University of Tehran Press

Journal of the Earth and Space Physics

Homepage: https://jesphys.ut.ac.ir

Vol. 50, No. 4, Winter 2025, P. 27-40

(Research Article)

Risk Hazard Zonation on Mishrif Formation in Sirri Oil Field with Reservoir Management Approach

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(Received: 20 Nov 2023, Revised: 26 Feb 2024, Accepted: 21 May 2024, Published online: 15 March 2025)

Abstract

Predicting reservoir performance in the future is closely related to the accurate identification of reservoir history in the past. In this study, based on a new approach, risk zonation in hydrocarbon reservoirs has been evaluated using different available data include well production, characteristics of fractures and faults, rock heterogeneity and seismic data, which can be used in the field of reservoir management. This study is carried out on Mishrif formation in Sirri oil fields. The well test results have been used in the period between 1977 and 1992, and permeability in the drainage area of all production wells have been calculated by applying an empirical relationship between wellhead pressure and permeability. By calculating the permeability in the production wells, the strain values, which represent the compaction parameter, are estimated based on the permeability-strain empirical relationships. Strain value is considered us an important parameter for predicting the future oil production rate. In this study, the effect of different parameters on strain distribution such as fault effects, characteristics of reservoir fractures, rock heterogeneity and rock density have also been investigated. Based on the obtained strain results, all existing wells have been classified into three different regions including region A (referred to high rate of volumetric strain), region B (referred to moderate rate of volumetric strain), and region C (referred to low level of volumetric strain), which can be used for the future performance of the wells and for making accurate decisions regarding better management of Mishrif formation reservoir in Sirri oil field.

Keywords: Risk Hazard Zonation, Permeability, Reservoir management, Strain, Sirri oil Field.

1. Introduction

The characterization of reservoirs has become a crucial issue in recent years. Permeability and porosity are fundamental properties of reservoir rocks that play a crucial role in hydrocarbon production. Permeability refers to the ability of a rock to transmit fluids, while porosity represents the void space within the rock that can hold fluids. The relationship between permeability and porosity is a key factor in understanding fluid flow behavior in reservoirs (Timur, 1969; Walsh and Brace, 1984).

The compaction parameter and strain are closely related in the context of reservoir state. The compaction parameter represents the degree of volume reduction or compression experienced by the reservoir rock due to the applied stress or pressure. In reservoir engineering, the compaction parameter is often calculated based on the relationship between permeability and strain. Empirical equations or correlations are developed to describe this relationship. These empirical relations can be affected by some factors such as rock type, stress conditions, and fluid properties (Biot, 1941; Lai et al., 1981; Zoback, 2007).

Understanding the relationship between the compaction parameter and strain is crucial for predicting and managing reservoir compaction. It helps in assessing the impact of compaction on reservoir properties such as permeability, porosity, and fluid flow (Geertsma, 1973a, 1973b). By monitoring and modeling the strain and compaction parameter, reservoir engineers can make informed decisions regarding reservoir management, production strategies, and well operations. The permeability-porosity relationship is influenced by various factors, including the rock type, grain size, sorting and diagenetic processes (Du and Wong, 2007). Increasing in porosity generally improved a better fluid flow in the reservoir, which provides a higher permeability. However, the relationship between permeability and

Cite this article: Talebi, A. (2025). Risk Hazard Zonation on Mishrif Formation in Sirri Oil Field with Reservoir Management Approach. *Journal of the Earth and Space Physics*, 50(4), 27-40. DOI: http//doi.org/10.22059/jesphys.2024.368089.1007577

Publisher: University of Tehran Press.
DOI: http//doi.org/10.22059/jesphys.2024.368089.1007577

Print ISSN: 2538-371X
Online ISSN: 2538-3906

porosity is not always straightforward and can be affected by factors such as compaction, cementation and the presence of fractures or other heterogeneities (Wang et al., 2004).

One important aspect related to reservoir management is the consideration of strain or compaction parameters. Strain refers to the deformation or change in shape experienced by the reservoir rock due to the applied stress or pressure (David et al., 2001). Compaction quantifies the degree of volume reduction or compression experienced by the reservoir rock (Settari and Mounts, 1998). In recent decades, numerous studies have been carried out to improve our understanding of reservoir systems. Lee and Holditch (1985) made significant contributions to the field of well testing analysis and introduced pressure change equations based on the diffusivity equation for radial systems. Zhang & Wang (2000) conducted a study by considering an imperial laboratory equation between permeability and stress, based on the field data and available relationships. It was found that the relationship between permeability and stress is not linear, but a high correlation exists between the two variables. Tortike & Ali (1993) developed an empirical equation using a coupled reservoir and geomechanics approach based on the Kozeny-Carmen relation (Kozeny, 1927). They also proposed an empirical equation in 1991 to describe the relationship between permeability and rock elastic parameters. Du and Wong (2007) considered a strain/permeability-induced model in a coupled reservoir and geomechanics setting and evaluated the accuracy and applicability of empirical equations between permeability and strain based on tensors in different directions. Pettersen (2010) investigated compaction-induced permeability reduction in Brent-Type Reservoirs, using well-testing data to calculate variations in permeability over time. In their study, volumetric strain was calculated and modeled based on empirical equations. Their results revealed a low variation in water saturation and oil relative permeability in different time laps. Asef et al. (2019) studied the structural analysis of the Sirri oilfield by using seismic and well log data to elucidate geological features. This study further investigates the impact of reservoir compaction on the field's performance. Notably, Hashemi et al. (2017) present a novel SSCSOM technique for optimized facies analysis using seismic data. While their focus differs, their work highlights the potential of advanced seismic data analysis methods in reservoir characterization, which could be explored in future research endeavors related to reservoir compaction. In this study, we aim to investigate the relationship between permeability, porosity and strain or compaction parameters in the context of reservoir management. We will analyze well testing data, incorporate empirical equations or constitutive models, and utilize a coupled geomechanics-reservoir simulator to simulate reservoir behavior under varying strain conditions. The findings of this study will contribute to a better understanding of the impact of strain or compaction parameters on reservoir performance and provide insights for future reservoir management strategies.

1-1. Geology of the Study Area (Sirri oil Fields)

The Sirri Oil Field is located in the southern part of the Persian Gulf, offshore Iran. It is one of the largest oil fields in the region and has been a significant contributor to Iran's oil production. The geology of the Sirri Oil Field is primarily composed of carbonate rocks, specifically the Mishrif Formation. The Mishrif Formation is a significant reservoir unit in the Persian Gulf region, known for its high porosity and permeability. It consists of limestone and dolomite layers deposited during the Cretaceous period. The reservoir rocks in the Sirri Oil Field are mainly composed of rudist reef build-ups, which are ancient coral-like organisms that formed extensive carbonate structures (Narim and Alsharhan, 1997; Alsharhan and Kendall, 2003).

The field is characterized by circular and flat domal structures, which are associated with the presence of these reef build-ups. These structures create favorable conditions for hydrocarbon accumulation and production. The reservoir quality and productivity in the Sirri Oil Field are influenced by factors such as the distribution of facies, fracture characteristics, and diagenetic processes. A Turonian uplift caused some high structural trends, and subsequent erosion during the Turonian unconformity removed much of the Mishrif formation on the crest of the paleostructure. The increased porosity and interconnectedness of these formations is largely the result of dissolution processes, the extent of which depends mainly on the length of time, the sediments were exposed to meteoric water. (Alsharhan and Kendall, 2003; Sadooni and Alsharhan, 2019) (Figure 1).

The area is dominated by mostly linear and planar extensional faults which formed a distinctive pattern on the crests of the domal structures (Reshadat & Resalat Oil Fields, 2003). In figure 2, domal structures are shown by two black arrows in the seismic section of Sirri C and Sirri D. Reshadat & Resalat Oil Fields (2003) concluded that the flexure within the surrounding rocks and setting up a tensional stress regime around the folding crests caused these features in the area.

2. Method

The variation in reservoir performance can be determined through analysis of well testing data and trends in productivity index. The average permeability of the reservoir around each drainage area can be estimated by measuring the pressure response at the bottom hole or wellbore (P_{ws}) during the testing and shut-in period. The well testing theory is based on the diffusivity equation solution (Aziz and Settari, 1979), which provides a mathematical framework to analyze the flow of fluids in porous media and is widely used in petroleum engineering. The equation is particularly used in the analysis of well testing data where time t is commonly recorded in hours (Equation 1). Pressure variations related to changes in fluid and rock properties that impact the stress/strain within the reservoir can lead to some alterations in basic reservoir properties. The average reservoir pressure can be calculated through transient pressure well testing analysis (Horner, 1951; Bourdet and Pirard, 1983; Lee and Holditch, 1985). Build-up/fall-off tests from two time periods (1977-1992) were analyzed for all wells in the study area to extract permeability across the drainage area around each well.

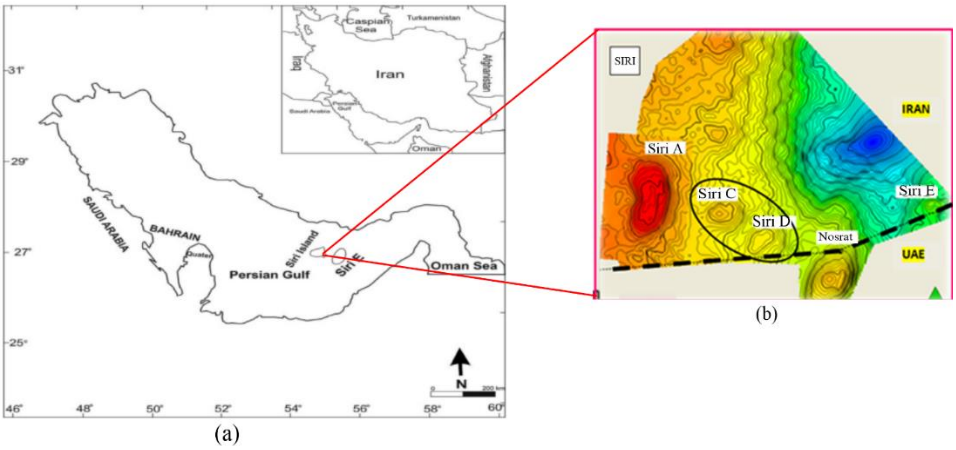


Figure 1. a) The location of Sirri oil fields in Persian Gulf, Iran. b) Contour maps indicating the thickness variation of the formation related to some parts of the Sirri oil Fields on Mishrif horizon.

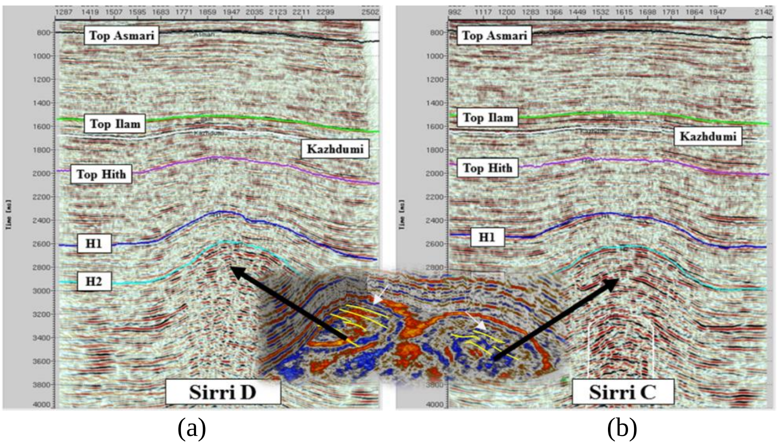


Figure 2. a) structural elements (faults and Domal structure-in Sirri C and D, b) Structural evolution analysis for Sirri C & D fields, (Reshadat & Resalat Oil Fields, 2003).

This is achieved by relating the pressure response to permeability using Equation (2). All parameters in Equation (2) were obtained from field and laboratory data. The pressure data at different time intervals are plotted, and a straight line is fitted to the data to determine the slope (m), which represents the permeability of the reservoir (Equation 3). By applying this procedure to all wells in the drainage area, the average permeability of the reservoir can be estimated. The curve of P_{ws} versus $\frac{t_p+\Delta t}{\Delta t}$ indicates that a plot of a semi-logarithmic scale would produce a straight line with an intercept of a and slope of m as given by Equation (3).

$$\frac{\partial^2 p}{\partial r^2}+\frac{1}{r}\frac{\partial p}{\partial r}=\frac{\phi\mu c_t}{0.006328\,k}\frac{\partial p}{\partial t} \quad (1)$$

$$P_{ws}=P_i-\frac{162.2qb\mu}{kh}\left[\log\left(\frac{t_p+\Delta t}{\Delta t}\right)\right] \quad (2)$$

$$p_{ws}=a+m\log\left(\frac{t_p+\Delta t}{\Delta t}\right)$$

$$m=\frac{162.2qB\mu}{kh} \quad (3)$$

Two types of well testing were performed between 1977 and 1992. Approximately after 15 years, acidizing was done for production wells and injection wells. Build-up test has been done for production and fall-off test was done for injection wells. Table 1 summarizes the wellbore pressure (P_{ws}) data collected during a fall-off test for well B3. In a fall-off test, the well is shut down after a period of production, which allows reservoir pressure to build up. The decline in wellbore pressure over time is carefully monitored and provides valuable insights into reservoir properties, flow characteristics, and wellbore conditions. As expected during a fall-off test, Table 1 reveals a consistent decline in wellbore pressure (P_{ws}) over time. This decline reflects the reservoir pressure gradually returning to equilibrium after the well is shut down. The curve of P_{ws} versus $\frac{t_p+\Delta t}{\Delta t}$ for this well is shown in Figure 3, which the slope of this curve is 400 psi/cycle.

Permeability evolution models have been studied by several researchers in terms of porosity, stress, strain, temperature, chemical process, etc. (Zhu and Wong, 1997; Morris et al., 2003; Ma, 2015). Generally, there are three main types of permeability evolution models under mechanical condition in porous media. These three main types include porosity, stress, and strain that can be applied to specific conditions.

Table 1. Fall-off test data for B3 well.

P_{ws} (psi)	$\frac{t_p+\Delta t}{\Delta t}$	P_{ws} (psi)	$\frac{t_p+\Delta t}{\Delta t}$	P_{ws} **(psi)**	$\frac{t_p+\Delta t}{\Delta t}$	P_{ws} (psi)	$\frac{t_p+\Delta t}{\Delta t}$
4993	-	4473	67.25	4353	33.42	4293	22.46
4803	508.93	4443	57.44	4343	30.88	4293	21.32
4683	218.69	4423	50.15	4333	28.87	4283	20.29
4603	139.53	4403	44.54	4333	26.83	4273	19.36
4543	102.59	4383	40.89	4313	28.82	4268	18.51
4503	81.20	4374	36.44	4303	23.74	4263	17.74

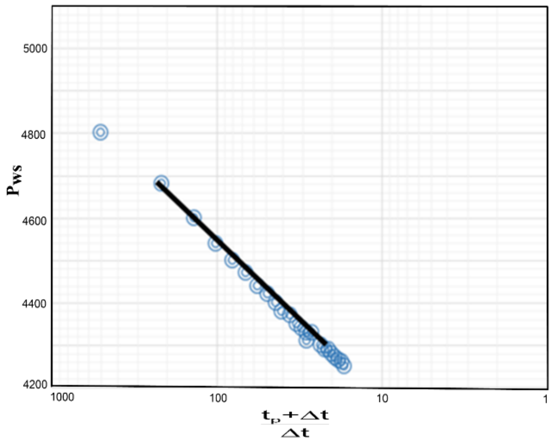


Figure 3. Interpretation of fall off test of B3 well.

3. Measurements

3-1. Permeability evolution models based on porosity

Macroscopic empirical equations are commonly used to predict the relationship between porosity and permeability. These empirical relationships are used to estimate the changes in permeability as porosity evolves due to various geological processes, such as compaction, diagenesis and fluid flow. Several semi-empirical equations have been proposed to estimate rock permeability κ based on the porosity ϕ (Kozeny, 1927; Carman, 1997; Walsh and Brace, 1984; Costa, 2006; Petunin et al., 2011; Nelson, 1994; Davies and Davies, 1999). Kozeny-Carman equation is widely applied to extract porosity from permeability using an empirical relationship (Equation 4).

$$\kappa = \frac{\phi^3}{c(1-\phi)^2 S^2} \tag{4}$$

In Equation (4) the permeability depends on the sample porosity, ϕ, specific surface area, S, and a Kozeny constant, c. The specific surface area is computed from the average grain diameter.

3-2. Strain-dependent permeability models

Porosity and permeability may change in response to an increase of the effective stress during the depletion of hydrocarbon reservoirs, which can alter the pore geometry of the reservoir rock (Zimmerman, 1991; Schatz et al., 1982). The variation of pore volume due to increase effective stress has an impact on both porosity and permeability. Due to the strain-dependent porosity and the direct relation of porosity with both deformation and pore pressure, the permeability evolution model based on porosity is used in order to estimate strain volumetric (Santos et al., 2014). In this study, we used the permeability model proposed by Du and Wong (2007) to calculate volumetric strain (Equation 5). In Equation (5), κ_0 is the initial permeability, κ is the current permeability, ϕ_0 is the initial porosity and ε_v is the volumetric strain.

$$\frac{\kappa}{\kappa_0} = \frac{(1 + \varepsilon_v / \phi_0)}{1 + \varepsilon_v} \tag{5}$$

In Table 2, the comparison of permeability changes as well as volumetric strain are summarized for all wells in the study area in lapse time of 1977 to 1992. The volumetric strain (ε_v) is estimated using Equation (5). This parameter represents the measure of how much the pore volume of the rock has changed due to the compaction. A negative value indicates that the rock has been compacted, reducing its pore space. The data in Table 2 demonstrates that, for most wells, a decrease in permeability corresponds to a negative volumetric strain that indicates compaction of the reservoir rock. All symbols used in the equations are presented in Table 3. While acknowledging the valuable insights provided by porosity-based permeability evolution models, their limitations must be recognized. These models often rely on simplified relationships between porosity and permeability, potentially overlooking the complex interplay of various factors influencing the reservoir behavior (Jones and Blunt, 2002). Additionally, their applicability might be restricted to specific geological settings and require careful consideration of additional permeability-controlling factors (Yu et al., 2019). Moreover, the accuracy of these models is highly dependent on the quality and availability of porosity data, with uncertainties associated with porosity measurements potentially propagating and impacting the reliability of model predictions. Furthermore, addressing the reviewer's insightful point, it is crucial to acknowledge potential error propagation in porosity calculations. Common sources of errors include limitations of various measurement techniques and potential human subjectivity during data interpretation. Mitigating these errors might involve employing multiple porosity measurement techniques, implementing robust data quality control measures, and acknowledging the associated uncertainties when interpreting the results.

Table 2. Permeability and volumetric strain for all wells in the Sirri oil field.

Well Name	D9	D3	D8	E1	A4	A5	D4	B4	B6	F14
Porosity (%)	0.25	0.28	0.26	0.25	0.24	0.25	0.23	0.24	0.21	0.24
K_0 (md)	116	85	410	77	240	142	130	64	195	13
K (md)	2	11	46	9	24	23	18	13	28	3
Δk (md)	114	74	364	68	217	119	112	51	167	10
Volumetric strain	-0.186	-0.144	-0.140	-0.134	-0.132	-0.121	-0.118	-0.105	-0.104	-0.101
Well Name	A2	A6	B3	F3	E2	F12	F10	B7	F13	
Porosity	0.22	0.22	0.22	0.29	0.08	0.22	0.23	0.21	0.26	
κ_0 (md)	77	160	58	31	14	5	7	151	6	
κ (md)	15	33	15	12	5	2	3	65	4	
$\Delta\kappa$ (md)	62	127	43	19	9	3	4	85	2	
Volumetric Strain	-0.097	-0.092	-0.085	-0.084	-0.079	-0.065	-0.062	-0.054	-0.045	

Table 3. All Symbols used in the equations.

Symbol	Meaning & unit	Symbol	Meaning & unit
r	Radius(ft)	h	Thickness
p	Pressure(psi)	κ_0	Initial Permeability
t	Time(hour)	m	Slope
μ	Viscosity(cp)	ϕ_0	Initial Porosity
ϕ	Porosity(percent)	B	Oil Formation Volume Factor (BBL/STB)
C_t	Compressibility(1/psi)	ε_v	Volumetric Strain (Milistrain)
κ	Permeability (md.)	c	Kozeny Constant
q	Oil production rate(bbl/day)	S	Specific Surface Area
P_{ws}	Wellbore pressure	t_p	Production Time, Hours
Δt	Shout in time, hours	a	Intercept

4. Results and discussion

The study area is classified into three regions according to the volumetric results (Figure 4). The classification of the regions provides a better understanding of the potential risks and hazards associated with reservoir compaction and deformation. The obtained information can be used for reservoir management decisions, like well placement, production strategies, and mitigation measures in high-risk hazard regions. Three classified regions include:

High Risk Hazard Region: (region a): This region exhibits a high rate of volumetric strain, indicating significant compaction and potential for reservoir deformation. In this category, permeability reduction is high (more than 7) and generally initial permeability is low.

Medium Risk Hazard Region: (region b): This region shows a moderate rate of volumetric strain, indicating some level of compaction but not as severe as the high-risk region. In this region, permeability reduction is medium (between 3 and 7).

Low Risk Hazard Region: (region c): This region exhibits a low level of volumetric strain, indicating minimal compaction and a lower risk of reservoir deformation. The region generally has low permeability reduction (between 1 and 3).

Understanding of the relation between the strain and permeability reduction is an important key in reservoir management concept. As the reservoir undergoes deformation, the strain in the rock increases, which can lead to a reduction in the interconnected pore space within the rock, resulting in a decrease in permeability. The relationship between the strain and permeability reduction can vary depending on different factors such as rock type, stress conditions, and fluid properties. According to the obtained volumetric strain and permeability reduction in each well, the reservoir divided into three regions (Table 4). This classification offers crucial insights in the field of reservoir management decisions, such as well placement and production strategies. The table highlights the crucial link between volumetric strain (rock deformation) and permeability reduction (reduced fluid flow). As the reservoir undergoes compaction (indicated by increasing strain), the interconnected pore space within the rock decreases, leading to a reduction in permeability.

Three different regions based on strain, initial permeability and amount of permeability reduction results for all wells are shown in Table 4.

In this study, we also consider some geological features like faults, fractures network, rock heterogeneities and rock density, which can influence the strain or compaction in reservoir. We examine the effect of these factors separately as follows:

4-1. Fault Effects

Faults are geological features which can have a significant impact on the distribution and magnitude of strain within a reservoir. The presence of faults can create zones of increased strain concentration or localized deformation. The faults can also act as pathways for fluid migration, affecting the pressure distribution and stress regime in the reservoir (Zoback, 2010). These variations in stress and pressure can enhance compaction and strain near fault zones.

Additionally, fault properties, such as permeability and slip behavior, can influence the distribution of strain and compaction (Zoback and Kohli, 2019). In this study, the distance from interpreted faults in the Mishrif formation is considered as an important factor which can change the value of the strain. Accordingly, the wells near the major faults in the region are classified in region a.

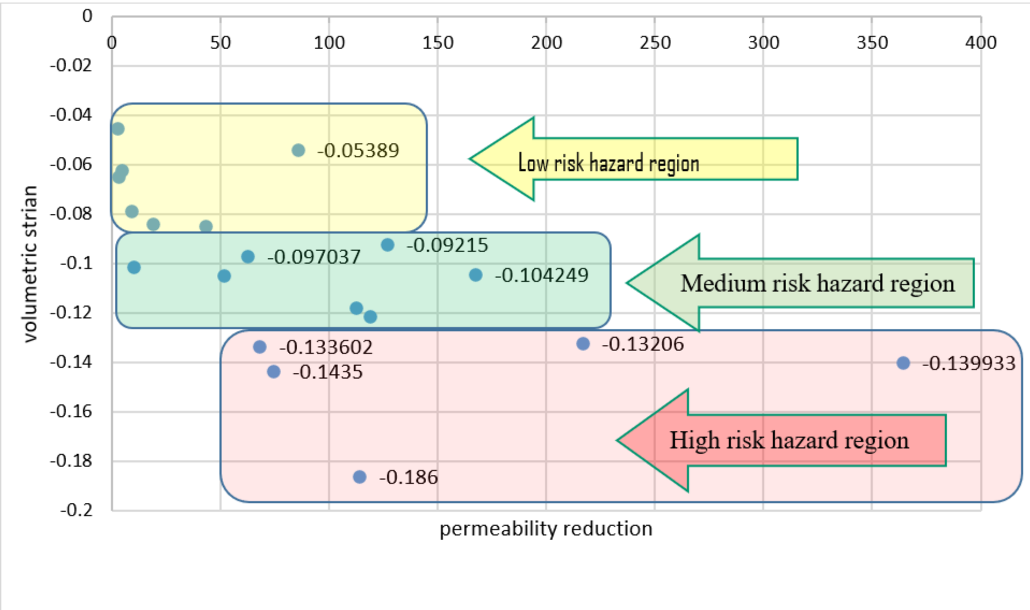


Figure 4. Strain versus permeability curve.

Table 4. Classification of three regions based on obtained results.

	Wells	Initial permeability (md)	Permeability reduction (md)	Volumetric Strain
Region a	D9	116	114	-0.186
	D3	85	74	-0.144
	D8	410	364	-0.140
	E1	77	68	-0.134
	A4	240	217	-0.132
	A5	142	119	-0.121
Region b	D4	130	112	-0.118
	B4	64	51	-0.105
	B6	195	167	-0.104
	F14	13	10	-0.101
	A2	77	62	-0.097
	A6	160	127	-0.092
	B3	58	43	-0.085
Region c	F3	31	19	-0.084
	E2	14	9	-0.079
	F12	5	3	-0.065
	F10	7	4	-0.062
	B7	151	85	-0.054
	F13	6	2	-0.045

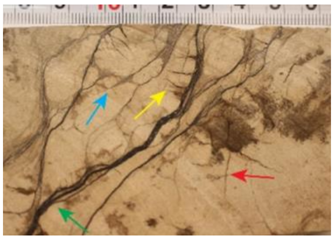
4-2. Fractures Network

Fractures are the most interesting issues for reservoir characterization studies, as they can greatly influence the behavior and properties of the reservoir. Fractures can be created as a result of faulting or folding processes, which can contribute to compaction. Compaction in a reservoir can be affected by fractures feature through different parameters such as stress redistribution, fluid flow and pressure changing and permeability.

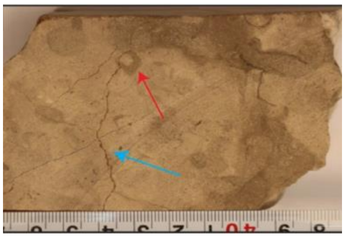
In Figure 5, different types of fractures on Mishrif formation are summarized. We consider the fractures in different category include: High Open Fracture Network (HOFN), High Partially Open Fracture Network (HPOFN), High Close Fracture Network (HCFN), and Rarely Close Fracture (RCF).

The HOFN refers to a fracture network that exhibits a high degree of aperture, providing good condition for fluid flow and communication. The presence of a high open fracture network indicates a higher potential for fluid migration and can have implications for reservoir behavior (Barton et al., 1985).

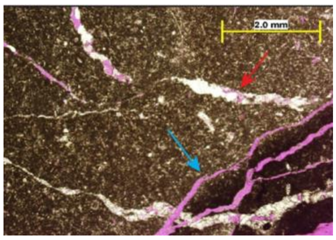
In the context of the Risk Zonation, the presence of a HOFN suggests a higher risk of reservoir integrity issues and potential flow restrictions. The high degree of openness in the fractures can lead to increased fluid flow pathways, which may result in reservoir compaction, fluid loss, or even formation damage (Nelson, 1985). To further illuminate the impact of micro-scale fractures on reservoir compaction, a dedicated discussion on their transition to macro-scale fractures is warranted. Mechanisms such as stress concentration, coalescence and fluid-aided propagation can contribute to this transition in the Sirri Field (Wang et al., 2020). The specific interplay of factors like rock properties, stress conditions, and reservoir fluid properties will determine the dynamics and extent of this micro-to-macro fracture transition, ultimately influencing the severity of compaction.



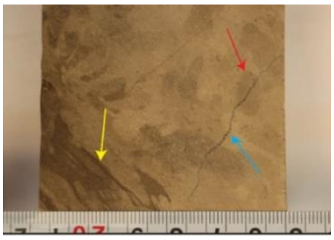
Core photo of A4: showing stylonodular fabric (green arrow), oil stained open tension microfractures (yellow arrow), oil stained open microfracture network/set (blue arrow), oil stained open shear microfracture (red arrow)



Core photo of A4: showing oil stained open microfracture set/network (blue arrow), which cross cutting each other, and oil stained burrows (red arrow) which cross cuts with microfracturs.

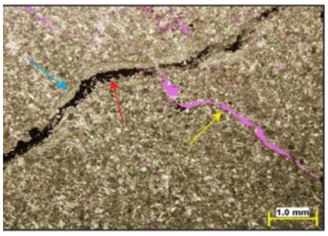


Photomicrograph (PL & gypsum filter) A4: showing open microfractures (blue arrow) cross cutting healed microfractures (red arrow)

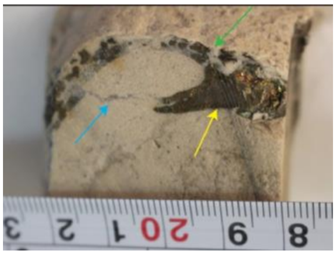


Core photo of A2: showing slightly oil stained, stylolaminated (yellow arrow), highly bioturbated limestone with two oil stained open microfractures (blue arrow), which cross cutting oil, stained burrows (red arrow).

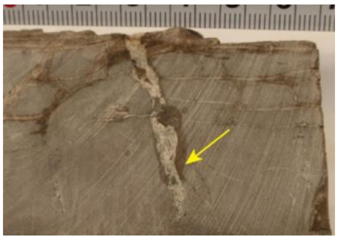
Core photo of A2: showing open microfracture (red arrow) which is partially filled by bitumen (yellow arrow)



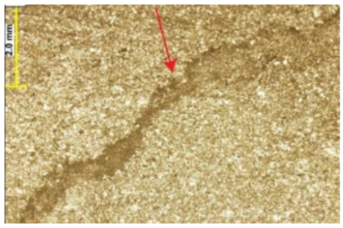
Photomicrograph (PL with gypsum filter) of A2: showing pyrizitaion (red arrow) partially masks vadose, recrystallization (blue arrow) and open microfracture (yellow arrow) cross cuts them.



Core photo of F13: showing pyritization (yellow arrow) and dolomitization (saddle dolomite) (green arrow) of shell fragment with healed microfractures with sparry calcite cement (blue arrow) which partially masked with pyritization.



Core photo of F13: showing healed vertical microfracture by calcite cement and filled by bitumen



Photomicrograph (NL) of D4: showing recrystallized matrix and bioclasts with vadose. recrystallization along microfracture or micro-channel or solution seam

Figure 5. Fracture network analysis in some wells in the study area.

4-3. Rock Heterogeneities

Rock heterogeneities are analyzed as another parameter that can impact reservoir behavior. The analysis involves examining core photos from wells to identify and characterize the heterogeneities present in the rock. For this purpose, core phots in some wells are analyzed and the observed information are shown in Figure 6.

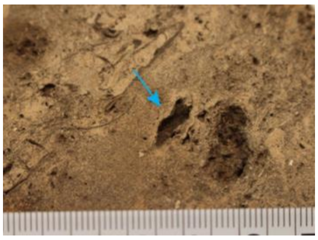
In Figure 6, vuggy porosity refers to irregular-shaped cavities or voids within the rock, which can significantly impact fluid flow and storage within the reservoir. Rudist floatstone is a type of rock that contains fossilized rudist shells, indicating the presence of a specific depositional environment. The presence of abundant vuggy porosity in rudist floatstone suggests that the reservoir has a higher potential for fluid flow and storage, which can lead to an increasing of permeability (Lucia, 1995).

Based on this observation, well A4 is considered in region "a", which is classified as a high-risk hazard region. This classification indicates that the combination of rock heterogeneities, such as abundant vuggy porosity, and other factors analyzed in the study pose a higher risk to reservoir integrity or performance.

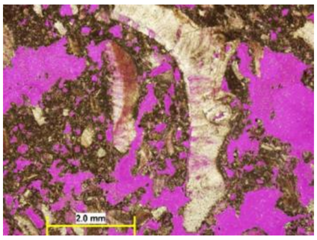
4-4. Rock Density

Rock density is analyzed as another parameter that can influence reservoir compaction. Inverted acoustic impedance data is used to extract information about the porous regions within the reservoir (Figure 7). The article claims that the acoustic impedance results revealed a well-porous media in the crest of anticlines and toward the saddle. It can be concluded that, these regions have a higher porosity, which can affect the compaction of the reservoir. It is expected that as the porous media increases, the reservoir compaction will also increase. As a result, by increasing the rock density, the compaction would be lower. This implies that regions with higher rock density will experience less compaction compared to regions with lower rock density. Based on the result, the Mishrif formation is divided into three different regions include: Porous Area, non-Porous Area and Transition Area.

Core photo of A4: showing abundant vuggy (red arrow), interparticle and intraparticle porosities in rudist floatstone-rudstone

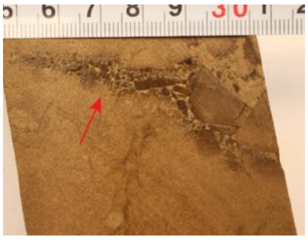


Core photo of A4: showing abundant vuggy porosity (yellow arrow) in rudist floatstone.

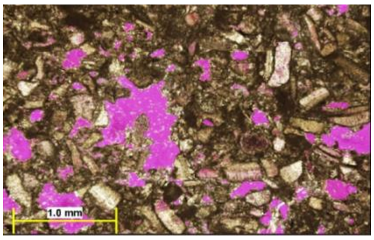


Photomicrograph (PL and gypsum filter),
A4: showing very porous (inter, intraparticle and vuggy porosities) rudist floatstone.

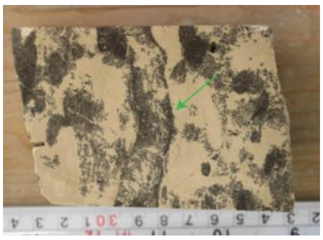
Core photo of A2: showing vuggy porosity inside insitu rudist in biocalasts floatstone



Core photo of A2: showing partial solution collapse breccia in karst cave (red arrow).

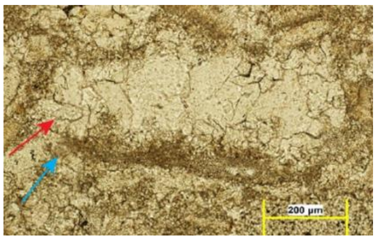


Photomicrograph (PL & gypsum filter) of A2: showing partially recrystallized bioclasts (rudist and echinoderm) packstone with interparticle and vuggy porosities.



Core photo of F13: showing light grey-white, chalky limestone bituminous burrow (green arrow).

Core photo of F13: showing solution collapse breccia because of karstification.



Photomicrograph (NL) of F13: showing recrystallized matrix and shell debris (red arrow) with micrite envelope (blue arrow).?

Figure 6. Rock heterogeneities analysis in some wells in the study area.

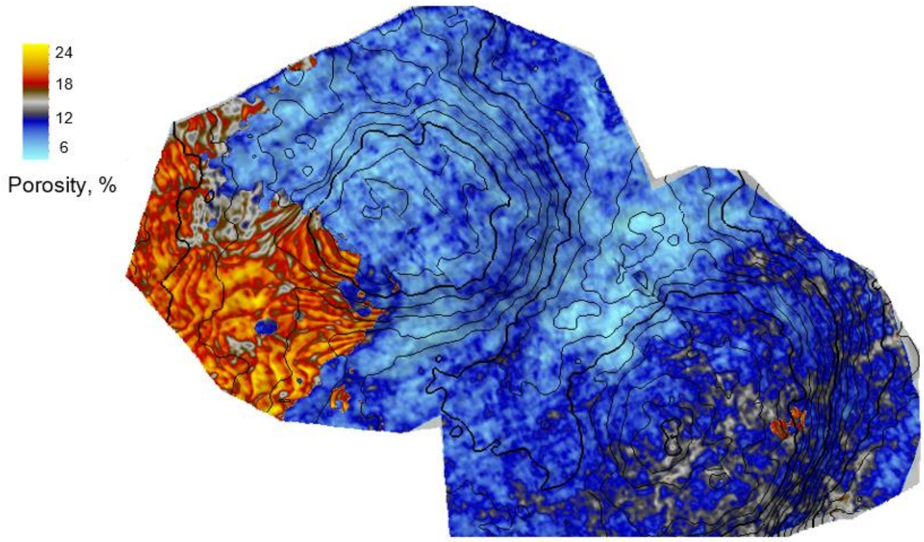


Figure 7. Porosity map distribution on Mishrif horizon.

Table 5 presents a comprehensive risk assessment model for reservoir compaction. This model integrates several geological key parameters including Fault Proximity, Fracture Networks, Rock Heterogeneities and Rock Density that influence strain distribution and potential compaction-related hazards. Based on the results, fracture network density, distance from faults and poor connection between vuggy and caves network are considered as vital keys in classification of risk hazard zonation. It is clear that, there are good correlation between strain results and these parameters.

Table 5. Integrated different parameters in risk assessment for reservoir compaction.

	Wells	Distance from Major Fault (m.)	fracture network / Rock Heterogeneities	rock density
Region a	D9	Toward Saddle	HOFN + Vuggy	Porous Area
	D3	140	HOFN + Vuggy	Porous Area
	D8	560	HOFN + Vuggy	Porous Area
	E1	310	HOFN + Vuggy	Porous Area
	A4	280	HOFN + Vuggy	Porous Area
	A5	46	HOFN + Vuggy	Porous Area
Region b	D4	250	HPOFN + Rarely Vuggy& Cave	Transition Area
	B4	93 FEP	HPOFN + Rarely Vuggy& Cave	Porous Area
	B6	20 FEP	HPOFN + Rarely Vuggy& Cave	Porous Area
	F14	1590	HCFN + Disconnect Vuggy	Non-Porous Area
	A2	238	HCFN + Disconnect Vuggy	Transition Area
	A6	500	HPOFN + Rarely Vuggy& Cave	Transition Area
	B3	380	HCFN + Disconnect Vuggy	Non-Porous Area
Region c	F3	735	RCF + Without Vuggy& Cave	Non-Porous Area
	E2	500	RCF + Without Vuggy& Cave	Non-Porous Area
	F12	400	RCF + Without Vuggy& Cave	Non-Porous Area
	F10	454	RCF + Without Vuggy& Cave	Non-Porous Area
	B7	185	RCF + Without Vuggy& Cave	Non-Porous Area

5. Conclusion

This study investigated the impact of reservoir compaction on the Sirri oil field using a combination of well test data analysis, geotechnical characterization, and empirical modeling. The analysis of well buildup and fall-off tests provided valuable insights into reservoir pressure behavior and permeability changes. Employing an empirical equation based on well data and geotechnical information, we established a regional risk zonation scheme for reservoir compaction. This zonation identified areas with varying susceptibility to compaction based on factors including distance to faults, fracture network density, presence of vuggy and cave formations, and initial reservoir porosity. The analysis of volumetric strain revealed significant heterogeneity in compaction across different areas of the reservoir during depletion. This information provides crucial insights for understanding the reservoir's behavior and can be utilized to guide future reservoir management strategies, such as well placement and production optimization. In this study, regional risk hazard zonation was established by employing an empirical equation to estimate volumetric strain. This zonation is classified into different areas based on the ratio of permeability reduction, calculated volumetric strain, and other contributing factors. This study identified several key factors that affected reservoir compaction, including the distance to faults, the density of the fracture network, the presence of vuggy and cave formations, and the initial condition of the porous media.

The strain results estimated from the analysis clearly demonstrates the heterogeneous nature of compaction across different reservoir areas during depletion. This information is crucial for understanding the behavior of the reservoir and can guide future reservoir management strategies. The findings of this study provide important insights into reservoir compaction and highlight the significance of considering geomechanical effects in reservoir management. Additionally, the limitations of using a single empirical equation and the dependence on well data availability could be further addressed in future research with broader data sets and more advanced modeling techniques.

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