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The mechanism of porous reservoir permeability deterioration due to pore pressure decrease

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Abstract:
This study investigates the causes of permeability decline in porous reservoirs under decreasing reservoir pressure by comparing laboratory experiments with well test data. Well tests indicate a greater sensitivity of permeability to pressure changes in reservoir formations compared to laboratory conditions and for this remain unclear. Field studies of permeability changes in northern Perm oil fields were conducted alongside laboratory experiments on core permeability under pressure. Results showed that highly permeable samples exhibited the greatest decline in permeability during elastic deformations, with reductions of 6% for limestones and 20% for sandstones. The relationship between permeability and purely elastic deformations for both rock types was accurately described by a power law. By comparing coefficients from field and lab studies, the mechanism of permeability decline in field conditions was established. A model incorporating elastic and plastic deformations of porous reservoirs was developed. The model considers the localization of plastic deformations in horizontal and vertical low-permeability deformation bands. Findings indicate that highly permeable formations are more susceptible to deformation band formation, particularly in thicker layers. The decrease in permeability was found to correlate strongly with the formation thickness, likely due to the formation of transverse deformation bands in pore layers.

1. Introduction

During hydrocarbon production, the decline in reservoir pressure inevitably leads to a reduction in the permeability of productive formations (Bernabe, 1987; Kozhevnikov et al., 2021a; Nolte et al., 2021). This decrease in pressure reduces the back pressure against the weight of overlying rocks, resulting in reservoir deformation (Sigal, 2002; Ma et al., 2013; Asahina et al., 2019; Lei et al., 2020a; Raziperchikolaee, 2023), irreversible decreases in well productivity, and increases in the development time of deposits. Despite these evident consequences, predicting changes in permeability with decreasing reservoir pressure often receives insufficient attention due to unpredictability and the lack of well-founded methods. Understanding the laws governing permeability changes with decreasing reservoir pressure is necessary to calculate hydrocarbon production time and justify injection feasibility.

Studies on changes in rock permeability due to pressure have been conducted since the first half of the last century (Terzaghi, 1925; Dobrynin, 1962). An analysis of existing methods for modeling rock permeability as a function of effective pressure reveals that, in most cases, researchers employ empirical dependencies derived from experimental results (Kozhevnikov et al., 2021b). Such approximations are well-suited to describe permeability changes in both porous and fractured media. The most common equation describing the change in permeability with pressure is the power law (Kilmer et al., 1987; Clauset et al., 2009; Jiang and Yang, 2018; Hu et al., 2020):

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$$\frac{k}{k_o} = A \cdot (\Delta P)^{-n} \tag{1}$$

where k and k_o are the current and initial permeability, respectively; ΔP is the pressure change; A is the empirical coefficient; n is an exponent characterizing the sensitivity of permeability to changes in pressure.

The permeability Eq. (1), being empirical in nature, is primarily suited for describing permeability reduction that has already occurred. Its application for predicting the productivity of new wells, even within the same reservoir, is limited. Moreover, significant discrepancies exist between core sample test results and field data, rendering core samples inadequate for predicting well productivity decline. In works it was noted that in reservoirs permeability is more sensitive to pressure changes than in laboratory conditions (Kozhevnikov et al., 2021a, 2021b). The calculated values of the exponent n in Eq. (1), determined from well tests, are an order of magnitude higher than for core plugs selected from the same layers (Kozhevnikov et al., 2021b). The significant discrepancy between laboratory core studies and field data hinders the utilization of readily available data from routine core tests for predicting well productivity. This study aims to bridge this gap by investigating the mechanisms underlying the observed decline in permeability with decreasing reservoir pressure.

This study focuses exclusively on porous reservoirs due to their pronounced discrepancy between field and laboratory data. Fractured reservoirs, as documented by laboratory studies, exhibit a significant decline in well productivity upon pressure depletion due to fracture closure. However, the literature lacks an explanation for the heightened sensitivity of high-strength, consolidated porous reservoirs to pressure decline. Existing research suggests that pressure-induced permeability changes are associated with plastic deformation within the formation, resulting in reservoir compaction and irreversible well productivity loss. Nonetheless, the distribution of plastic deformation remains unclear: Whether it is uniform throughout the formation or localized in certain areas. Inspired by the idea that natural porous formations are not homogeneous, and also taking into account the mechanism of plastic deformation of porous media we propose that the significant reduction in permeability observed with decreasing pore pressure is primarily attributed to the development of deformation bands within the pore structure (Main et al., 2000; Lothe et al., 2002; Ngwenya et al., 2003; Sulem and Ouffroukh, 2006; Alkhasli et al., 2022). Deformations occur when the decline in reservoir pressure surpasses the yield strength of the rock. Due to the heterogeneous nature of the reservoir, these deformations are unevenly distributed within the porous medium. Initially, the most porous and productive interlayers are subject to crushing, leading to localized deformation concentrated in narrow bands. While the transport properties of the majority of the porous medium remain relatively unaffected, the presence of deformation bands reduces the overall formation permeability, acting as low-permeability barriers between layers. Experimental studies confirm the efficacy of this compaction mechanism under reservoir conditions (Lothe et al., 2002; Ngwenya et al., 2003). Furthermore, deformation bands have been observed in surface rock outcrops globally.

To validate the proposed mechanism of permeability deterioration in porous reservoirs, this study analyzed well test data from oil fields in the northern Perm region. These analyses were complemented by comparative laboratory investigations of core plugs. The sensitivity of rock transport properties to stress loading is directly linked to their mechanical properties, which are influenced by factors such as grain size, cement content, and mineral composition. However, since the considered layers C_1bb and C_2b of the fields in the north of the Perm region share the same geological age and similar structure, the influence of these factors is not addressed in this study.

2. Analysis of well testing

To obtain the information about changes in formation permeability, it is necessary to use well testing data. This study utilized data from the oil-bearing formations C_1bb and C_2b in the northern Perm region, which have similar geological structures. Formation properties are outlined in Table 1. More than 800 well tests conducted in the fields over 23 years since 1995 were analyzed. The results of well tests using steady-state flow and pressure buildup methods were examined. To comparatively assess the impact of changes in reservoir pressure on permeability, the data were normalized.

Only wells without cracks near the formation were chosen. Additional criteria included maintaining reservoir pressure above saturation pressure and a water cut below 5%. Deposition of paraffins and salts in such conditions is unlikely and was disregarded. No enhanced oil recovery methods and intervention jobs were performed during the observation period. 42 wells were selected: 16 for the carbonate reservoir (C_2b) and 26 for the terrigenous reservoir (C_1bb). Permeability curves from pressure drop (dP) are depicted in Fig. 1. Formation properties and calculated coefficients (A and exponent n) for Eq. (1) are listed in Table 1.

Analysis of well tests revealed a significant influence of reservoir pressure on permeability. In some wells, a decrease in reservoir pressure by 5 MPa led to a reduction in permeability of over 90%. It has been determined that the permeability of carbonate and terrigenous formations is accurately described by a power law (Eq. (1)) (see Fig. 1). In the vicinity of all selected wells, the permeability of the carbonate formation and its sensitivity to changes in reservoir pressure are described by the following average equation with a high accuracy ($R^2 = 0.9825$):

For wells in the C_2b formation, the calculated values of coefficient A and exponent n range from 0.4815 to 1.0265 MPa^{-1} and from 0.946 to 1.357, respectively (Table 1).

Analysis of well tests of the C_1bb terrigenous formation showed that its permeability also decreases according to a power law (Eq. (1)) on pressure. The graph (Fig. 1(b)) shows that all wells can be divided into 3 groups, with different sensitivity of the formation to pressure reduction.

In group 1, permeability is described by the equation:

$$\frac{k}{k_o} = 0.9362 \cdot (dP)^{-1.186} \tag{2}$$

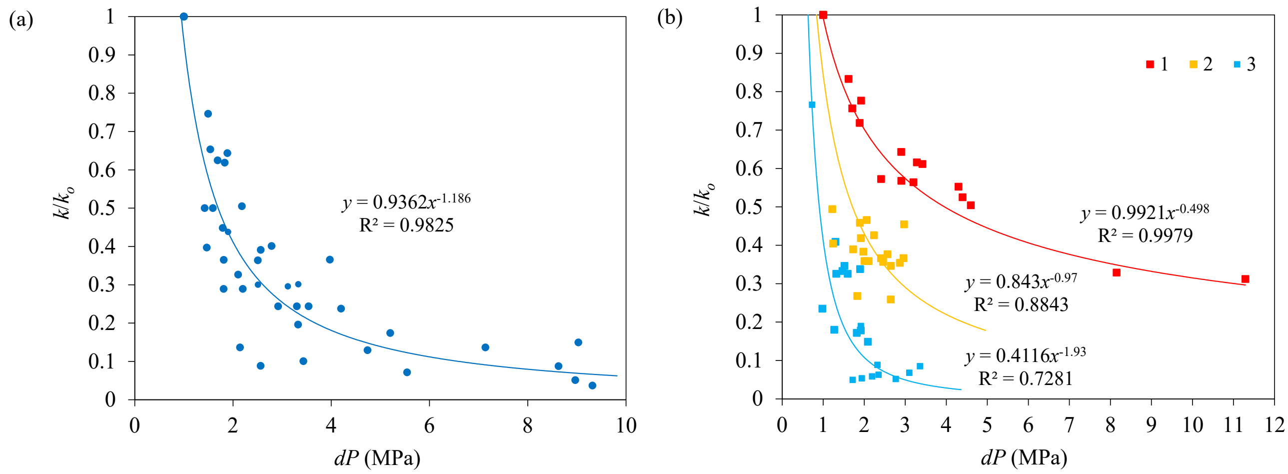

Fig. 1. Effect of reservoir pressure drop (dP) on permeability. (a) Carbonate reservoir C_2b and (b) terrigenous reservoir C_1bb, numbers 1, 2 and 3 mean groups of wells in the vicinity of which the reservoir has different sensitivity to pressure.

Table 1. Properties of oil-bearing formations and coefficients of Eq. (1).

Formation	C_2b	C_1bb
Rock	Limestone	Sandstone
k_o ($\mu m^2 \cdot 10^{-3}$)	1-193	6-663
m (%)	9.7-16	7.6-18
P (MPa)	15.5-18.0	15.87-16.36
h (m)	8.5-15.2	9.2-20.9
H (m)	1,979-2,167	2,144-2,353
A (MPa^{-1})	$0.4815 \cdots 1.0265$	$0.4116 \cdots 0.9921$
n	$0.946 \cdots 1.357$	$0.498 \cdots 2.115$

$$\frac{k}{k_o} = 0.9921 \cdot (dP)^{-0.498} \tag{3}$$

In group 1 reservoir thickness varies from 1.8 to 5.7 m, permeability varies from 6×10^{-3} to 663×10^{-3} μm^2.

In group 2, permeability is described by the equation:

$$\frac{k}{k_o} = 0.843 \cdot (dP)^{-0.97} \tag{4}$$

In group 2 reservoir thickness varies from 5 to 10.6 m, permeability varies from 12×10^{-3} to 564×10^{-3} μm^2.

In group 3, permeability is described by the equation:

$$\frac{k}{k_o} = 0.4116 \cdot (dP)^{-1.93} \tag{5}$$

In group 3 reservoir thickness varies from 9.2 to 20.9 m, permeability varies from 83×10^{-3} to 330×10^{-3} μm^2.

Correlation analysis revealed that a common feature among the groups is the layer thickness (h). Greater thickness leads to a faster relative decline in productivity with decreasing pressure. Permeability alone has minimal influence on formation sensitivity, but in highly permeable formations with greater thickness (group 3), the sensitivity to pore pressure (exponent n) is highest.

2.1 Core plug tests

For comparative analysis, laboratory studies were conducted on cores obtained from wells drilled into the C_1bb and C_2b deposits in the north of the Perm region. The properties of the core samples are listed in Table 2, showcasing a wide range of permeability corresponding to that determined by well testing. The collection also includes samples with maximum porosity (K_{por}), which are highly susceptible to deformation when reservoir pressure decreases. Cleaned and dried core samples of standard size (30 mm diameter, 30 mm length) were tested using nitrogen on an UltraPoroPerm-500 unit (CoreLab Instruments, USA). The test procedure was as follows:

1) The core was placed in a core holder, with the initial confining pressure of 2.76 MPa. It was held at this pressure for 10 minutes to allow for stress relaxation, which research confirmed to be sufficient for complete stabilization of deformations.
2) Permeability was measured by injecting pure nitrogen through the sample at a flow rate not exceeding 1 ml/s to maintain a linear flow regime.
3) Pore pressure changes were modeled by adjusting the confining pressure. During tests, the confining pressure was increased stepwise from 2.76 to 13.8 MPa, then decreased back to 2.76 MPa in increments of 2.76 MPa. The chosen maximum confining pressure allowed for the evaluation of purely elastic deformations. Nitrogen injection was conducted at a constant flow rate to minimize the influence of slip effects on the research results. The injection pressure did not exceed 21 kPa.
4) Sensor data were recorded on a computer at one measurement per second, and instantaneous permeability values were calculated by Darcy's formula for gases.
5) Graphs illustrating the permeability of core samples versus confining pressure were obtained based on the test results (see Fig. 2).

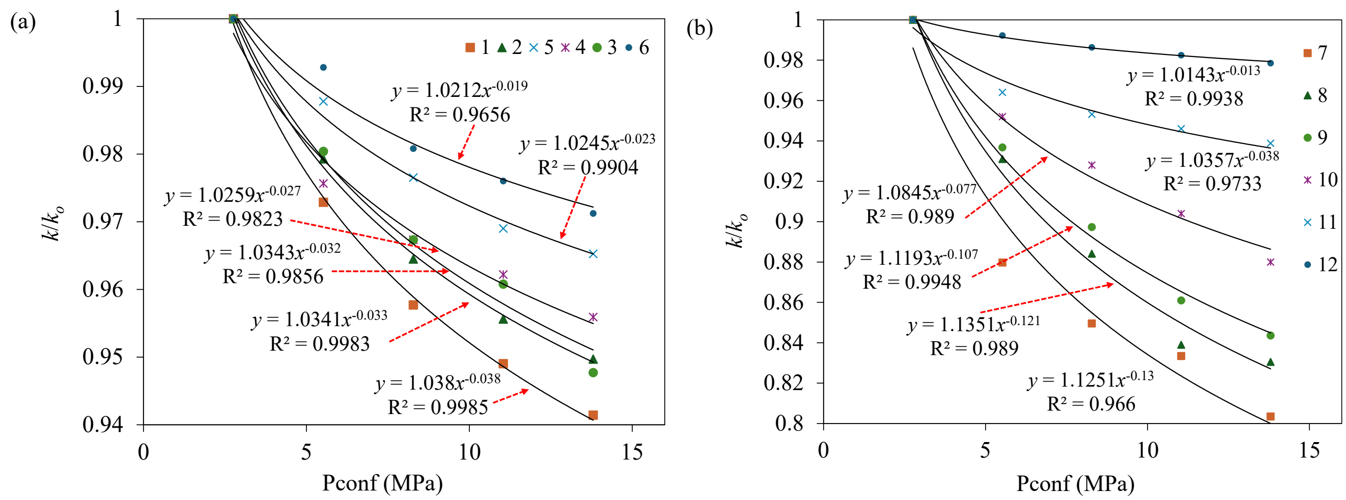

Fig. 2. Effect of confining pressure on permeability. The equations for the curves are arranged in the same sequence as the permeability curves - from top to bottom. (a) Limestone samples and (b) sandstone samples.

Table 2. Properties of core samples and calculated values of the coefficients and exponents of the equations from Fig. 2.

Rock	Sample	k ($\mu m^2 \cdot 10^{-3}$)	K_{por} (%)	A (MPa^{-1})	n
Limestone	1	384	14.14	1.038	0.038
	2	34	14.79	1.034	0.033
	3	15	10.11	1.034	0.032
	4	156	14.97	1.026	0.027
	5	107	13.51	1.025	0.023
	6	42	15.63	1.021	0.019
Sandstone	7	427.5	15.19	1.125	0.130
	8	117.4	15.19	1.135	0.121
	9	6.3	11.08	1.119	0.107
	10	13.2	11.58	1.085	0.077
	11	41.5	9.69	1.014	0.013
	12	27.8	7.60	1.036	0.038

Analysis of the results from laboratory studies revealed that the permeability of limestone and sandstone samples under purely elastic deformations is accurately described by power laws, with high precision (R^2 = 0.98-0.99) as indicated by Eq. (1). The coefficients and exponents calculated are presented in Table 2. Irrespective of the rock type, the most significant reduction in permeability is observed in highly permeable samples, amounting to 6% and 20% for limestones and sandstones, respectively.

Despite the considerable variation in permeability among the samples studied, the calculated values of coefficient A in Eq. (1) exhibit low dispersion across all samples, ranging from 1.021 to 1.038 MPa^{-1} for limestones and from 1.014 to 1.135 MPa^{-1} for sandstones. The exponent (n) of the power law (Eq. (1)), which characterizes the sensitivity of rocks to pore pressure, averages 0.029 for limestones, ranging from 0.019 to 0.038, and for sandstones, it ranges from 1.014 to 1.135 with an average of 0.081.

Notably, under purely elastic deformations, the permeability of sandstones, owing to their coarse-grained structure, exhibits greater sensitivity to loading compared to that of fine-crystalline limestones.

3. Discussion and modeling

Analysis of field test data from wells (Table 1) and laboratory studies of rock samples (Table 2) revealed that permeability of formations under field conditions is more sensitive to pressure variations than under laboratory conditions. This suggests that under reservoir conditions, as reservoir pressure declines, both elastic and plastic deformations occur within the rock matrix. While elastic deformations are typically small and do not significantly alter the pore structure, their contribution to overall permeability changes is minimal. Conversely, plastic deformations, due to the inherent heterogeneity of porous formations, are localized within deformation bands, which exert a substantial influence on the formation's overall transport capacity. Fig. 3 provides a schematic representation of the deformation band formation mechanism as pore pressure decreases. Initially, the formation exhibits a continuous pore space with undisturbed transport properties (Figs. 3(a) and 3(b)), leading to optimal well productivity and unrestricted fluid flow to perforations. However, as pore pressure decreases (Fig. 3(c)), the back pressure counteracting the weight of the overlying rocks diminishes, resulting in collapse of the porous medium.

When subjected to a relatively small decrease in pore pressure over a relatively short production period, the elastic deformation of the porous media and associated displacements are negligible. This results in deformation localized primarily within horizontal deformation bands (Figs. 3(c) and 3(d)). While horizontal deformation bands do not impede plane-parallel fluid flow through the formation, they can act as

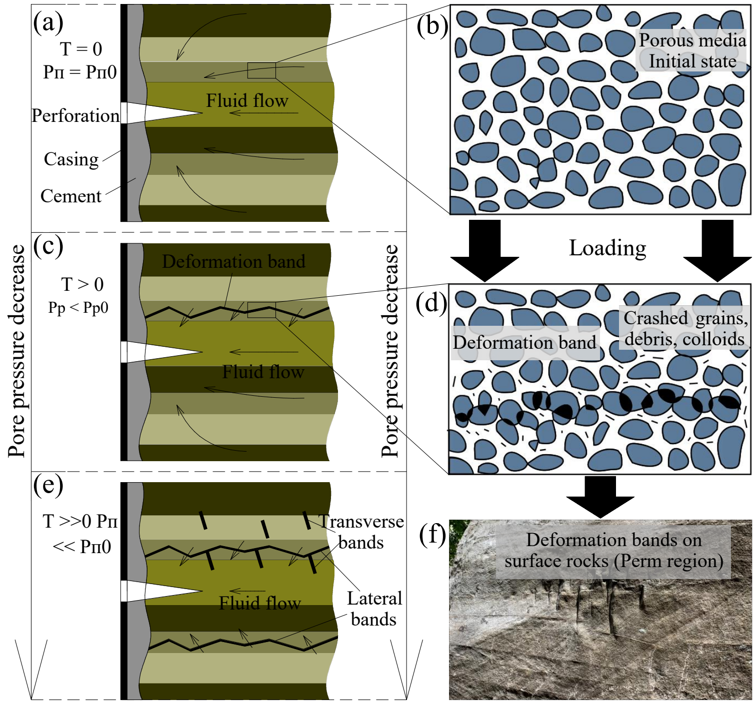

Fig. 3. Scheme of the development of deformation bands in the near-wellbore zone of a heterogeneous formation with decreasing formation pressure and their impact on fluid flow within the formation. Initial state of (a) the pore layer and (b) medium, the appearance of (c) horizontal deformation bands in the formation and (d) pore medium with the initial decrease in pressure, the appearance of (e) transverse deformation bands with a large decrease in pore pressure and (f) deformation bands on surface rock outcrops.

barriers to vertical filtration (Fig. 3(c)). Productive formations typically consist of multiple layers, each exhibiting distinct interconnected transport and mechanical properties. Interlayers with higher permeability tend to possess higher porosity and lower strength, while the opposite is true for less permeable layers. Deformation preferentially localizes within the most permeable interlayer.

As reservoir pressure declines, deformation bands exhibit an increase in width and may develop within less permeable layers, which typically possess higher strength. Furthermore, significant deformation results in amplified formation displacements, enhancing the probability of vertical deformation band formation (Fig. 3(e)). Vertical bands, oriented perpendicular to the bedding planes, significantly hinder fluid flow towards the well. In situ, the assessment of this deformation mechanism remains challenging using conventional logging methods. However, the presence of deformation bands in porous rock outcrops worldwide, including the Perm region (Fig. 3(f)), provides evidence for this pore space compaction mechanism. Unlike deformation bands observed in surface outcrops (Fig. 3(f)), which formed prior to rock uplift and have undergone healing over time, resulting in impermeable barriers, newly formed deformation bands lack substantial strength and do not completely obstruct fluid flow (Ngwenya et al., 2003).

Microscopic analysis of thin sections (Fig. 4) reveals that the sandstone core, subjected to plastic deformation in laboratory studies, exhibits compaction. Grain fracturing is observed near the outer boundary of the core (Fig. 4(a)), while the inner portion remains intact (Fig. 4(b)). These findings indicate that plastic deformation in porous formations is non-uniform and localized within deformation bands.

The reduction in transport properties of formations is contingent upon the size, number, and orientation of deformation bands relative to fluid flow. Deformation bands do not occur in isolation but rather form clusters, ranging in width from several centimeters to tens of meters (Main et al., 2000; Ngwenya et al., 2003; Sulem and Ouffroukh, 2006; Alkhasli et al., 2022). The formation and characteristics of deformation bands are influenced by the magnitude and direction of relative layer displacement. Larger deformation bands are typically associated with tectonic events such as earthquakes. In productive formations, a decrease in reservoir pressure may have minimal impact on the development of deformation bands, particularly when the deformation is small and does not significantly impede fluid flow. The transport properties of reservoir layers are significantly affected by the orientation of deformation bands relative to the direction of fluid flow. Lateral deformation bands have minimal impact on parallel flow towards the well, while transverse bands can significantly restrict fluid flow. The orientation of deformation bands is primarily determined by the direction of principal stress and the homogeneity of deformation throughout the formation. Uniform pressure depletion leads to homogeneous deformation, characterized by a greater number of lateral bands. Conversely, heterogeneous deformation, often caused by uneven pressure depletion, results in the formation of more

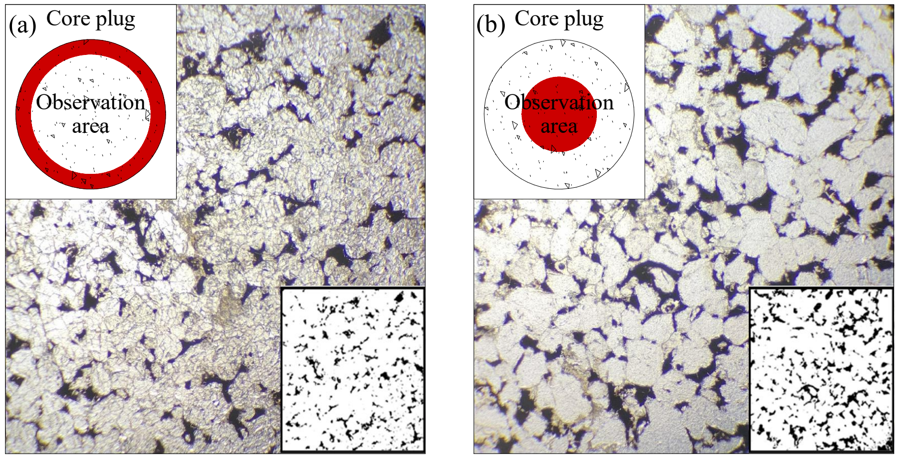

Fig. 4. Photographs of thin sections of consolidated porous sandstone, odservation areas are red colored. (a) Compacted sandstone at the outer boundary of the core with destroyed quartz grains. The fine network of cracks is very clearly visible. Binary image shows damaged void space and (b) state of porous sandstone inside the core. Binary image shows intact void space.

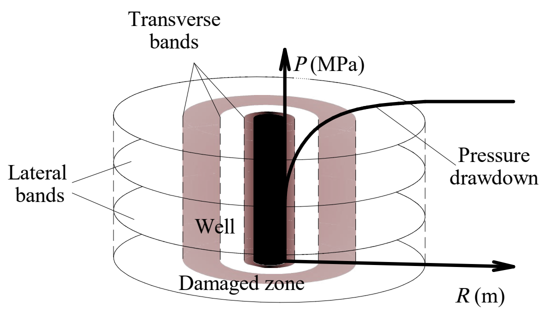

Fig. 5. Diagram illustrating the cone of depression around the well and its impact on the formation of deformation bands.

transverse shear bands. Pressure depletion in a formation is generally uneven, with the cone of depression inducing significant deformation in the near-wellbore zone, while the formation may remain largely undeformed at greater distances. This disparity in deformation across the formation results in the formation of transverse bands. Fig. 5 illustrates the schematic distribution of deformation bands around a well in the presence of a cone of depression.

The occurrence of transverse deformation bands is influenced by layer thickness. This phenomenon can be attributed to several factors. Firstly, thicker layers tend to exhibit a higher density of inhomogeneities. Secondly, assuming constant elasticity and other relevant parameters, a thicker layer experiences a larger absolute displacement, leading to a greater number of transverse deformation bands. A schematic comparison of the formation mechanisms of deformation bands in layers of varying thicknesses is presented in Fig. 6.

Formation pressure depletion can induce the development of deformation bands within sedimentary formations (Figs. 6(a) and 6(b)). These bands, in addition to causing compaction and reducing porosity and permeability, act as sources of fine clastic material. In thin formations (Fig. 6(a)), transverse deformation bands primarily exhibit tensile characteristics (Fig. 6(c)) and generate a limited amount of clastic material. Conversely, in thicker formations (Fig. 6(b)), larger displacements promote the formation of vertical, pure-shear deformation bands, which produce significant quantities of fine clastic material. Such bands typically serve as effective barriers to fluid flow (Fig. 6(d)). The fracturing of rock grains within deformation bands facilitates the detachment of fine clastic material. This material can subsequently migrate with the fluid, potentially forming an internal filter cake (Kozhevnikov et al., 2022a, 2022b, 2023). An anomalous change in permeability occurs as destroyed particles migrate towards the well, forming a low-permeability clogged area (Bedrikovetsky et al., 2012; Anyim and Gan, 2020; Wang et al., 2023). The decrease in permeability during migration of colloids has a power-law dependence on the volume of produced oil (Turbakov et al., 2022). The permeability of a porous medium is inversely proportional to the concentration of colloids and fines within the fluid. This relationship indicates that higher concentrations of these particles lead to a greater reduction in permeability. In deformation bands, the impact of colloid migration on permeability reduction is constrained by several factors. The concentration of colloids and fines within the band is limited by its thickness, composition, and the relative orientation of the band to the fluid flow direction. This orientation influences the migration potential of particles. Furthermore, the mobility of colloids and fines decreases during migration, as they become trapped within pore spaces and their movement is hindered (Kozhevnikov et al., 2024).

The occurrence and density of deformation bands are directly influenced by pressure. As the reservoir undergoes compaction, the overall deformation increases according to a power law relationship (Dyke and Dobereiner, 1991; Clauset et al., 2009; Lei et al., 2020b; Alkhasli et al., 2022). Measuring the influence of deformation bands on permeability is a challenging task in relation to well conditions, given the unknown geometric dimensions of these bands. Taking into account the mechanisms discussed above and the fact that formation permeability exhibits a pure power-law dependence

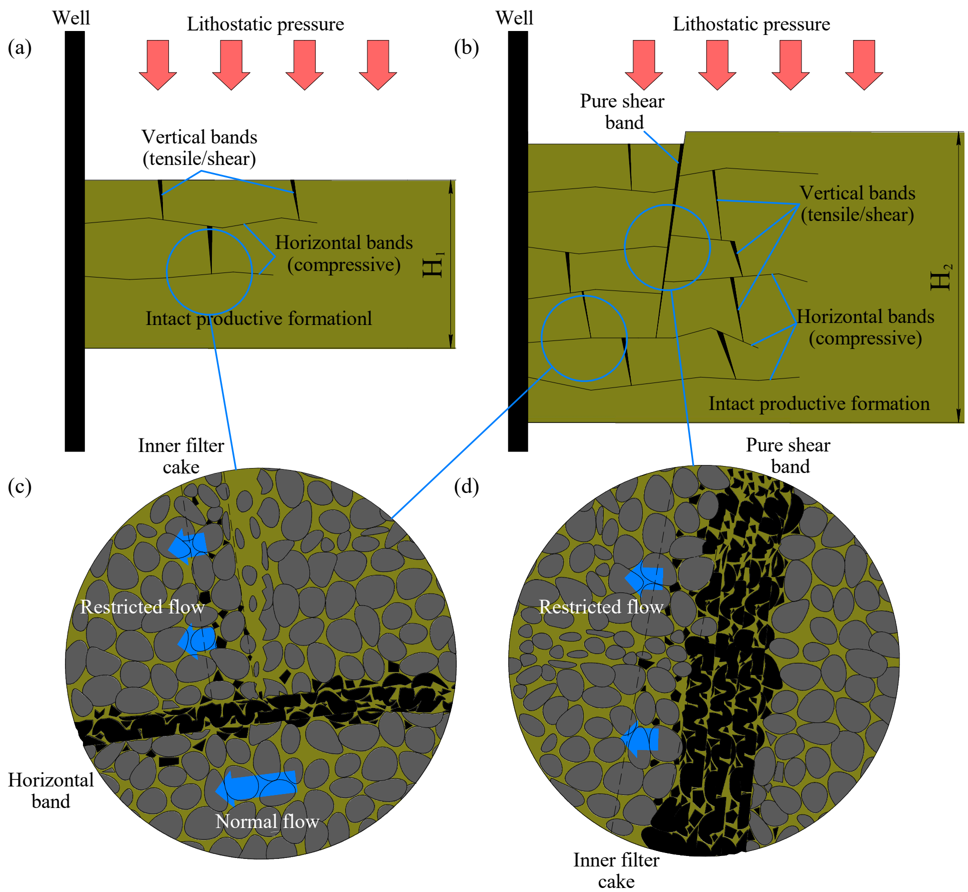

Fig. 6. Schematic representation of the formation of deformation bands in layers with different thicknesses. (a) Thin layer, (b) thick layer, (c) image of a horizontal deformation band and (d) image of a vertical shear deformation band. Light gray shows intact rock grains, dark gray shows destroyed grains and fragments. The blue arrow shows the direction of fluid flow, its size corresponds to the flow rate.

on pressure according to well tests, the difference in the exponents of the permeability equations derived from laboratory studies and well tests can be attributed to the formation of a network of deformation bands and associated factors. The impact of elastic deformation on permeability is characterized by a power law (Eq. (1)), with the coefficients and exponents for rocks determined based on laboratory test results (Table 2). Therefore, considering both elastic and plastic deformations of the formation, the overall decrease in permeability due to changes in pore pressure, as indicated by well test results, can be expressed as:

$$\frac{k}{k_o} = A \cdot (dP)^{-n} \cdot B \cdot (dP)^{-m} - C \cdot dP \tag{6}$$

where B and C are empirical coefficients; m is the exponent characterizing the sensitivity of permeability due to deformation bands. A and n characterize elastic deformations; their values can be determined from the results of laboratory core studies (Table 2). The values of B and m indicate the impact of plastic deformations on the overall permeability of the formation. C represents the compressibility of the formation, the inverse value of stiffness, characterizing the decrease in permeability during compression of the rock minerals. The calculated values of the coefficients and exponents of Eq. (6) for certain wells are outlined in Table 3.

The components of the right side of the power Eq. (6) consist of elastic (A and n) and plastic (B and m) parts. Based on the results of curve fitting analysis of field data with the setting of coefficients and exponents (A and n) obtained during laboratory studies in Eq. (6), the calculated empirical values of A, B, C, n and m were obtained (Table 3). The product of the calculated coefficients A and B for all wells is close to unity, then in general, Eq. (6) can be written as:

$$\frac{k}{k_o} = (dP)^{-(n+m)} - C \cdot dP \tag{7}$$

Analysis of the developed model's coefficients and exponents revealed that the exponent m, which characterizes the probability of occurrence of deformation bands, exhibits a linear dependence on formation thickness (Fig. 6). The approximations for the exponent m in carbonate and terrigenous formations display a close convergence, suggesting a similar mechanism for permeability degradation. Deformation of the formation at greater thickness induces substantial displacements in the rocks, resulting in significant tangential stresses within the formations. These stresses contribute to the forma-

Table 3. Properties of oil-bearing formations in the studied wells.

Reservoir	Parameter	Well										
		1	2	3	4	5	6	7	8	9	10	11
C_2b	k_o ($\mu m^2 \cdot 10^{-3}$)	34	31	4	2	2	3	9	40	11	22	193
	h (m)	10.2	10.6	8.5	9.8	12.2	15.2	7	10	15	8	3
	A (MPa^{-1})	1.034	1.034	1.034	1.034	1.034	1.034	1.034	1.034	1.034	1.034	1.026
	n	0.033	0.033	0.032	0.032	0.032	0.032	0.032	0.033	0.032	0.032	0.027
	B (MPa^{-1})	0.948	0.940	0.975	0.953	0.961	0.954	0.968	0.964	0.98	0.965	0.968
	m	1.052	1.36	1.07	0.847	1.164	2.087	0.82	1.142	2.271	0.9537	0.479
	C ($\times 10^{-14}$)	2	2	2,000	9	30	2	2	30	30	2	2
C_1bb	k_o ($\mu m^2 \cdot 10^{-3}$)	330	83	12	564	144	3	6	242	663	217	20
	h (m)	19	14	4.4	10.6	20.9	8	5.1	3	1.8	3	5.7
	A (MPa^{-1})	1.125	1.135	1.085	1.125	1.135	1.085	1.085	1.125	1.125	1.125	1.085
	n	0.130	0.121	0.077	0.130	0.121	0.077	0.077	0.13	0.13	0.13	0.077
	B (MPa^{-1})	0.889	0.821	0.896	0.858	0.881	0.689	0.921	0.891	0.909	0.854	0.922
	m	2.568	2.046	1.147	1.103	2.613	0.7114	0.428	0.293	0.398	0.247	0.443
	C ($\times 10^{-14}$)	4	2	2	2	70	2	2	2	50	600	2

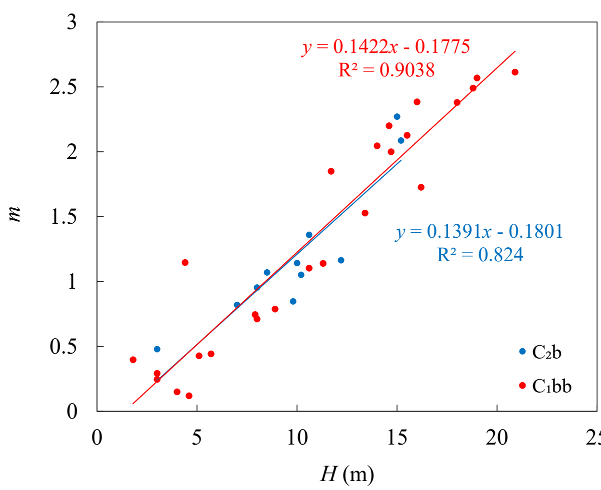

Fig. 7. Influence of layer thicknesses on the exponent m of Eq. (7).

tion of transverse deformation bands, as depicted in Fig. 6, which notably impact the productivity of the formation.

4. Conclusions

The work presents a comparative analysis of the findings from laboratory and field studies on how pressure affects the permeability of terrigenous and carbonate rocks. A novel model has been introduced for the first time, enabling the combination of results from both types of studies to forecast permeability changes when reservoir pressure decreases. This model, considering the initial permeability of rocks and formation thickness, accurately predicts alterations in pore reservoir permeability during the initial phase of well operation. The investigation uncovers the mechanism behind the decline in pore reservoir permeability as reservoir pressure drops, incorporating elastic and plastic deformations along with the development of deformation bands. It's noted that highly permeable and thick layers are notably prone to plastic deformations through the creation of longitudinal and transverse deformation bands.

The summary displacement of the formation and the occurrence of transverse deformation bands are contingent upon the thickness of the formation; thicker formations yield more transverse bands and a comparatively larger reduction in permeability. Conversely, thinner formations exhibit diminished summary displacement when reservoir pressure declines, thereby reducing the likelihood of transverse bands.

Further research should be aimed at studying the number of longitudinal and transverse deformation bands and their characteristics to more accurately predict these processes, as well as to use this mechanism as a way to increase the hydraulic connection of the perforation and the productive formation due to cross-flows along the transverse deformation bands.

Reservoir deformation is an irreversible process leading to diminished transport properties of the formation. A cone of depression and a reduction in reservoir pressure are inevitable during hydrocarbon production, making it impossible to prevent deformation within the near-wellbore zone. Planning enhanced oil recovery must consider formation deformations. Traditional methods like acidizing may not be effective in restoring well productivity in the presence of deformed formations. Acid injection enhances well productivity by forming highly conductive channels, though these channels form with least resistance paths in acid flow directions. Deformation bands hinder acid penetration and treatment coverage. However, understanding the productivity decline in the well zone helps create a program for restoring well productivity. The most preferred methods for boosting oil recovery, considering deformations and compaction zones, include acid treatments with simultaneous pulse actions and thermochemical methods like powder charges and binary mixtures. Restoring reservoir pressure close to initial values before using such methods is crucial, as intervention at lower pressures could lead to further compaction of reservoir rocks and decreased well productivity.

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Conflict of interest

The authors declare no competing interest.

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