IJE TRANSACTIONS A: Basics Vol. 39, No. 10, (October 2026) 2521-2528

International Journal of Engineering

Journal Homepage: www.ije.ir

Impact of Effective Pressure Variations on Reservoir Rock Porosity and Compressibility

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PAPER INFO

Paper history:
Received 17 September 2025
Received in revised form 15 December 2025
Accepted 03 Januray 2026

Keywords:
Porosity
Compressibility
Pressure
Exponential Dependence
Logarithmic Dependence

ABSTRACT

Pressure transient analysis programs typically use a linear diffusion equation. However, according to extensive petrophysical investigations by various authors, the relationship between porosity and pressure is nonlinear. This factor, like the reservoir compressibility coefficient, can significantly impact the accuracy of various transient flow problems. This applies particularly to determining the distance to reservoir boundaries and estimating reserves using pressure buildup tests for exploratory wells. Therefore, the aim of this study was to investigate the predominant type of porosity pressure function for subsequent refinement of the diffusion equation used for PTA. To solve the set task, petrophysical studies of core samples from terrigenous and carbonate formations were conducted in a pressure range of 1.44–64.65 MPa (200–9000 psi) using a compression rig. The results were compared with studies by other authors. These studies are not unique, but the results obtained differ from generally accepted ones. It is shown that the dependence of porosity on pressure follows a logarithmic law, rather than an exponential one, as is commonly believed. PTA calculations have demonstrated a significant impact of compressibility coefficient variability on the accuracy of determining the distance to reservoir boundaries. A detailed study revealed that core unloading results in an abrupt change in the compressibility coefficient, caused by the formation of microcracks. Therefore, using linear and exponential porosity-pressure relationships with a constant compressibility coefficient is highly inappropriate for solving PTA problems.

doi*: 10.5829/ije.2026.39.10a.14*

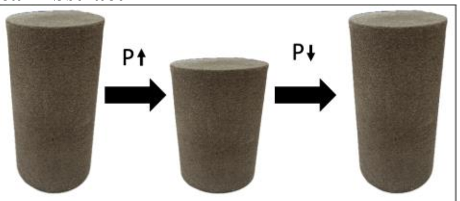
Graphical Abstract

Relevance. Reliable transient-flow analysis and safe/efficient reservoir operation require realistic pressure-dependent storage. Using constant c_m, or linear m(P) biases storage estimates and pressure-derivative diagnostics.

Alm. Establish compact laws for porosity m(P) and rock compressibility c_m(P), identity critical pressures on unloading/loading, and embed these relations into transient-flow models to improve prediction and operating limits.

Object. Reservoir rock core samples tested in the laboratory under confining stress with controlled pore-pressure paths (unloading/loading).

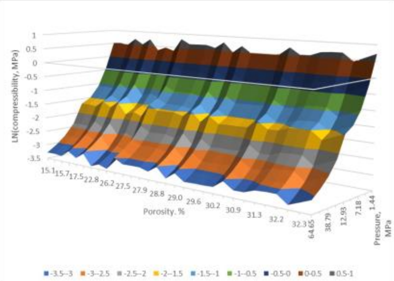
Subject. Functional relations between effective pressure and porosity and rock compressibility-specifically log-law m(P) and inverse-pressure c_m(P) - their critical-pressure behavior, and impacts on transient-flow interpretation and design.



$m = m_0 + \beta_m (P - P_0)$ Linear (R^2=0,75)

$m = m_0 \, e^{\beta_m (P-P_0)/m_0}$ Exponential (R^2=0,76)

$m - m_0 = -a \ln\left(\frac{P}{P_0}\right)$ Logarithmic (R^2=0,99)



Conclusion:

- **Porosity–pressure relationship:** Porosity varies with pressure according to a logarithmic law rather than linear or exponential models.
- **Reservoir compressibility:** The compressibility coefficient is not constant; it is inversely proportional to effective pressure, resulting in wide variability across pressure ranges.
- **Core unloading behavior:** A sudden increase in compressibility occurs due to the initiation of microfractures, representing a critical threshold.
- **Core loading behavior:** A discontinuous decrease in compressibility is observed, reflecting abrupt consolidation of the reservoir rock.

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Please cite this article as: Iktissanov VA, Bernatov MS. Impact of Effective Pressure Variations on Reservoir Rock Porosity and Compressibility. International Journal of Engineering, Transactions A: Basics. 2026;39(10):2521-8.

1. INTRODUCTION

The pressure diffusivity equation (1, 2) is used to describe unsteady-state filtration processes in the oil reservoirs numerical modeling and for the pressure transient analysis (PTA). The classical linear pressure diffusivity equations are valid for slightly compressible fluids and rocks, where the compressibility coefficients can be assumed constant. It is also assumed that permeability and viscosity are invariable parameters (3, 4).

Undoubtedly, these assumptions are far from reality, as none of the noted parameters is a constant (5). Several modifications of the diffusivity equation have been proposed to date – for deformable reservoirs (6, 7), for the filtration of non-linear fluids, accounting for relaxation processes (8-10), high flow velocities, etc.

The accuracy of describing real filtration by the diffusivity equations significantly impacts the precision of the calculations (11). These calculations, in turn, affect the reliability of the determined reservoir parameters and the success of various methods for designing, monitoring, and managing oil field development processes. The compressibility of the reservoir rock and the saturating fluids is one of the most significant factors in describing unsteady-state filtration processes (12, 13). Therefore, this work focuses on the task of more accurately accounting for rock compressibility in the diffusivity equations, as these parameters govern the rate of pressure redistribution within the reservoir.

All pressure diffusivity equations are based on four fundamental equations: the continuity equation, the filtration equation, and the equations of state for the porous medium and the fluid.

Let's consider the most common pressure dependences of porosity, presented in Equations 1 and 2.

In most cases, a linear equation is adopted to describe the dependence of porosity on pressure (Equation 1):

$$\phi = \phi_0 + c_f\left(P - P_0\right), \tag{1}$$

where ϕ_0 - initial porosity at initial pressure P_0; ϕ - porosity at pressure P; c_f - formation compressibility.
Some authors believe that porosity is best described by an exponential relationship (Equation 2):

$$\phi = \phi_0\, e^{c_f(P-P_0)/\phi_0}. \tag{2}$$

Given the Taylor approximation $e^x \cong 1+x$, the linear Equation 1 is easily obtained from the exponential relationship 2.

At this point, the problem of describing porosity from pressure could be considered solved, but as shown by our further studies and studies of other authors, the dependence of porosity on pressure has a completely different character in contrast to Equations 1 and 2.

Another, no less important parameter for describing the processes of unsteady filtration is the compressibility coefficient (Equation 3), characterising the pore volume change at some pressure change:

$$c_f = -\frac{1}{V}\frac{\partial V_p}{\partial P} = -\frac{\partial \phi}{\partial P}, \tag{3}$$

where ∂V_p is the pore volume change, ∂P is the pressure change, V is the pore volume of the rock element, m is the porosity.

Sometimes, the reservoir compressibility coefficient is determined by a slightly different Equation 4:

$$c_f = \frac{\partial \phi}{\phi \partial P}, \tag{4}$$

from which the exponential pressure Equation 2 is derived.

The compressibility coefficient significantly influences pressure redistribution processes in porous and fractured reservoirs during unsteady-state flow (14, 15). As an example, a 10% error in total compressibility leads to a 5% error in determining the distance to reservoir boundaries (16).

Typically, in diffusivity equations and various field numerical modeling and PTA programs, formation compressibility is assumed constant, with primary focus placed solely on fluid compressibility (17).

Therefore, the aim of this work is to determine more accurate dependencies of formation porosity and compressibility coefficient on pressure to enhance the accuracy of unsteady-state fluid flow calculations.

2. METHOD AND MATERIALS

Experimental studies were conducted on a PBC-920 filtration equipment to determine porosity and pore compressibility coefficient under triaxial compression across a wide pressure range. Pore pressure remained unchanged and equal to atmospheric pressure. Preliminary preparation involved extracting native reservoir fluids from the pore space of the samples via extraction. The samples were then dried for 48 hours at 80°C. Subsequently, the dry samples were weighed, vacuumed, and saturated with brine having a density of 1170 kg/m³. Finally, the initial porosity was estimated from the mass difference between the dry and saturated samples, which was taken as the volume of fluid imbibed into each sample.

Rock samples with a diameter of 2.5 cm were placed in a high-pressure chamber. Confining pressure was increased to 64.65 MPa (9000 psi) and then stepwise reduced to fixed values of 51.72, 38.79, 25.86, 12.93, 10.77, 7.18, 3.59, and 1.44 MPa. At each stage, the increase in pore volume was recorded using a graduated pipette. The studies were performed on 60 reservoir rock samples from fields of the Verkhnekamsk Depression, with half being terrigenous rocks of the Visean stage and the other half being carbonates (13 from the Vereiskian horizon of the Moscovian stage and 17 from the Bashkirian stage). The parameters of the investigated rock samples are presented in Table 1. Overall, the conducted research represents typical core analysis procedures.

3. ANALYSIS OF RESEARCH RESULTS. LOGARITHMIC DEPENDENCE OF POROSITY ON PRESSURE

The results of experimental studies, presented in Figures 1 and 2, show an increase in porosity with decreasing pressure for sandstones in the range of 2.9 ÷ 6.9% and for limestones in the range of 1.6 ÷ 5.8%, which in itself is not unusual. To avoid cluttering the graphs, the equations and correlation coefficients are shown only for the extreme curves.

What was unusual for us was that the ratio of porosity to initial porosity (at a pressure of 1.44 MPa) is described with high accuracy by a logarithmic equation of the type (Equation 5):

$$\phi = alnP + b, \tag{5}$$

where a and b - coefficients of line.

The correlation coefficient R^2 for the all experimental data ranges from 0.962 to 0.998, unlike other dependencies. This contradicts the linear and exponential

TABLE 1. Parameters of rock samples

Parameter name	Sandstones	Carbonates
Age of the rock	C1v	C2vr/ C2b
Formation depth, m	1688.1-1737.1	1358.4-1365.5 1375.8-1392.0
Porosity, %	16.1-33.3	14.2-24.8/8.1-27.1
Permeability, mD	3.61-931.9	0.68-732.5

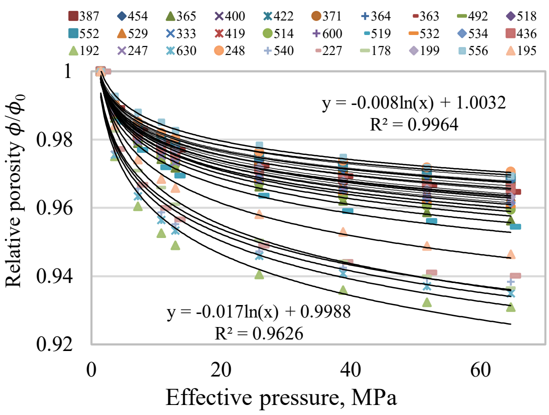

Figure 1. Pressure dependence of relative porosity for sandstones (parameter of the curves is the number of the core)

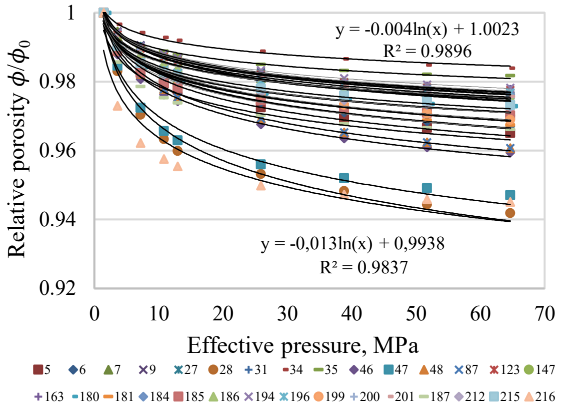

Figure 2. Pressure dependence of relative porosity for limestones (parameter of the curves is the number of the core)

dependencies $\phi(P)$ in Equations 1 and 2, which are used in commercial PTA software, particularly in the Saphir program.

It can be assumed that for small pressure changes, the logarithmic function is close to linear, considering the Taylor series expansion ln(1+x)≅x (18, 19). However, during hydrocarbon field depletion under natural drive mechanisms, the decrease in reservoir pressure compared to the initial pressure can be substantial. For example, in a number of gas fields in Western Siberia, reservoir pressure has decreased by more than an order of magnitude. In some small oil fields in the Ural-Volga region, developed without pressure maintenance or with significant delays in its implementation, reservoir pressure dropped to 0.4 – 0.5 of the initial pressure.

Naturally, in these cases, it is necessary to account for a more accurate dependence of porosity on pressure. Literature analysis showed that the logarithmic dependence of porosity on pressure has been known since the work of Terzaghi (Equation 6), and this formula is over 90 years old:

$$\phi - \phi_0 = -a \ln\left(\frac{P}{P_0}\right), \tag{6}$$

This formula can be easily derived from Equation 5 by subtracting the expression $\phi_0 = alnP_0 + b$ for a specific initial condition. If we base the compressibility coefficient on Equation 3 and differentiate Equation 6 or 5 with respect to pressure, we obtain Equation 7:

$$c_f = \frac{\partial \phi}{\partial P} = (-alnP + b)' = -\frac{a}{P}, \tag{7}$$

where a is the dimensionless coefficient preceding the logarithm. Expression 7 shows that the compressibility coefficient is not a constant but is inversely proportional to pressure. In this study, compressibility coefficients for carbonate and terrigenous reservoirs were obtained in the range of 3×10^{-5} – 2×10^{-3} MPa^{-1}, which is significantly wider than the ranges reported by other authors. The primary reason for this discrepancy is the pressure dependence of the compressibility coefficient.

By performing the inverse operation of integrating Equation 7, we obtain the Terzaghi Equation 8:

$$\phi - \phi_0 = -\int_{P_0}^{P} c_f(P)dP = -a\ ln\left(\frac{P}{P_0}\right) \quad (8)$$

Some researchers employ various approaches to determine pore compressibility, such as integral, differential, and their variants, which lead to different values of the coefficient (20-22). The reason for this lies in the fact that compressibility coefficients differ depending on the pressure steps used. For instance, from initial to final pressure or with fine incremental steps. We have adopted a fundamentally different approach—using the derivative according to the definition of the compressibility coefficient 3. This eliminates the need to specify different pressure steps, as the derivative inherently assumes an infinitesimal step size. To determine the change in porosity, integration over specified intervals is required (23). For this purpose, it is first necessary to fit the experimental data points with an equation exhibiting a high correlation coefficient. As previously mentioned, the highest accuracy in describing porosity is achieved using the logarithmic dependence.

A more detailed analysis of the obtained porosity versus pressure curves, presented in Figures 1 and 2, reveals the existence of a distinct break point in the logarithmic curves. This is most clearly visible on the graph with the logarithm of pressure (Figure 3).

At the point of this abrupt structural change, a sharp increase in the compressibility coefficient is observed. The cause of this break is likely a change in the structure of the tested samples due to the formation of micro-fractures (24-26). Consequently, the effective pressure at which this process occurs can be interpreted as the fracturing initiation pressure.

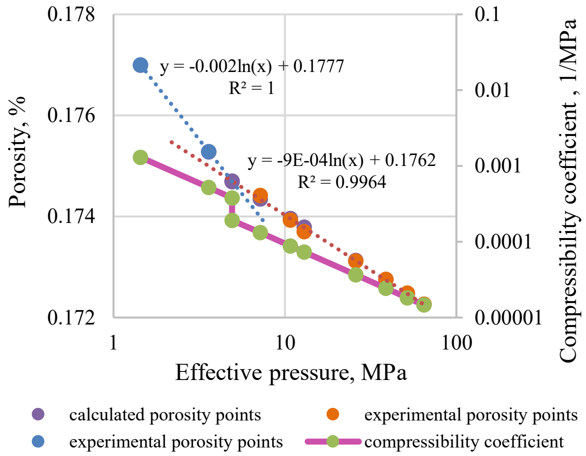

Figure 3. An example of the presence of a sharp change in porosity and compressibility coefficient due to pressure (sample 215 of carbonate formation)

Unfortunately, acoustic emission data or post-test CT scans before and after the experiments were not performed to confirm this assumption. However, supporting this hypothesis is the fact that, on average, the intersection point of the logarithmic curves is observed at a mean pressure of 8.1 MPa for the carbonate rocks of the studied fields and about 8.7 MPa for terrigenous rocks (Table 2). This range corresponds to the order of magnitude of the fracturing pressure for injection wells in the region under consideration (27, 28). As an example, Figure 4 presents result of inflow performance relatiomship (IPR) where the determined effective pressure is 8.6 MPa.

Additionally, Figure 5 shows the fracturing pressure range of 5.7 ÷ 12.2 MPa, which depends on the effective pressure. These studies were performed for injection wells in Tournaisian carbonate deposits (29, 30).

When the injection pressure increases, it leads to the opening of natural fractures or the creation of induced fractures, which alters the injectivity index and fluid conductivity. Determining this pressure is of significant practical importance because exceeding the fracturing pressure during injection leads to inefficient fluid loss, a rapid increase in water cut in responding production wells, and other negative factors (31-33). These issues are discussed in more detail in our monograph on the limiting and optimal pressures for injection and production wells (34, 35).

TABLE 2. Statistical results of pressure of change of core structure

Parameter name	Sandstones	Carbonates
Average effective pressure, MPa	9.6	8.7
Standard error, MPa^2	0.6	0.7
Minimum, MPa	4.1	1.4
Maximum, MPa	15.6	17.3
Number of samples	30	30

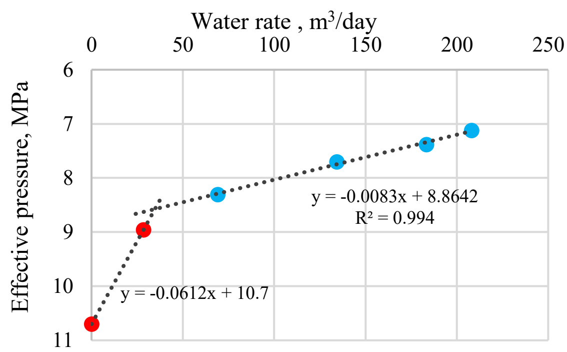

Figure 4. An example of determining the fracturing pressure (8.6 MPa) according to IPR for the injection well (№ 3081 Tournaisian deposits of JSC “Tatneft”)

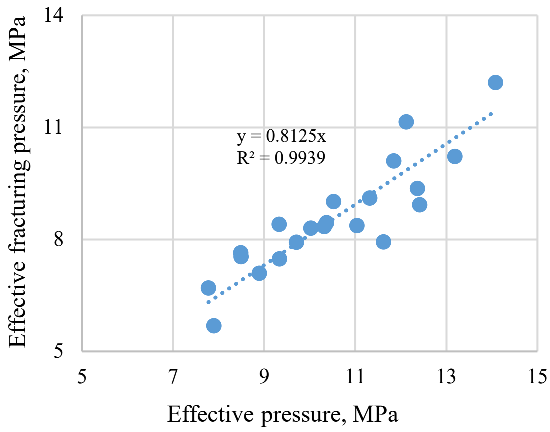

Figure 5. The dependence of fracturing pressure on the effective pressure, determined by IPR of injection wells for Tournaisian deposits

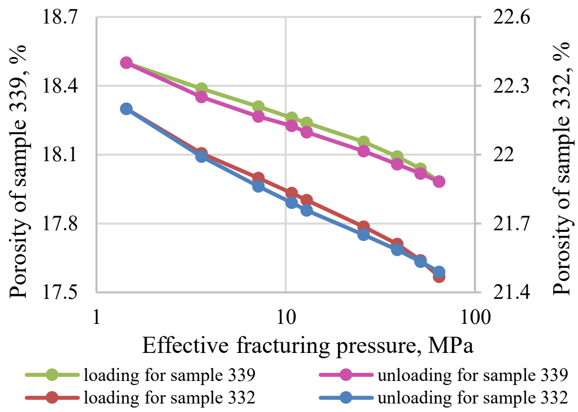

Figure 6. Example of change in compressibility coefficient under unloading and loading for two core samples

In conclusion, the fracturing pressure can potentially be determined not only from IPR but also from the core unloading curve. Notably, the nature of the dependence of the compressibility coefficient on pressure remains unchanged and inversely proportional to the effective pressure (Equation 7).

Naturally, of interest are not only core unloading but also the deformation processes during loading. For this purpose, tests involving core unloading and subsequent reloading were conducted on two samples. The nature of the curves, presented in Figure 6, indicates an approximate return of porosity to its initial state, which aligns with the results of other researchers. However, the pattern of the porosity recovery differs from the original, which is also consistent with the well-established concept of the difference between loading and unloading elastic moduli.

4. NON-LINEAR DIFFUSION EQUATION

As noted earlier, expression 7 shows that the compressibility coefficient is not a constant but is inversely proportional to pressure, which violates the linearity of the diffusion equation and complicates its solution (Equation 9):

$$\frac{\partial P}{\partial t}\frac{\mu a}{k(P+P_0)} = \nabla^2 P, \tag{9}$$

where P - pressure, P_0 - initial bottomhole pressure, t - time, k - permeability, μ - oil viscosity.

The coefficient α in Equation 9 is determined by the rule of additivity for the reservoir and oil (Equation 10):

$$a = \phi\alpha_l + (1-\phi)c_f, \tag{10}$$

where α_l is the coefficient for fluid and rock.

The possibility of using Equation 10 is justified by the fact that at pressures above the bubble point pressure, according to the empirical formula of Vasquez, M., Beggs, H.D., the oil compressibility is also inversely proportional to pressure (36).

An approximate solution of Equation 9 using the Laplace transform is presented in our work. The main results of the calculations show a significant difference in the distance to the impermeable boundary when using the proposed model compared to the traditional solution (Figure 7, Table 3).

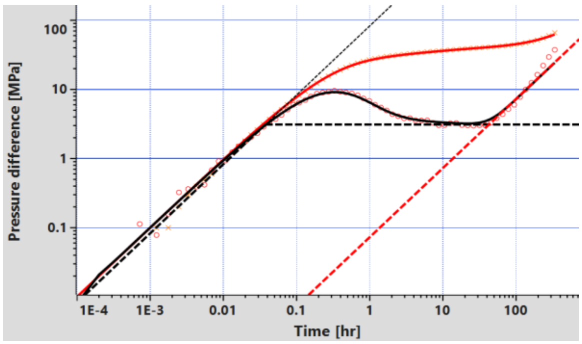

Figure 7. An example of interpretation of the created pressure curve where $c_t = a/P$ using the linear filtration model $c_t = const$ (the red curve is pressure, the black curve is the pressure derivative, the red dashed curve with an angle of 1/2 is a sign of a closed boundary, the black horizontal dashed curve is a sign of radial flow)

TABLE 3. Comparison of the results of interpretation of the pumping curve by different models

Parameter name	**According to the proposed model,** a **=0.0008**	**According to the traditional model (Saphir)** c_t**= 8-10 Pa**$^{-1}$
Wellbore storage, m^3/MPa	0.01	0.012
kh, mkm^2·m	10.0	9.2
Skin	0.10	1.1
The radius of the closed circle, m	250.0	32.5

5. CONCLUSION

Porosity–pressure relationship: Thus, the predominant type of porosity versus pressure function is the rather logarithmic dependence, than the linear or exponential dependencies. This confirms the conclusion made by K. Terzaghi over 90 years ago.
Reservoir compressibility: It was found that in this case, the formation compressibility coefficient is inversely proportional to the effective pressure, resulting in a wide range of its variation. For the considered pressure range of 1.44 – 64.65 MPa (200-9000 psi), the compressibility coefficient varied within $3\times10^{-5} - 2\times10^{-3}$ MPa^{-1}.
It has been demonstrated that the dependence of the compressibility coefficient on pressure significantly affects the accuracy of determining the distance to reservoir boundaries using pressure buildup data.
Core unloading behavior: A detailed study of the porosity curves revealed that for all investigated core samples during unloading, an abrupt change in the compressibility coefficient occurs, which may be caused by the formation of micro-fractures. The obtained pressure range correlates with the fracture pressure determined from indicator diagrams for injection wells.

Acknowledgements

The author appreciates Empress Catherine II Saint Petersburg Mining University for providing necessary facilities to conduct present research.

Funding

This research did not receive any specific grant from funding agencies in the public, commercial, or not-for-profit sectors.

Ethics Approval and Consent to Participate

This article does not involve any studies with human participants or animals performed by any of the authors. Therefore, ethics approval and consent to participate are not applicable.

Competing Interests

The author declares no financial or organizational conflicts of interest.

Data Availability

The data supporting the findings of this study are available from the corresponding author upon reasonable request.

Declaration of Generative AI and AI-assisted Technologies in the Writing Process

During the preparation of this manuscript, the author used ChatGPT exclusively for minor language editing and stylistic refinement to improve clarity and readability. The author carefully reviewed, revised, and approved the final content and takes full responsibility for the accuracy, integrity, and originality of the work.
The author declares that there are no known financial or organizational conflicts of interest that could have influenced the work reported in this paper.

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Persian Abstract

چکیده

زمینه :مخازن با نفوذپذیری کم و مخازن حاوی نفت با گرانروی بالا به طور فزایندهای به دلیل تخریب ساختار ذخیره و تعدادی از عوامل منفی، به موضوعات توسعه تبدیل میشوند .در نتیجه، زمان لازم برای رسیدن مشتق لگاریتمی فشار به شرایط جریان شعاعی به طور قابل توجهی افزایش مییابد که این امر تفسیر منحنی افزایش فشار را در یک زمان قابل قبول برای پژوهش غیرممکن میسازد.هدف :توسعه و جمعبندی توصیهها برای تحلیل گذرای فشار در مخازن با ضرایب تحرک کم. مواد و روشها :برای حل وظیفه تعیین شده، از روشهای شناختهشده و توسعهیافته توسط نویسنده برای تفسیر و پژوهش هیدرودینامیکی استفاده شد. نتایج :نشان داده شد که بهینهترین روشها عبارتند از : استفاده از منحنی کاهش فشار به جای منحنی افزایش فشار، استفاده از مدلهای جریان قبل از جریان شعاعی هنگام تفسیر منحنیهای فشار برای چاههای با هندسه پیچیده، و تفسیر سنتی دادههای فشار بلندمدت با استفاده از فشارسنجهای ته چاهی. نتیجهگیری :روشهای پیشنهادی امکان کاهش زمان خاموشی برنامهریزی شده چاه در طول آزمایش چاه را فراهم کرده و در نتیجه باعث کاهش تلفات در تولید نفت هنگام حل مسئله تعیین پارامترهای فیلتراسیون مخزن و ناحیه اطراف چاه میشوندتولید چاهها مطابقت دارد.