Palacký University Olomouc

Faculty of Science

Department of Geology

Multi-Pore Network in Carbonate Reservoirs and Its Implications on Reservoirs Production Performance

Bachelor thesis

Abdulmajeed Nazar Majeed

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Supervisor: Prof. Howri Mansurbeg

Adviser: Mr. Salaheddin Shahrokhi

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Anotace:

Tato studie se zabývá komplexním zkoumáním nejvýznamnějších dostupných zdrojů týkajících se multipórovitosti a její role v zásobnících uhlovodíků a produkci ropy na Blízkém východě. Primární zaměření této práce zahrnuje klíčová témata, jako jsou základní důvody rozvoje multipórovitosti, její výhody a problémy, s nimiž se setkáváme při těžbě ropy z karbonátových ložisek. Provedený výzkum podtrhuje, že různé procesy diageneze probíhající v různých fázích hrají klíčovou roli při vytváření různých typů pórovitosti v karbonátových nádržích. Proto se stává nezbytností přesně identifikovat diagenetická stádia a historii v karbonátových formacích fungujících jako rezervoáry. Pochopení diagenetického vývoje je zásadní, protože ovlivňuje tvorbu a distribuci pórovitosti, což v konečném důsledku ovlivňuje chování tekutiny v nádrži. Kromě toho zjištění získaná z četných studií o karbonátových nádržích na Středním východě ukazují, že multipórovitost významně zvyšuje průtokovou kapacitu a skladovací potenciál uhlovodíkových nádrží. Přítomnost více pórovitostí s odlišnými petrofyzickými charakteristikami však přináší značnou složitost při predikci chování kapalin a konstrukci přesných modelů nádrží. Tato složitost představuje významnou výzvu pro ropné inženýry působící v tomto regionu.

Tato studie ukazuje, že pochopení faktorů přispívajících k vytváření více pórovitosti spolu s jejich výhodami a výzvami zlepšuje naše znalosti o inženýrství nádrží v karbonátových formacích. Řešení problémů, které představuje multipórovitost, a efektivní využití jejích výhod je zásadní pro zlepšení obnovy uhlovodíků a zajištění úspěšné produkce ropy v karbonátových rezervoárech regionu.

Klíčová slova: Střední východ, karbonátové nádrže, multipórovitost, heterogenita, modelování nádrží, procesy diageneze.

Anotation:

This study undertakes a comprehensive examination of the most significant available sources regarding multi-porosity and its role in hydrocarbon reservoirs and oil production within the Middle East. The primary focus of this thesis encompasses key topics such as the underlying reasons for the development of multi-porosity, its benefits, and the challenges encountered in oil production from carbonate reservoirs. The conducted research underscores that various diagenesis processes occurring during different stages play a pivotal role in generating diverse types of porosities within carbonate reservoirs. Therefore, it becomes imperative to accurately identify the diagenetic stages and history within carbonate formations acting as reservoirs. Understanding diagenetic evolution is crucial as it influences the creation and distribution of porosity, ultimately affecting fluid behavior within the reservoir. Moreover, the findings obtained from numerous studies on carbonate reservoirs in the Middle East demonstrate that multi-porosity significantly enhances the flow capacity and storage potential of hydrocarbon reservoirs. However, the presence of multiple porosities with distinct petrophysical characteristics introduces considerable complexity in predicting fluid behavior and constructing accurate reservoir models. This complexity poses a significant challenge for oil engineers operating in this region.

This study shows, understanding the factors contributing to the creation of multiple porosities, along with their benefits and challenges, enhances our knowledge of reservoir engineering in carbonate formations. Addressing the challenges posed by multi-porosity and effectively leveraging its benefits is crucial for enhancing hydrocarbon recovery and ensuring successful oil production in carbonate reservoirs of the region.

Keywords: Middle East, Carbonate reservoirs, Multi-porosity, Heterogeneity, Reservoir modeling, Diagenesis processes.

Number of pages: 48

I declare that I have prepared the bachelor's thesis myself and that I have stated all the used information resources in the thesis.

In Olomouc, May 24th, 2024 ……………………………………………

Acknowledgment

I want to deliver my excitement through this acknowledgement letter that I am very grateful to have the opportunity to be able to discuss my bachelor's thesis and to graduate from the Palacky University of Olomouc.

I would like to extend my deepest appreciation to my supervisor, Dr. Hawre Mansurbeg for his guidance, and a special thanks to his assistance for guiding me through the right way and providing the help needed.

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1. Introduction

Porosity is an inherent characteristic of reservoir rock, quantifying the presence of void spaces or interstitial gaps within the rock matrix that has the capacity to accommodate various fluids, including oil, gas, or water (Sharifi, 2022). The porosity of a rock sample is quantitatively described as the proportion of void space (also known as pore space) relative to the total volume of the sample, typically represented as a percentage or a decimal fraction (Bohnsack, et al., 2020).

The presence of porosity is of utmost importance in assessing hydrocarbons' storage capacity and flow properties within a reservoir as the reservoir's capacity to store and send fluids is directly impacted (Ehrlich, 2019; Ougier-Simonin et al., 2016). Rocks exhibiting high porosity can accommodate a greater quantity of fluids, whereas rocks characterized by low porosity exhibit a restricted capacity for storage (Liu et al., 2022).

1.1 Types of Porosity

Porosity identification in carbonated rocks can be a challenging task due to the complex nature of these rocks (Bohnsack, et al., 2020). Carbonate rocks exhibit various types of porosity, each with its own characteristics and formation processes (Sharifi, 2022). Understanding these different porosity types is crucial for accurately assessing carbonate reservoirs' storage and flow properties (Liu et al., 2022).

One of the primary reasons for the difficulty in identifying porosity in carbonate rocks is their intricate composition (Ehrlich, 2019). Carbonate rocks are typically composed of grains or crystals of calcium carbonate, such as limestone or dolomite, which are often cemented together (Ougier-Simonin et al., 2016). These rocks can contain various porosity types, which can vary in size, shape, and connectivity (Liu et al., 2022).

The most important ones are mentioned below and, in an introduction, (Figure 1)

1) Intergranular Porosity: This type of porosity occurs between the individual grains or crystals of the carbonate rock (Milliken and Hayman, 2019). Carbonate sediments are commonly formed by the original gaps between shell fragments, skeletal remains, or

ooids (small, rounded grains) (Clarkson et al., 2016). Cementation, dissolution, and compaction can affect the intergranular porosity (Dale et al., 2018).

2) Intragranular Porosity: In contrast to intergranular porosity, intragranular porosity occurs within the grains themselves (Dale et al., 2018; Clarkson et al., 2016). It can develop due to various processes, such as dissolution, recrystallization, or the presence of fossils or other organic material within the grains (Dale et al., 2018).
3) Fracture Porosity: Carbonate rocks may contain fractures or cracks that intersect the rock matrix, creating additional pore spaces (Clarkson et al., 2016). These fractures can be formed by tectonic forces, dissolution, or other mechanical processes (Sari et al., 2020). Fracture porosity can significantly enhance the permeability of carbonate rocks, allowing fluid flow through interconnected fractures (Ougier-Simonin et al., 2016).
4) Vuggy Porosity: Vugs are irregular-shaped cavities or holes in carbonate rocks, often formed by dissolution of soluble minerals or fossils (Song et al., 2020). Vuggy porosity can vary in size and shape and is typically connected to the rock's surface or existing pore networks (Bohnsack et al., 2020).
5) Moldic Porosity: Moldic porosity refers to the void spaces left behind when a solid object, such as a shell or a fossil, dissolves or decomposes within the carbonate rock (Bohnsack et al., 2020). The resulting holes can create interconnected pore networks (Huang et al., 2023; Huang, Zhou, and Deng, 2020).
6) Fenestral Porosity: Fenestral porosity is characterized by elongated, tubular, or slit-like cavities found within carbonate rocks (Janjuhah et al., 2021). These cavities are usually formed by the preferential dissolution of certain minerals or organic matter (Janjuhah et al., 2021).
7) Microporosity: Microporosity refers to extremely small pores at the microscopic scale, often less than 1 micrometer in size (Ougier-Simonin et al., 2016). It can result from the fine-scale intergranular porosity, dissolution, or the presence of clay minerals within the rock (Ougier-Simonin et al., 2016).

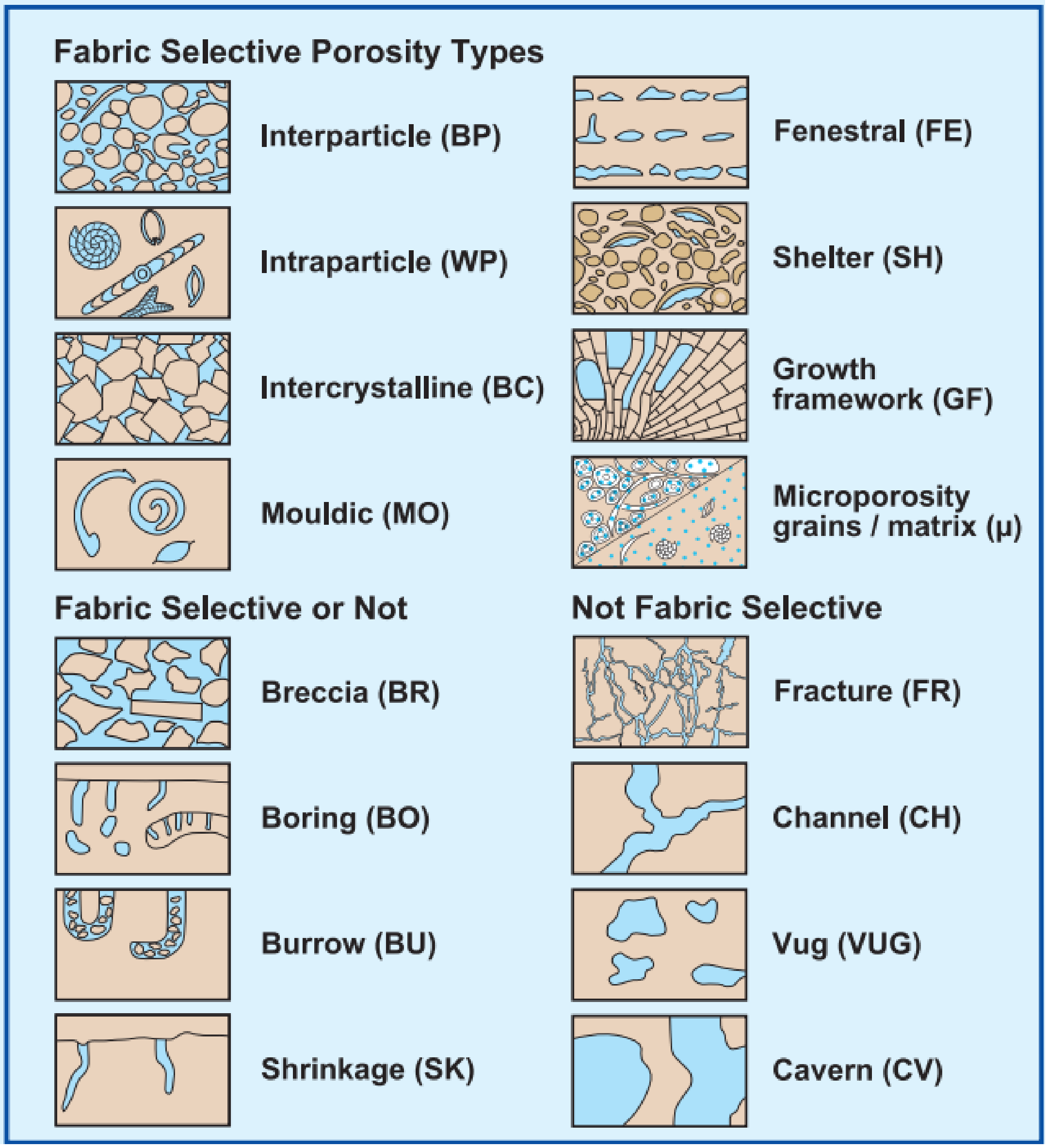

Figure 1. Different types of porosity in carbonate rock (Cambridge Carbonate Ltd.)

1.2 Multi-Porosity and Dual Porosity

Multi-porosity refers to a condition in which a reservoir contains multiple distinct pore systems (Ehrlich, 2019; Figure 2). These pore systems can differ in various physical aspects, including pore size, connectivity, and fluid storage and flow properties (Eker, Uzun, and Kazemi, 2017). Each pore system may exhibit unique behavior within a multi-porosity reservoir and respond differently to fluid flow (Ehrlich, 2019).

On the other hand, dual porosity specifically refers to the presence of two distinct pore systems within a reservoir: intergranular porosity and fracture porosity (Liu, 2022). Intergranular porosity refers to the interconnected smaller pores within the rock matrix, while fracture porosity pertains to the larger interconnected fractures or fissures in the reservoir rock (Eker, Uzun, and Kazemi, 2017). The presence of fractures can significantly enhance the permeability and fluid flow within the reservoir (Dale et al., 2018).

Understanding the behavior of fluids in hydrocarbon reservoirs necessitates a comprehensive understanding of multi-porosity and dual porosity concepts (Gong et al., 2023; Eker, Uzun, and Kazemi, 2017; Ougier-Simonin et al., 2016). The different pore systems can have a substantial impact on fluid flow patterns, production rates, and the overall efficiency of hydrocarbon recovery (Kargarpour, 2020). Consequently, the presence of multiple pore systems poses both opportunities and challenges for reservoir engineers, demanding thorough study and modeling to accurately define and predict reservoir performance (Kargarpour, 2020).

By considering the complexities of multi-porosity and dual-porosity reservoirs, engineers can develop effective strategies for optimizing hydrocarbon recovery (Gong et al., 2023; Eker, Uzun, and Kazemi, 2017; Ougier-Simonin et al., 2016). Various techniques, such as numerical modeling, simulation, and enhanced recovery methods, are employed to capture the behavior of fluids in these complex systems (Zhu et al., 2023; Kargarpour, 2020). Accurate characterization and quantification of each pore system's properties and their interactions are crucial for making informed decisions regarding reservoir management, well placement, and production strategies (Gong et al., 2023).

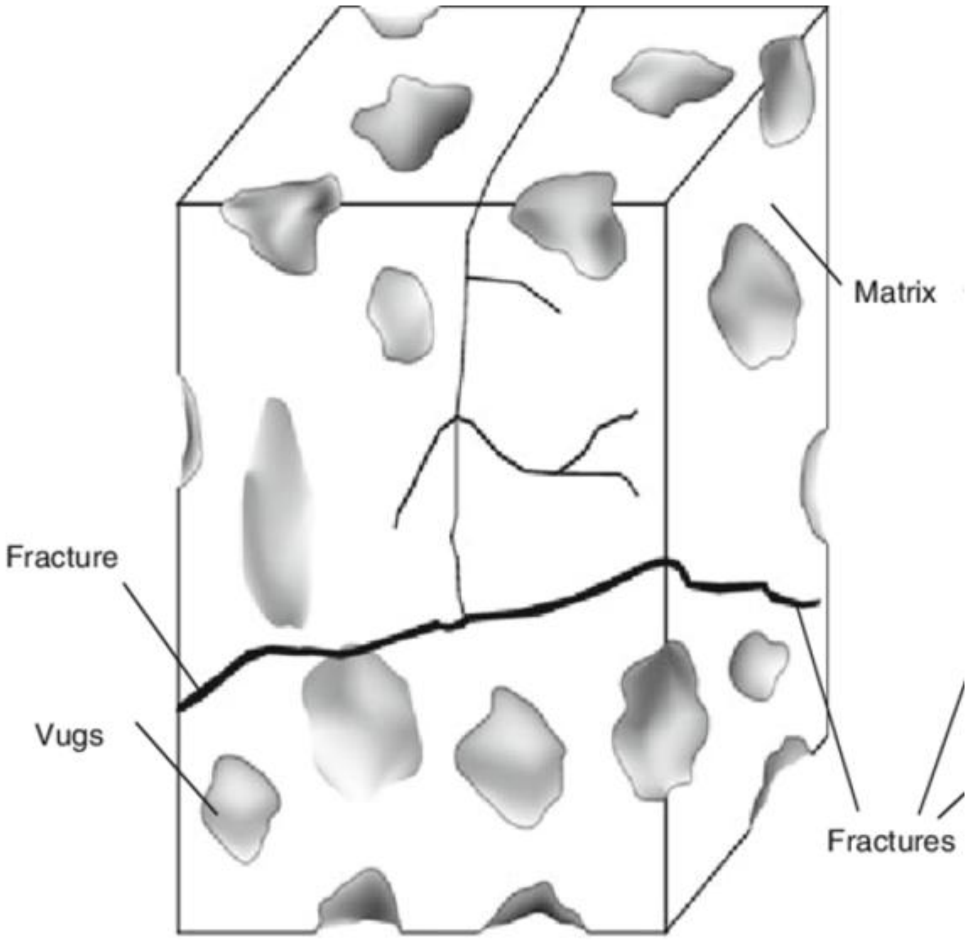

Figure 2. Types of porosity (after Warren and Root, 1963).

1.3 Study Aim

The objective of this study is to comprehensively examine the significant challenges and advantages associated with dual porosity systems in hydrocarbon reservoirs. The investigation aims to shed light on the effects of dual porosity and multi-porosity on fluid behavior within reservoir rocks and the overall production of hydrocarbon reservoirs. Additionally, the study seeks to determine how secondary porosity influences fluid flow, production rates, and recovery rates in hydrocarbon reservoirs. By understanding the complexities and potential benefits of dual and secondary porosity systems, it becomes possible to enhance reservoir management techniques and optimize hydrocarbon recovery. Dual porosity systems present unique challenges and opportunities in the exploitation of hydrocarbon reservoirs (Sun, 2015). The coexistence of intergranular porosity and fracture porosity necessitates a detailed understanding of how these two distinct pore systems interact and impact fluid flow (Eker, Uzun, and Kazemi, 2017). The presence of fractures enhances the overall permeability of the reservoir, facilitating fluid movement and increasing production potential (Dale et al., 2018). However, it also introduces challenges related to reservoir heterogeneity, preferential fluid pathways, and the allocation of fluid flow between the intergranular and fracture networks (Jiang et al., 2013).

Furthermore, multi-porosity, which includes the combined effects of multiple pore systems, can significantly influence fluid behavior and reservoir productivity (Kargarpour, 2020). The variation in pore size, connectivity, and storage capacities among different pore systems can lead to complex flow patterns and affect the displacement of hydrocarbons during production (Eker, Uzun, and Kazemi, 2017). Understanding and quantifying the impact of multi-porosity on fluid behavior are essential for accurate reservoir characterization and the development of effective production strategies (Dale et al., 2018).

Another key focus of this study is to investigate the effects of secondary porosity on fluid flow, production, and recovery rates in hydrocarbon reservoirs. Secondary porosity, such as vuggy porosity, moldic porosity, or fracture porosity, can significantly contribute to the overall reservoir porosity and permeability (Pak et al., 2016). The presence of secondary porosity offers additional storage capacity and preferential fluid pathways, influencing the flow behavior and recovery potential of hydrocarbons (Gong et al., 2023).

1.4 Study Area

The Middle East is home to some of the world's most significant carbonate reservoirs, which exhibit unique complexities and challenges (Nikbin et al., 2020). These reservoirs, found in countries such as Saudi Arabia, Iraq, Kuwait, Iran, and the United Arab Emirates, contain vast hydrocarbon resources and play a crucial role in global oil and gas production (Figure 3). As a result, this study places a particular emphasis on hydrocarbon reservoirs located in the Middle East region. Carbonate reservoirs in the Middle East exhibit distinctive characteristics that set them apart from reservoirs in other geological formations

(Nikbin et al., 2020). The region's geological history, tectonic activities, and depositional environments have contributed to the formation of highly heterogeneous carbonate rocks with diverse pore systems and diagenetic alterations (Asgarinezhad, 2016). These complexities pose significant challenges in terms of reservoir characterization, fluid behavior, and hydrocarbon recovery strategies (Hoffman, 2013). The Middle East's carbonate reservoirs often display a wide range of porosity types, including intergranular, vuggy, fracture, and moldic porosity (Gomes et al., 2018). The presence of these diverse porosity types leads to variations in permeability, fluid storage, and flow properties within the reservoir (Asgarinezhad, 2016). Understanding and effectively managing these complexities are crucial for optimizing hydrocarbon production and maximizing recovery rates (Nikbin et al., 2020).

Moreover, the Middle East region's unique geological features, such as extensive dolomitization, karstification, and faulting, further contribute to the complexity of its carbonate reservoirs (Asgarinezhad, 2016). These features can result in complex fluid flow pathways, compartmentalization, and reservoir compartment connectivity, requiring sophisticated reservoir engineering techniques and robust modeling approaches for accurate reservoir characterization and production forecasting (Gomes et al., 2018; Hoffman, 2013).

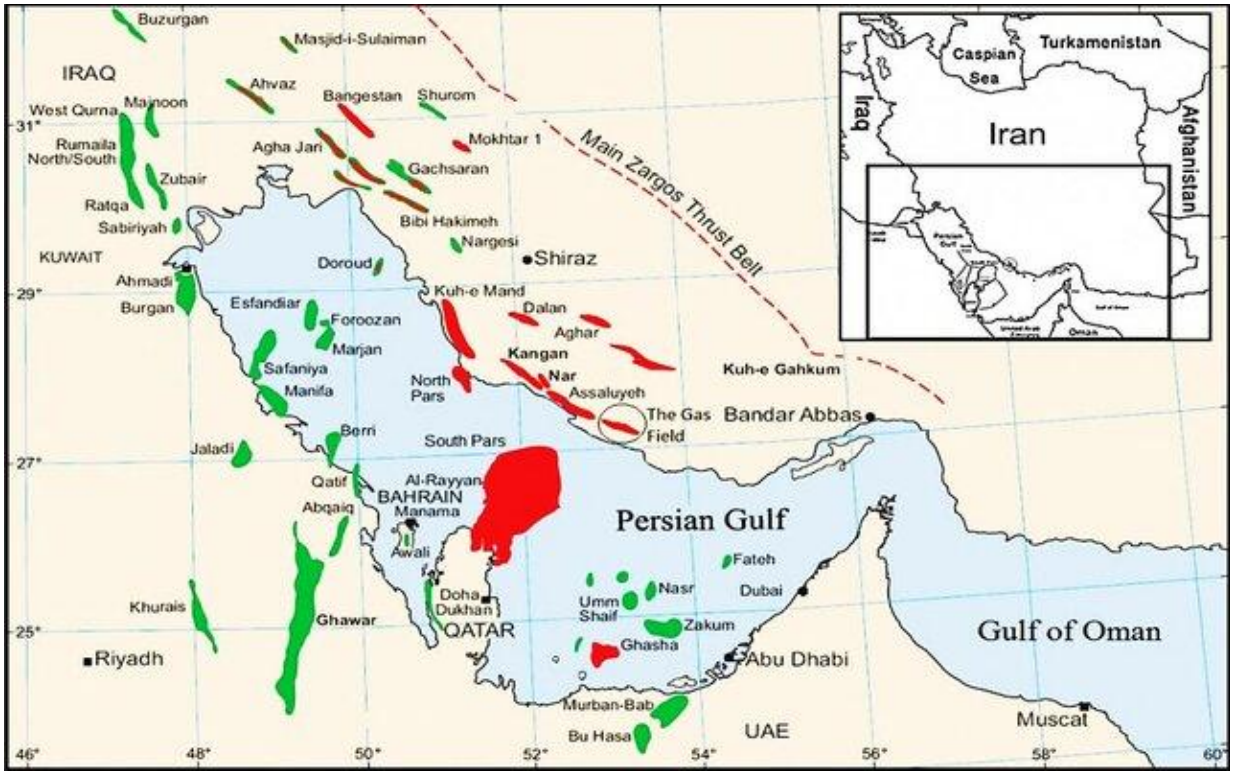

Figure 3. Some of the important hydrocarbon field in the Middle East (Nikbin et al., 2020).

2. Methodology

This chapter provides an explanation of the approach utilized in this research study to examine the impact of the multi-pore network on reservoir production performance. The research approach utilized in this paper was a review which is a method of research that incorporates the results of multiple scientific studies to reach conclusions about the study issue, which in this case is the multi-pore network in carbonate reservoirs and its implications on reservoirs production performance.

The first step in the review was the collection of relevant studies from reliable and authoritative scientific journals through platforms such as Science Direct and Google Scholar. The research phrases used were porosity and its types, dual and multi porosity, benefits and challenges of multi-porosity systems, and the implication of multi-porosity on production performance. Also, the research study's advisors and supervisors shared journal articles that were relevant to the topic and included extensive information on the research topic.

Then, the gathered papers were thoroughly examined to determine and highlight all of the relevant information including but not limited to the physical characteristics of the reservoir, such as porosity and permeability, the benefits and challenges of multi-porosity systems, and the impact of dual porosity and multi-porosity on the behavior of fluids in reservoir rocks and the production of hydrocarbon reservoirs. More specifically, various aspects of each paper were evaluated to determine the methods and samples used, the variables assessed, and the conclusions reported.

Lastly, the information obtained from various reservoirs was combined to draw conclusions about important challenges and benefits of dual porosity systems in hydrocarbon reservoirs, how dual porosity and multi-porosity affect the behavior of fluids in reservoir rocks and the production of hydrocarbon reservoirs, and how secondary porosity affects hydrocarbon reservoirs' fluid flow, production, and recovery rates. Data, findings, and conclusions from each study were thoroughly examined to look for recurrent patterns, trends, and discrepancies. The researcher gained insights into the big picture by systematically contrasting the data and interpretations. With the help of this method, it was possible to acquire a thorough grasp of the subject, summarize the key findings, and provide a well-informed conclusion based on the overall information obtained from the articles under consideration.

This research approach enabled us to exploit the advantages of individual studies, recognize similarities, and comprehensively comprehend the topic at hand. This approach was advantageous in presenting a thorough perspective of existing research and recognizing limitations in the current knowledge base, thereby emphasizing potential pathways for future research.

A few of the papers studied for this research were Controls on the formation and evolution of multimodal pore network in lower cretaceous limestone reservoir, Abu Dhabi, United Arab by Alabere et al. (2023), Depositional and diagenetic controls on reservoir quality of microporous basinal lime mudstones (Aptian), United Arab Emirates by Alsuwaidi et al. (2021), Pore-scale dual-porosity and dual-permeability modeling in an exposed multi-facies porous carbonate reservoir by Zambrano et al. (2021), Carbonate reservoir characterization: an integrated approach by Kargarpour (2020), and Diagenesis of a limestone reservoir (Lower Cretaceous), Abu Dhabi, United Arab Emirates: Comparison between the anticline crest and flanks by Morad et al., (2019).

3. Results and Discussions

Different porosities in carbonate rocks can arise from various geological processes and factors (Bohnsack et al., 2020). For example, the depositional environment in which carbonate rocks are formed plays a crucial role in determining the initial porosity (Bohnsack et al., 2020). Diagenetic processes greatly influence the porosity development and evolution in carbonate rocks (Yang, 2018). Carbonate's Diagenetic processes include cementation, compaction, dissolution, recrystallization, and dolomitization (Pak et al., 2016). These processes can enhance or reduce porosity, depending on the carbonate rock's specific conditions and mineralogical composition (Pak et al., 2016). In general, it can be stated that diagenesis processes following sedimentation play a pivotal role in creating multi-porosity within carbonate rocks (Morad et al., 2019). The extent and diversity of these diagenetic processes greatly influence the complexity and evolution of multi-porosity in carbonate rocks (Morad et al., 2019). The diversity and extent of these diagenetic processes shape multi-porosity complexity in carbonate rocks (Alsuwaidi et al., 2021). When diagenetic processes are varied and extensive, a wider range of pore types and sizes can form, resulting in a more intricate and challenging evolution of multi-porosity (Alabera et al., 2023). The interplay between these diagenetic processes and their effects on pore connectivity, distribution, and storage capacity can create a complex and heterogeneous reservoir (Morad et al., 2019).

Diagenesis processes occur in various environments and stages, each influenced by different conditions (Morad et al., 2019). Diagenesis can be broadly divided into three stages: eugenesis, mesogenesis, and telogenesis, which represent different periods in the geological history of sedimentary rocks (Alsuwaidi et al., 2021).

Eugenesis: Eugenesis refers to the early diagenetic processes that occur shortly after deposition and during burial (Ehrenberg, 2022; Morad et al., 2019). It encompasses the initial physical, chemical, and biological changes that take place in the sedimentary environment (Ehrenberg, 2022; Figure 4). Eugenesis processes are influenced by conditions such as sedimentation rate, water chemistry, and the availability of pore fluids (Alsuwaidi et al., 2021). Examples of eugenesis processes include the formation of early diagenetic minerals, compaction, and the initial stages of cementation (Ehrenberg, 2022).

Mesogenesis: Mesogenesis represents the intermediate stage of diagenesis, occurring during deeper burial and higher levels of temperature and pressure (Ehrenberg, 2022; Morad et al., 2019). During this stage, further mineral transformation, recrystallization, and compaction take place (Alsuwaidi et al., 2021). Mesogenesis processes are influenced by factors such as temperature, pressure, and the composition of pore fluids (Morad et al., 2019). Cementation and the growth of authigenic minerals continue during mesogenesis, further altering the rock's properties and porosity (Ehrenberg, 2022).

Telogenesis: Telogenesis refers to the late-stage diagenesis that occurs during uplift of sedimentary rocks (Kargarpour, 2020; Morad et al., 2019). This stage is characterized by reduced burial depth, lower temperature, and decreased fluid activity (Alsuwaidi et al., 2021). Telogenesis processes can include cement dissolution, fracturing, and the formation of secondary porosity (Alabere et al., 2023). During telogenesis, the rock experiences additional changes due to exposure to meteoric waters and other surface processes (Alabere et al., 2023).

The environments and conditions under which diagenesis occurs vary depending on factors such as depositional environment, geological history, and the duration of burial (Figure 5). For instance, diagenesis processes in marine environments may be influenced by seawater chemistry, while those in continental settings may be influenced by freshwater compositions and groundwater flow (Alabere et al., 2023).

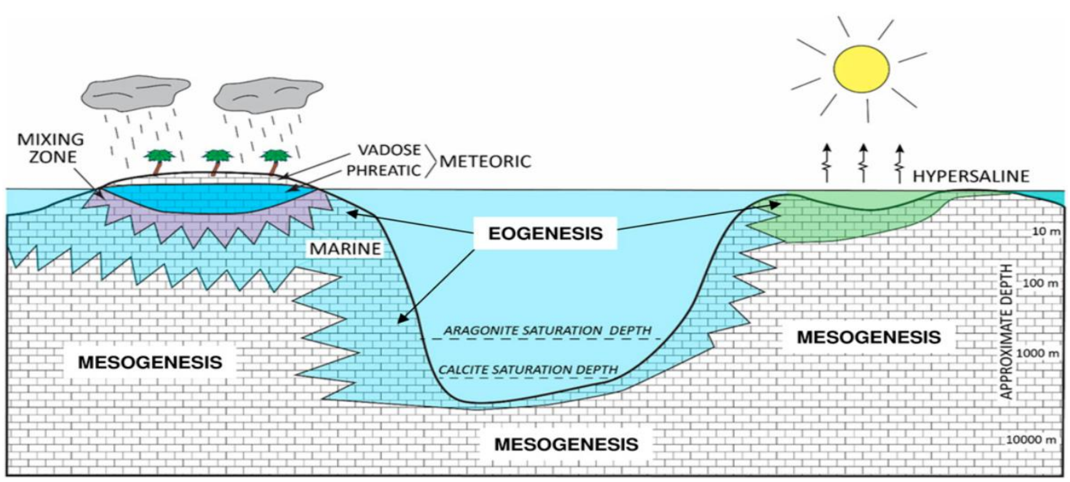

Figure 4. Diagenesis processes are created in different environments and stages under different conditions, such as eogenesis, mesogenesis (Ehrenberg, 2022).

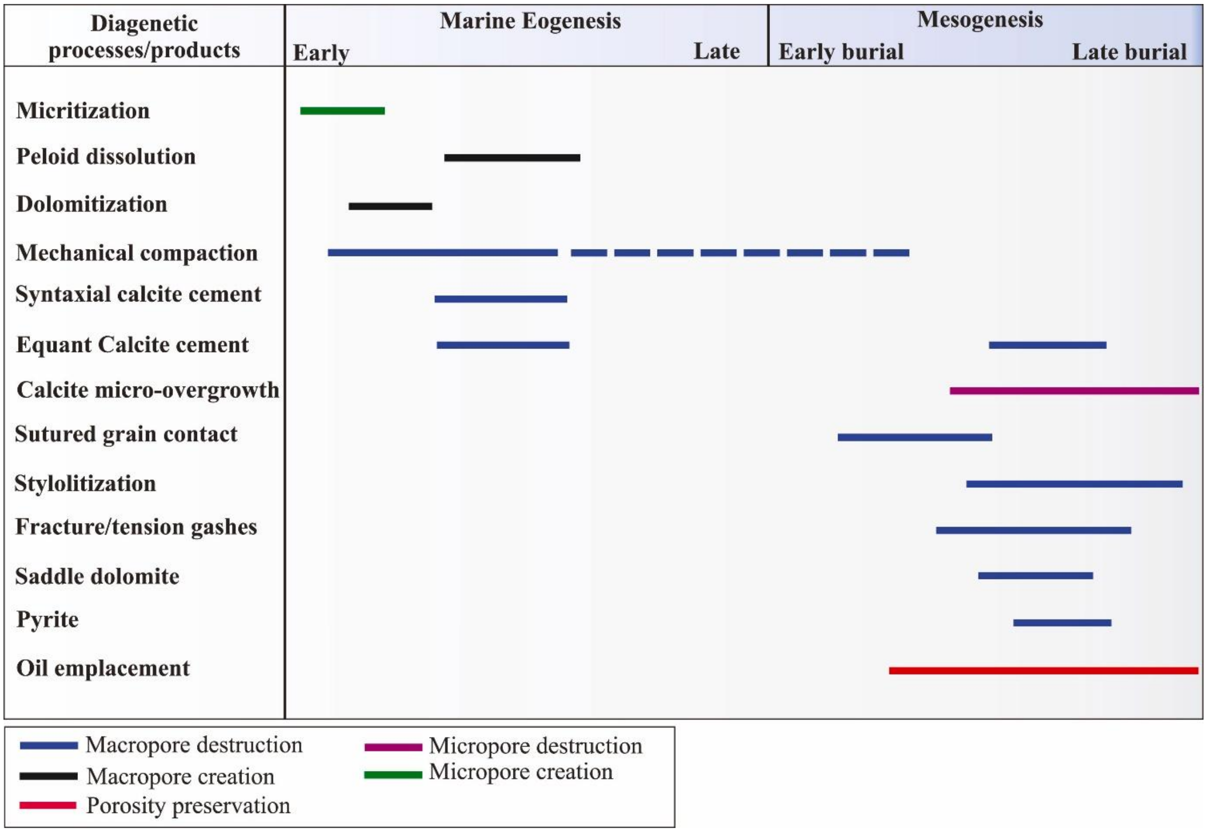

Figure 5. Paragenetic sequence that shows the effect of diagenesis on the creation of various porosities in carbonate sediments (Alabere et al., 2023).

3.1 Relationship Between Secondary Porosity and Multi-Pores Reservoir

As mentioned previously, porosities in reservoir rocks can be broadly classified into two categories: primary and secondary porosities. While primary porosities are inherent to the sedimentary rock formation, secondary porosities develop through post-depositional processes and play a crucial role in the creation of multi-porosity reservoirs (Milliken and Hayman, 2019). The formation of secondary porosities is influenced by various geological processes that significantly contribute to the development of complex pore systems (Kamali, Vahedi, and Mohammadi, 2020).

Secondary porosities arise from diagenetic processes that occur after the initial sedimentation of the rock (Elhaj et al., 2020; Figure 6). These processes involve physical and chemical alterations that modify the rock's composition and structure, leading to the creation of additional pore spaces (Jafari Behbahani et al., 2021; Figure 7). These secondary porosities are often more extensive and diverse compared to primary porosities, making them key factors in the formation of multi-porosity reservoirs (Rashid et al., 2022).

The development of secondary porosities is a result of various diagenetic mechanisms (Elhaj et al., 2020). These mechanisms include dissolution, compaction, cementation, recrystallization, dolomitization, and other alteration processes (Mastalerz, 2018). Dissolution, for example, involves the removal of minerals from the rock matrix through chemical weathering, resulting in the creation of pore spaces (Anovitz and Cole, 2015). Compaction refers to the reduction in pore volume caused by the weight of overlying sediments, while cementation involves the precipitation of minerals within existing pore spaces, which can either enhance or reduce porosity (Elhaj et al., 2020).

In addition, the wide range of diagenetic processes contributing to secondary porosity formation leads to the creation of complex and diverse pore systems within the reservoir (Mastalerz, 2018). These pore systems include vuggy porosity, fracture porosity, moldic porosity, intergranular porosity, and other types, each with its own unique characteristics (Mastalerz, 2018; Anovitz and Cole, 2015; Figure 8). The interconnected nature of these pore systems forms a complex network that significantly affects fluid flow patterns, permeability, and storage capacity within the reservoir (Sharifi, 2022). Moreover, the presence of secondary porosities is instrumental in the development of multi-porosity reservoirs (Kamali, Vahedi, and Mohammadi, 2020). These complex pore systems provide additional storage capacity, enhanced fluid flow pathways, and increased permeability (Kamali, Vahedi, and Mohammadi, 2020). The heterogeneity resulting from the interplay between primary and secondary porosities contributes to the complexity of the reservoir and influences hydrocarbon recovery strategies (Ehrenberg, 2022).

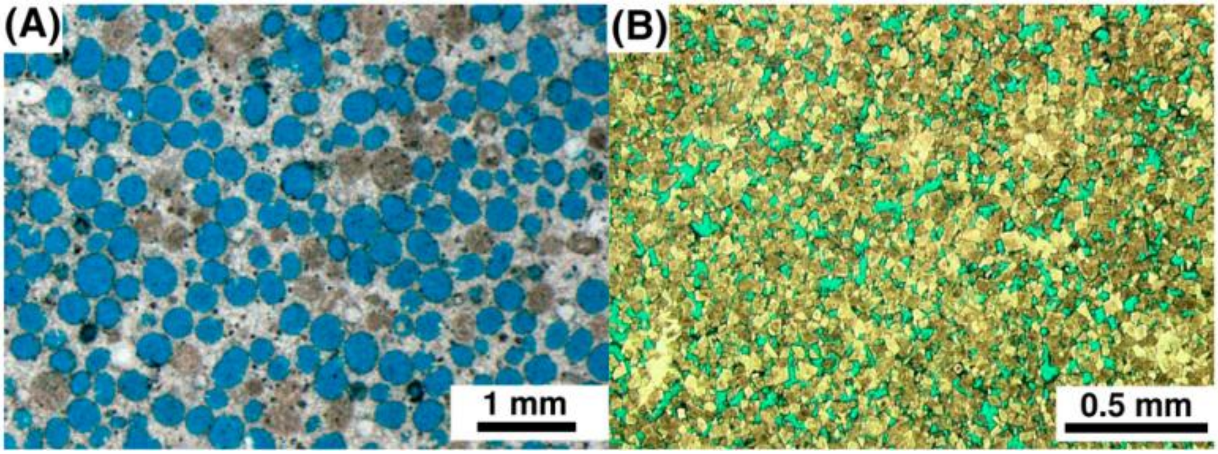

Figure 6. Samples of secondary porosity in carbonate thine section. (A) moldic pore (B) intercrystalline pore between dolomite (Ehrenberg, 2022).

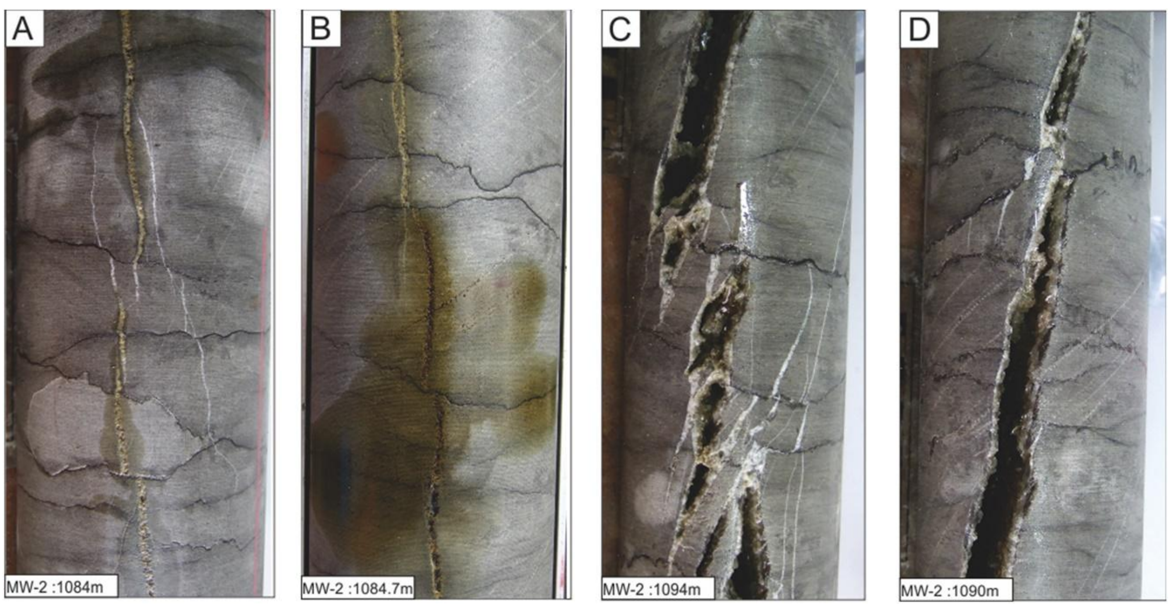

Figure 7. Samples of secondary porosity (A-B) Fracture (C-D) channel (Gomes et al., 2018).

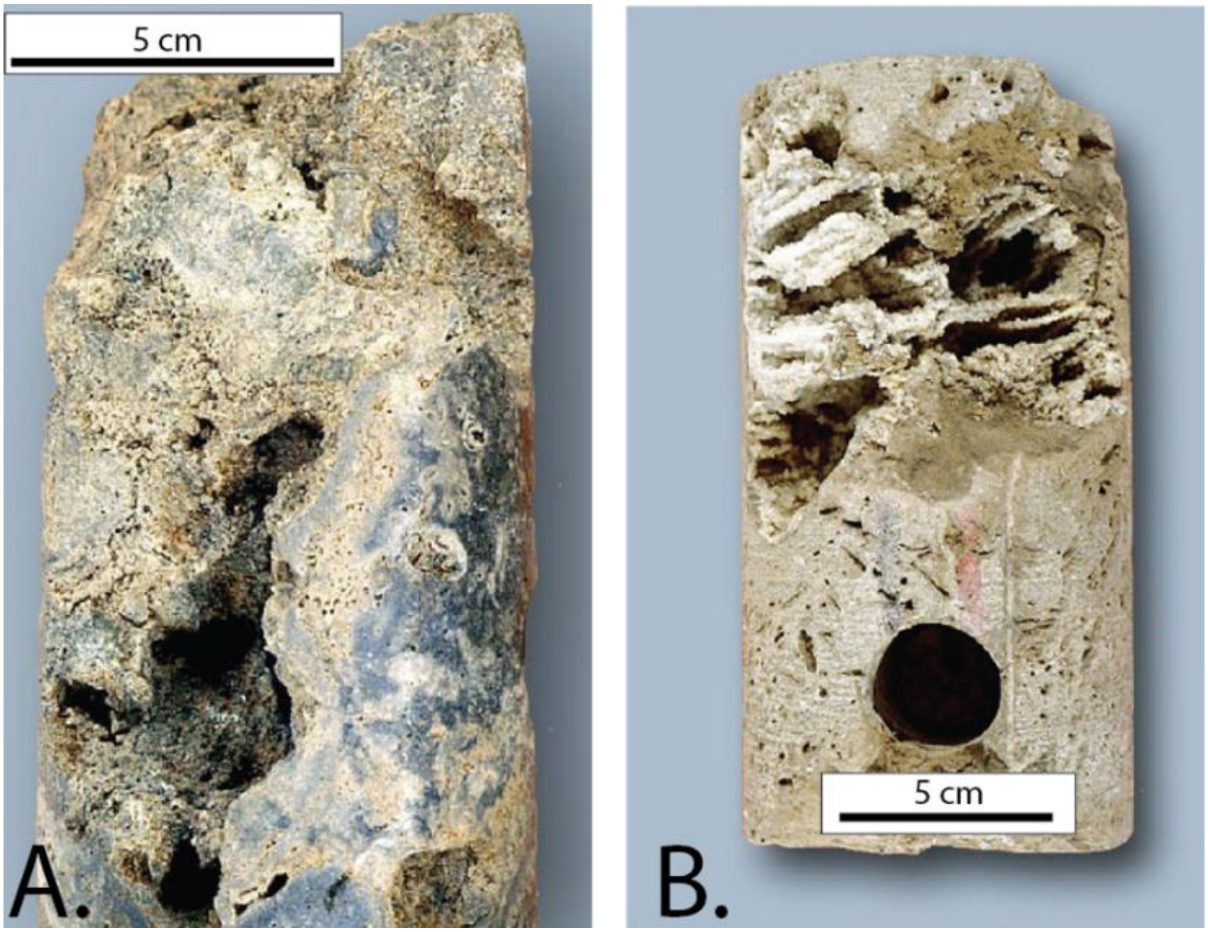

Figure 8. A and B Samples from the cores in which vuggy and channel porosity are observed (Lucia, 1983).

Accurately characterizing and understanding the formation and distribution of secondary porosities is crucial for reservoir engineers and geoscientists (Janjuhah et al., 2021; Milliken and Hayman, 2019). Advanced techniques, such as core analysis, well logging, imaging technologies, and laboratory experiments are employed to identify and quantify the different types of secondary porosities within the reservoir (Zhu et al., 2023; Elhaj et al., 2020). This information is then integrated into reservoir models and simulations to optimize hydrocarbon recovery strategies and predict fluid behavior (Sari et al., 2020; Bohnsack, 2020; Sharifi, 2022).

3.2 Challenges of Multi-Porosity Systems

3.2.1 Heterogeneity

Multi-porosity systems in hydrocarbon reservoirs introduce a significant level of reservoir heterogeneity (Wang, 2018). The presence of different pore systems with variations in pore size, connectivity, and fluid flow properties results in complex flow patterns and poses challenges in accurately predicting fluid behavior (Eker, Uzun, and Kazemi, 2017; Figure 9). This heterogeneity can have several implications for hydrocarbon production (Alabere et al., 2023; Chen, 2022; Wang, 2018). One of the primary challenges posed by multi-porosity systems is the establishment of preferential fluid pathways (Gong et al., 2023). Due to the variations in permeability and connectivity among different pore systems, fluids may favor certain pathways over others, leading to uneven distribution and flow (Chen, 2022; Wang, 2018). This preferential flow can cause localized areas of high production rates, while other areas may remain bypassed or have lower sweep efficiency (Gong et al., 2023). Predicting and managing these preferential fluid pathways is crucial for optimizing hydrocarbon recovery (Gong et al., 2023; Fumagalli, 2016).

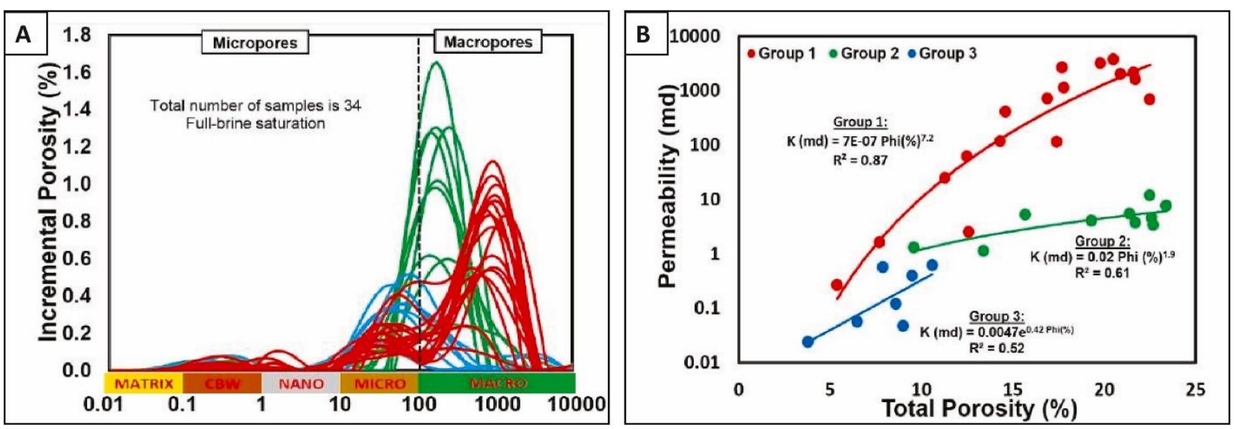

Figure 9. The difference in the size and type of porosity causes the difference in permeability (Alabere et al., 2023).

Another consequence of reservoir heterogeneity in multi-porosity systems is compartmentalization (Heidsiek et al., 2020; Sun, 2015). The presence of distinct pore systems with different permeabilities and fluid flow properties can result in the formation of isolated compartments within the reservoir (Heidsiek et al., 2020; Figure 10). These compartments may act as separate flow units, leading to compartmentalized fluid flow and potentially limiting the effective sweep of hydrocarbons (Jiang et al., 2013). Identifying and understanding these compartments are essential for effective reservoir management and maximizing recovery (Heidsiek et al., 2020; Sun, 2015; Jiang et al., 2013).

The non-uniform sweep efficiency is another challenge arising from the heterogeneity in multi-porosity systems (Sun et al., 2020; Bohnsack et al., 2020; Dale et al., 2018). Due to the complex flow patterns and variations in permeability, different areas of the reservoir may have different sweep efficiencies (Alabere et al., 2023; Sun et al., 2020). Some regions with higher permeability or more connected pore systems may undergo more effective fluid displacement and recovery, while other regions with lower permeability or less connected pore systems may experience poor sweep efficiency and trapped hydrocarbons (Khoshdel et al., 2022). Managing this non-uniform sweep efficiency requires accurate reservoir characterization and the design of appropriate production strategies (Bohnsack et al., 2020; Dale et al., 2018).

To address these challenges, advanced reservoir characterization techniques and modeling approaches are employed (Alabere et al., 2023; Jafari Behbahani et al., 2021). Integrated studies involving well logs, core analysis, geophysical data, and reservoir simulation help to capture the heterogeneity and understand the interactions between different pore systems (Khoshdel et al., 2022). Upscaling methods are utilized to transfer small-scale measurements to large-scale reservoir models, enabling a better representation of the multi-porosity system behavior (Jafari Behbahani et al., 2021; Zhao et al., 2019) Additionally, advanced production techniques, such as selective stimulation or enhanced oil recovery methods, may be employed to improve sweep efficiency and increase hydrocarbon recovery from each pore system (Jafari Behbahani et al., 2021).

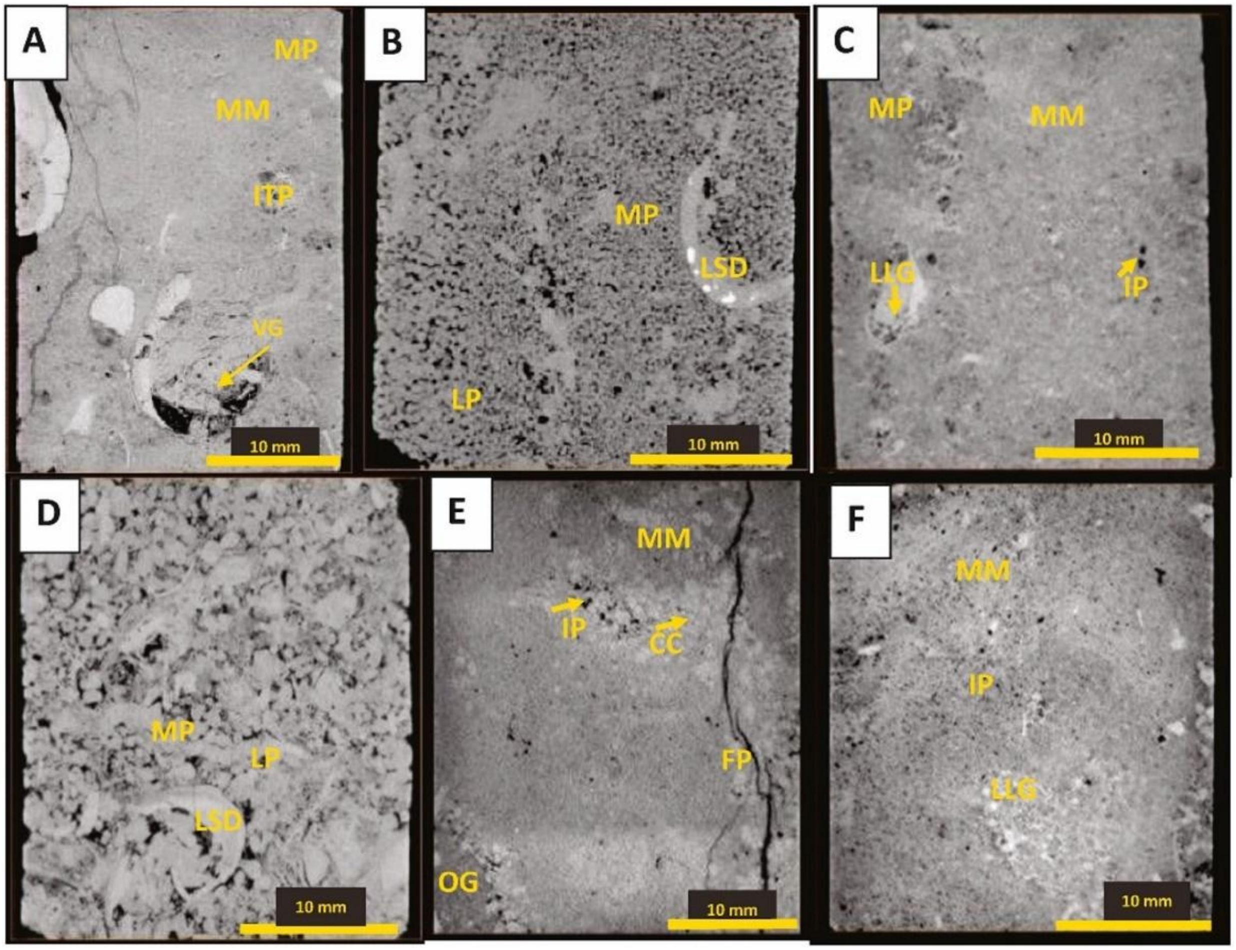

Figure 10. Micro-CT scan at 40 μm resolution showing: (A) vugs, intraparticle pores (ITP), muddy matrix (MM), and micropores (MP) within skeletal wackestone-mud dominated packstone; (B) microporosity (MP), large skeletal debris (LSD), and large pores (LP) within skeletal ooidal packstone to grainstone; (C) muddy matrix (MM), microporosity (MP), locally leached grain (LLG), and isolated porosity (IP) within skeletal peloidal packstone; (D) micropores (MP), large pores (LP), and large skeletal debris (LSD) within skeletal oncoidal grainstone to rudstone; (E) fracture porosity, oncoidal grains (OG), isolated porosity (IP), muddy matrix (MM), and calcite cement (CC) within oncoidal wackestone to floatstone; and (F) isolated porosity (IP), locally leached grain (LLG), and muddy matrix (MM) within oncoidal packstone (Alabere et al., 2023).

3.2.2 Simulation Complexity

Simulating fluid flow and recovery in multi-porosity systems significantly increases the complexity of reservoir simulation models (Baumann, Dale, and Bellout, 2020; Figure 11). Properly capturing the interactions between different pore systems and accurately representing the heterogeneity in the reservoir requires advanced modeling techniques and computational resources (Abbaszadeh and Shariatipour, 2018). Developing accurate and efficient numerical models that consider the properties of each pore system is crucial for reliable reservoir performance predictions and the optimization of production strategies (Baumann, Dale, and Bellout, 2020; Abbaszadeh and Shariatipour, 2018).

The complexity of simulating fluid flow in multi-porosity systems arises from the need to account for the interactions between different pore systems (Ougier-Simonin et al., 2016). Each pore system may have distinct properties such as permeability, porosity, and connectivity, which affect fluid flow behavior (Dale et al., 2018). Capturing these interactions and accurately representing the flow between different pore systems is essential for reliable reservoir simulations (Abbaszadeh and Shariatipour, 2018).

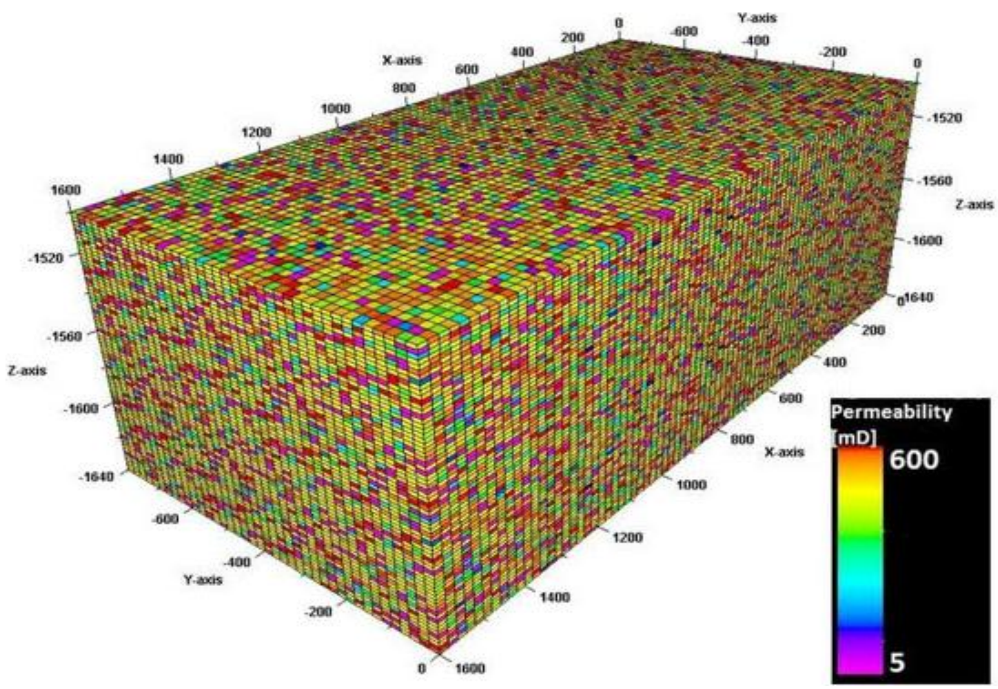

Figure 11. Multi porosity creates different permeability and modeling complexity (Abbaszadeh and Shariatipour, 2018)

The heterogeneity introduced by multi-porosity systems poses another challenge in simulation (Asgarinezhad, et al., 2016). The variations in pore size, connectivity, and fluid flow properties require the development of advanced modeling techniques to effectively represent the reservoir's complexity (Asgarinezhad, et al., 2016). This may involve employing numerical methods that can handle the intricacies of multi-porosity systems, such as dual-porosity or multi-porosity modeling approaches (Altameemi and Alzaidy, 2018; Eker, Uzun, and Kazemi, 2017). These techniques aim to accurately capture the differences in flow characteristics between intergranular matrix porosity and fracture porosity or other distinct pore systems (Sun et al., 2015; Figure 12).

Accurate representation of the heterogeneity in multi-porosity systems necessitates the use of computational resources (Eker, Uzun, and Kazemi, 2017; Sun et al., 2015). The modeling and simulation of such systems often require sophisticated software packages and substantial computational power (Altameemi and Alzaidy, 2018; Al-Baldawi, 2015). Advanced algorithms and numerical methods are employed to handle the complexity of multi-porosity models, enabling reliable predictions of fluid flow and recovery performance (Hoffman, 2013). Developing accurate numerical models that consider the properties of different pore systems is crucial for reliable reservoir performance predictions (Al-Baldawi, 2015). This involves integrating data from various sources, such as well logs, core analysis, and laboratory experiments, to quantify the properties of each pore system (Asgarinezhad, et al., 2016; Sun et al., 2015).

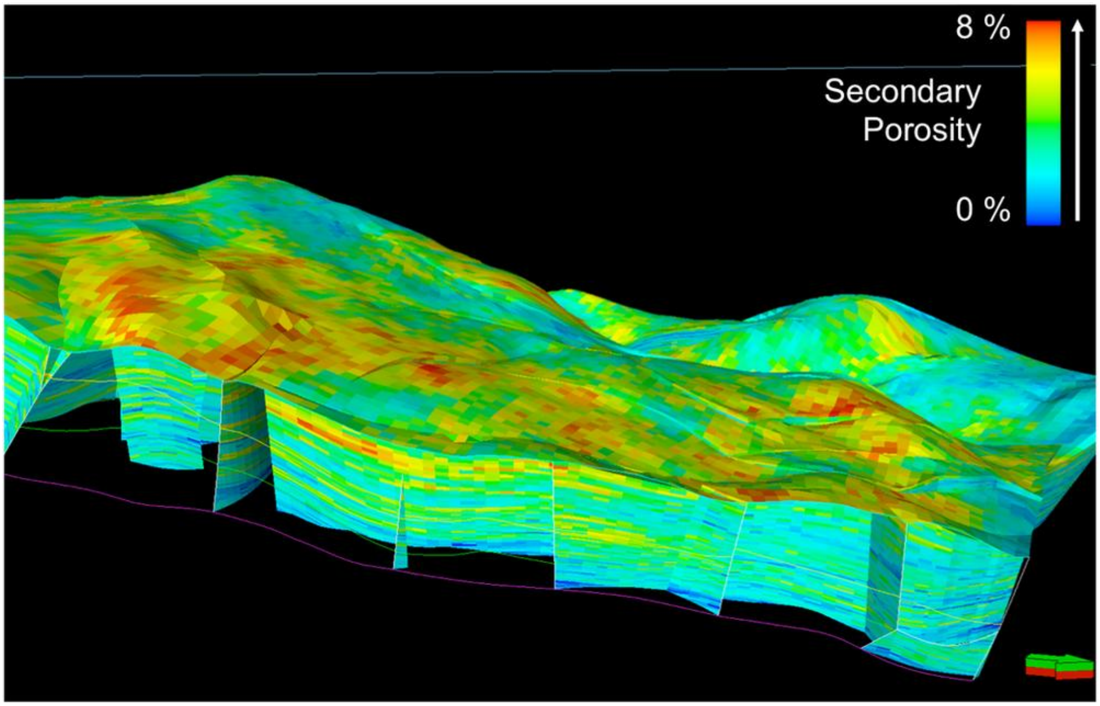

Figure 12. The complexity of a designed carbonate model (Altameemi and Alzaidy, 2018).

Upscaling techniques may be utilized to transfer these small-scale measurements to the larger reservoir simulation models, ensuring that the different pore systems' properties are properly represented (Altameemi and Alzaidy, 2018). Efficiency is also a critical aspect when simulating multi-porosity systems (Masindi, Trivedi, and Opuwari, 2022). Developing computationally efficient models allows for faster simulations and iterative optimization of production strategies (Masindi, Trivedi, and Opuwari, 2022; Panfili et al., 2015). Advanced modeling techniques, parallel computing, and optimization algorithms are employed to achieve computational efficiency while maintaining accuracy (Radwan, 2022).

3.3 Benefits of Multi-Porosity Systems

3.3.1 Increased Reservoir Storage Capacity

Multi-porosity systems offer substantial benefits by significantly enhancing the storage capacity of hydrocarbon reservoirs (Bohnsack et al., 2020). The presence of multiple pore systems with varying sizes and properties within the rock matrix allows for a greater volume of fluids, such as oil and gas, to be stored (Sari et al., 2020). In addition, the diverse pore systems in multi-porosity reservoirs provide additional storage space for hydrocarbons (Bohnsack et al., 2020; Figure 13). Intergranular porosity, for example, offers storage within the spaces between individual grains or crystals, while fracture porosity provides storage within interconnected fractures and fissures (Milliken and Hayman, 2019).

Moreover, the combination of these different pore systems increases the overall storage capacity of the reservoir (Milliken and Hayman, 2019). The ability to store a larger volume of fluids within the rock matrix has several advantages (Bohnsack et al., 2020; Asgarinezhad, et al., 2016). It contributes to higher recoverable reserves, as more hydrocarbons can be retained within the reservoir (Sari et al., 2020). This, in turn, enhances the economic viability of the reservoir, as the increased storage capacity allows for a greater potential for hydrocarbon production and revenue generation (Bohnsack et al., 2020; Dale et al., 2018).

Figure 13. Secondary porosity and multi-porosity provide more space for hydrocarbon storage (Bohnsack et al., 2020).

Furthermore, the enhanced storage capacity provided by multi-porosity systems can help optimize reservoir management and production strategies (Milliken and Hayman, 2019). It allows for better utilization of the available hydrocarbon resources, maximizing the recovery factor and extending the production life of the reservoir (Yang, 2018). By efficiently utilizing the increased storage capacity, operators can optimize production rates, reduce production costs, and enhance the overall profitability of the reservoir (Dale et al., 2018).

3.3.2 Increased Permeability

Multi-porosity systems offer a distinct advantage by often exhibiting higher overall permeability compared to single-porosity systems (Janjuhah et al., 2021). The presence of multiple pore systems, including fracture porosity, contributes to the increased permeability within the reservoir (Yang, Xue, and Chen, 2018). Fracture porosity, in particular, can provide high-permeability pathways for fluid flow, enabling faster and more efficient hydrocarbon production (AlRassas et al., 2021; Nandlal and Weijermars, 2019; Figure 14). Fractures within multi-porosity systems act as conduits for fluid movement, offering highly permeable pathways through which hydrocarbons can flow (Flório and Almeida, 2015). Fracture porosity can arise from tectonic activity, such as faulting or fracturing, or from the dissolution and collapse of minerals during diagenesis (Zambrano et al., 2021). These fractures create interconnected networks that allow for the efficient movement of fluids, promoting enhanced permeability and improved productivity (AlRassas et al., 2021; Zambrano et al., 2021; Flório and Almeida, 2015). In addition to fracture porosity, the combinatcontributeerent pore systems within multi-porosity reservoirs contributes to the overall increase in permeability (Zambrano et al., 2021).

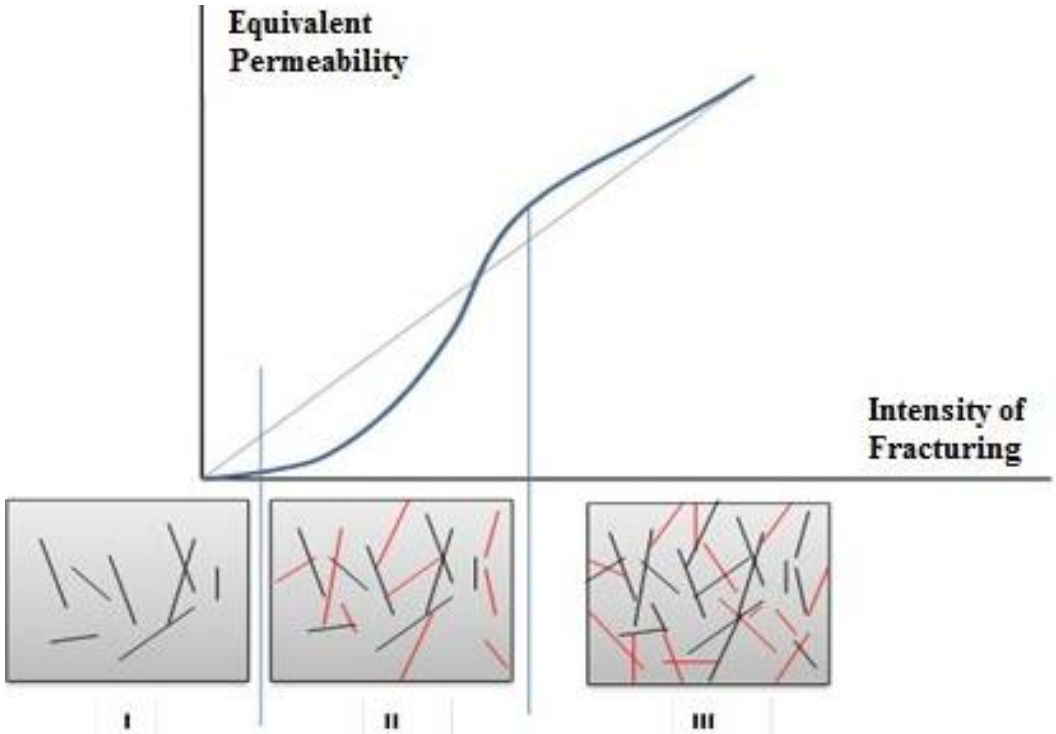

Figure 14. The conceptual correlation between fracture intensity and the resulting permeability equivalent (Flório and Almeida, 2015).

Each pore system may possess varying permeabilities, which collectively enhance the reservoir's permeability (Khoshdel et al., 2022; Heidsiek et al., 2020). For example, intergranular matrix porosity may have lower permeability compared to fracture porosity, but its presence still contributes to the overall connectivity and fluid flow within the reservoir (Zambrano et al., 2021; Flório and Almeida, 2015). The higher overall permeability in multi-porosity systems facilitates improved fluid flow and productivity (Yang, Xue, and Chen, 2018). Different pore systems' interconnected nature and high-permeability pathways reduce flow restrictions and pressure differentials within the reservoir (Nandlal and Weijermars, 2019). This enables hydrocarbons to flow more easily and efficiently, allowing for faster production rates and enhanced recovery (Nandlal and Weijermars, 2019). The increased permeability in multi-porosity systems has several advantages (Heidsiek et al., 2020). It enables more effective utilization of the reservoir's hydrocarbon resources by providing pathways for fluid movement and reducing the barriers to production (Guan et al., 2018). The improved connectivity and permeability also contribute to better sweep efficiency, ensuring a more thorough displacement of hydrocarbons during production operations (Heidsiek et al., 2020; Nandlal and Weijermars, 2019).

Accurately characterizing the permeability distribution within multi-porosity reservoirs is crucial for reservoir engineers (Janjuhah et al., 2021; Zambrano et al., 2021). Advanced techniques, such as well testing, pressure transient analysis, and dynamic data integration, are employed to quantify and map the permeability variations across different pore systems (Masoudi, 2021; Liu et al., 2017). This information is then integrated into reservoir models to accurately simulate fluid flow and optimize production strategies (Khoshdel et al., 2022).

3.3.3 Enhanced Recovery Potential

Multi-porosity systems present significant advantages by offering enhanced recovery potential for hydrocarbon reservoirs (Gong et al., 2023; Alobaidy et al., 2022). The presence of interconnected pore systems and the ability to access previously untapped or bypassed regions within the reservoir greatly improve the chances of recovering additional hydrocarbons (Song et al., 2020). By leveraging and producing from multiple pore systems, operators can maximize the recovery factor and optimize hydrocarbon extraction from the reservoir (Nandlal and Weijermars, 2019). One of the key benefits of multi-porosity systems is the ability to tap into previously untapped regions of the reservoir (Nandlal and Weijermars, 2019; Wang et al., 2017). In conventional single-porosity reservoirs, hydrocarbon production mainly occurs from the dominant pore system (Janjuhah et al., 2021). However, in multi-porosity systems, additional pore systems, such as fractures or vugs, offer untapped potential for hydrocarbon recovery (Nandlal and Weijermars, 2019). By accessing these previously bypassed regions, operators can unlock new reserves and increase the overall recovery factor of the reservoir (Gong et al., 2023). The interconnected nature of different pore systems within multi-porosity reservoirs enables efficient fluid flow and enhances the recovery potential (Alobaidy et al., 2022; Song et al., 2020). Fluids can flow through interconnected fractures or vugs, providing alternative pathways for hydrocarbon migration and extraction (Nandlal and Weijermars, 2019). This interconnectivity improves sweep efficiency, reduces bypassed zones, and enables a more effective recovery of hydrocarbons from the reservoir (Song et al., 2020).

By producing from multiple pore systems, operators can optimize hydrocarbon extraction and maximize the recovery factor (Masindi, Trivedi, and Opuwari, 2022; Ahr, 2011). Each pore system may have unique characteristics, such as varying permeabilities, porosities, or fluid saturations, which affect fluid flow behavior (Masindi, Trivedi, and Opuwari, 2022; Al-Baldawi and Nasser, 2013). By understanding and utilizing these differences, operators can design production strategies that target each pore system individually, tailoring the extraction methods to the specific properties of each system (Song et al., 2020; Al-Baldawi and Nasser, 2013). This targeted approach improves overall recovery efficiency and enhances hydrocarbon production rates (Gong et al., 2023; Wang et al., 2017).

Additionally, the ability to access multiple pore systems offers flexibility in reservoir management (Alobaidy et al., 2022). In situations where one pore system experiences declining production rates or becomes depleted, operators can shift their focus to other productive pore systems within the multi-porosity reservoir (Dejam, 2018). This adaptability and flexibility ensure a more sustainable and prolonged production life for the reservoir (Guan et al., 2018).

To fully exploit the enhanced recovery potential of multi-porosity systems, accurate reservoir characterization and modeling are crucial (Khanal et al., 2021). Understanding each pore system's distribution, connectivity, and properties is essential for developing effective production strategies (Masindi, Trivedi, and Opuwari, 2022). This involves integrating various data sources, such as well logs, core analysis, and dynamic reservoir monitoring, to quantify the behavior and potential of each pore system (Rashid et al., 2022). Advanced reservoir simulation techniques are then employed to evaluate the effectiveness of different recovery methods and optimize the hydrocarbon extraction process (Thanh et al., 2019).

3.4 The Effect of Multi-Porosity on the Fluid Behavior in the Carbonate Reservoir

Multiple interconnected pore systems within a multi-porosity reservoir profoundly impact fluid behavior (Alobaidy and Risal, 2022; Kamali, Vahedi, and Mohammadi, 2020). These diverse pore systems, such as fractures, vugs, and intergranular porosity, exhibit variations in fluid saturation and distribution (Khoshdel et al., 2022; Yarmohammadi, Kadkhodaie, and Hosseinzadeh, 2020). This fluid saturation heterogeneity influences the overall fluid behavior in the reservoir, including flow rates, pressure differentials, and the displacement of hydrocarbons during production (Yarmohammadi, Kadkhodaie, and Hosseinzadeh, 2020). The variation in fluid saturation across different pore systems can result in complex fluid flow patterns (Li et al., 2020; Wennberg et al., 2016). Pore systems with higher fluid saturation may experience faster flow rates, contributing to higher overall reservoir productivity (Seyyedi et al., 2020; Yang et al., 2018). Conversely, pore systems with lower fluid saturation may impede fluid flow and create flow barriers within the reservoir (Wennberg et al., 2016). Understanding fluid saturation distribution and its impact on fluid behavior is crucial for accurate reservoir modeling and effective production strategies (Wang and Sun, 2019). One important factor affecting fluid behavior in multi-porosity systems is capillary pressure (Setiati and Jasmine, 2023; Li et al., 2020; Dejam, 2018). Capillary pressure arises from the interplay between fluids and the pore structure (Dejam, 2018). Different pore systems can exhibit varying capillary pressures due to differences in pore size, connectivity, and surface characteristics (Seyyedi et al., 2020). These variations influence the ability of fluids to imbibe into the rock matrix or be displaced by injected fluids during production operations (Li et al., 2020). By considering these capillary pressure variations, reservoir engineers can better predict fluid behavior and optimize production strategies to maximize hydrocarbon recovery (Yarmohammadi, Kadkhodaie, and Hosseinzadeh, 2020; Dejam, 2018).

Accurate characterization of capillary pressure variations across different pore systems is crucial for understanding fluid behavior in multi-porosity reservoirs (Yang et al., 2018). This requires integrating data from various sources, such as core analysis, well logs, and laboratory experiments (Wennberg et al., 2016). Advanced reservoir simulation models incorporating capillary pressure effects can simulate fluid flow behavior and optimize production strategies (Setiati and Jasmine, 2023; Dejam, 2018). By capturing the complexities of capillary pressure variations within the multi-porosity system, operators can make informed decisions and maximize hydrocarbon recovery from the reservoir (Alobaidy and Risal, 2022; Yarmohammadi, Kadkhodaie, and Hosseinzadeh, 2020).

3.5 Discussion

Carbonate reservoirs often exhibit a complex network of interconnected pore systems, encompassing intergranular porosity, fracture porosity, vugs, and other secondary porosities (Gomes et al., 2018). Each pore system possesses distinct characteristics, such as pore size, connectivity, and permeability, significantly influencing fluid flow dynamics within the reservoir (Janjuhah et al., 2021).

The multi-pore network in carbonate reservoirs provides diverse flow pathways and connectivity for fluids (Sharifi, 2022). Fracture porosity, for instance, acts as high-permeability conduits that facilitate rapid fluid flow, thereby enhancing the overall productivity of the reservoir (Yang, Xue, and Chen, 2018). On the other hand, intergranular porosity contributes to matrix storage and serves as a medium for hydrocarbon retention (Geris et al., 2015). The interconnected nature of these diverse pore systems allows for fluid migration and redistribution, effectively shaping flow patterns and influencing the production performance of the reservoir (Sadeghnejad, Enzmann, and Kersten, 2021).

The presence of a multi-pore network introduces heterogeneity into the reservoir, resulting in variations in pore size, permeability, and connectivity (Heidsiek et al., 2020; Yarmohammadi, Kadkhodaie, and Hosseinzadeh, 2020; Pak et al., 2016; Jiang et al., 2013). This heterogeneity leads to the non-uniform distribution of fluids and potential compartmentalization (Sun et al., 2020; Bohnsack et al., 2020; Dale et al., 2018). The uneven sweep efficiency, which reflects the efficiency of hydrocarbon displacement by injected fluids during production, can cause bypassed zones and reduce overall hydrocarbon recovery (Bohnsack et al., 2020; Dale et al., 2018). Proper characterization and a comprehensive understanding of the multi-pore network are essential for optimizing sweep efficiency and enhancing overall reservoir performance (Sadeghnejad and Gostick, 2020; Clarkson et al., 2016).

The multi-pore network significantly impacts permeability and productivity in carbonate reservoirs (Liu, Phan, and Abousleiman, 2022; Zambrano et al., 2021; Wang and Sun, 2018). The interconnected fracture porosity establishes high-permeability pathways that promote efficient fluid flow and elevate reservoir productivity (Sadeghnejad, Enzmann, and Kersten, 2021). The interplay between fracture porosity and matrix porosity influences the overall permeability, thereby governing fluid flow behavior within the reservoir (Bohnsack et al., 2020). To accurately model the reservoir, optimize well placement, and plan production strategies, it is crucial to comprehend the permeability distribution within the multi-pore network (Liu, Phan, and Abousleiman, 2022; Zambrano et al., 2021).

The presence of a multi-pore network in carbonate reservoirs unlocks opportunities for deploying enhanced recovery techniques (Chen, 2022). Techniques such as hydraulic fracturing, acid stimulation, and other reservoir stimulation methods can be employed to target specific pore systems and increase permeability, thereby enhancing hydrocarbon recovery (Panfili et al., 2015). By selectively stimulating and accessing different pore systems, operators can optimize recovery and elevate reservoir production performance (Radwan, 2022). Effective reservoir characterization and modeling of the multi-pore network are pivotal for understanding the reservoir's production behavior (Sun et al., 2020; Zhang, Chen, and Zhao, 2019). This entails integrating diverse data sources, such as well logs, core analysis, and dynamic monitoring, to capture various pore systems' spatial distribution and properties (Asgarinezhad et al., 2016). Advanced reservoir simulation models, capable of accounting for the complexities of the multi-pore network, are utilized to predict fluid flow behavior, optimize production strategies, and maximize hydrocarbon recovery (Sadeghnejad and Gostick, 2020; Al-Baldawi, 2015).

Moreover, the multi-pore network in carbonate reservoirs significantly impacts reservoir production performance (Epelle and Gerogiorgis, 2020; Sadeghnejad and Gostick, 2020). It governs flow pathways, connectivity, sweep efficiency, permeability, and productivity (Kamali, Vahedi, and Mohammadi, 2020; Jiang et al., 2013). Attaining a comprehensive understanding and effectively characterizing the multi-pore network are vital for precise reservoir modeling, production optimization, and the successful application of enhanced recovery techniques (Liu et al., 2017; Clarkson et al., 2016; Anovitz and Cole, 2015). By considering the complexities associated with the multi-pore network, operators can enhance reservoir performance and maximize hydrocarbon recovery from carbonate reservoirs (Abbaszadeh and Shariatipour, 2018; Wennberg et al., 2016).

4. Conclusions

By studying the most important characteristics of multi-porosity in hydrocarbon reservoirs in the Middle East, it was determined that carbonate reservoirs possess a complex network of interconnected pore systems, including intergranular porosity, fracture porosity, and other secondary porosities. Each pore system has distinct characteristics that impact fluid flow dynamics. Moreover, the multi-pore network offers diverse flow pathways and connectivity, with fracture porosity facilitating rapid fluid flow and intergranular porosity contributing to hydrocarbon retention. On the other hand, heterogeneity in pore size, permeability, and connectivity introduces challenges, such as non-uniform fluid distribution and bypassed zones, affecting hydrocarbon recovery. Understanding the multi-pore network is crucial for optimizing sweep efficiency. It also influences permeability and productivity, with fracture porosity enhancing flow efficiency. In addition, enhanced recovery techniques can target specific pore systems to increase permeability. Reservoir characterization, integration of diverse data sources, and advanced simulation models are essential for predicting fluid behavior and optimizing production strategies.

In general, the multi-pore network significantly impacts reservoir production performance, necessitating a comprehensive understanding of accurate modeling, production optimization, and enhanced recovery techniques to maximize hydrocarbon recovery.

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