

Assessing the impact of drilling methods on formation damage - A case study of an Iranian oil field reservoir

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Abstract

Formation damage, resulting from the invasion of drilling and completion fluids, significantly affects reservoir productivity. This study investigates the relationship between drilling methods and formation damage using data from 54 vertical, horizontal, and directional wells. Core plug tests and well test data quantify formation damage. The findings reveal that drilling and completion operations contribute to 50% of observed damages in the reservoir. Parameters such as total permeability, radial permeability, productivity index (PI), average reservoir pressure, and skin index were calculated for each well. Results demonstrate that wells drilled under underbalanced drilling (UBD) exhibit at least 300 bbl/d/psi higher PI than overbalanced drilling. Vertical wells with low radial permeability display the highest PI and average production pressure compared to horizontal and directional wells. Conversely, horizontal and directional wells show higher damage rates and lower PI than vertical wells. Directional wells exhibit the lowest PI at 70 bbl/d/psi, followed by horizontal wells at 150 bbl/d/psi, while vertical wells exhibit the highest PI at 250 bbl/d/psi. These results suggest the use of oil-based mud and UBD methods to mitigate formation damage and optimize well productivity. The authors emphasize the importance of both proper fluid design and drilling method selection in preventing formation damage.

1. Introduction

Formation damage caused by drilling fluid leakage through natural fractures results in mud losses. Also, formation damage occurs in permeable formations. It is a challenging problem in drilling operations [1]. Such damage significantly reduces production efficiency, leading to considerable revenue losses at a field scale [2]. Identifying and mitigating formation damage is essential for improving well productivity and extending the field life [3]. There are various mechanisms that result in formation damage and permeability reduction in hydrocarbon reservoirs [4]. External fluid invasion during drilling, fracturing, completion, enhanced oil recovery, and workover interacts with the reservoir rock and fluids, resulting in damage such as clay swelling, deflocculation, and solid particle invasion, which decrease productivity and incur significant economic losses. Such invasion of foreign fluids can have unintended consequences on reservoir behavior and productivity [5].

Formation damage occurs across six operational activities. In drilling operations, the fluid's solid particles penetrate the pores of the formation and reduce permeability. Additionally, the migration of drilling fluid can cause cementation, which is another influential factor. The second activity pertains to well completion, where the penetration of drilling fluid into the formation may also result in damage. Similarly, during perforation, solid particles penetrating the formation can cause obstructions and decrease permeability. The third operation involves stimulation fluids used for well stimulation, which can transfer sediments into the porous environment near the well, leading to a decrease in permeability. Injection operations, production activities, and other internal well factors also contribute to permeability reduction [6].

While vertical drilling with its simplicity is often the preferred technique for reaching the reservoir, directional drilling technique is employed due to technical and economic considerations. This technique can be used to divert the well through several oil-bearing layers to increase the contact surface between the well and reservoir, reduce water and gas encroachment and ultimately increase production flow [7]. However, the directional section, having extensive contact between the drilling fluid and the reservoir, causes severe formation damage and makes the drilling and completion operations challenging. In reservoirs with low pressure, the risk of formation damage resulting from drilling fluid loss necessitates the use of suitable drilling methods such as underbalanced drilling (UBD) [8].

The reservoir of this study contains many micro-fractures that serve as the primary conduits for production. If the permeability of these fractures is reduced due to formation damage, it significantly diminishes reservoir efficiency. Therefore, studying and preventing such damage is important. Existing literature has explored various aspects of formation damage. Radwan conducted a comprehensive analysis of reservoir damage by integrating reservoir, geological, and production data, to propose strategies to mitigate damage [9]. Kalhor Mohammad et al. investigated the impact of drilling fluids on formation damage and highlighted the potential of nanotechnology for prevention [10]. Ngata et al. conducted a field study utilizing nanotechnology to control formation damage, demonstrating its superiority over traditional materials in oil and gas development [11]. Karimi et al. examined the efficacy of casing pipe drilling in reducing mud loss and formation damage, revealing twice the efficiency compared to conventional methods [12]. Gamal et al. investigated the relationship between contact time, porosity, and formation damage caused by drilling fluid [13]. Zhang et al. focused on controlling formation damage in fractured saline environments during drilling, reporting a 7.7% productivity increase through the use of optimized drilling fluids. He et al. conducted numerical simulations to explore the influence of drilling fluid characteristics on formation damage, specifically addressing pressure reduction in areas experiencing mud loss [14]. A comprehensive review of laboratory and field studies identified research gaps in formation damage and emphasized the need for further investigation [15].

The objective of this study is to quantify the formation damage resulting from drilling fluid loss by evaluating parameters such as productivity index (PI), permeability, average reservoir pressure, and formation damage rate in the wells under investigation. The findings of this study will contribute to the design of optimal drilling paths and the selection of appropriate drilling fluids for future operations in the studied area.

2. Geological setting

The studied field is situated within the geographic longitude of 50° 12' to 53° 50' East and latitude 54° 29' to 16° 30' North, approximately 230 km southeast of Ahvaz. This field, located in southern Iran (Fig. 1), represents one of the largest carbonate reservoirs in the country. The anticline of this field is about 70 km long and 15 km wide. Its anticline trend is Northwest-Southwest. The vertical hydrocarbon closure within the reservoir is estimated to be around 243 m with limestone as its principal lithology. The vertical hydrocarbon closure within the reservoir is estimated to be approximately 2438 m, with limestone

being the predominant lithology. The Asmari reservoir of the studied field is further classified into four distinct zones (A, B, C, D) based on their petrophysical and lithological characteristics. The Asmari reservoir consists of three units: Lower Asmari from the Oligocene age, Middle Asmari from the early Miocene age (Aquitania), and Upper Asmari from the early Miocene age (Burdigalian). This reservoir predominantly comprises carbonate layers, including limestone and dolomite. In terms of pressure distribution, the reservoir is categorized into nine distinct sections.

Different well tests have been performed to evaluate the reservoir characteristics of these sections. Notably, the Western parts have better porosity and permeability than the Eastern parts of the field. The average thickness of Zone A across the entire field is 44 m, with a minimum thickness of 17 m and a maximum thickness of 62 m. Generally, the average porosity in this zone is 6%, while the average permeability measures 349 mD. These values, along with the predominant rock type of dense limestone, collectively suggest a limited hydrocarbon potential for the A1 zone. On the other hand, Zone B exhibits one of the highest hydrocarbon potentials. It has an average thickness of 48 m, with a maximum thickness of 56 m and a minimum thickness of 18 m. The porosity in this zone ranges from 1–20%, with an average of 9%. The average permeability reaches 685 mD. As for Zone C, it is the thickest zone in the reservoir, with a maximum thickness of 143 m and a minimum thickness of 37 m. The dominant rock in this zone consists of relatively thick and dense limestones, with an average porosity of 6%. The average permeability is recorded at 280 mD. Zone D, with an average thickness of 51 m, exhibits an average porosity of 5% and an average permeability of 569 mD. These characteristics indicate a relatively weaker reservoir potential for Zone D in comparison to the other zones within the reservoir.

3. Methodology

3.1. Overview of methodology

The methodology section outlines the collection, processing, and analysis of core, log, and well test data to assess formation damage in the studied reservoir. Initially, data from drilling, completion, and production operations were gathered and quantified in terms of total formation damage and damage removal risks. This quick quantification method relies on visual inspection of the collected core plug samples. The goal was to estimate the contribution of drilling activities to formation damage in comparison to other operations.

Subsequently, core and log data from wells in the Asmari reservoir were utilized to explore formation damage mechanisms linked to drilling operations. This involved average permeability values across North, East, and South directions, physical measurements of core plugs collected vertically and horizontally, and details of drilling fluids and drilling methods along with their respective measured PI values. Filtration tests on core plug samples, conducted in both vertical and horizontal positions, measured fluid invasion rate and extent, indicating the impact of drilling operations on formation damage.

Finally, well test data, including layer thickness, relative and gross permeabilities, skin factor, average reservoir pressure, and PI, were integrated to analyze formation damage. The evaluation considered the influence of reservoir characteristics and well types on formation damage and well productivity. The aim is to offer insights for mitigating formation damage and enhancing reservoir productivity.

3.2. Data collection

This study investigated the Asmari reservoir, utilizing well test data from 54 wells drilled in the Asmari reservoir. A total of 44 well tests, consisting of 21 vertical wells, 16 directional wells, and 7 horizontal wells, were evaluated. The dataset also incorporated vertical and horizontal core plug samples used for filtration tests. In assessing formation damage in the selected wells, the study additionally utilized integrated production, reservoir, and geology datasets, along with their operational histories. The collected data provided details on reservoir rock type, drilling fluids, production, core analysis, rock mineralogy and drilling techniques.

3.3. Formation damage caused by different drilling fluids

Drilling in formations above the caprock usually involves the use of water-based mud (WBM), resulting in fluid invasion. While such an invasion may not significantly affect hydrocarbon production, it significantly causes severe damage to the reservoir rock in the near-wellbore area and thus reduces the well-productivity index. The depth of invasion varies depending on the type of drilling fluid and its rheological properties. Oil-based mud (OBM) with its lower penetration depth exhibits better performance and less damage due to its petroleum compounds. On the other hand, WBM exhibits greater penetration depth into the producing formation, resulting in more severe formation damage.

Drilling operations in the studied fractured reservoir of Asmari exhibit complex challenges due to the coexistence of high and low formation pressures. Stuck pipes are a frequent problem that arises from fluid loss and filtration. Another problem is the formation damage due to the entry of liquid phase or solid particles from drilling mud into the formation, resulting in decreasing permeability and well efficiency.

3.4. Drilling fluid invasion depth caused by different well geometries

Well geometry can influence the severity and type of formation damage. Horizontal wells, often completed as open hole, are more susceptible to damage compared to vertical wells, which are typically protected by casing pipes and perforations. In open-hole horizontal wells, reservoir fluid must pass through the damaged zone before reaching the wellhead. That results in reduced permeability and significant skin, even for the penetration of particles at shallow depths. Factors such as greater invasion depth, damage removal difficulty, and challenging stimulation operations contribute to the higher severity of damage in horizontal wells compared to vertical wells. Other factors such as greater invasion depth, damage removal and complex stimulation operations also contribute to the higher severity of damage in horizontal wells compared to vertical wells.

Production wells are mainly drilled vertically, and as analyzed earlier, the permeability around the well is reduced due to formation damage. This permeability reduction can be visualized and estimated based on the well geometry. Figure 2 illustrates the invaded and uninvaded zones around the well due to mud loss or filtration.

zones around the well

Permeability reduction comes from two main factors: plugging of pores or openings with solid particles and a decrease of effective pore radius due to increased water content. The penetration depth of solid particles is lower than that of the liquid phase, and the severity of formation damage decreases with distance from the well wall. Fluid velocity decreases as drilling fluid penetrates the formation, leading to the precipitation of solid particles. This invasion reduces permeability around the well and results in additional pressure drops.

The pressure drop (ΔP_{skin}) caused by the skin effect, which has been estimated using numerical reservoir simulation models based on the below equation:

$$\Delta P_{\text{skin}} = 6.33 \times Q \times \mu \times h \times S / (K \times r_w^2) \quad (1)$$

where ΔP_{skin} is the pressure drop caused by the skin effect (psi); Q is the flow rate of the reservoir fluid (bbl/d); μ is the viscosity of the reservoir fluid (cP); h is the net pay thickness (ft); S is the skin factor (dimensionless); K is the permeability-thickness product (mD-ft); r_w is the wellbore radius (ft).

It should be noted that this equation provides only an estimation and may not fully account for the effects of reservoir damage. Therefore, well test data and analysis under real conditions were employed to determine the skin factor (S) and assess its impact on well performance. The PI, used to assess well productivity as the amount of oil produced for a specific pressure decrease, is defined as the ratio of flow rate to pressure drop (ΔP_{skin}), as below:

$$PI = Q / \Delta P_{\text{skin}} \quad (2)$$

where Q is the flow rate of oil production (bbl/d), and ΔP is the pressure drop due to the skin (psi).

4. Results and discussion

This section provides detailed assessments of how drilling methods impact formation damage and well productivity through the analysis and evaluation of the collected data. These findings contribute to the understanding of the behavior of the studied reservoir and offer recommendations for drilling strategies to mitigate formation damage and enhance reservoir productivity.

4.1. Assessing the risk of formation damage in various operations

Different drilling, completion, and workover operations that involve the use of drilling fluids can result in various types of formation damage. The overall damage to the formation was quickly estimated by visually inspecting core plug samples. The total damage percentage caused by each operation was then assessed through a qualitative survey. Additionally, damage removal (R) in the formation was calculated using the empirical formula:

$$R = K * (V / D)^n \quad (3)$$

where K is a constant that depends on the material and the type of removal damage, V is the volume of the material removed, D is the diameter of the hole and n is an exponent that depends on the material and the type of removal damage.

The rapid risk assessment of each operation conducted on the studied formation is depicted in Fig. 3. The results revealed that both drilling and completion operations exerted a significant influence on formation damage, contributing to a total of 50% of the damages observed in the reservoir sector.

damage and damage removal

4.2. Assessing the impact of drilling methods on formation damage

The studied reservoir is characterized by natural fractures with relatively high formation permeability and porosity. However, the reservoir pressure has declined over years of production, resulting in complete fluid loss during conventional overbalanced drilling (OBD). Permeability data played a crucial role in understanding the characteristics of this reservoir. Table 1 presents the permeability values obtained from core samples and well log interpretations. These permeability values provide insights into the areas of the reservoir that are susceptible to considerable fluid loss. The highest permeability in the Asmari reservoir zones is observed in the southern part of the field (sector 2), the western part (sectors 3 and 4), and the eastern part of sector 8, which aligns with major fault lines. It is noteworthy that the permeability of fractures in the three directions (X, Y, and Z) within the Asmari reservoir zones differ. Specifically, zones B and D exhibit the highest permeability in the X, Y, and Z directions, respectively. The overall average permeability of the Asmari reservoir was determined to be approximately 350 mD in the North direction, 486 mD in the East direction, and slightly over 599 mD in the South direction.

Table 1
Permeability values of fractures in three directions (X, Y, and Z) by different zones in terms of mD

Zonation	PERM-X			PERM-Y			PERM-Z		
Asmari	MAX	MIN	AVG	MAX	MIN	AVG	MAX	MIN	AVG
A	1690	79	350	3420	58	577	2808	103	594
B	1897	115	431	2667	60	566	2781	182	697
C	1359	60	240	2801	9	342	2433	12	374
D	2820	280	381	1687	167	462	2492	308	733

Consequently, the damages caused by the natural fractures not only resulted in severe harm to the reservoir but also posed challenges in drilling operations, as evidenced by the observations in the well drilling report. Therefore, UBD becomes essential in this field. This method aims to reduce the damage effects caused by the invasion of solid particles and liquid phases of the drilling mud, both of which can decrease the effective permeability of reservoir oil or gas phases. Ultimately, UBD improves the well productivity compared to OBD. A comparison of the impact of OBD and UBD methods on well productivity for the studied reservoir was conducted, with the results illustrated in Fig. 4. The maximum PI experienced with OBD was 650 bbl/d/psi, whereas wells utilizing UBD exhibited a PI that was at least 300 bbl/d/psi higher. It is important to note that, however, UBD technique does not always help reduce formation damage due to the chemical incompatibility between drilling fluid and formation fluid.

Furthermore, experiments were conducted on core plug samples to measure the filtration rate of drilling fluid under various pressures. Carbonate core samples were collected for the test using an OBM system, in both horizontal and vertical directions. Due to the limited availability of wells with core plugs, options were limited. In this study, core samples were obtained from both vertical and horizontal directions, all belonging to Zone B, the most productive zone in the reservoir (Fig. 5). The core plugs used in this investigation had a standard diameter of 1 inch (2.54 cm) and a length of 3 inches (7.62 cm). To conduct the filtration tests, the core samples prepared for the experiments were placed in the core holder. Fluid was injected into the core from one side at different pressures, and filtration measurements were recorded for the four wells. The volume of 100 ml fluid injected through the core plug within a 10-minute period was measured, and the filtration rate was calculated by dividing the volume of fluid by time.

Table 2 presents the results of these experiments, which compare the volume of damage caused by drilling fluid filtration at different pressures. Gravity effects in the horizontal position caused mud particles to accumulate at the bottom of the sample, resulting in more severe damage in that area. Therefore, the formation of impermeable mud cakes and reduced filtration penetration were observed in the horizontal positions compared to the vertical positions.

Table 2
Comparison of drilling fluid filtration at different pressures for core plugs

Core Number	Pressure (psi)	Horizontal Sample (ml/hour)	Vertical Sample (ml/hour)
1	120	2.2	2.8
2	170	2.5	3.2
3	220	3	4.2
4	270	3.4	4.3

4.3. Analysis of well test data in the studied oil reservoir

The decision to drill horizontal wells was based on two factors: low fracture density in western parts of sectors 5, 6 and 7 and low oil layer thickness in sectors 3 and 4. Table 3 presents the well test data to demonstrate the influence of well types on parameters such as skin volume and damage. The table considers 18 wells across three categories: directional, horizontal, and vertical wells, in nine sectors of the field. Their average values are included in the calculations for parameters S_d , K_r , K_t , and h . Here, parameter h represents the net thickness of the productive zone in the reservoir, K_r denotes the relative permeability, K_t represents the gross permeability, and S_d refers to the degree of impairment or damage to the near-wellbore region. Additionally, the table provides a formula to determine an efficiency factor (FE) based on the skin factor (S): $FE = 7 / (7 + S)$. This implies that as the skin factor decreases, the efficiency factor increases, indicating less near-wellbore damage and improved flow performance. The horizontal wells exhibited the most severe formation damage, with the lowest flow efficiency of 1.2, approximately. In contrast, vertical wells exhibited the lowest rate of damage, with skin damage of -1.4 and flow efficiency of 2.4. The skin volume near the wellbore in the reservoir indicates the reduction of effective permeability due to drilling fluid invasion or completion methods in those wells.

Table 3
Skin volume and damage in vertical, horizontal and directional wells

Well Type	Number of PI_{test}	h (ft)	K_r (gross)	K_t (gross)	S_d	$FE = 7/(7 + S)$
Vertical	25	1400	1600	1650	-1.4	2.4
Horizontal	5	600	2400	2600	-0.6	1.2
Directional	14	900	110	120	-1	2

Table 4 presents the average reservoir pressure and PI for different well types. The average reservoir pressure and layer thickness are the main criteria in designing well paths. In particular, directional and horizontal well types were chosen based on lower average reservoir pressure and thin layer thickness. The low values of these two reservoir parameters also result in reducing well productivity while the vertical wells achieved the highest PI values of all. In Table 4, ψ represents the average pressure gradient in the

reservoir. The parameter " $\Delta\psi$ " from ψ " denotes the change in flowing BHP relative to the average reservoir pressure. Completion damage (CD) resulted from various factors, including drilling fluids and cementing. P_{ave} (psi) refers to the average reservoir pressure at the wellbore during a 24-hour period, which was derived from well testing, production data analysis, and pressure transient analysis. PI_{real} represents the measured PI of a well, obtained from production data including flow rates, pressure differentials, and other relevant parameters. In contrast, PI_{test} is derived from well testing activities, which involve controlled flow rate and pressure measurements to assess the reservoir's characteristics and production potential. It should be noted that PI_{test} may not always match PI_{real} due to factors such as reservoir behavior, fluid dynamics, and testing limitations. Nonetheless, the PI_{test} is valuable for estimating productivity and designing optimal production strategies.

Table 4
Average pressure and PI in vertical, horizontal and directional wells

Well Type	No. of PI_{test}	h (ft)	ψ (psi)	$\Delta\psi$ from ψ	CD (dimensionless)	P_{ave} (psi)	PI_{test} (bbl/d/psi)	PI_{real} (bbl/d/psi)
Vertical	25	1400	0.25	0.033	180000	2600	250	160
Horizontal	5	600	0.13	0.005	3500000	2570	150	110
Directional	14	900	0.16	0.015	380000	2550	70	40

In Fig. 6 and Fig. 7, the PI and permeability comparisons further support the findings discussed. It emphasizes the advantages of vertical wells in terms of PI. The higher PI in vertical wells can be attributed to high fracture density, increased total and radial permeability resulting from reduced damage and higher average pressure. Here, total permeability represents the average permeability of a porous media in all directions, while radial permeability specifically refers to permeability in the radial direction. The results indicate that although horizontal wells exhibit higher radial permeability and total permeability due to their expanded contact surface with the reservoir, this increased permeability does not significantly impact the PI. Additionally, the findings suggest that low pressure can significantly diminish well efficiency, even in wells with high total and radial permeability.

5. Conclusions

The following conclusions can be drawn based on the study conducted in this work:

- A comparison of the PI between wells drilled using OBD and UBD methods indicated that the UBD method resulted in less formation damage. The maximum PI experienced with UBD was 950 bbl/d/psi, while the maximum PI experienced with OBD was 650 bbl/d/psi.
- The measurements of the filtration rate of drilling fluid at different pressures on the vertical and horizontal core plug samples indicated that in the horizontal position, the gravity effect caused the drilling mud particles to move downward and accumulate at the bottom of the sample. This led to

the formation of impermeable mud cake, resulting in severe damage in those areas and considerably reduced filtration in the horizontal position compared to the vertical position.

- Well test data indicated that horizontal wells experienced the most severe formation damage, reflected in the lowest flow efficiency of 1.2. In contrast, vertical wells exhibited the least damage, with a skin damage of -1.4 and a flow efficiency of 2.4. This contrast may be attributed to a higher pressure drop in horizontal wells relative to vertical wells, potentially influenced by gravitational effects, the length of the horizontal section, and multiphase flow behavior in horizontal wells.
- Despite horizontal wells exhibiting greater radial and total permeability due to their increased contact surface with the reservoir, this higher permeability does not have a substantial impact on the PI. Furthermore, the findings indicate that low pressure can significantly reduce well efficiency, even in wells characterized by high total and radial permeability.

Declarations

Declaration of interest

There are no conflicts of interest to declare.

Author Contribution

K.T. and F.M.T. contributed to conceptualization, literature review, methodology, data analysis, and the original draft. H.T.N. contributed to methodology, data analysis, and reviewed and edited the final version of the manuscript.

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Figures

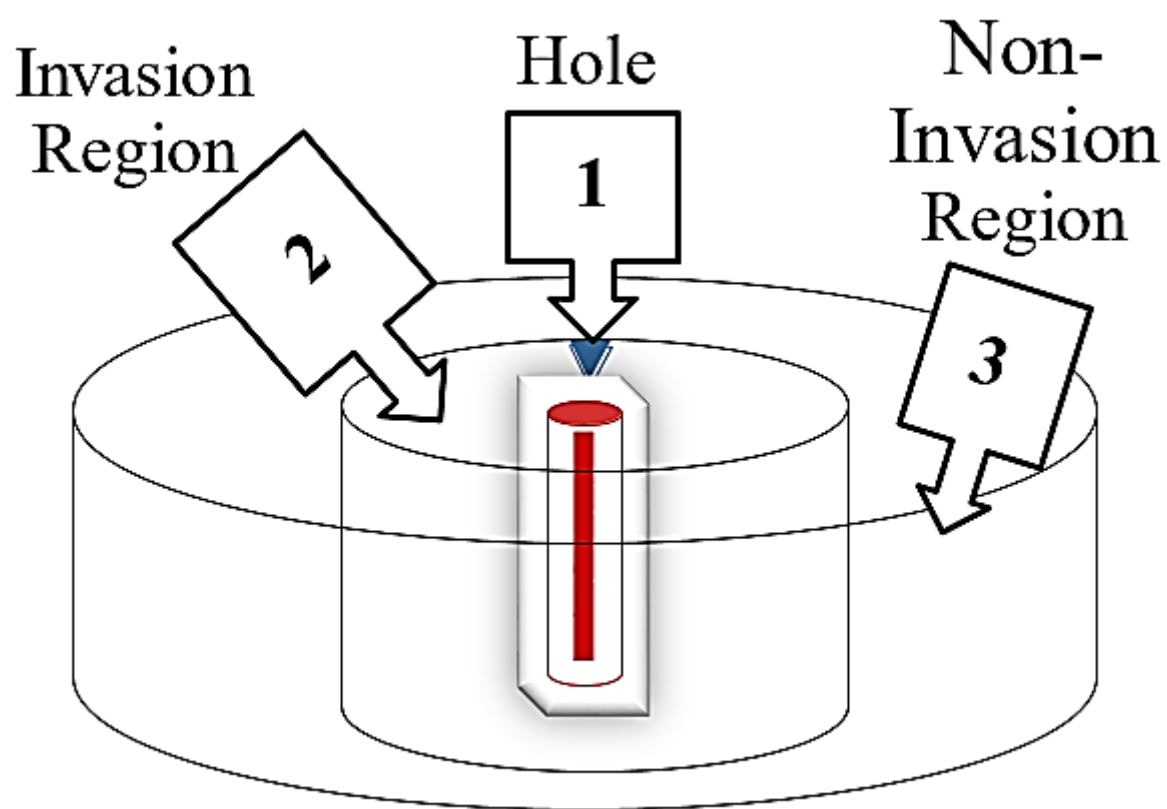


Figure 2

Uninvaded and invaded zones by drilling fluid loss in three radial zones around the well

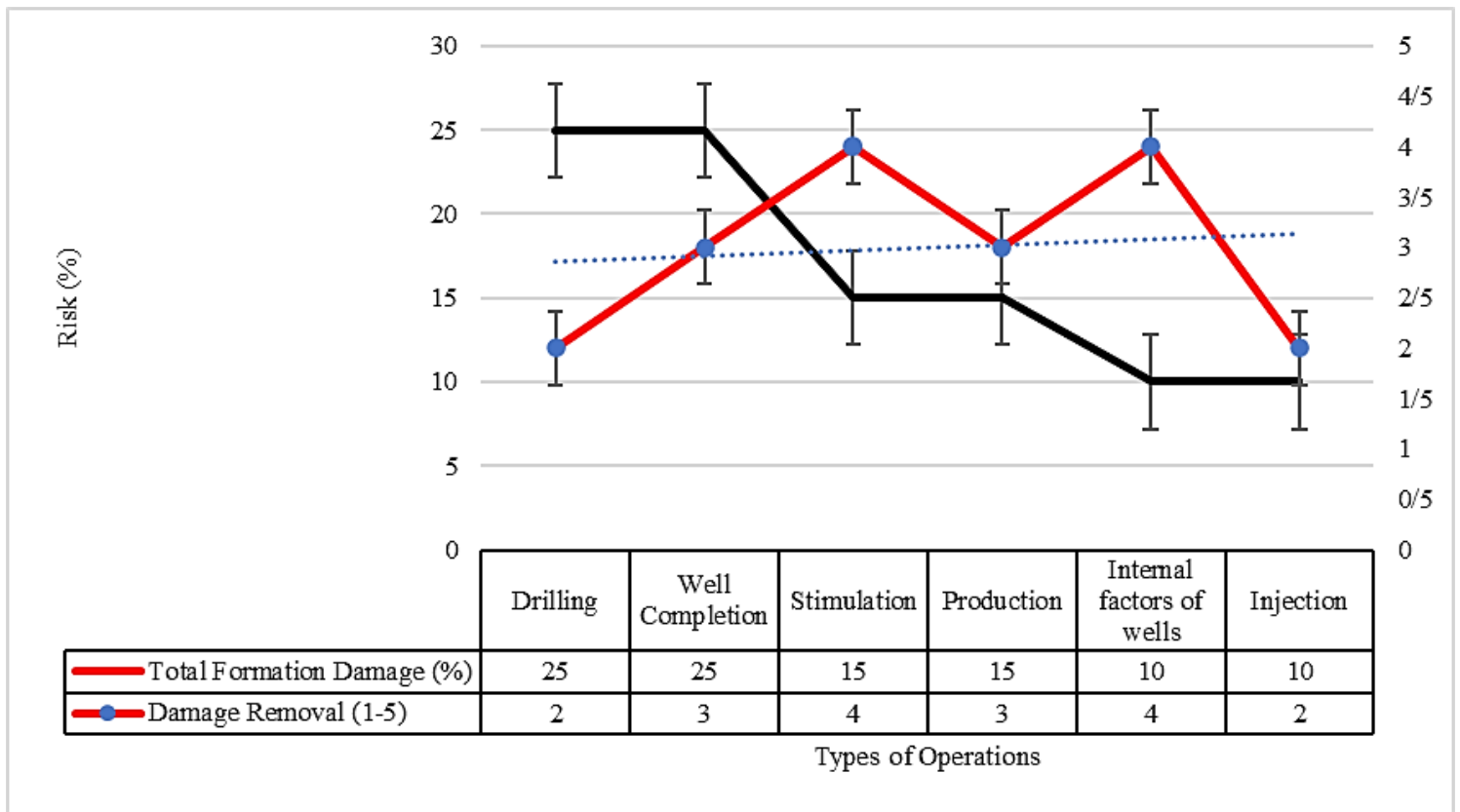


Figure 3

Estimated risk of different operations in terms of total formation damage and damage removal

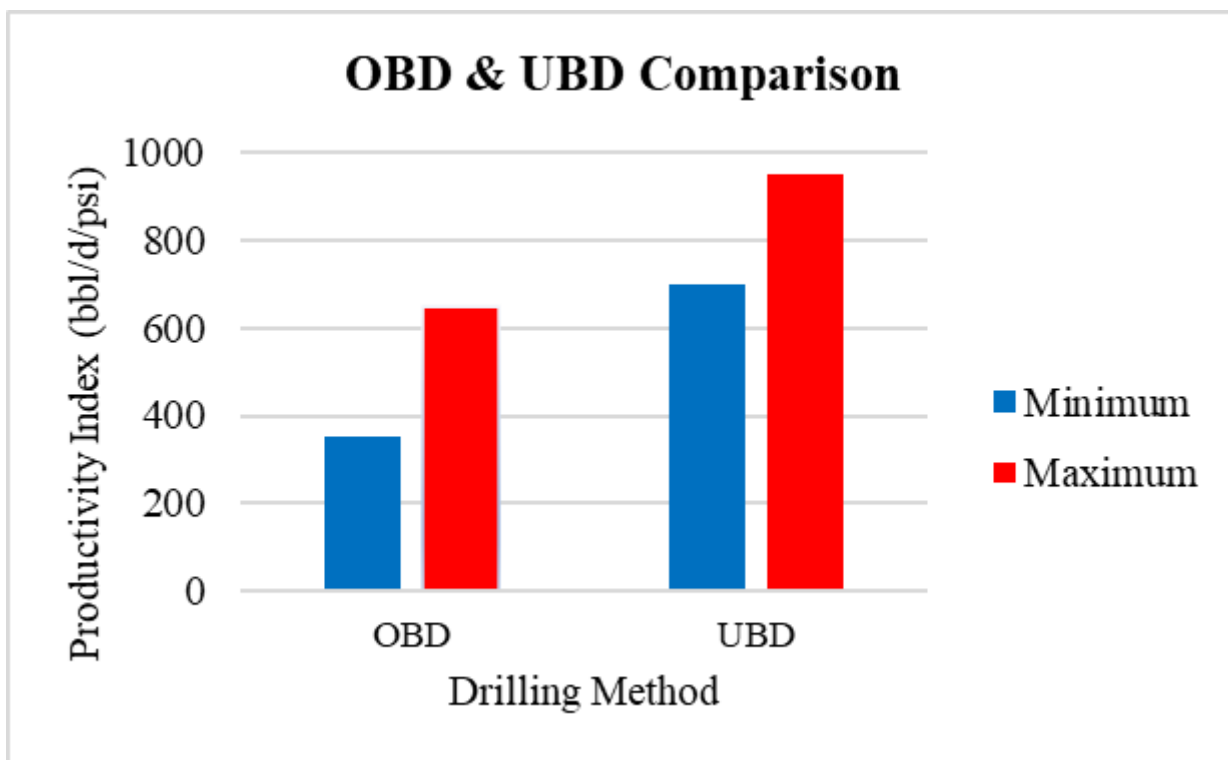


Figure 4

Comparison of PI for different methods of drilling in the studied field



Figure 5

Core samples collected from Zone B for the experiments, with samples taken in both vertical and horizontal directions for each core plug

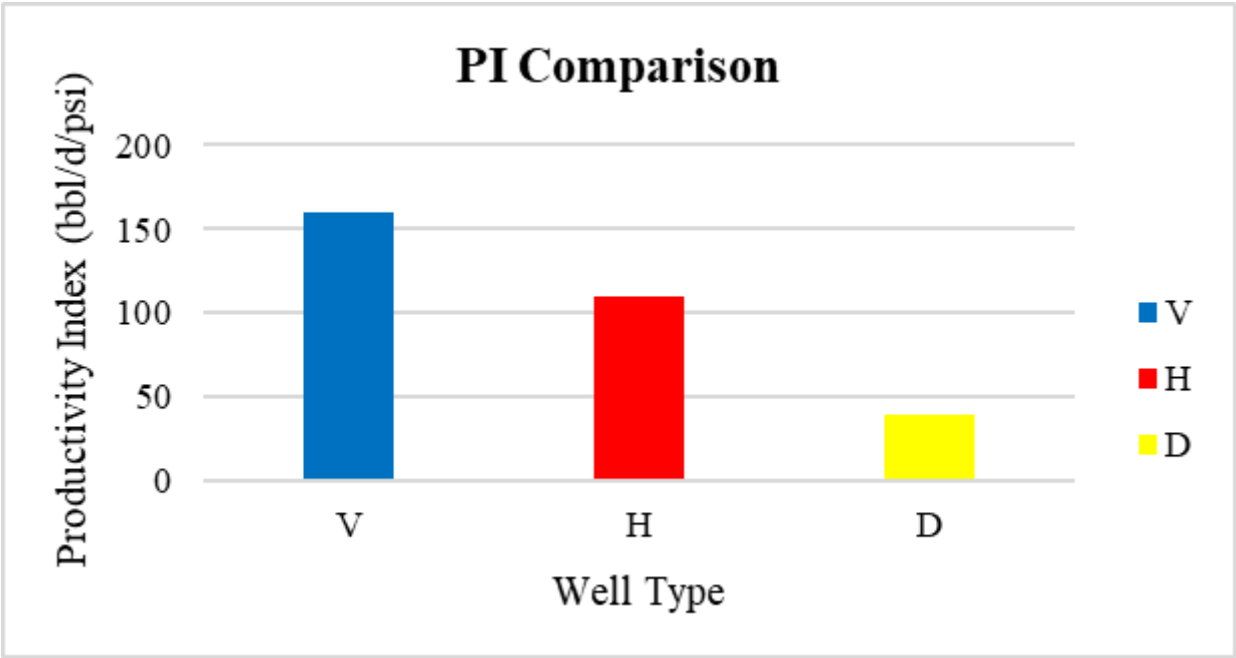


Figure 6

Comparison of PI in different types of wells in the studied field

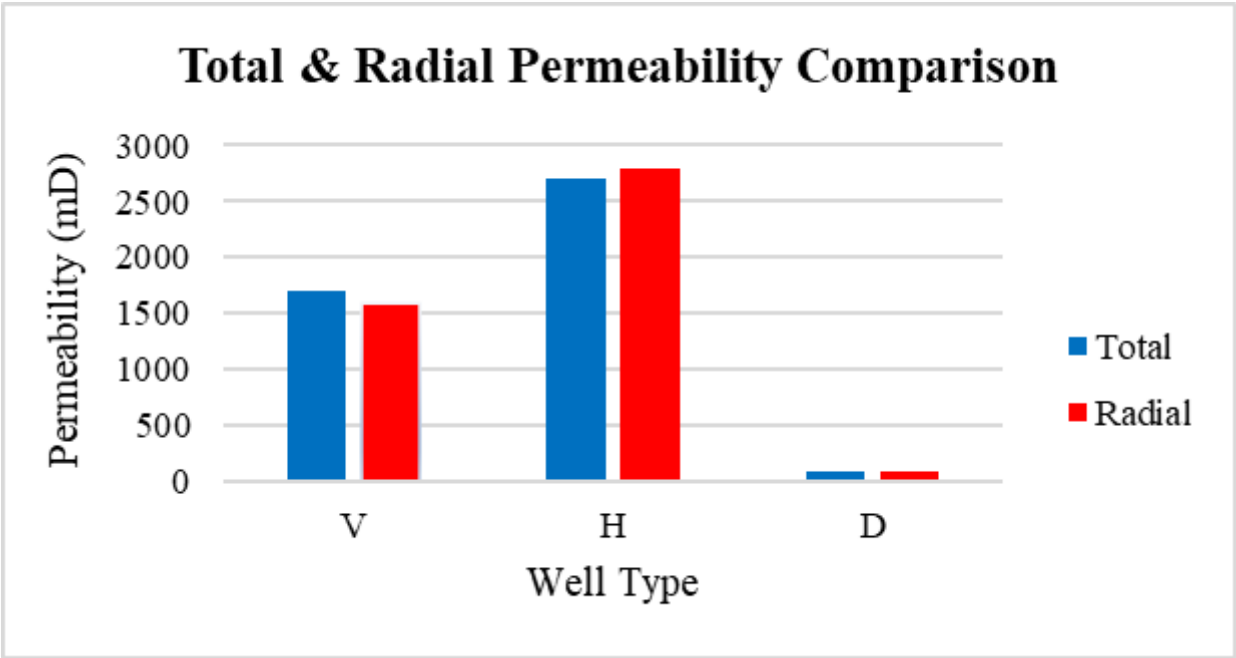


Figure 7

A comparison chart of total and radial permeability in different directional wells of the studied field