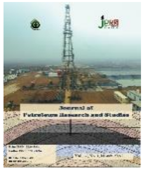
Journal of Petroleum Research and Studies

journal homepage: https://jprs.gov.iq/index.php/jprs/

Print ISSN 2220-5381, Online ISSN 2710-1096



Predictive Study to Mitigate Sand Production through Identifying the Critical Bottom Hole Flowing Pressure and Critical Flow Rate for the Productive Wells

Mustafa A. Issa[1,2*], Muntadher A. Issa[3], Farqad A. Hadi[2], Ali A. Al-Zuobaidi[1]

[1]Basra Oil Company, Ministry of Oil, Basra, Iraq.

[2]Department of Petroleum Engineering, College of Engineering, University of Baghdad, Baghdad, Iraq.

[3]Iraqi Drilling Company, Ministry of Oil, Basra, Iraq.

[*]Corresponding Author E-mail: m.issa1908m@coeng.uobaghdad.edu.iq

Article Info

Received 16/06/2024
Revised 06/10/2024
Accepted 20/01/2025
Published 19/03/2026

DOI: http://doi.org/10.52716/jprs.v16i1.981

This is an open access article under the CC BY 4 license. http://creativecommons.org/licenses/by/4.0/

Copyright (c) 2026 to Aurhor(s).

Abstract

In several productive oil and gas sites around the world, sand production remains a significant concern. It has the potential to decrease the recovery of hydrocarbons or entirely cease production, destroy the downhole and surface facilities, and other environmental problems related to sand disposal. These obstacles can lead to increased non-productive time and the annual loss of billions of dollars for petroleum companies. To evaluate the possibility of sand production, a field study in the south of Iraq was carried out. The third pay unit is a crucial sandstone reservoir belonging to the Zubair Formation that has been adopted in this investigation. To achieve the study's aims, offset well logs and relevant core sample data were used to develop a calibrated one-dimensional geomechanical model for the interested region, which serves as the input parameter to predict the onset of sanding, i.e., identify the critical bottom-hole flowing pressure (P_{cwf}). Then, the inflow performance relationship (IPR) curves were constructed employing constant productivity index (J) and empirical approaches (Vogel and Standing methods) through assuming different values of bottom-hole flowing pressure (P_{wf}) and computing the corresponding oil rate. Consequently, the critical oil flow rate (Q_c) as a function of the value of P_{cwf} can be estimated; below these critical values, the sanding will commence. The results demonstrated that, at the perforated point (3356 m), the value of P_{cwf} at the start of production was1352.74 psi. Thus, the drawdown area will become smaller or narrower as the depletion grows over time. Furthermore, any depletion or drawdown will lead to the generation of sand when the reservoir pressure is equal to 2735 psi or has depleted around 35% of its initial value. Finally, this study could serve as a reference for sand management, serving as an indicator of the possibility of sand throughout a well's productivity life, thus resulting in a positive economic advantage.

Keywords: Sand production, Critical flow rate, Critical bottom hole flowing pressure, Geomechanical model, Inflow performance relationship.

دراسة تنبؤية لتقليل من إنتاج الرمال من خلال تحديد ضغط التدفق الحرج ومعدل التدفق الحرج للآبار المنتجة

الخلاصة

في العديد من مواقع إنتاج النفط والغاز حول العالم، يعتبر إنتاج الرمال مصدر قلق كبير. حيث يمكن ان يؤدي الى تقليل استخلاص الهيدروكربونات أو ايقاف الإنتاج تمامًا، واحداث تضرر في معدات تجويف البئر والمنشأت السطحية، وغيرها من المشاكل البيئية المتعلقة بالتخلص من الرمال. ويمكن أن تؤدي هذه العقبات إلى زيادة الوقت غير الإنتاجي وخسارة شركات النفط السنوية مليارات الدولارات. لتقييم إمكانية إنتاج الرمال أجريت هذة الدراسة الميدانية في جنوب العراق. اعتمدت هذة الدراسة على طبقة العطاء الثالث وهي طبقة مكمنية مهمة تتكون من الحجر الرملي تنتمي إلى تكوين الزبير. ولتحقيق أهداف الدراسة، تم إنشاء نموذج جيوميكانيكي أحادي البعد متكامل للمنطقة الدراسة بالاعتماد على بيانات مجسات الابار ونتائج المختبرية للعينات الصخرية، يعتبر هذا النموذج احد المدخلات الاساسية والضرورية للتنبؤ ببداية انتاج الرمال، أي تحديد ضغط التدفق الحرج (P_{cwf}). بعد ذلك، تم إنشاء منحنيات علاقة أدائية التدفق (IPR) باستخدام مؤشر الإنتاجية الثابت (J) والأساليب التجريبية (طرق Vogel وStanding) من خلال افتراض قيم مختلفة لضغط التدفق في قاع البئر (P_{wf}) وحساب معدل التدفق للنفط. وبالتالي، يمكن تقدير معدل تدفق النفط الحرج (Q_c) كدالة لقيمة (P_{cwf})، حيث سيكون انتاج الرمال في حالة كون قيم الضغوط ومعدلات التدفق اقل من القيم الحرجة. أظهرت النتائج أنه عند النقطة المثقبة (3356 م)، كانت قيمة P_{cwf} عند بداية الإنتاج 1352.74 رطل لكل بوصة مربعة. وبالتالي، فإن منطقة السحب سوف تصبح أصغر أوتتضيق مع زيادة معدلات السحب مع مرور الوقت. علاوة على ذلك، فإن أي استنفاد أو سحب سيؤدي إلى توليد الرمال عندما يكون ضغط المكمن مساوياً لـ 2735 رطل لكل بوصة مربعة أو استنفاد حوالي 35% من قيمته الأولية. وأخيرا، يمكن أن تكون هذه الدراسة بمثابة مرجع لإدارة الرمال، حيث تكون بمثابة مؤشر على إمكانية وجود الرمال طوال الحياة الإنتاجية للبئر، مما يؤدي إلى ميزة اقتصادية إيجابية.

1. Introduction

The scientific discipline of geomechanics is concerned with the study of how rocks behave in response to changes in temperature, pressure, and stress. It has demonstrated an increasing involvement in energy-related topics, particularly issues concerning petroleum exploitation. Furthermore, geomechanics is expanding its applications to serve as an important reference for the petroleum industry's technological advancements [1], [2]. There are several applications of petroleum geomechanics in the oil and gas industry; one of them is sand production prediction, which depends heavily on an understanding of the geomechanical properties of subsurface strata. In-situ stresses, formation pore pressure, and the mechanical properties of the rock are the crucial characteristics that are responsible for constructing the geomechanical models [3].

In the petroleum industry, sand production mitigation is a significant and difficult problem that necessitates sand management decision-making. Roughly 70% of the world's petroleum reservoirs are found in sandstone layers. Hence, the production of sand may become an imminent danger [4]. There are usually issues associated with hydrocarbon production, i.e., wax, scale, hydrates, and sand production, in complicated reservoir circumstances, including deep-water, high pressure, and temperature. Consequently, the production of these substances can result in abrasion, integrity loss, and degradation of the bottom-hole equipment and accompanying surface facilities [5]. Sand production occurs due to the breakdown of sand formations as a result of the in-situ stress effects (vertical stress, maximum and minimum horizontal stresses) and the flow of the hydrocarbon fluid. However, the mechanism of producing sand can be broken down into three steps: (1) collapse of the rock matrix; (2) separation of solid or sand particles from the collapsed rock; and (3) movement of the free particles through reservoir fluid flow to the wellbore and then upward to the surface [6].

Three categories exist for sand production: unstable, continuous, and catastrophic high-rate. These classifications are based on features of sand formation observed in oil production. Sand production is a very complex process that can occur at any stage of drilling, injection, and production. Although some sand-producing triggers can be avoided since they result from engineering efforts, others are not under operational control [7]. If the issue with sand production is not resolved, it will grow in importance and affect the growth of oil and gas fields. Artificial techniques to limit sand production can be classified into several categories based on their capacity for excluding sanding. These include screen and gravel packs, frac packing, and chemical sand-control procedures. These techniques attempted to achieve the best possible oilfield advancement, essential rates of production, and long-term effectiveness [8]. Sand management is a concept of design, decision-making, and production management technique executed by properly considering elements such as production rate and the sand-transporting capacity of the well, processing of the surface equipment, as well as expenses on the scenario of either producing without sand or releasing with a small quantity of sand. This method provides the best control over production by managing the value of pressure loss, the fluid's flow velocity, and the influx of sand grains. It differs significantly from the usual approach of avoiding sand [9], [10].

Additional research efforts have been conducted in the past few years that have demonstrated Early studies introduced traditional mathematical models that proved effective in evaluating the stability of perforated arches [11], [12]. Subsequent experimental investigations demonstrated that sand failure and the resulting production behavior can be predicted through laboratory testing [13], [14]. These studies also indicated that the relationship between sand failure mechanisms, wellbore differential pressure, and rock strength is relatively limited. Furthermore, finite element analysis combined with experimental techniques was employed to provide a comprehensive evaluation of volumetric sand production mechanisms [15]. More advanced predictive models were later developed to estimate sand production as a function of key parameters, including drawdown pressure, formation strength, fluid type, flow rate, and reservoir pressure [16]–[20]. These models could be useful for several field requirements, such as managing and regulating the production of sand, enhancing well-completion plans, and raising productivity. Nevertheless, under a specific set of field conditions, no model can accurately assess the risks of sanding. Additionally, these models can be implemented locally, therefore, this study was motivated. Furthermore, the main distinction between this study and others is that it introduced a vital methodology in which the critical bottom-hole flowing pressure (P_{cwf}) and critical flow rate (Q_c) were identified to prevent the initiation of sand production. Thus, the hydrocarbon produced from wells in the area of interest may be controlled without sanding. Ultimately, this study could be used as a guide for sand management to achieve the best completion efficiency possible, which would reduce workover operations. It could also be used as an indicator of the possibility of sand throughout a well's productivity life, which would yield a positive economic advantage.

1.1. Area of Study

To address the issue of sand production throughout the hydrocarbon production phase, a field case in southern Iraq was implemented in this study to estimate the critical bottom-hole flowing pressure and critical flow rate that are needed to successfully transport the reservoir fluids from the perforated holes to the surface facilities without sanding. The geologic column that includes many Iraqi oilfields spans from the Upper Jurassic to the Tertiary Ages, specifically extending from the bottom of the Sulaiy Formation to the Dibdiba Formation. It is mostly composed of clastic rocks distributed throughout extensive layers of carbonate [21]. Approximately thirty percent of Iraq's contributions of natural gas and crude oil originate in the Zubair Formation, which is a clastic reservoir corresponding to the early cretaceous ages. The Zubair Formation has been identified owing to the sand-to-shale ratio of five units, as depicted in Figure (1). The third pay, or upper sand unit, is a more critical sandstone reservoir with an average thickness of about 120 m in the field of interest that has been focused on in this investigation (Figure 1).

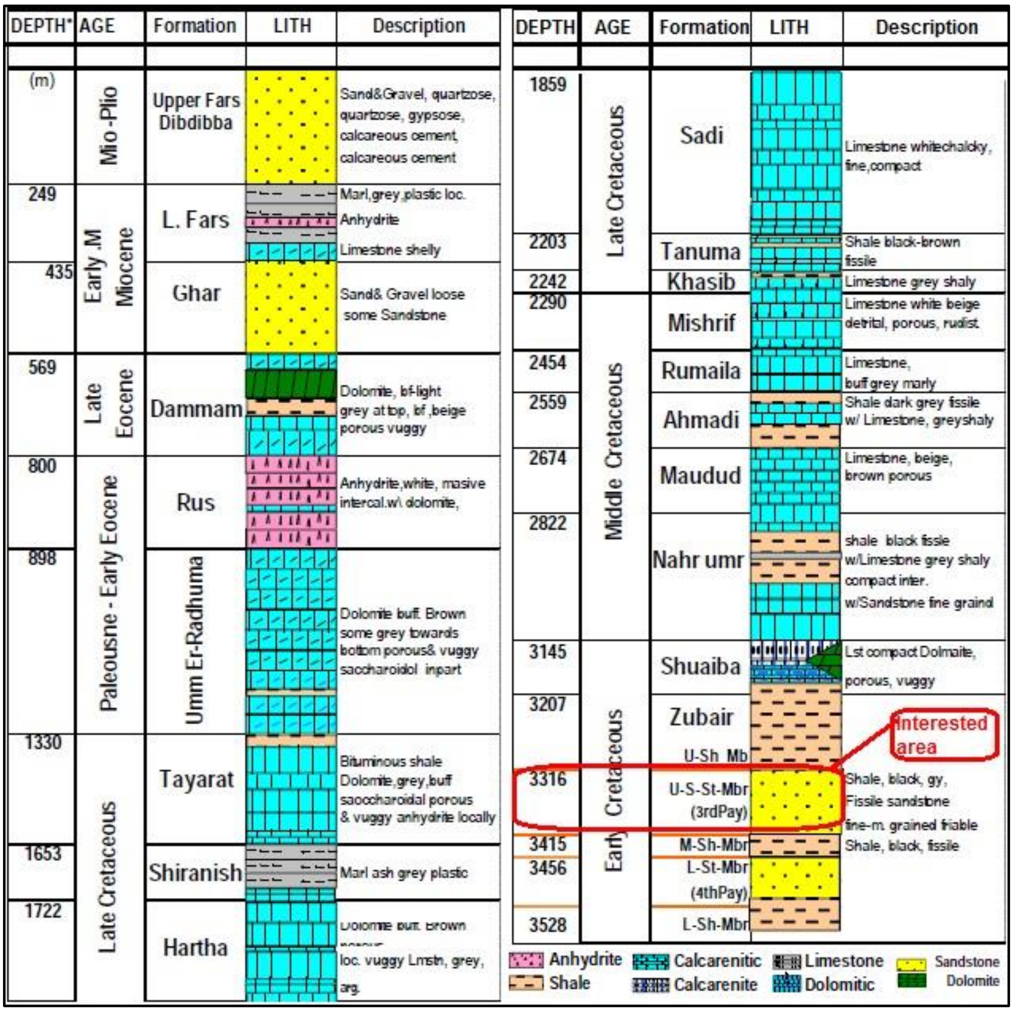


Fig. (1): Lithological column of the southern Iraqi oilfields [22].

2. Methods

2.1. Research Methodology

The procedure for this study can be completed effectively using the following steps:

- Preparing, collecting, and auditioning the required data for the area of interest to ensure a reliable workflow and results. This data includes well-logging data (i.e., compression and shear waves, micro-imager, density, caliper, gamma-ray logs) and field tests, including the mini-frac test and rock mechanical tests.
- Establish a one dimensional geomechanical model for the area of interest (third pay unit). This model was developed employing pertinent offset well core sample data and well logs. Once the model is established, the hazardous and sand-free regions can be identified at various ranges of the flowing bottom-hole pressure (P_{wf}) and reservoir pressure.

- Determine the P_{cwf} at diverse depletion rates at which the wellbore could produce the reservoir fluids without sanding.
- Develop the inflow performance relationship (IPR) by utilizing the constant productivity index (J) and empirical methods (Vogel and Standing) to determine the oil flow rate at any value of bottom-hole flowing pressure (P_{wf}).
- Finally, when the P_{cwf} is identified, Q_c can be estimated through IPR methods. Thus, more control over hydrocarbon production without sanding will occur.

2.2. Geomechanical Characteristics

Due to variations in the shape, size, and direction of the grain, rocks are typically neither homogeneous nor isotropic. For geomechanical applications, it is therefore essential to precisely identify the geomechanical properties of the area of interest [23]. These features can be divided into three groups: mechanical rock parameters, formation pore pressure, and in-situ or far-field stresses.

Understanding the rock mechanical characteristics of the subsurface layers is essential for addressing issues related to subsidence. According to the distorting regime, rocks can be classified mechanically into two groups: elastic properties (including Poisson's ratio, Young's modulus, bulk and shear moduli) and rock strength parameters (including friction angle, unconfined compressive strength (UCS), and tensile strength), [24]. Static and dynamic are two methods that are utilized to calculate these properties. The static technique is more accurate and performed in the lab using special apparatus, while the dynamic technique depends on the correlations that rely on the well logs data [25]. In this investigation, the bulk density and sonic wave logs along the area of interest were measured to derive the dynamic rock parameters, namely Young's modulus (E) and Poisson's ratio (v) using Eqs. 1 and 2, respectively. Where the ρ_b is bulk density (g/cc), V_s & V_p are shear and compressional wave velocities, respectively (Km/s), [2], [26].

$$E = \frac{\rho_b \, V_s^2 \left(3V_p^2 - 4V_s^2\right)}{\left(V_p^2 - V_s^2\right)} \tag{1}$$

$$v = \frac{\left(V_p^2 - 2V_s^2\right)}{2\left(V_p^2 - V_s^2\right)} \tag{2}$$

Reservoir geomechanical models rely heavily on formation pore pressure (p_p). In the petroleum industry, direct and indirect methods are frequently employed to figure out pore pressure. The repeated formation test (RFT) is one instance of a direct technique utilized in well testing to measure the formation pressure. Despite providing reliable results, it is limited by financial and time constraints [27]. In contrast, the indirect techniques rely on the theoretical and empirical correlations constructed based on the petrophysical data to estimate the pore pressure, e.g., the Eaton equation (Eq .3) [28]. A sonic wireline log served as the basis for the derivation of this equation.

$$P_{pg} = OBG - (OBG - P_{ng})\left(\frac{NCT}{\Delta T}\right)^3 \quad (3)$$

Where P_{pg} is the pore pressure gradient; P_{ng} is the hydrostatic or normal pressure gradient; OBG represents the overburden gradient; ΔT represents a compressional sonic wave (sonic transit time); NCT indicates a normal compaction trend that fits observations of compressional waves.

The in-situ or far-field stresses refer to the three perpendicular principal stresses that should be applied to any point below the earth's surface. the far-field stresses are categorized according to their magnitude and direction: the vertical stress (σ_v) and the maximum (σ_H) and minimum (σ_h) horizontal stresses [29].

Vertical stress (σ_v) is oriented toward the center of the earth. It is caused by the combined weight of the upper strata and the fluid containing it [30]. At certain depths, the vertical stress can be computed employing Eq. 4, where ρ is the bulk density, z is the formation thickness, and g is the gravitational constant.

$$\sigma_v = \int_0^z \rho_b\,(z) g dz \quad (4)$$

Because the vertical stress compresses the formation rock vertically, it tends to slide horizontally. Therefore, the minimum and maximum horizontal stresses are affected by this alteration. These stresses are crucial for geomechanical modeling applications, including predicting sand production and evaluating the stability of wellbore walls [31]. However, estimating the magnitude of the horizontal stresses (minimum and maximum) is challenging. Further methods for quantifying these stresses include theoretical computations involving the poro-elastic constitutive model and field measurements like the mini-frac and extended leak-off tests. In this investigation, horizontal stresses were determined using (Eqs. 5 and 6) according to a poro-elastic horizontal strain model [32]. Where: E is Young's modulus; v is Poisson's ratio; p_p is the formation pore pressure; α is Biot's constant (generally α =1); ε_H & ε_h are the tectonic strains in the direction of the maximum and minimum horizontal stresses, respectively [26].

$$\sigma_h = \frac{v}{1-v}\left(\sigma_v - \alpha\, p_p\right) + \alpha\, p_p + \frac{E}{1-v^2}\,(\varepsilon_h + v\,\varepsilon_H) \quad (5)$$

$$\sigma_H = \frac{v}{1-v}\left(\sigma_v - \alpha\, p_p\right) + \alpha\, p_p + \frac{E}{1-v^2}\left(\varepsilon_H + v\,\varepsilon_h\right) \quad (6)$$

3. Results and Discussion

3.1. Establishment of a Geomechanical Model

The use of a three-dimensional mechanical earth model (3D MEM) has gained popularity as a more precise method for addressing wellbore issues. To construct this model, access to multiple wells with extensive data from various domes of the concerned field is necessary. Then, a one-dimensional mechanical earth model (1D MEM) of each well must be created as the input for the 3D MEM. Regrettably, the absence of sufficient data has hindered the development of the 3D MEM. Therefore, in this study, a 1D MEM was established along the interested area. The dynamic elastic moduli and sonic logs' theoretical relationship serves as the foundation for this model. Assuming that the formation is homogenous, isotropic, and elastic.

The characteristics of geomechanics are a fundamental aspect of any application concerned with geomechanics. To construct a one-dimensional geomechanical model, the following parameters should be established: (1) mechanical rock parameters; (2) formation pore pressure; and (3) in-situ or far-field stresses.

To select the more appropriate correlations to determine the mechanical rock properties in this study, all available correlations (geomechanical aspects) in Techlog software were checked with field data (core specimens) extracted from mechanical rock testing. This allowed for the establishment and verification of these properties. However, the profiles of the mechanical rock properties were established and verified with field data points, as illustrated in Figure (2) (third to fifth tracks). Unconfined compressive strength (UCS) is a rock mechanical parameter related to the degree of consolidation. A practical investigation was conducted to determine continuous profiles of mechanical rock properties, where the results indicated that sanding is likely to occur when the unconfined compressive strength (UCS) is below 7250 psi. The study further showed that at different depths (e.g., 3322 m and 3394–3402 m), the UCS and Poisson's ratio values were approximately 2000 psi and 0.43, respectively, as illustrated in the third and fifth tracks of Figure (2). Accordingly, UCS can be considered a reliable and consistent indicator for predicting sanding or rock collapse phenomena [33]. In addition, the mechanism of sand production resulting from rock failure around the perforation tunnels of the wellbore was analyzed, highlighting the role of stress concentration and mechanical instability in initiating sand production [34]. It was concluded that sanding is not necessarily initiated by drawdown pressures at the early stages, but is more likely influenced by external stresses. The pore pressure profile was created using the Eaton equation (Eq. 3), as shown in the sixth track of Figure (2). This profile has been verified and corrected using actual measurements obtained from RFT. It was additionally modified according to the original drilling mud density that was utilized when drilling the region of concern. Also, in this track, the profiles of the far-field stresses have been created. (Eq. 4) was used to establish the vertical stress profile throughout the area of interest. Furthermore, the wellbore's minimum and maximum horizontal stress profiles were determined using the poro-elastic equations (Eqs. 5 and 6). Additionally, the calibration of the minimum horizontal stress profile in this track was done by matching its values with the closure pressure values that were derived from measurements made during the mini-frac test.

By determining the geomechanical properties, the one-dimensional geomechanical model has been completed. The next step will involve a discussion about the identification of P_{cwf} and Q_c to achieve the purpose of the investigation.

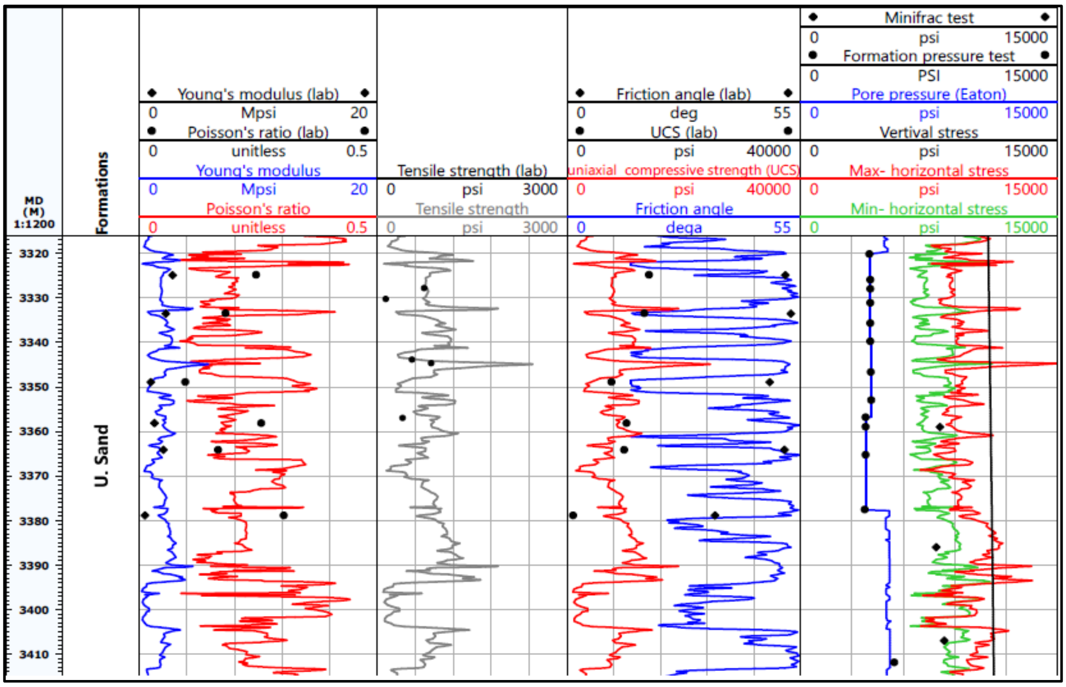


Fig. (2): The one-dimensional geomechanical model for the third pay unit.

3.2. Assessment of the Onset of Sand Production Based on P_{cwf} and Q_c Values

Once the geomechanical model was accomplished, the P_{cwf} at various depletion rates was established to identify the potential of sanding, as depicted in Figure (3). The region highlighted in red indicates an unsafe area or a potential sanding hazard during production. On the other hand, an area colored green indicates that it is sand-free or an appropriate location for production. At perforated point (3356 m), the value of reservoir pressure was 4100 psi, UCS = 5915 psi, σ_v =11090 psi, σ_h = 7175, and σ_H = 8325 psi. To assure production while preventing sanding, the bottom-hole flowing pressure (P_{wf}) must be lower than the reservoir pressure (P_R), but higher than the (P_{cwf}). The variation between the reservoir pressure and P_{cwf} is called the critical drawdown pressure (CDDP) (Eq. 7) [26].

$$CDDP = P_R - P_{cwf} \tag{7}$$

As seen in this Figure, the values of CDDP across the 3356 m of upper sand reservoir are more significant (maximum value) at zero depletion rate (no production) than at other depletion rates (i.e., 5, 10, 15, 20, 25, and 30%). This implies a lesser required P_{cwf} value that can be obtained in the absence of sanding. In other words, the value of P_{cwf} at the beginning of production is 1352.74 psi, meaning that the CDDP is 2747 psi. Additionally, as the depletion increases with time, the drawdown area will shrink or narrow, meaning the value of P_{cwf} will rise as a result of reservoir pressure decline (i.e., the value of CDDP becomes smaller). For example, when the reservoir pressure depleted about 15% to be 3500 psi, the value of P_{cwf} was 1900 psi, thus the value of the CDDP is 1600 psi. When the value of reservoir pressure is equivalent to 2735 psi (i.e., the depletion rate is about 35%), any depletion or drawdown will lead to hazardous sand production, as illustrated in Figure (3). Table (1) presents CDDP at different deletion rates (0%, 15%, 25%, and 35%) for various perforated intervals of the upper sand unit.

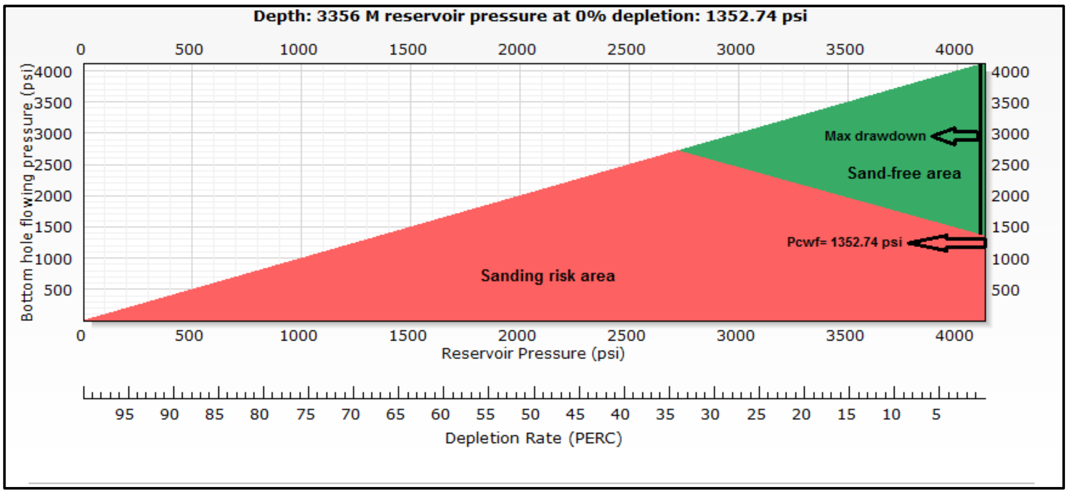


Fig. (3): Illustrate the safe and unsafe production zones at the perforated wellbore.

Table (1): Depicts the CDDP at different depletion rate for one well in the field of interest.

Interval depth (m)	CDDP (psi) @ 0%	P_{cwf} (Psi) @ 0%	CDDP (psi) @ 15 %	P_{cwf} (Psi) @ 15 %	CDDP (psi) @ 25 %	P_{cwf} (Psi) @ 25 %	CDDP (psi) @ 35 %	P_{cwf} (Psi) @ 35 %
3325	4016	4.87	3414	606	3012	1008	2611	1409
3328	4071	0	3460	611	3053	1018	2646	1425
3356	2747	1377	1600	2524	738	3386	0	4124
3359	3799	0	3229	570	2849	950	2469	1330
3363	2028	1770	1000	2798	316	3482	0	3798
3365	3295	503	2142	1656	1374	2424	605	3193
3366	3818	0	3245	573	2864	954	2482	1336

The main topic of this section is the construction of IPR curves as a means of determining the critical oil flow rate (Q_c). The constant productivity index (J) and two empirical methods, i.e., Vogel (Eq. 8) and Standing (Eq. 9) were used in this study to establish the IPR curves, consequently the Q_c can be identify as a function to the value of P_{cwf}. Additionally, it can be identify the oil flow rate with time at any value of P_{wf}.

$$\frac{Q_o}{(Q_o)_{max}} = 1 - 0.2\left(\frac{P_{wf}}{P_r}\right) - 0.8\left(\frac{P_{wf}}{P_r}\right)^2 \qquad (8)$$

$$Q_o = \left(\frac{J_f\,(P_r)_f}{1.8}\right)\left[1 - 0.2\left(\frac{P_{wf}}{(P_r)_f}\right) - 0.8\left(\frac{P_{wf}}{(P_r)_f}\right)^2\right] \qquad (9)$$

Where: Q_o = oil rate (STB/day) at P_{wf}; $(Q_o)_{max}$= maximum oil flow rate at zero wellbore pressure; P_r = current average reservoir pressure, psi; and P_{wf} = wellbore pressure, psi; f is the subscript refer to a future condition.

The constant productivity index (J) is a widely utilized indicator of a well's production capacity and it gives the straight line relation, as illustrated in Fig.4. Furthermore, Vogel (1968) [35] noted that the IPR diverges from the standard of a straight line, as illustrated in Fig. 4, once the pressure falls below the bubble-point pressure (Pb). In the end, Standing (1970) [36] expanded the use of Vogel's to forecast a well's future IPR as an estimation of the reservoir pressure value. In other words, the standing method predicts the reservoir deliverability for the future by selecting how much the reservoir will deplete with time.

As depicted in Figure (4), at the Pb value (2600 psi), the Vogel and Standing curves start to deviate from their straight relationship, and the oil flow rates were 1685 and 779 STB/day, respectively. In contrast, the productivity index relation remains constant at the Pb value, where the oil rate was 1772 STB/day. As for the values of Q_c , they were selected as a function of the P_{cwf} value (1352.74 psi) employing the mentioned methods, and their values were 2587.4 and 1525.8 STB/day for the Vogel and Standing, respectively. While it was 3244.5 STB/day for the J method. Ultimately, by using the above techniques, the values of oil rate and corresponding wellbore flowing pressure can be estimated with time.

The research results may eventually be applicable in the oilfields of southern Iraq. The outcomes should be modified if they are to be extended to other fields of study. It is also essential to implement field tests to determine the amount and size of sand grains to improve the sanding model.

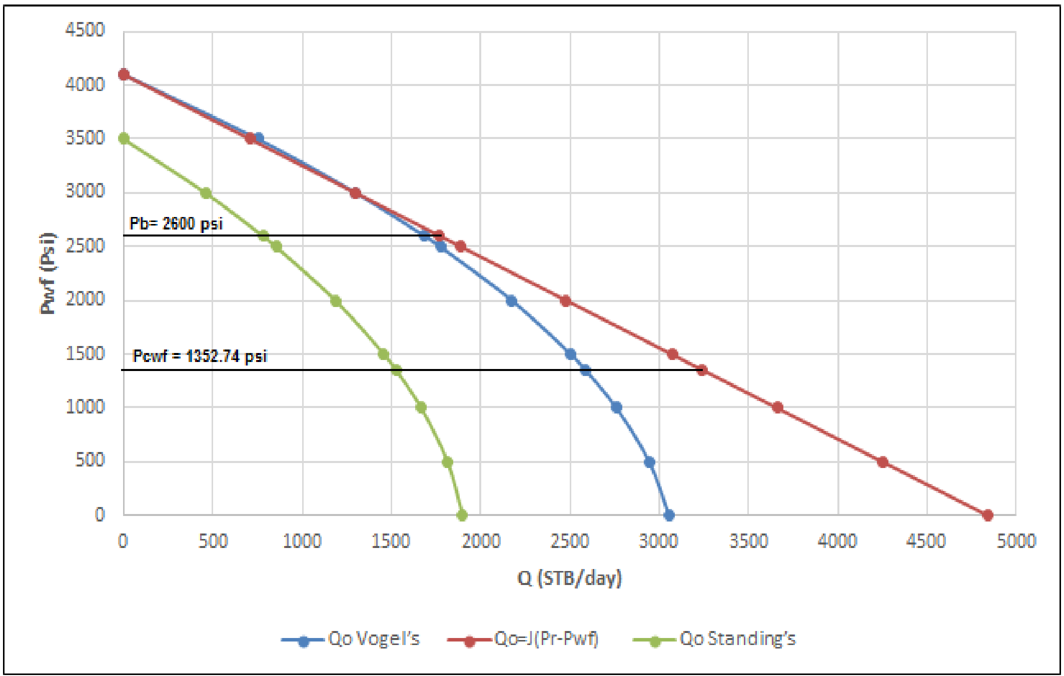


Fig. (4): IPR curves using different methods to estimate the critical oil flow rate.

4. Conclusions

The following findings have been achieved after analyzing the data from one well located in southern Iraqi oilfields and performing the required computing:

- At perforated points (3356 and 3363 m), the CDDP reaches zero value at the 35% depletion rate of the reservoir pressure (4100 psi); thus, the hazard of sand production will occur.
- When the reservoir pressure depleted about 15% to be 3500 psi, the value of P_{cwf} was 1900 psi, thus the value of the CDDP is 1600 psi at the perforated point (3356 m).

- At the perforated point (3356 m), the value of P_{cwf} at the start of production is 1352.74 psi (i.e., the value of CDDP is 2747 psi). Furthermore, the drawdown area will become smaller or narrower as the depletion grows over time; thus, the value of P_{cwf} will increase due to the drop in reservoir pressure.
- The IPR criteria, i.e., constant productivity index, and Vogel and Standing empirical methods were utilized to identify the Q_c as a function of the P_{cwf} value (1352.74 psi), below these critical values, the sanding will commence. The results showed that the values of the critical oil flow rates were 2587.4 and 1525.8 STB/day for the Vogel and Standing, respectively. While it was 3244.5 STB/day for the J method. Ultimately, the values of the oil rate and associated wellbore flowing pressure can be calculated over time by employing the aforementioned procedures.
- When the rock's UCS is relatively low, sanding is possible. This provides credibility to the theory that sand production could be initiated for reasons other than drawdown pressures.

Acknowledgements

The authors express gratitude to Basra Oil Company and the University of Baghdad for providing vital support for conducting this work.

Conflict of Interest

The authors do not have any conflicts of interest related to this article that need to be disclosed.

Author Contributions Statement: Mustafa A. Isaa contributed to the Methodology; Data Analysis and Interpretation; Writing Original Draft. Muntadher A. Issa contributed to the Conception; Literature review. Farqad A. Hadi contributed to the Writing – review & editing. Ali A. Alzuobaidi contributed to the Data Curation. All authors have read and approved the final version of the manuscript.

References

[1] J. C. Jaeger, N. G. W. Cook, and R. Zimmerman, "*Fundamentals of rock mechanics*", John Wiley & Sons, 2007.

[2] E. Fjar, R. M. Holt, A. M. Raaen, and P. Horsrud, "*Petroleum related rock mechanics*", Elsevier, 2008.

[3] M. A. Issa, M. A. Issa, A. N. Abdulkareem, A. A. Al-Zuobaidi, and F. A. Hadi, "Construct a Geomechanical Model to Estimate the Critical Drawdown Pressure for the Sandstone Reservoirs", *Journal of the Geological Society of India*, vol. 100, no. 2, pp. 268–276, 2024. https://doi.org/10.17491/jgsi/2024/173826.

[4] J.-W. Choi, "*Geomechanics of subsurface sand production and gas storage*", Georgia Institute of Technology, 2011.

[5] T. T. L. Bui, “Geomechanical model and sanding onset assessment: A field case study in Vietnam”, *Petrovietnam Journal*, vol. 10, pp. 40–46, 2021. https://doi.org/10.47800/PVJ.2021.10-04.

[6] A. Joseph, L. C. Akubue, J. A. Ajienka, and A. B. Oriji, “Sanding Prediction using Rock Mechanical Properties (A Parametric Study)”, in *SPE Nigeria Annual International Conference and Exhibition*, Lagos, Nigeria, August 6–8, 2012. https://doi.org/10.2118/162945-MS.

[7] M. Adil Issa, F. Ali Hadi, and R. Nygaard, “Coupled reservoir geomechanics with sand production to minimize the sanding risks in unconsolidated reservoirs”, *Petroleum Science and Technology*, vol. 40, no. 9, pp. 1065-1083, 2021. https://doi.org/10.1080/10916466.2021.2014522.

[8] M. A. Issa, A. N. Abdulkareem, F. A. Hadi, M. A. Issa, M. Al-moamen, and A. Jasim, “Review of Sand Production Control and Management”, *Texas J. Eng. Technol.*, vol. 11, no. 2014, pp. 48–56, 2022. Available: https://zienjournals.com/index.php/tjet/article/view/2282.

[9] H. Ben Mahmud, V. H. Leong, and Y. Lestariono, “Sand production: A smart control framework for risk mitigation”, *Petroleum*, vol. 6, no. 1, pp. 1–13, 2020. https://doi.org/10.1016/j.petlm.2019.04.002.

[10] J. Tronvoll, M. B. Dusseault, F. Sanfilippo, and F. J. Santarelli, “The tools of sand management”, in *SPE Annual Technical Conference and Exhibition*, Society of Petroleum Engineers, 2001. https://doi.org/10.2118/71673-MS.

[11] C. D. Hall Jr and W. H. Harrisberger, “Stability of sand arches: a key to sand control,” *Journal of Petroleum Technology*, vol. 22, no. 07, pp. 821–829, 1970. https://doi.org/10.2118/2399-PA.

[12] R. K. Bratli and R. Risnes, “Stability and failure of sand arches”, *Society of Petroleum Engineers Journal*, vol. 21, no. 02, pp. 236–248, 1981. https://doi.org/10.2118/8427-PA.

[13] A. P. Kooijman, P. J. Van den Hoek, P. De Bree, C. J. Kenter, Z. Zheng, and M. Khodaverdian, “Horizontal wellbore stability and sand production in weakly consolidated sandstones”, in *SPE Annual Technical Conference and Exhibition?*, SPE, p. SPE-36419, 1996. https://doi.org/10.2118/36419-MS.

[14] S. M. Willson, Z. A. Moschovidis, J. R. Cameron, and I. D. Palmer, “New model for predicting the rate of sand production”, in *SPE/ISRM Rock Mechanics Conference*, Society of Petroleum Engineers, 2002. https://doi.org/10.2118/78168-MS.

[15] E. Papamichos, I. Vardoulakis, J. Tronvoll, and A. Skjaerstein, “Volumetric sand production model and experiment”, *International Journal for Numerical and Analytical Methods in Geomechanics*, vol. 25, no. 8, pp. 789–808, 2001. https://doi.org/10.1002/nag.154.

[16] L. M. Yeow, Z. Johar, B. Wu, C. Tan, and M. A. Yaakub, “Sand production prediction study using empirical and laboratory approach for a multi-field gas development”, *SPE Asia Pacific Conference on Integrated Modelling for Asset Management*, Kuala Lumpur, Malaysia, pp. 57–70, March 2004. https://doi.org/10.2118/87004-MS.

[17] P. Ray, W. Hilarides, R. J. Wetzel, and M. N. Sweep, “Mechanical Earth Model Calibration for Sanding Potential Estimation: A Case Study from the Tombua-Landana Development in Angola’s Deepwater Block 14”, *IPTC 2007: International Petroleum Technology Conference*, 2007. https://doi.org/10.3997/2214-4609-pdb.147.iptc11472.

[18] S. O. Isehunwa and O. Olanrewaju, “A simple analytical model for predicting sand production in a Niger Delta oil field”, *International Journal of Engineering Science and Technology*, vol. 2, no. 9, pp. 4379-4387, 2010.

[19] M. T. Hayavi and M. Abedifar, “A sensitivity study of relevant parameters on sand production in unconsolidated sandstone reservoirs”, *Journal of Petroleum and Gas Engineering*, vol. 8, no. 7, pp. 49-59, 2017. https://doi.org/10.5897/JPGE2016.0258.

[20] N. Okereke, V. Ogbuka, N. Izuwa, F. Kara, N. Nwogu, O. Nwanwe, Y. Baba, S. Kanshio, J. Odo, and I. Oguama, "Advanced Mathematical Model for Prediction of Sand Production Rate: A Niger-Delta Case-Study", in *SPE Nigeria Annual International Conference and Exhibition*, OnePetro, 2020. https://doi.org/10.2118/203692-MS.

[21] S. Z. Jassim and J. C. Goff, "*Geology of Iraq*", Brno, Czech Republic, Dolin, Prague and Moravian Museum, 2006.

[22] BOC, "*Final well Report*", 2012

[23] B. Aadnoy and R. Looyeh, "*Petroleum rock mechanics: drilling operations and well design*", Gulf Professional Publishing, 2019.

[24] M. A. Issa and F. A. Hadi, "Estimation of Mechanical Rock Properties from Laboratory and Wireline Measurements for Sandstone Reservoirs", *Iraqi Geol. J.*, vol. 54, no. 2D, pp. 125–137, 2021. https://doi.org/10.46717/igj.54.2D.10Ms-2021-10-29.

[25] C. Chang, M. D. Zoback, and A. Khaksar, "Empirical relations between rock strength and physical properties in sedimentary rocks", *Journal of Petroleum Science and Engineering*, vol. 51, no. 3–4, pp. 223–237, 2006. https://doi.org/10.1016/j.petrol.2006.01.003.

[26] J. J. Zhang, "*Applied petroleum geomechanics*", Elsevier, 2019. https://doi.org/10.1016/C2017-0-01969-9

[27] M. A. Issa, F. A. Hadi, A. N. Abdulkareem, M. A. Issa, and R. Nygaard, "An integrated one-dimensional geomechanical model to identify the optimal mud weight and the well trajectory for the Zubair formation", *Arab. J. Geosci.*, vol. 16, no. 10, p. 586, 2023. https://doi.org/10.1007/s12517-023-11694-6.

[28] B. A. Eaton, "The Equation for Geopressure Prediction from Well Logs," at *Fall Meeting of the Society of Petroleum Engineers of AIME*, Dallas, Texas, Sep. 1975. https://doi.org/10.2118/5544-MS.

[29] M. D. Zoback, "*Reservoir geomechanics*", Cambridge University Press, 2010.

[30] M. A. Issa, M. A. Issa, and A. A. A. A. Alrazzaq, "Developing a Geomechanical Model to Mitigate the Risks of Wellbore Instability in an Iraqi Oilfield," *Indian Geotech. J.*, vol. 53, pp. 1064–1077, 2023. https://doi.org/10.1007/s40098-023-00726-3.

[31] M. A. Issa, M. A. Issa, A. N. Abdulkareem, and F. A. Hadi, "Review of Mechanical Rock Properties Measurement and Estimation Techniques", *International Journal of Analytical, Experimental and Finite Element Analysis*, vol. 9, no. 3, pp. 43 - 49, Sept. 2022.

[32] M. J. Thiercelin and R. A. Plumb, "A core-based prediction of lithologic stress contrasts in east Texas formations", *SPE Form. Eval.*, vol. 9, no. 04, pp. 251–258, 1994. https://doi.org/10.2118/21847-PA.

[33] K. Edimann, J. M. Somerville, B. G. D. Smart, S. A. Hamilton, and B. R. Crawford, "Predicting rock mechanical properties from wireline porosities", in *SPE/ISRM Rock Mechanics in Petroleum Engineering*, Trondheim, Norway, July 1998. https://doi.org/10.2118/47344-MS.

[34] A. Kim, "Sand control mechanism and its impact on mature fields", *Halliburtonblog. Com*, 2012.

[35] J. V. Vogel, "Inflow performance relationships for solution-gas drive wells", *J. Pet. Technol.*, vol. 20, no. 01, pp. 83–92, 1968. https://doi.org/10.2118/1476-PA.

[36] M. B. Standing, "Inflow performance relationships for damaged wells producing by solution-gas drive", *J. Pet. Technol.*, vol. 22, no. 11, pp. 1399–1400, 1970. https://doi.org/10.2118/3237-PA.