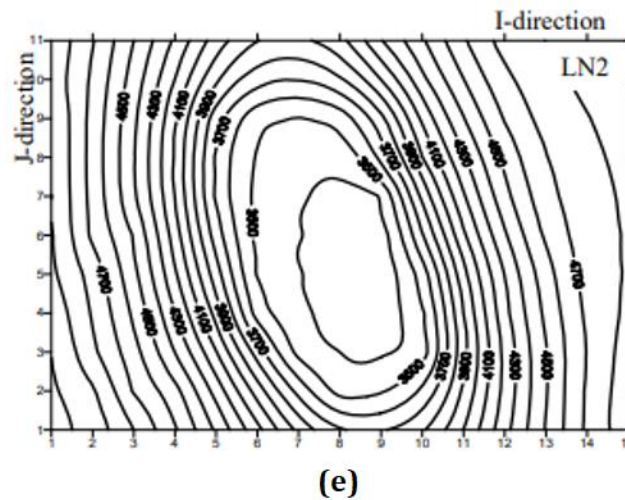

(a)

(b)

(c)

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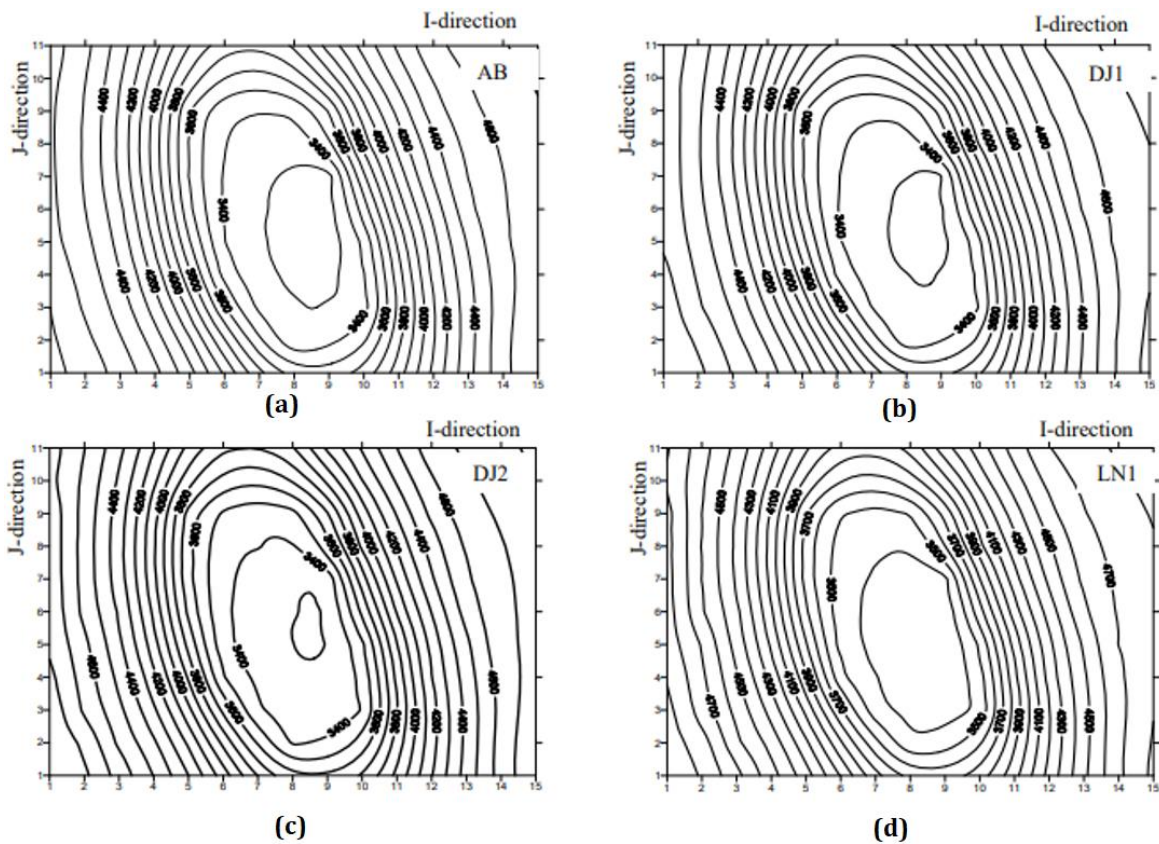
Figure 7. Reservoir layer isobaric contour maps at the end of December 2006, psia, a) layer AB, b) layer DJ1, c) layer DJ2, d) layer LN1, e) layer LN2, **(Mohammed et al., 2010).**

(Zou et al., 2012) investigated reservoir pressure performance for coalbed methane wells using the CBM reservoir simulation model; two sets of simulations were performed: the first was for a single well with reservoir pressure distribution over three time periods, and the second was for an assumed well net group with the same drainage time points as the single well. They noticed that as drainage time increases, the average declining rate of reservoir pressure of the well net group is unmistakably larger than that of a single well; to be more specific, it is almost double that of the single well; this is due to well interference, especially in the middle of the drainage process as shown in **Fig. 8**. This is believed to be more conducive to CBM drainage. Because according to the model of plane radial gas flow, the daily gas production correlates positively with the daily pressure declining rate. This indicates that the higher the daily reservoir pressure decline rate, the greater the daily gas production. **(Ali et al., 2015)** conducted a simulation study for a reservoir with two hydrocarbon accumulations—Pay-one and Pay-two—with faults and natural fractures, using a black-oil three-phase, three-dimensional dual-porosity model CMG-Builder/IMEX 2010.

The production is primarily from fractures for the first pay zone and fractures and matrix for the second pay zone, with active water drive, depletion, and water injection serving as the Field's primary derive mechanisms. The average reservoir and well block pressure are matched during several runs. The bottom aquifer is the most effective drive mechanism for preserving pressure in the second pay zone is pointed. The aquifer partly helps to support the pressure in the first pay together with water injection, as demonstrated in **Fig. 9**. **(Ma et al., 2015)** developed a dynamic model to construct an optimum pressure maintenance project. It was noticed that the pressure of the target formation significantly decreased after a certain number of years under the natural drive mechanism, which served as the foundation for the option of water injection as a supporting strategy.

According to the anticipated workflow presented in this paper, the pressure maintenance project successfully halted the pressure decrease and re-pressurized the reservoir, achieving a reasonable secondary recovery. It also provided recommendations for drilling pace and rig availability, minimizing uncertainties in the field development plan.
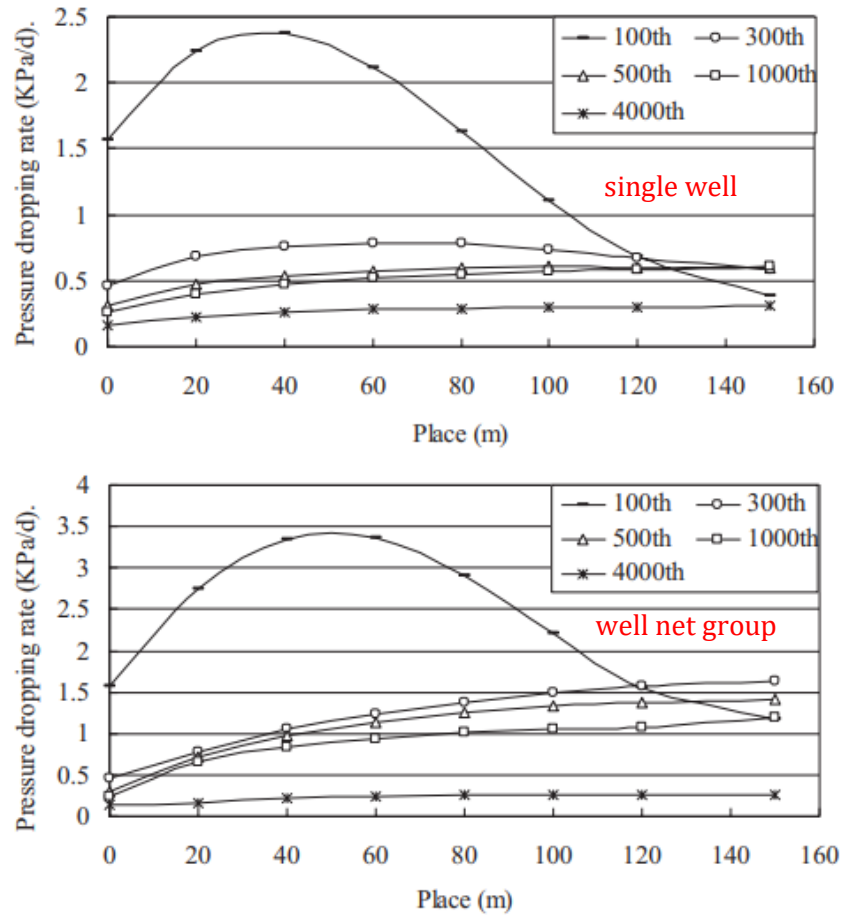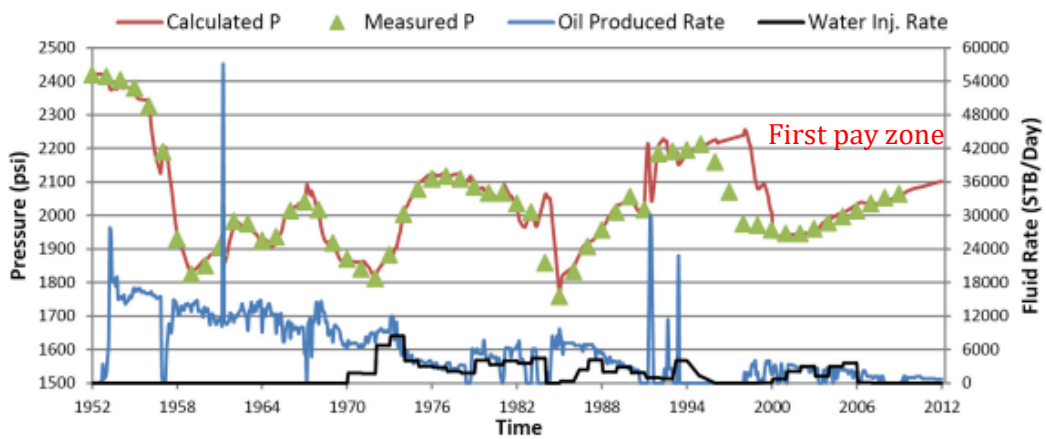
Figure 8. Dynamic changes in reservoir pressure drop rates between single well and well net group **(Zou et al., 2012).**
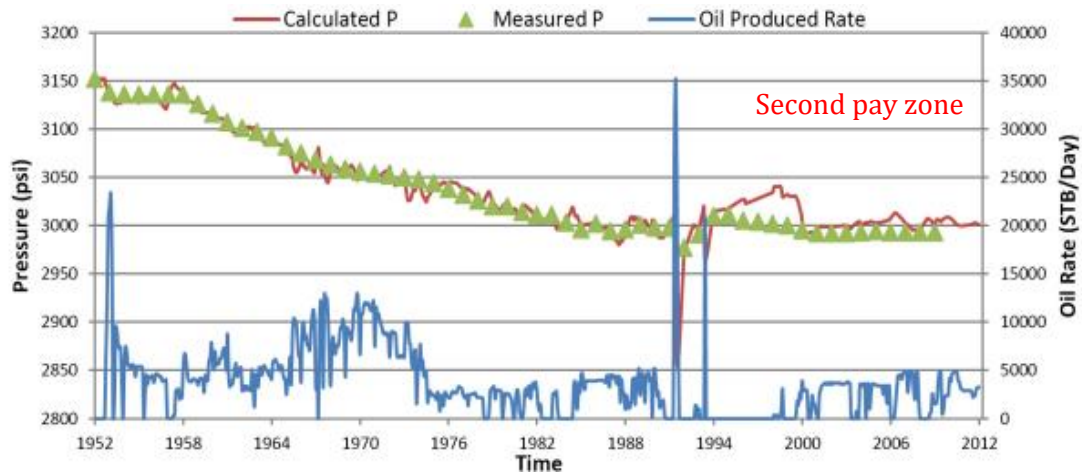
Figure 9. Average reservoir pressure and oil rate of the first and second pay zone **(Ali et al., 2015).**

(Sallam et al., 2015) investigated the reservoir behavior under various production strategies using ECLIPSE simulating software. This study intended to evaluate reservoir fluid production under the influence of primary recovery and compare it with production under five schemes for injecting water, which depend on adjusting the positions of the wells' perforations depth. The findings of this study demonstrated the effects of the decreased average reservoir pressure and provided a potential remedy for halting this decline and enabling extended periods of oil production. According to this, the authors suggested that water injection is suitable for boosting the oil recovery factor because it improves and maintains the average reservoir pressure at optimal levels, enabling the reservoir oil to be pushed into the producing wells. **(Wigwe et al., 2020)** implemented several simulation cases to examine the impacts of the grid sizes, local grid refinement, and horizontal and hydraulically fractured wells on reservoir performance. The most crucial point observed in this study is that adding some grid cells in the grid block by LGR surrounding the wells makes it necessary for the pressure wave to span more grids before it reaches the wellbore; therefore, it takes longer than the stipulated simulation time to get to the wellbore, resulting in a low recovery factor. **(Mohammed and Almaqtri, 2022)** The main objective of their paper was to compare future reservoir performance using the Eclipse software under both the natural drive mechanism and gas injection scenarios over a predetermined period. The study pointed out that the pressure falls below the bubble point pressure during reservoir depletion, allowing gas liberation from the oil and resulting in poor recovery factors. When gas is reinjected, it will mix with the oil, which raises reservoir pressure and lowers oil viscosity, increasing oil mobility into the producing wells and improving the reservoir's overall recovery. Consequently, systematically connecting injection and production wells would lead to significant pressure improvement and a rapid gas breakthrough.

2.2 Material Balance Method

The Material Balance Equation (MBE) is an analytical method representing the reservoir as an isotropic tank with constant temperature T and average pressure P in a zero-dimensional model (**Ibarra, 2016**). It is a well-established technique used to calculate the initial hydrocarbons (oil and gas) in place, predict future reservoir behavior, and determine ultimate hydrocarbon recovery under various scenarios (**Tracy, 1955**).

Schilthuis presented a form of the material balance equation that gives an overview of the drive mechanisms existing in the reservoir so that the depletion in the average reservoir pressure can be observed, as well as the determination of initial hydrocarbon in situ under various natural drive mechanisms and other reservoir characteristics relating to production. As a result, the Schilthuis formula has long been regarded as one of the most crucial tools for predicting future reservoir performance **(Gyan et al., 2019)**.

As a tool for analyzing reservoir performance, the material balance method was used in reservoir management before the numerical simulation technology that has been overgrown and widely applied to reservoirs. In contrast to numerical simulation, the material balance method offers the following advantages:

1. The reservoir geometry, petrology, geophysics, and other factors are all sources of uncertainty in the three-dimensional reservoir model. On the other hand, the material balance equation has a fairly low degree of uncertainty because it simply relies on data from PVT, pressure, and the conservation of production.

2. The material balance analysis method can quantitatively identify the various driving energy sources in the production of hydrocarbons by computing the driving index. This cannot be done using the reservoir simulation model alone since it is impossible to determine the rate at which various driving energies contribute to production.

3. The material balance equation method does not consider the fluid flow direction, hydrodynamic aspects of fluid flow in porous media, fluid differentiation, spatial variations in the rock and fluid characteristics, reservoir geometry, well placement, or the production of various fluids. Instead, the MBE examines the relationship between geological reserves, remaining reserves, and reservoir recovery. Based on the review above, the material balance method can provide valuable information before using reservoir numerical simulation, guiding efforts to reduce uncertainty **(Yang et al., 2021)**.

The workflow for general reservoir studies by Material Balance Using M-BAL software is shown in **Fig. 10**. A brief review of the most common applications of the material balance principle is presented. **(Walsh, 1995)** provided a generalized form of the material balance equation. The whole range of fluids, including volatile oils and gas condensates, can be applied using this approach since it mainly considers volatilized oil. Comparatively, it has been demonstrated that the traditional material balance equation produces incorrect conclusions for volatile oil and gas condensate reservoirs. The new generalized material balance equation leads to an enhanced technique of reservoir behavior prediction since it developed the use of the volatile gas/oil ratio Rv, which describes the volume of oil that is volatilized in the reservoir gas phase. Notably, the Rv is separate from but equivalent to, the dissolved gas-oil ratio. Therefore, this new formula used in this study is the first to be created and used to analyze the whole range of reservoir fluids. **(Auman et al., 1997)** combined the material balance method with the linear programming technique to create a model to estimate the original gas in place and forecast the performance of any gas reservoir. They presented this modified model by adjusting Craft and Hawkins' equation to consider the impacts of water influx, connate water expansion, shale compaction, and rock compaction. It is highly challenging to utilize this equation to predict reservoir performance because it is challenging to get precise values for the variables in the equation, such as aquifer and reservoir sizes, the proportion of shale in the reservoir, and compressibilities. Thus, the linear programming optimization approach was employed.
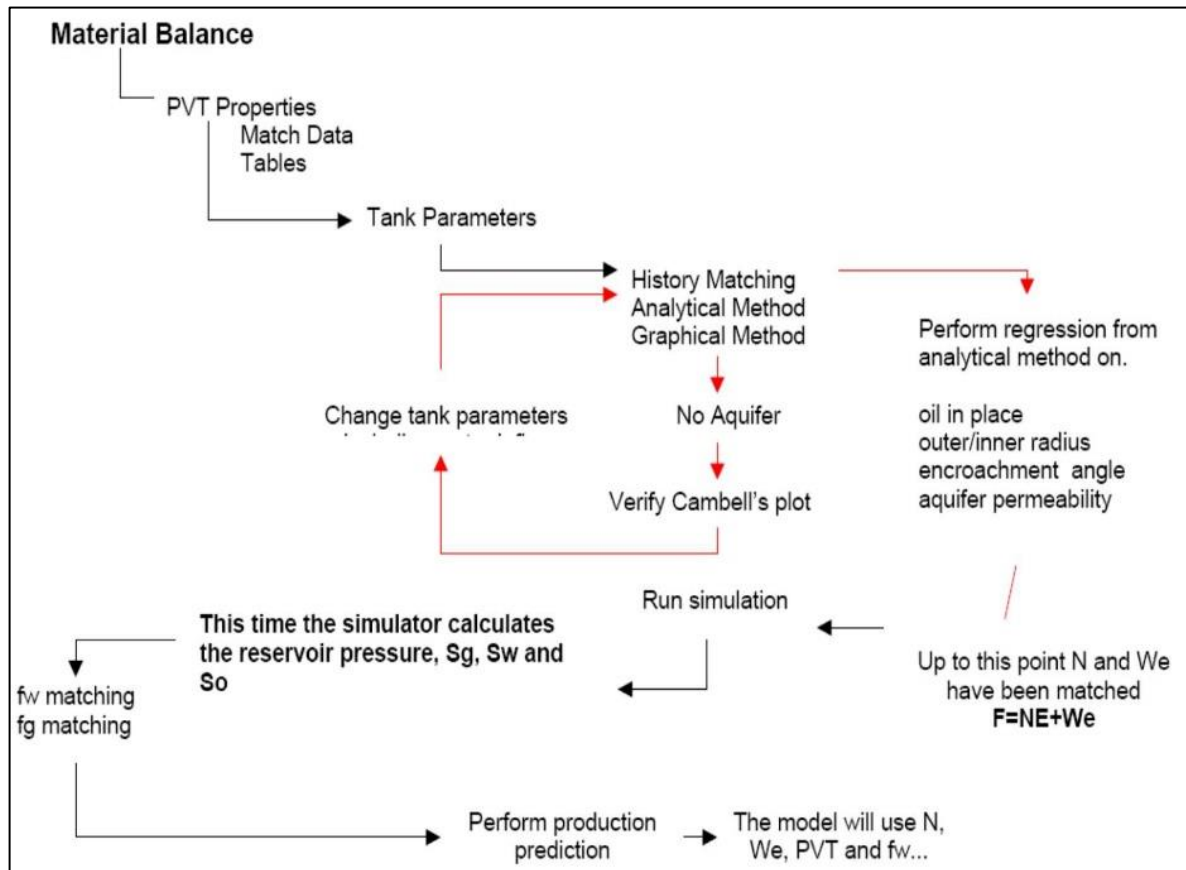
Figure 10. Workflow for Material Balance Using M-BAL software (**Mashallo, 2020**).

The linear programming model modified the variables, including shale fraction, water saturation, porosity, rock compressibility, and the aquifer's ratio to reservoir volume. After the ideal parameter values were derived from the linear programming model, Pressure behavior and reservoir performance were predicted. The researcher compared the results with those of an earlier developed single-phase (gas), two-dimensional dry gas reservoir simulator specifically to investigate the validity of this approach. **(Auman et al., 1997)** discovered that the estimated value of the initial gas in place provided by this simulator and the value acquired by the offered model were so close. **(Mattar and Anderson, 2005)** introduced the "dynamic material balance" method, developing the "flowing material balance." It works for constant and changing flow rates and can be used for gas and oil. This process transforms the flowing pressure at any given time to the average reservoir pressure present in the reservoir at that precise moment, see **Fig. 11**. The concept of this method is based on the fact that a well's production rate depends on a wide range of variables, including permeability, viscosity, thickness, etc. Additionally, the driving force in the reservoir, or the difference between the average reservoir pressure and the sand face-flowing pressure, also directly impacts the rate. Consequently, it is plausible to assume that if the flow rate and flowing pressure are both detected, the reservoir pressure can deduce from the sand face pressure. Although the flowing material balance approach has shown to be very effective, it can only be used for constant flows and fails for varied flows. The developed equation adds situations when the flow rate is not constant to the scope of the Flowing Material Balance approach.
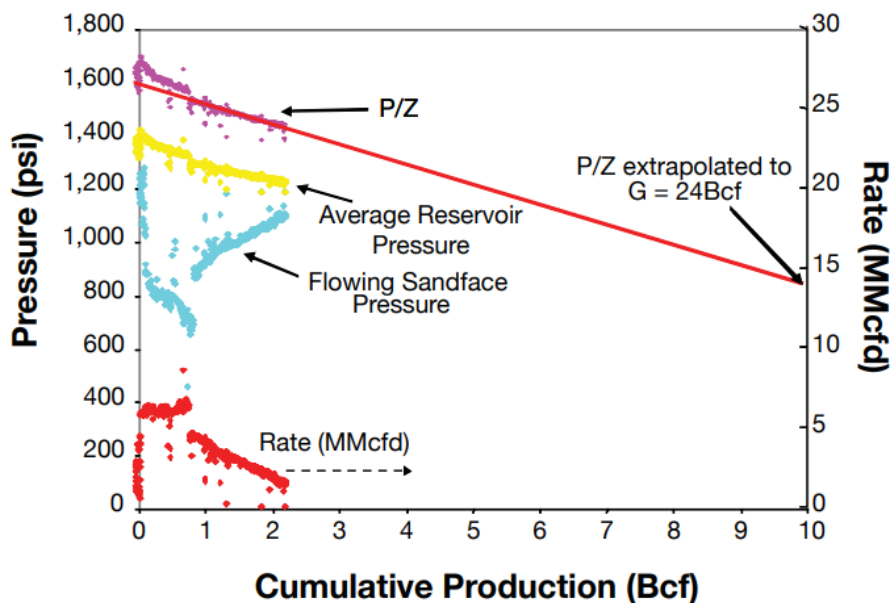
Figure 11. Dynamic material balance plot **(Mattar and Anderson, 2005).**

(Idogun et al., 2015) compared the pressure and production profiles from MBAL and 3D simulation for an offshore Niger delta, a multi-lobate system with a main and horn region, and a multi-tank system of a hydraulically connected reservoir under the waterflooding strategy. The results of history matching and prediction from MBAL were compared with those from the simulation; the results revealed a satisfying observation between the two approaches, which led to the belief that the material balance equation is an efficient substitute tool for reservoir simulation in terms of predicting the reservoir performance when time and supplies are scarce. **(Manzir et al., 2015)** used the material balance equation to forecast how reservoir performance will change over time for the reservoir (x) of the onshore Niger Delta Field Y. (MBE) and Darcy equation were used together since the MBE alone offers performance as a function of the average reservoir pressure in the absence of the fluid flow concept. The results of a forecast plot spanning forty-one years show that the reservoir pressure would have a total depletion from its initial value. The validated Campbell plot revealed that fluid expansion, pore volume compressibility, and a minor water influx were the primary drive fractional contributions of energy. Hence reservoir "X" can be considered a solution gas drive reservoir since the main driving force is the expansion of the oil and its initially dissolved gas. Where pressure linearly and quickly declines with production.

 (Sapale et al., 2019) provided a comparison between the predictive material balance approach and dynamic simulation in MBAL software for reserve estimation after history matching for both of them. Integrated Production Modeling (IPM) software package was created to predict the hydrocarbon reservoir's performance based on material balance. The researcher discovered no opposition between material balance and simulation; they were mutually helpful. Although the material balance method has a disadvantage in prediction since the prediction is closely tied to numerical reservoir simulation modeling, it performs best for matching pressure and production performance historically. The MBAL model demonstrated a sufficient pressure and production match for the tank with previous

production and pressure data, as it had attained a good history match.

(Widiyaningsih et al., 2021) used the manual material balance technique and integrated production modeling IPM-MBAL software to estimate the future reservoir's performance and the methods that must be implemented for the subsequent field development plan. Three material balance methods—the P/Z, the Havlena-Odeh, and the Cole plot were used to calculate the initial gas in place (IGIP), the average reservoir pressure, gas physical properties, and the determination of the drive mechanism. This study's average reservoir pressure prediction is based on reservoir pressure data for each production well versus production time and cumulative production. The curve fitting equation shown in **Fig. 12** is used to figure out the pressure in the reservoir at any specific date, where x is the total amount of production that will be considered.
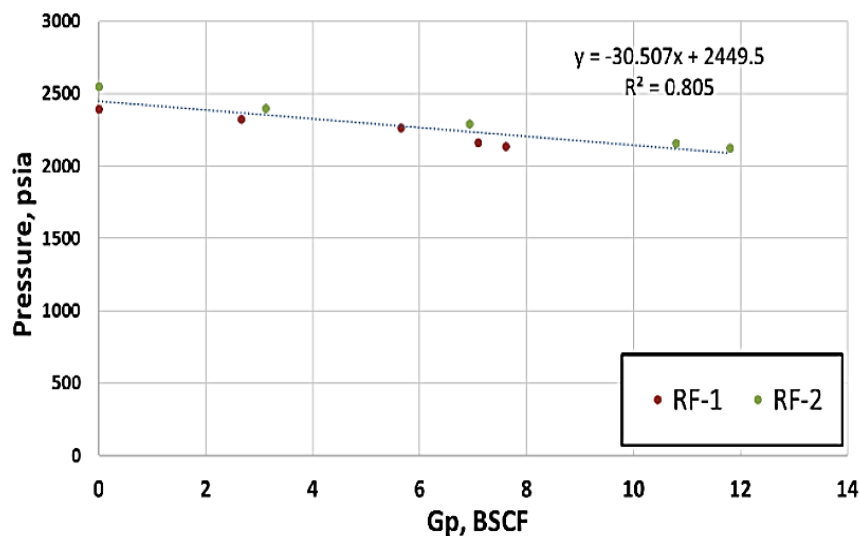

Figure12. Average reservoir pressure vs. cumulative production
(Widiyaningsih et al., 2021).

2.3 Time-lapse Seismic Data

Time-Lapse 4D seismic data, commonly called 4D seismic, is a cutting-edge method for tracking and controlling reservoirs that can significantly improve reservoir management (**Landa et al., 2015**). It offers a robust method of detecting changes in reservoir fluid composition and pressure (**Chadwick et al., 2012**). The problem this sector is trying to solve is matching the 4D seismic response to measurable quantities of pressure and fluid saturation in the reservoir. This would allow for preferable control of fields with more production and less environmental damage (**Bagley et al., 2004**). It is helpful to consult quantitative pressure and saturation maps obtained from seismic data for making decisions regarding drilling and reservoir management, detecting bypassed oil, tracking injected fluids, and comprehending aquifer drive. Additionally, this data might be helpful for seismic history matching, a process where reservoir models are updated to be consistent with production and time-lapse seismic data (**Landa et al., 2015**). A detailed workflow for observing the pressure and saturation changes from 4D seismic data is shown in **Fig. 13.**
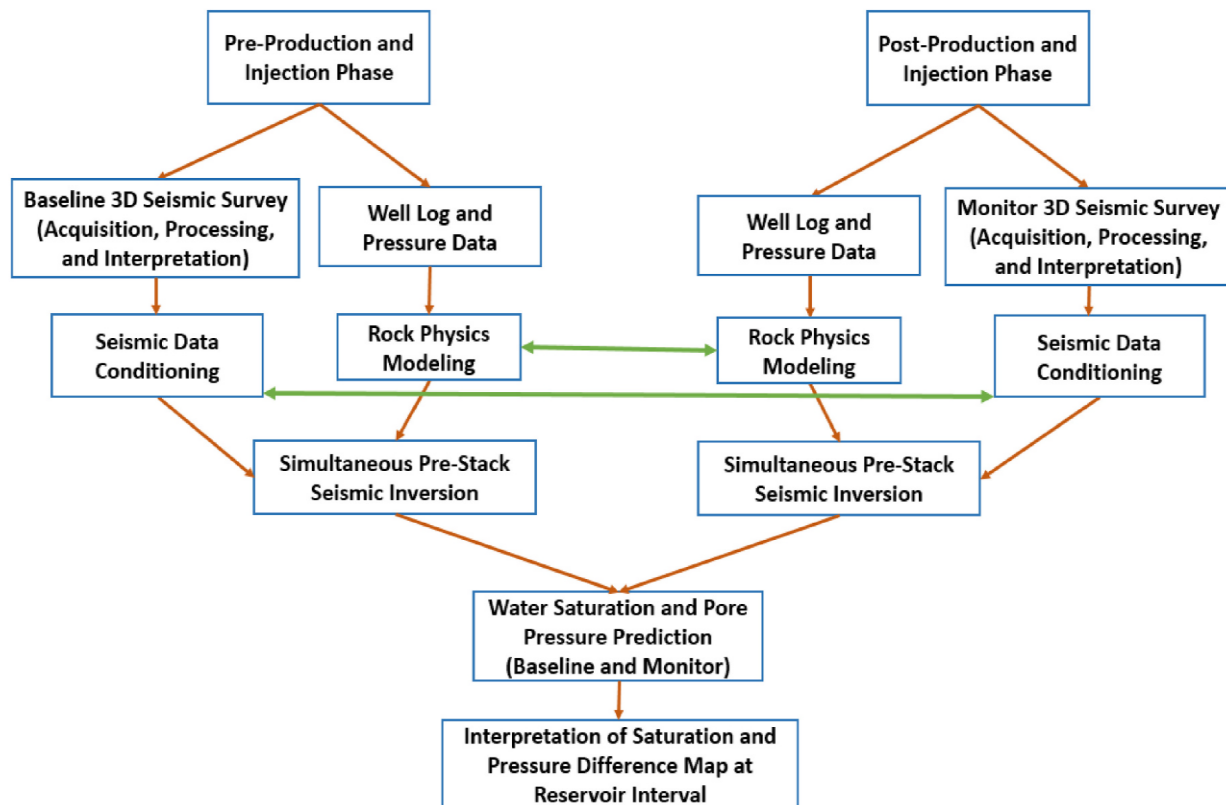
Figure 13. A general overview of the 4D workflow (**Babasafari et al., 2021**).

A brief review of the most common applications of 4D seismic data to predict pressure performance is adopted. **(Hoversten et al., 2003)** proposes a method incorporating seismic and electromagnetic (EM) observations to forecast changes in water saturation, pressure, and CO_2-oil ratio in a reservoir experiencing a CO_2 injection. The method is based on the theory that the dissolved CO_2 in the oil phase will barely reach the gas phase after its absorption of CO_2 reaches its maximum value under the existing pressure and temperature circumstances. The essential benefit of this method is its ability to dissociate the pressure and water saturation responses from those produced by CO_2, making it easier to find a link between the observed CO_2-oil ratio and the CO_2 injectivity logs, compared to visuals depicting how the geophysics is changing. **(Reddy et al., 2013)** investigated the dynamic changes in the reservoir of the Ravva Field situated off the shore of the Godavari Delta using a 4D seismic survey. To determine the reservoir's measurable elastic property changes, a 4D Simultaneous AVO Inversion was performed, and (Ip) and (Vp/Vs.) maps were produced. Both maps showed an apparent rise in (Ip) and (Vp/Vs.) (hardening) above the oil-water contact, which is related to the water flooding. An increase in pore pressure in the reservoir can be inferred from the drop in AI (softening) and the modest shift in the (Vp/Vs.) map below the oil-water contact, as shown in **Fig. 14**.

In both maps, the softening response was found in the structure's crestal section, representing gas emerging from the solution. Thus, to quantitatively understand the 4D response in the Ravva Field, it is necessary to separate the pressure and saturation components of the 4D signal. A decoupling technique is required to isolate pressure and saturation effects from (Vp/Vs.) and (Ip) utilizing a Petro Elastic Model to convert the 4D inversion-determined elastic characteristics into Saturation (Sw) and Pressure (P) proxies

as shown in **Fig. 15**. These Sw and P values represent the variations associated with pore fluid type and pore pressure, respectively. These results are being used to improve reservoir management and forecasting by updating the models of the reservoirs.
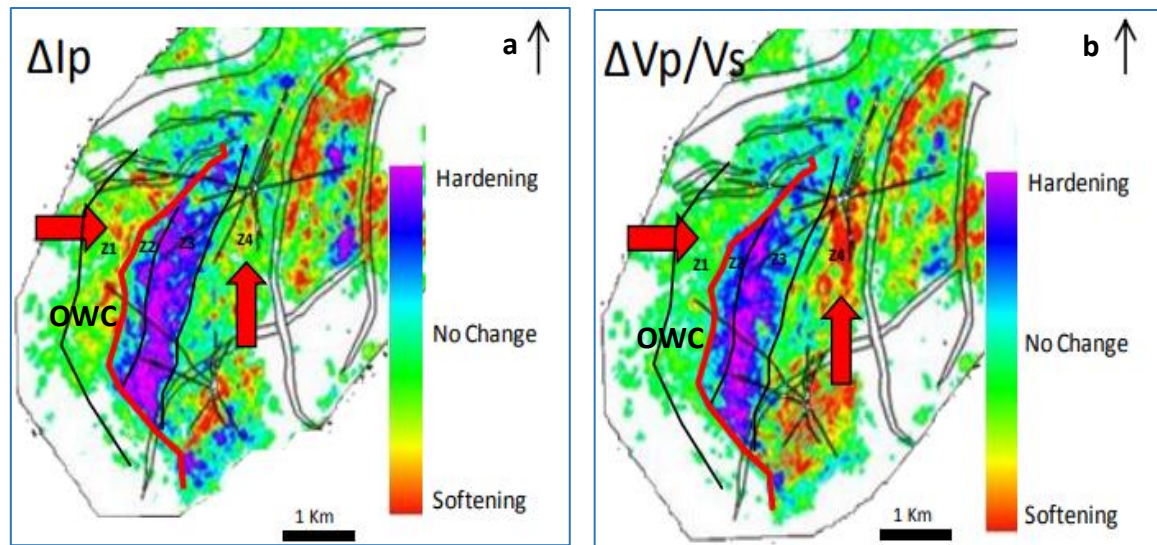

Figure 14. (a) ΔIp map at the top of the reservoir, b) ΔVp/Vs. Map at the top of the reservoir **(Reddy et al., 2013).**

(Grana and Mukerji, 2014) suggested using time-lapse seismic data to come up with a method for simultaneously evaluating both petrophysical properties, such as porosity, and dynamically changing properties, such as pressure and saturation.
 This method uses a Bayesian inversion technique to evaluate reservoir properties and how they change. Since there are noises in seismic data and their low vertical resolution compared with dynamic property changes, uncertainty analysis in pressure and saturation changes is crucial. As a result, a probability method to time-lapse seismic inversion is required; this is unusual because 3D seismic data is usually used to describe the static properties of a reservoir then time-lapse seismic information is used to determine how saturation and pressure have changed. Instead, this method simultaneously inverts static and dynamic parameters using the rock physics interrelations between pressure-saturation variations and porosity-lithology; this will enhance reservoir characterization statically and dynamically and minimize reservoir forecast uncertainties.
(Landa et al., 2015) presented a mathematical technique and a data-driven methodology that uses 4D seismic data and information about producing and injecting wells to create the reservoir pressure and saturation changes maps. Two inversion methods are involved: one for standardizing correlation models and another for 4D seismic inversion using the correlated models. The appropriateness of the data-driven approach to field data was evaluated through a probability study employing made data derived from reservoir history-matched models and field-calibrated seismic modeling. The findings from this study of the anticipated reservoir pressure and saturation change maps can be utilized immediately in field reservoir management and history matching for flow simulation models.
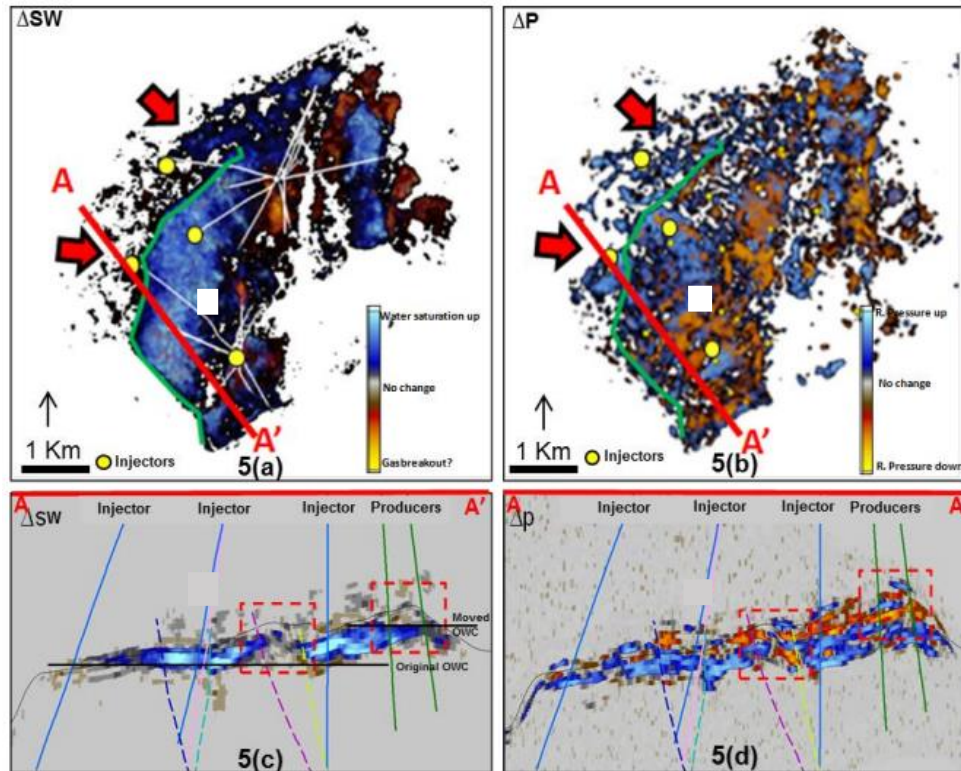
Figure 15. (a), (c) Estimated ΔSaturation map and section shows flooding signature and undrained areas (red box). No 4D changes below OWC. (b), (d) Estimated ΔPressure map and section shows pressure up near injectors and pressure down near producers 4D changes below OWC. **(Reddy et al., 2013).**

2.4 Other Methods

Other methods for investigating reservoir pressure performance, such as Artificial Intelligence applications, are presented. **(Vaferi et al., 2012)** investigated the applicability of the Orthogonal Collocation (OC) technique for the solution of the diffusivity equation in a radial unsteady state flow regime. These approaches are advantageous when reservoir characteristics like porosity and permeability are reported as a function of reservoir pressure or distance. Sometimes, the exact analytical method is complicated or unattainable, justifying the OC method's precedence. Comparing the outcomes produced by the suggested technique to the results from the exact analytical solution reveals that if the number of collocation points was increased, it would improve the precision of the OC technique, as shown in **Fig. 16**. Thus, this approach has demonstrated its accuracy, applicability, and stability in computations.

(Ali and Guo, 2019) presented an Artificial Intelligence (AI) based reservoir modeling process that tracks a gas condensate reservoir's production and pressure tendencies using petrophysical-based data to overcome the problems and limits of the present simulation methodology. An Adaptive Neuro-Fuzzy concept was constructed and experienced, utilizing a portion of the numerical simulation data. The findings from this study demonstrated that the devised approach rejuvenates the numerical simulation results for production rate and pressure decline at various bottom hole pressures with extremely high precision.
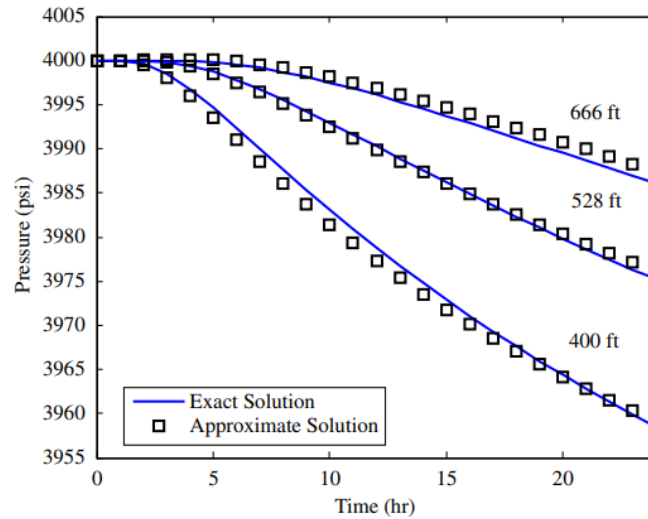
Figure 16. Comparison of exact and approximate solution, NP=20, for pressure profiles at 400, 528, and 666.5 feet from the wellbore **(Vaferi et al., 2012).**

(Ali and Guo, 2021) proposed Dynamic Mode Decomposition (DMD). This data-driven method resolves and rebuilds the field pressure of a drained reservoir model that simulates the performance of subsurface natural gas storage. The outcomes of using DMD on the field pressure data demonstrated that the suggested method might approximate the average reservoir pressure behavior and pore pressure improvement over time, as shown in **Fig. 17**.
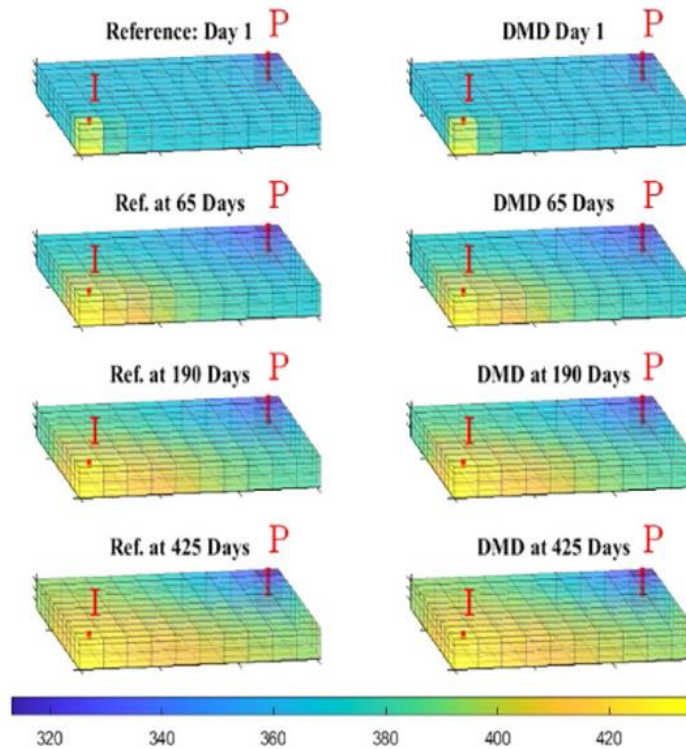

Figure 17. Comparisons of reservoir pore pressure variations versus DMD output for selected days **(Ali and Guo, 2021).**

3. CONCLUSIONS

Due to the great importance of reservoir pressure, which plays an essential role in the development of any reservoir, it is necessary to monitor pressure performance over distance and time during production periods. In this study, the methods used to determine the pressure behavior, as well as the research that support each technique and their results, were presented over an extended period, and the following conclusions were reached:

1. It is arguable which method is preferable: analytical forecasts or reservoir modeling. For example, despite their rapid development, analytical models sometimes have limited uses and cannot adequately explain complex reservoirs. On the other hand, reservoir modeling is suitable for complicated reservoirs but time-consuming.
2. The material balance equation method should be used in conjunction with simulation, not as a substitute for it, to enhance the examination of the hydrocarbon reservoirs.
3. Reservoir pressure and saturation change maps resulting from time-lapse seismic data are being used to improve reservoir management and forecasting by updating the models of the reservoirs.
4. All the methods to be used and their accuracy level are heavily influenced by the quantity and availability of the data required.
5. According to all of the above, it's obvious that every approach has value, but the availability of relevant data and the time needed to finish the study will ultimately determine which strategies will be prioritized. Therefore, it can be considered that these methods are complementary and not alternative.

NOMENCLATURES

AI	Artificial Intelligence	MBE	Material balance equation
AVO	Amplitude versus offset	OC	Orthogonal collocation
DB	Diagenetic barrier	OGIP	Gas initially in place
DMD:	Dynamic mode decomposition	OIP	Oil initially in place
EM	Electromagnetic	OWC	Oil-water contact
GOR	Gas/oil ratio	RV	Volatile gas/oil ratio
IPM	Integrated production modeling	WOR	Water/oil ratio
LGR	Local grid Refinement		

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Credit Authorship Contribution Statement

Manar M. Amer: Writing – review & editing, Writing – original draft, Resources, Investigation. Dahlia A. Al-Obaidi: Writing – review & editing, Visualization, Supervision.

Declaration of Competing Interest

We declare that we have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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