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Comparison of diagenesis and reservoir quality of microporous lime mudstones between anticline crest and flanks: middle east carbonate reservoir.

Bachelor Thesis

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Comparison of diagenesis and reservoir quality of microporous lime mudstones between anticline crest and flanks: middle east carbonate reservoir.

Anotace:

Tato přehledová práce zkoumá rozdíly v kvalitě a diagenezi nádrže mezi hřebenem (ropná zóna) a boky (vodní zóna) v karbonátových nádržích na Blízkém východě po prostudování mnoha publikovaných článků a zpráv. Stanovení kvality nádrže v různých nádržích je zásadní pro stanovení různých vlastností, jako je akumulace uhlovodíků, procento porozity a propustnost. V jedné horninové matrici lze nalézt několik typů pórovitosti. Pórovitost je schopnost horniny ukládat a přenášet tekutinu (vodu, ropu a plyn). Tato studie se zaměří na mikroporéznost a makroporéznost v hřebenu (olejová zóna) i na bocích (vodní zóna) a na to, jak proces cementace probíhá a ovlivňuje mikroporéznost a mikroporéznost v různých zónách za různých okolností, k cementaci dochází, když se rozpuštěné minerály vysrážejí uvnitř póru Tyto minerály časem ztvrdnou a vytvoří vazbu, která slepí zrna dohromady a sníží celkovou poréznost útvaru. Proces cementace působí odlišně v olejové a vodní zóně. Ve vodní zóně je proces cementace aktivnější a rychlejší díky vysokému obsahu vody, která je vysoce reaktivní s minerály. Proto může efektivněji vytvářet cement; na druhé straně v olejové zóně je cementační proces méně aktivní a pomalejší, protože většinu tekutiny v této zóně tvoří olej nebo uhlovodíky s menším množstvím vody; proces proto obvykle probíhá během přechodové zóny s využitím fyzikálních a chemických změn, ke kterým v této zóně dochází.

Klíčová slova: pórovitost, cementace, kvalita nádrže, diageneze.

Počet stran: 35

Comparison of diagenesis and reservoir quality of microporous lime mudstones between anticline crest and flanks: middle east carbonate reservoir.

Annotation

This review thesis investigates the reservoir quality and diagenesis features difference between the Crest (oil zone) and the flanks (water zone) in the Middle East carbonate reservoirs after going through multiple published articles and reports. The determination of reservoir quality in different reservoirs is vital for the determination of various properties such as accumulation of hydrocarbons, porosity percentage and permeability. Multiple types of porosities can be found in one rock matrix porosity is the ability of the rock to store and transmit the fluid (water, oil, and gas). This study will focus on microporosity and macroporosity in both crest (oil zone) and flanks (water zone), and how the process of cementation occurs and affects microporosity and microporosity in different zones under different circumstances, cementation occurs when dissolved minerals precipitate inside the pore spaces, with time these minerals will harden creating a bond that glues the grains altogether reducing the overall porosity of the formation. The cementation process acts differently in the oil and water zones. In the water zone, the cementation process is more active and quicker because of the high presence of water, which is highly reactive with minerals. Therefore, it can create cement more efficiently; on the other hand, in the oil zone cementation process is less active and slower because most of the fluid in this zone is oil or hydrocarbons with less amount of water; therefore, the process usually takes place during the transition zone taking in advantage the physical and chemical changes that occur in this zone.

Keywords: porosity, cementation, reservoir quality, diagenesis.

Number of pages: 35

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, July 27, 2023

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Abdulazeez Jabbar Ali Aljumaili

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Without the assistance and inspiration of these extraordinary people, my effort would not have been possible. Any remaining mistakes are entirely my own responsibility.

Thank you all for being an essential part of this academic journey, and I hope to meet you all again in the upcoming years.

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1. Introduction

Microporosity in carbonate rocks is an important research topic because they are the targeted tight oil reservoirs. A controversial article by Ehrenberg and Walderhaug (2015) concludes that macropores are cemented more readily than micropores in limestones. The micropores occur between the abundant tiny (mostly < 2 microns) micrite ($CaCO_3$) particles, whereas the macropores are commonly chambers in micritized bioclasts (shell fragments) and Moldic pores/vugs.

In contrast to their conclusion, many petrographic observations in several other studies show exactly the opposite to what they conclude. Also an important case should be mentioned which is the process of cementation which refers to the process of connecting grains of sediment or gluing them together by depositing minerals in the pore spaces between them (Like calcite or silica etc.), Small pores are cemented faster by the growth of calcite around existing numerous tiny nuclei and not by nucleation and growth, as it should be the case for the large crystals which fill the large pores. (Ehrenberg and Walderhaug, 2015).

Carbonate cement is the most common authigenic substance in sandstone reservoirs. Calcite, dolomite, ferroan calcite, ferroan dolomite, which is a type of carbonate minerals, but it includes the presence of iron in the chemical formula that's why it has the name ferroan, and siderite are the primary elements. They were created at various geological eras, in a diversity of compositions, and are extensively scattered (Anjos et al., 2010; Carlos et al., 2001; Taylor et al., 2000; Wang et al., 2008).

In the initially homogeneous and huge reservoirs, the carbonate-cemented layers will obstruct fluid flow, resulting in very complicated heterogeneity (Boles and Ramseyer, 2002; Dutton et al., 2002, 2008). However, carbonate cementation regulates the quality of the sandstone reservoir since it decreases the reservoir's porosity and permeability and has an impact on the flow of fluid during production (Marcos and De Ros, 1995; Dutton, 2008).

1.1 Aim of the study

In order to highlight the unique characteristics of each zone concerning reservoir quality and diagenesis in the context of cementation, this thorough review thesis compares the anticline flanks (the water zone) and the crest (the oil zone) in great detail. This is to shed an understanding of the intricate interplay between geological processes, fluid dynamics, and rock cementation, all of which significantly impact the overall reservoir behavior, by investigating these two key zones. This study aims to provide significant insights through a thorough analysis that can improve our comprehension of reservoir characterization and optimization tactics, resulting in more efficient and sustainable oil recovery practices.

1.2 Study area

The study took place in the Middle East, with a specific focus on Abu Dhabi, United Arab Emirates. Abu Dhabi is a significant region known for its massive hydrocarbon reserves, particularly in carbonate reservoirs, and according to Schlumberger (2019), around 70% of the middle east oil reserves can be found in oil reservoirs; due to that and to the region's special geological features make it the perfect place to study the different types of cementation and microporosity in tight oil reserves.

This study aims to shed light on the complicated relationship between geological processes, fluid dynamics, and rock cementation, which have a significant impact on the overall reservoir behavior and oil production in the oil-producing region, by comparing the anticline flanks (water zone) and the crest (oil zone).

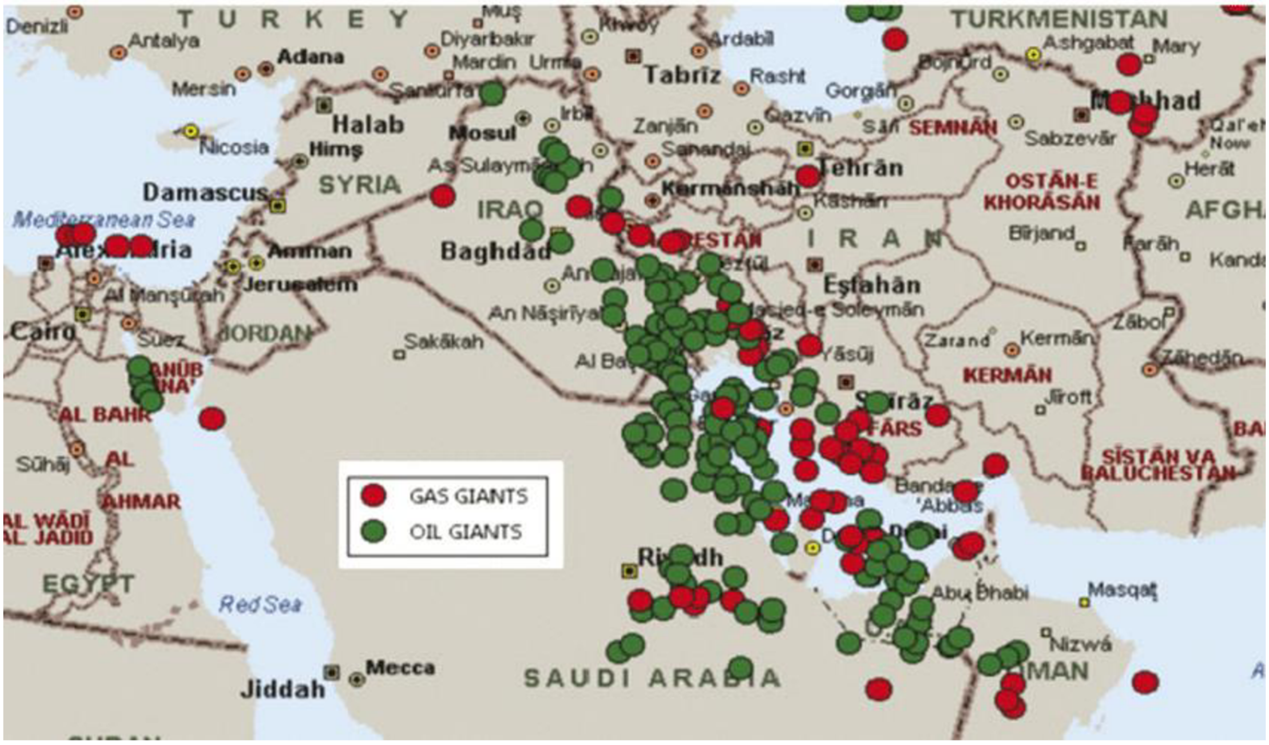

Figure 1: Map of the giant oil and gas fields in the Middle East (Horn, 2004).

It is important to consider the importance of the study of the carbonate reservoirs, especially in the middle east area, because it is considered the most significant kind of hydrocarbon reserves. According to many sources (Akbar et al. 2000; Aljuboori et al. 2019; Bourbiaux 2010; Firoozabadi 2000; Schlumberger 2019), this type of reservoir is present throughout the planet. However, Akbar et al. (2000) indicated that around 60% of the world's oil reserves are contained in carbonate reservoirs. And as I mentioned earlier, according to Schlumberger (2019) and reported by Aljuboori et al. (2019), 70% of the Middle East's conventional oil reserves are found in carbonate reservoirs.

It is especially true if one considers this type of reservoir's most significant property, which is a dual or even multiple porosity (permeability) feature. This form of reservoir might be viewed as being more heterogeneous than sandstone reservoirs. Basic diagenetic processes and fractures cause secondary porous media to form. (Lucia 2007; Ahr 2008; Moore 2001; Van Golf-Racht 1996).

It is challenging to effectively regulate the output of carbonate reserves because of this variation. The operating business should have a good set of geology and hydrodynamic data throughout the reservoir to efficiently drain a hydrocarbon resource. The dual nature of carbonate reservoirs requires that the necessary data for both media be gathered. The data that have been collected traditionally and conventionally are primarily characterizing the matrix (initial reservoir's medium). According to Lucia 2007, Nelson 2001, Van Golf-Racht 1982, Heinemann and Mittermeir (2014), these data are often gathered during well logging and well testing of drilled wells. Geostatistical techniques are available to close the data gap between logged wells in a reservoir (Lucia, 2007).

According to Kim and Schechter (2009), common techniques for estimating the parameters of second media (fracture system) include outcrop properties, electrical borehole scans, fractal discrete fracture networks (FDFN), and analogy with other reservoirs. Most carbonate reservoirs are non-producing formations, or at the very least, their production would not be profitable. Therefore, it is essential to accurately evaluate the parameters of this second porous medium. The longest-lasting dynamic behavior of a reservoir or/and a well can be used to gather the most reliable data.

2. Literature review

Porosity is the percentage between the grains in the rock matrix; in other words, it is the pores within the rock that allows hydrocarbons or any type of fluid to flow through; different types of porosities can occur in various types of rocks, Macroporosity (Weathering and erosion or Tectonic activity) of the rock refers to the presence of large pores > 50nm. (Boggs, S. Jr., 2006). Microporosity (changes during diagenesis or by mechanical compaction) is the smallest pore media in any reservoir rock < 2nm. (Nelson, R. A., 2009).

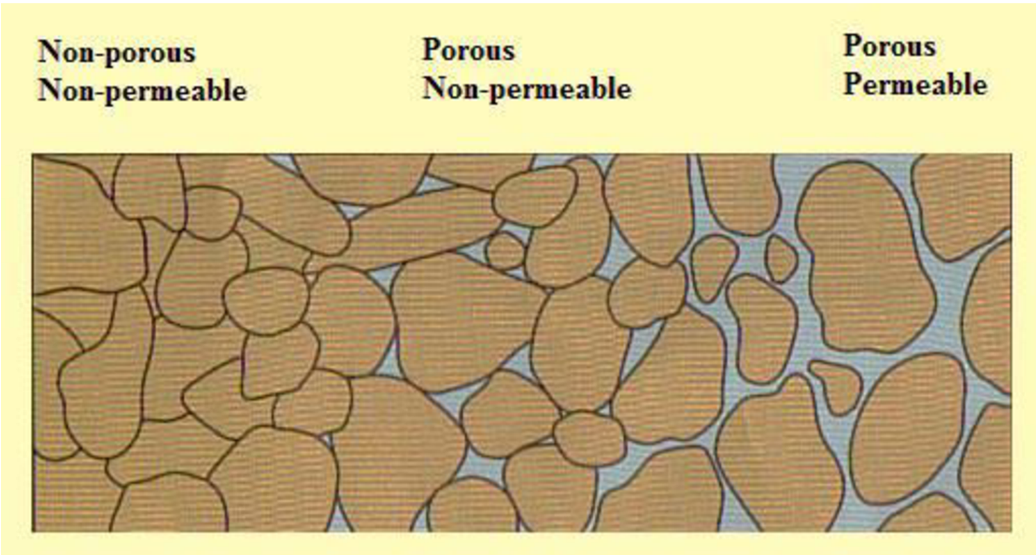

Figure 2: This figure demonstrates the differences in porosity and permeability according to the connection amount between the grains. (Raymond Joseferd, 2015)

2.1 Cementation process

A key geological process involved in the formation and modification of sedimentary rocks is cementation. Sediments are subject to a variety of environmental and geological conditions as they accumulate and undergo burial over time. Cementation appears as a important agent during this process, binding loose grains together and transforming them into solid sedimentary rock. The cementing material fills the pores between sediment particles, giving the rock strength and cohesion. It is frequently composed of minerals like calcite, silica, iron oxides, or clay minerals.

Cementation has significant implications for the quality of their overall reservoirs as well as their physical properties, such as porosity, permeability, and strength. The porosity and permeability of the rock are affected by the nature and timing of cementation, determining its capacity to store and transmit fluids, including water, oil, and natural gas. Cementation can also protect and preserve important geological features, like fossils and sedimentary structures, which can give valuable insights into the history and evolution of the Earth.

The cementation process refers to the process of the precipitation of dissolved minerals inside the pore spaces creating a bond between them that will affect the percentage of porosity and permeability, minerals such as calcite, dolomite, siderite etc., are formed under certain conditions of temperature, pressure, and physical or chemical compaction. (Tucker, 2023).

The exact geological location and the conditions in which the cementation takes place are some of the factors that might affect the timing of calcite cementation in sedimentary rocks. The process of cementation occurs during the diagenesis stage, which is the process of physical and chemical changes that applies to the sediments transforming them into solid rock. The availability of calcium carbonate, the presence of fluids carrying dissolved calcium, as well as temperature and pressure all affect the timing of calcite cementation. (Blatt, et al., 1980).

Sometimes, right after the deposition of the first layer of sediment and during the first compaction, calcite cementation can take place early in the diagenetic process. This early cementation can strengthen the rock overall and help bind the sediment grains together.

(Boggs Jr., S. 2005 - 408-410). Alternately, as a result of changes in pore fluids, calcite cementation may happen later in the diagenesis process, during burial. Deeper burial in the Earth's crust exposes sedimentary rocks to higher temperatures and pressures. These changes may set off chemical processes that cause calcite to precipitate from pore fluids, cementing the rock. (Blatt, H., Middleton, G., & Murray, R., 1980).

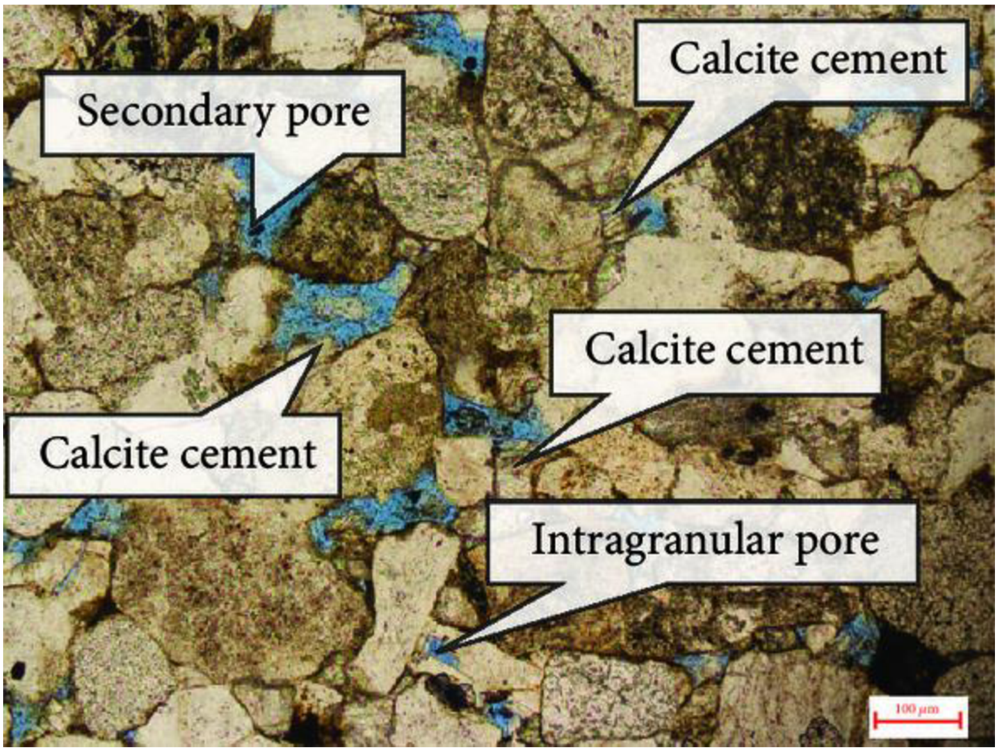

Figure 3: microscope thin section taken from (Wang Furong et al., 2017)

The cementation figure demonstrates the full view of pores and intergranular secondary pores developed from a blue-epoxy-filled thin sections of conventional core samples. The remnant of calcite and feldspar can be found after dissolution.

2.2 Timing of the cementation process

According to a study that was done by (Neilson et al., 1997) in the middle east directly in Abu Dhabi and the Amu Darya Basin mentioned that the reservoir quality is better in grainstones and packstones compared to wackestones and lime mudstones in the study area Kharaib Formation, because of the presences of macroporosity (intergranular, vuggy, moldic), but in the finer unites the porosity that was noticed and dominated in this section was microporosity. In the same study, it was also noticed that within the grainstones and packstones, macroporosity is variably filled by calcite cement. Porosity and permeability variations in grainstones and packstones at a reservoir scale are therefore controlled by the variation in the amount of calcite cement.

This in turn, depends on the timing of the precipitation of this cement relative to petroleum emplacement, where petroleum emplacement has occurred relatively early, at migration foci, prior to significant burial cementation by equant sparry calcite, and reservoir quality is preserved. Where it has occurred after effective burial cementation, reservoir quality has been destroyed.

The timing of calcite cementation can be crucial for several reasons:

- **Diagenesis**: Calcite cementation is a diagenetic process, meaning it takes place after the deposition and burial of sediment but before lithification. The timing of cementation can affect the rock's porosity and permeability as well as its overall diagenetic history. Late cementation may preserve more porosity, while early cementation may reduce pore space and restrict fluid flow. (Pettijohn, F. J., Potter, P. E., & Siever, R., 2012).

- **Fluid flow**: When fluid passes through the sediment or rock, calcite cementation may result. The geographical distribution and concentration of cement depend on the time of cementation in relation to fluid flow events. Late cementation may be limited to fracture or pore surfaces, while early cementation may take place during fluid flow and lead to more pervasive cementation. (Goldstein, R. H., & Reynolds, T. J., 1994).

- **Reservoir quality**: The timing of calcite cementation is crucial for reservoir quality in the context of hydrocarbon reservoirs. The porosity and permeability of the reservoir can be improved or harmed by cementation. Late cementation could block pores and reduce permeability, while early cementation may lower porosity and restrict fluid flow. (Morrow, N. R., 1990).

2.3 Cementation in the crest and the flanks

Comparing samples from anticline crest (i.e. oil zone) versus flanks (i.e. water zone), Abu Dhabi, United Arab Emirates. Higher porosity and permeability and larger pore-throat radii in the crest than in the flank mudstones are attributed to the retardation of calcite cementation in the crest due to oil emplacement (Mansurbeg et al., 2022). Calcite cement has precipitated as syntaxial micro-overgrowths around micrite particles and as equant microspar in Moldic pores and small vugs. Deviation of a large number of samples from this crest versus flanks porosity and permeability trend reflects the impact of other parameters, including: (i) subtle grain-size variations (ii) proportion of intact (i.e. with intragranular pores) versus broken coccolith tests, and (iii) degree of calcite cementation. Calcite cement was sourced by stylolitization of the limestones, which is more frequent and extensive in the flanks than in the crest. The reservoir quality and diagenesis are also relatively different in the crest than in the flanks. (Mansurbeg. et, al, 2022).

2.4 Oil emplacement

According to numerous carbonates (e.g. Scholle, 1977; Scholle and Halley, 1985; Feazel and Schatzinger, 1985), petroleum emplacement has a significant impact on reservoir quality. Where petroleum emplacement occurs very early in the history of the burial of porous and permeable limestone, it seems to be especially significant. Depending on how far burial diagenesis has advanced, if it occurs relatively late (a consequence of things like burial depth, the extent of pressure solution, over-pressurizing, etc.), its impact will be determined.

Several crucial pieces of evidence are needed to prove that petroleum emplacement has had an impact:

(A) the presence of porosity-depth trends that, in the first place, are steeper than those caused by compaction, in the second place, are correlated with structural elevation, and in the third place, are correlated with the extent to which macropores have been filled with cement.

(B) the presence of petroleum inclusions in the reservoir's more porous regions and their absence in less porous areas.

According to Joyce E. Neilson et al. (1997), a key factor in accurately predicting the reservoir quality of limestones is the relative timing of petroleum emplacement and burial cementation. Two scenarios are excellent from an economic standpoint:

1. Significant burying cementation does not take place before petroleum emplacement. The geographical distribution of macroporosity will be preserved and depend on the lithofacies and structural layout.

2. Although burial cementation does not occur due to other factors (such as over-pressuring), petroleum emplacement is geologically late.

There could not be a straightforward correlation between lithofacies and structure on the one hand, and porosity distribution on the other, where petroleum emplacement occurs after cementation.

2.5 Reservoir quality

The physical and fluid properties of an underground rock formation that are ideal for oil and gas production are referred to as a reservoir's quality. It includes several characteristics that impact the flow of fluids inside the reservoir and the possibility of economically recovering hydrocarbons. (Dandekar, 2013)

- **Porosity**: The percentage of open spaces or voids in a rock formation is known as porosity. Since more porosity allows more area for hydrocarbons to gather, higher porosity typically signals a higher reservoir quality. The rock type, faults or fractures, and diagenetic processes (changes in the rock caused by burial and compaction) are all factors that affect porosity. (Gluyas, J. G., & Swarbrick, R. E, 2016).

- **Permeability**: The capacity of a rock to let the passage of liquids is referred to as permeability. Better reservoir quality is desired to allow for the movement of hydrocarbons within the rock, which is made possible by higher permeability. Permeability can be affected by elements, including pore space connectivity, the occurrence of natural cracks, and the kind of rock matrix. (Blunt, M. J., 2017).

- **Saturation**: The percentage of pore space that is filled by fluids, typically hydrocarbons, is referred to as saturation. A higher hydrocarbon saturation level suggests a higher reservoir quality since it means that more of the desirable fluids are occupying the rock's volume. Saturation is influenced by elements such as the fluids' composition, characteristics, and interactions with the rocks. (Fanchi, J. R., 2001).

- **Fluid Properties**: The viscosity and density of the fluids in the reservoir can impact the reservoir's quality. For instance, a fluid with a high viscosity may block the flow, while a fluid with a low density can ascend to the top of a reservoir, leaving fewer desirable hydrocarbons behind. (McCain Jr, W. D., 1991).

- **Rock Texture and Composition**: The reservoir's quality can be strongly affected by the rock's texture and composition. The permeability and porosity of rocks with fine-grained textures and significant clay contents may be lower, lowering their reservoir quality. Rocks with finer-grained textures and greater concentrations of pure, well-sorted sandstone or limestone, on the other hand, typically have good reservoir quality. (Boggs Jr, S., 2009).

- **Diagenesis**: The term "diagenesis" describes the physical and chemical alterations sedimentary rocks undergo as they are buried and compacted. The quality of the reservoir can be greatly impacted by these activities. For instance, cementation of pore spaces can lower porosity and permeability, while dissolution can increase these properties. (Blatt, H., Middleton, G., & Murray, R., 1980).

2.6 Reservoir quality in the crest and the flanks

Reservoir quality can be different in the crest than in the flanks due to several factors such as geological formation, depositional environment, and tectonic history. Porosity, permeability, saturation, and heterogeneity can be considered the main differences between the crest and the flanks. Porosity tends to increase from the flanks to the crest, as it will be less affected by cementation or any other digenetic process, and the compaction forces will be less also in the crest. Permeability acts similarly to porosity in the case of differences, as it can be decreased in the flanks due to the high levels of compaction and cementation, negatively affecting the ease of the fluid flow. The saturation level in the crest is higher than in the flanks due to the different structural trapping and fluid migration (Morad et al., 2018)

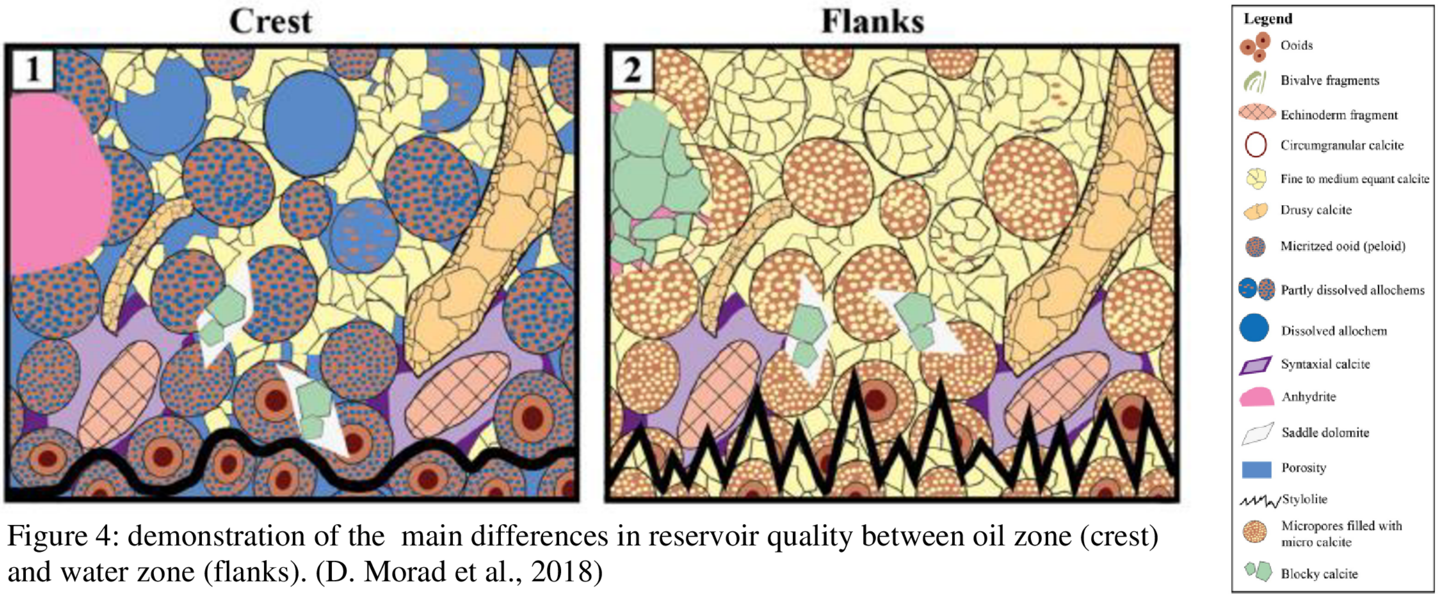

Figure 4: demonstration of the main differences in reservoir quality between oil zone (crest) and water zone (flanks). (D. Morad et al., 2018)

The previous figure (fig 3) demonstrates the oil zine and water zone; in the water zone, low porosity and permeability can be noticed due to the high presence of several types of calcite cement; also, the process of Hydrocarbon accumulation and production is less efficient in this zone due to the high presence of water which leads to a low reservoir quality. In the oil zone, the exact opposite properties can be noticed; the high presence of oil in this zone leads to less amount of calcite cement in the area, which in its turn leads to good porosity and permeability and the process of Hydrocarbons accumulation is more efficient leading to a good reservoir quality.

2.7 The effect of diagenesis on Reservoir quality

Diagenesis describes the internal physical, chemical, and biological processes that take place both during and after the production of sedimentary rocks. It includes a broad range of operations, such as mineralogically altered compaction, cementation, dissolution, and recrystallization. The uppermost few kilometres of the Earth's crust are where diagenesis primarily takes place.

Diagenesis can have a substantial impact on reservoir quality. The characteristics of a rock that affect its capacity to store and convey fluids, such as oil or natural gas, are referred to as reservoir quality. Diagenesis may enhance or negatively impact reservoir quality depending on the particular processes involved.

Reservoir quality is impacted by diagenesis through a number of ways. As sediments are buried, compaction occurs, lowering pore space and rock density, lowering reservoir porosity and reducing fluid storage capacity. When fluids rich in minerals precipitate and bind grains together, cementation occurs. Excessive cementation lowers porosity and permeability while increasing mechanical strength, which lowers reservoir quality. Mineral dissolution by diagenetic fluids can boost porosity, which enhances reservoir quality. For instance, secondary porosity is produced when carbonate minerals dissolve, which improves fluid storage. Uneven dissolution, however, can result in cavernous or vuggy porosity, which may result in reservoir compartmentalization. As mineral grains change during diagenesis, recrystallization occurs, resulting in bigger crystals' development. This process negatively impacts the reservoir quality, which decreases overall porosity and permeability.

Organic-rich rocks, such as source rocks, are also impacted by diagenesis. Organic matter matures through processes as burial depth and temperature rise. These include the production of hydrocarbons and thermal cracking. The quantity and quality of hydrocarbons produced are affected by the degree to which diagenesis occurs. (Mazzullo, S. J., & Graham, C. M., 1998).

2.8 Stylolites

Stylolites are common geo-patterns found in rocks in the upper crust, including deformation zones, folds, faults, shear zones, and geological reservoirs in sedimentary rocks. These uneven surfaces have a significant impact on how rocks dissolve near strained contacts, how dissolved material is transported, and how precipitation occurs in nearby pores. As a result, they actively contribute to developing rock microstructures and rheological characteristics in the crust of the Earth. They are seen singly or in networks, close to joints and fractures, and in a variety of geological contexts (R. Toussaint et al., 2018)

A localized dissolution process creates them, and the interface of these rocks includes minerals in concentrations that are different from those of the host rock around it. Initially attributed to organic species (Klöden, 1828), they were later identified as connected to diagenetic processes in various sedimentary rocks.

In sedimentary formations, the presence of stylolites with varying levels of clays along the interface can influence fluid movement. For instance, Dunnington (1954) stated that fluids must be released from the rock if stylolites are related to compaction. He added that because of their ability to compact, stylolites can serve as seals to prevent the upward migration of hydrocarbons. The strong ties between stylolites and the minerals left behind by a percolating fluid were noted by Park and Schot in 1968. Because of the clay parting that borders them and the decreased permeability that surrounds them, stylolites have been theorized to block flow in the host rock (e.g., Heald, 1959; Burgess and Peter, 1985; Koepnick, 1987).

A key aspect of petroleum exploration is thought to be how stylolitization affects permeability and regional fluid flow. The two main degrading factors on reservoir quality have been identified as stylolites and reprecipitation resulting from stylolization. In many reservoir rocks, the stylolites have been explored as fluid flow barriers because they reduce the porosity and permeability of the parent rocks (Nelson, 1981; Burgess and Peter, 1985; Koepnick, 1987; Finkel and Wilkinson, 1990; Dutton and Willis, 1998; Alsharhan and Sadd, 2000).

3 Samples and methods

This chapter in this review thesis will be focusing on providing an explanation of the approach utilized in this research study to examine the impact of cementation on reservoir quality in both crest (oil zone) and the flanks (water zone), all the methods that are going to be approached in this chapter were obtained from a past published papers in order to achieve the aim and reach the result for this study.

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, cementation process, stylolites, diagenesis, and reservoir quality. 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 the main differences in the crest (oil zone) and the flanks (water zone) in carbonate reservoirs, how cementation and diagenesis effects the behavior of fluids in reservoir rocks and the production of hydrocarbon reservoirs, and how stylolites affect carbonate 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.

In a study by (D. Morad et al., 2018), 240 samples were taken from four wells. The anticline has four wells: three on its crest (wells A, B, and C) and one on its flank (well D), shown in (figure 6). All samples were vacuum impregnated with blue epoxy, followed by the preparation of thin slices. To differentiate between dolomite and calcite and determine their iron contents, petrographic investigations were carried out on the thin slices after they had been stained with alizarin red S and potassium ferricyanide (Dickson, 1966).

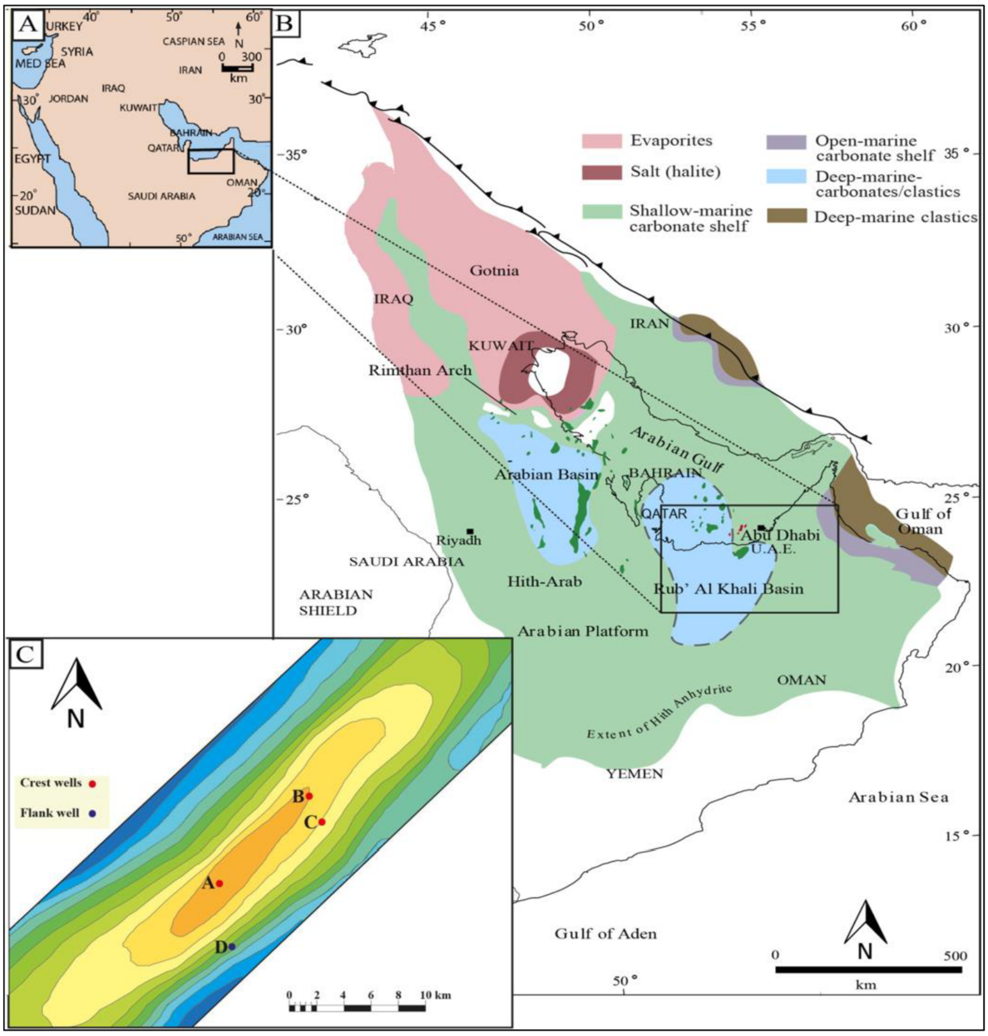

Figure 5: (A) Small-scale map of the Arabian Peninsula. (B) Location of the field based on a paleofacies of the Late Jurassic during the deposition of the Arab and Hith formations (C) Map of the studied anticline showing the location of the studied wells in the crest (A, B and C) and flank (D). (D. Morad et al., 2018)

Microsamples were collected from cleaned rock slabs using a dental drill and a computerized micro-mill mounted on binocular microscopes for oxygen, carbon, sulfur, and strontium isotope studies. Nine dolomite samples and eighty-nine calcite samples each had their carbon and oxygen isotopes measured. Calcite and dolomite samples were reacted with 100% phosphoric acid at 25 °C and 50 °C for four hours, respectively, for the purpose of oxygen and carbon isotope studies. A Delta-plus mass spectrometer from the University of Windsor (Canada) was used to examine the isotopic ratios of the evolved CO_2 gas. The fractionation factors for phosphoric acid for calcite at 25 °C and dolomite at 50 °C were used (see Al-Aasm et al., 1990). According to the V-PDB standard, the isotopic data are expressed as per mil(%). The accuracy of the results for carbon and oxygen isotopes is better than 0.05%.

Twenty-six samples' sulfur isotope ratios were examined, and the 34S values are shown in per cent relative to CDT. On a Costech Elemental Analyzer (CHNS-O ECS 4010-Italy) connected to an Isochrom Continuous Flow Stable Isotope Ratio Mass Spectrometer (GVI/Micromass-UK, 1995; University of Waterloo, Canada), solid samples were examined for sulfur. 882 core plugs with a diameter of 3.8 cm from the four investigated wells were given porosity data. The core plugs were cleaned with an oil extractor, checked for microfractures, and dried in a vacuum oven for 24 hours at 60 °C before measurements. The porosity was measured using a helium porosimeter.

In another study which was made by (Mansurbeg et al., 2022), regarding also the same case, a total of 144 samples were taken from drill cores in the four wells (C1 and C2) on the top of the anticline (oil zone) and (MF and F) on the southwest flank (water zone) (figure 7).

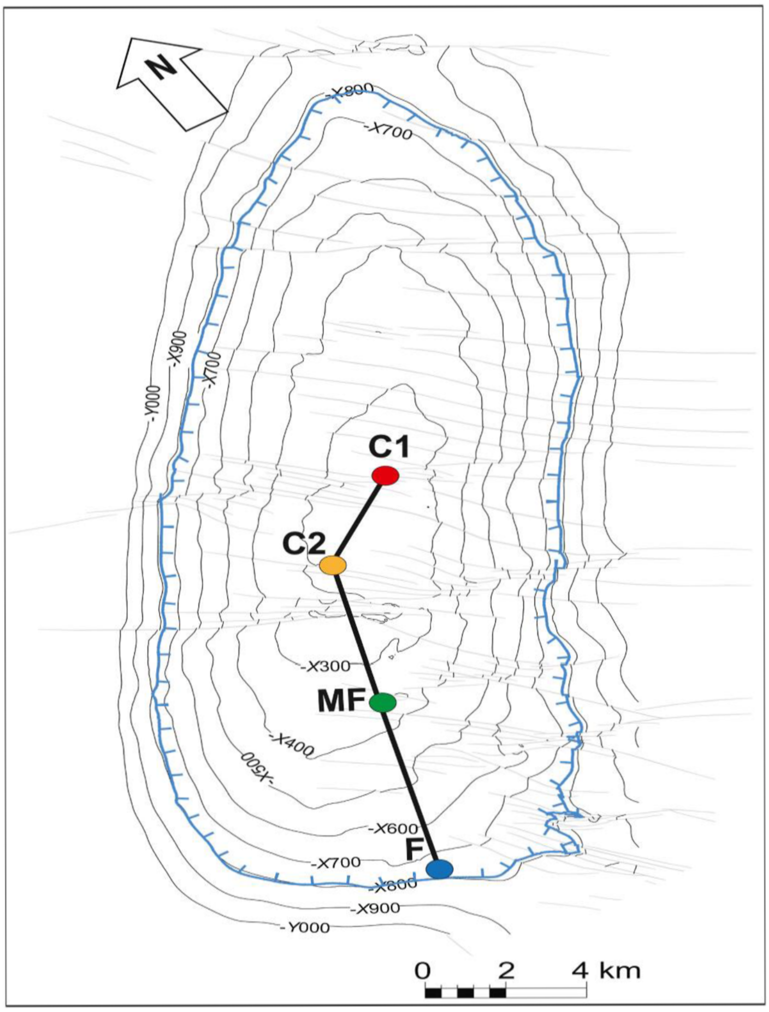

Figure 6: Contour map showing the depth of top of A0 in Field A. Blue line shows the oil-water contact (OWC) at the top of Thamama Zone A. Grey lines show the seismic picked faults. Circles in red, yellow, green, and blue show the location of the four studied wells in the crest (C1and C2) and flanks (MF, F). (M. Alsuwaidi et al., 2022).

Thin sections were prepared for all the samples after impregnation with blue colored epoxy. Also, Alizarin red-S staining was used to detect the dolomite from the calcite during petrographic analyses on half of each thin section. The cores were also put through Routine Core Analysis (RCA), which included measuring the permeability and porosity of the core plugs. Stylolites, hydrocarbon stain, and depositional facies features (texture, sedimentary structures, color, and fossils) were investigated in the four wells' cored intervals of the analyzed formation.

Using a very small dental drill to avoid macro cement and shell fragments, 189 samples were collected from the lime mudstones for carbon and oxygen stable isotope analysis. Samples were ground into powder and processed via a VG Instruments MultiPrep preparation apparatus at 90°C with 100% orthophosphoric acid. The Kiel IV Carbonate device connected to a MAT253Plus dual inlet IRMS was used to process the resulting CO_2 gas. The calibration was performed using the NBS18 and NBS19 standards, and the deviation from the Vienna Pee-Dee Belemnite (VPDB) standard was reported in mils. For both the carbon and oxygen isotope ratios, the standard reproducibility was typically less than 0.10% To identify the source and level of thermal maturation of six samples of organic matter along stylolites (three from well C and three from well F), Rock-Eval VI/Oil Show Analyzer pyrolysis was used (Behar et al., 2001).

On plug trims with a 1-inch diameter, mercury injection capillary pressure (MICP) studies were carried out at room temperature to determine the distribution of pore-throat sizes and the capillary pressure curves.

According to Frank et al. (2005), pore throats are divided into macropores (>5 μm), mesopores (0.5–5 μm), and micropores (0.5 μm). The mercury injection procedure includes applying pressure on mercury and injecting it into the plug trims evacuated pores. Starting with the well-connected macropores, mesopores, and finally micropores, the mercury enters progressively smaller pore throats as the injection pressure rises.

Each injected volume increment corresponds to an additional pore volume that is reachable through pore throats within a given size range.

In the third study which construct on the idea of calcite cementation of macropores in micropores limestones done by Ehrenberg and Walderhaug in 2015, concludes that macropores are cemented more quickly than micropores in limestones, although the two previous studies shows exactly the opposite to what they conclude, Small pores are cemented faster by the growth of calcite around existing nuclei and not by nucleation and growth, as it should be the case for the large crystals which fill the large pores.

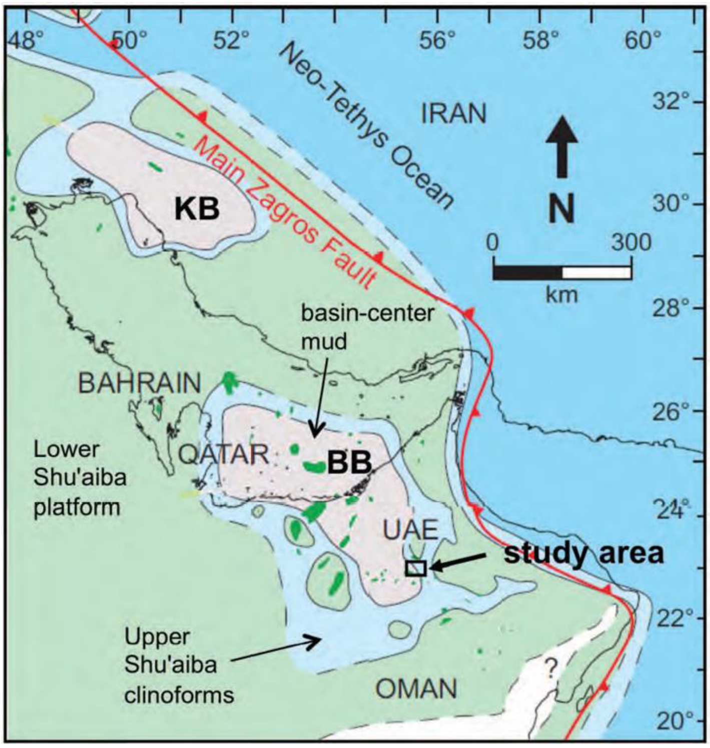

Figure 7: Late Aptian paleogeographic map of the eastern Arabian Plate where the study took place. (Ehrenberg and Walderhaug, 2015).

The database for the current study consists of 15 vertical wells, four of which have a total core length of 127.9 meters, and four horizontal wells with a core length totalling 38.4 meters. Petroleum Development Oman conducted quality control on the conventional core analyses (CCA) of helium porosity, gas permeability, grain density, and drainage mercury injection capillary pressure (MICP).

A series of 158 core samples, mostly corresponding with CCA plugs, was selected to cover the ranges of depth and lithofacies in each of the core intervals.

Thin sections were described using a set of standard categories of information, including textural classification (Dunham, 1962, as modified by Embry and Klovan, 1971, and Lucia 1995), biotic assemblages, cements, stylolites, and pore types.

As the samples were not prepared with fluorescent-dyed epoxy, the percentage of visible porosity was estimated using comparator charts, and microporosity was approximated by the difference between CCA porosity and estimated visual macroporosity.

4 Results

By reviewing various studies, it was found that the anticline's crest and flank both display similar diagenetic features, including cementation by calcite and saddle dolomite, mechanical and chemical compaction, and minor non-carbonate phase cementation (Morad et al., 2017). However, the frequency of these stages and events varies between the crest and flank wells. Interestingly, the three crest wells exhibit comparable diagenetic phases and events abundances. In terms of reservoir quality, the crest demonstrates higher porosity values in both packstones and grainstones, with approximately 15% greater core-plug porosity compared to the flank. Similarly, mudstones and wackestones in the crest exhibit around 5% higher average core-plug porosity. This disparity in reservoir quality can be attributed to the presence of stylolites, with the flank showing greater abundance and higher amplitudes of these features. Stylolitization in the flank resulted in the release of more calcite mass, ultimately contributing to the lower porosity observed in packstones and grainstones. In contrast, the crest's reservoir quality is better due to the smaller amplitudes and lower amounts of stylolites. According to Feazel and Schatzinger (1985), Oswald et al. (1995), Neilson et al. (1998), Heasley et al. (2000), and Cox et al. (2010), the delay effect of gas emplacement on diagenesis accounts for these differences in stylolite characteristics between the crest and flank of the anticline.

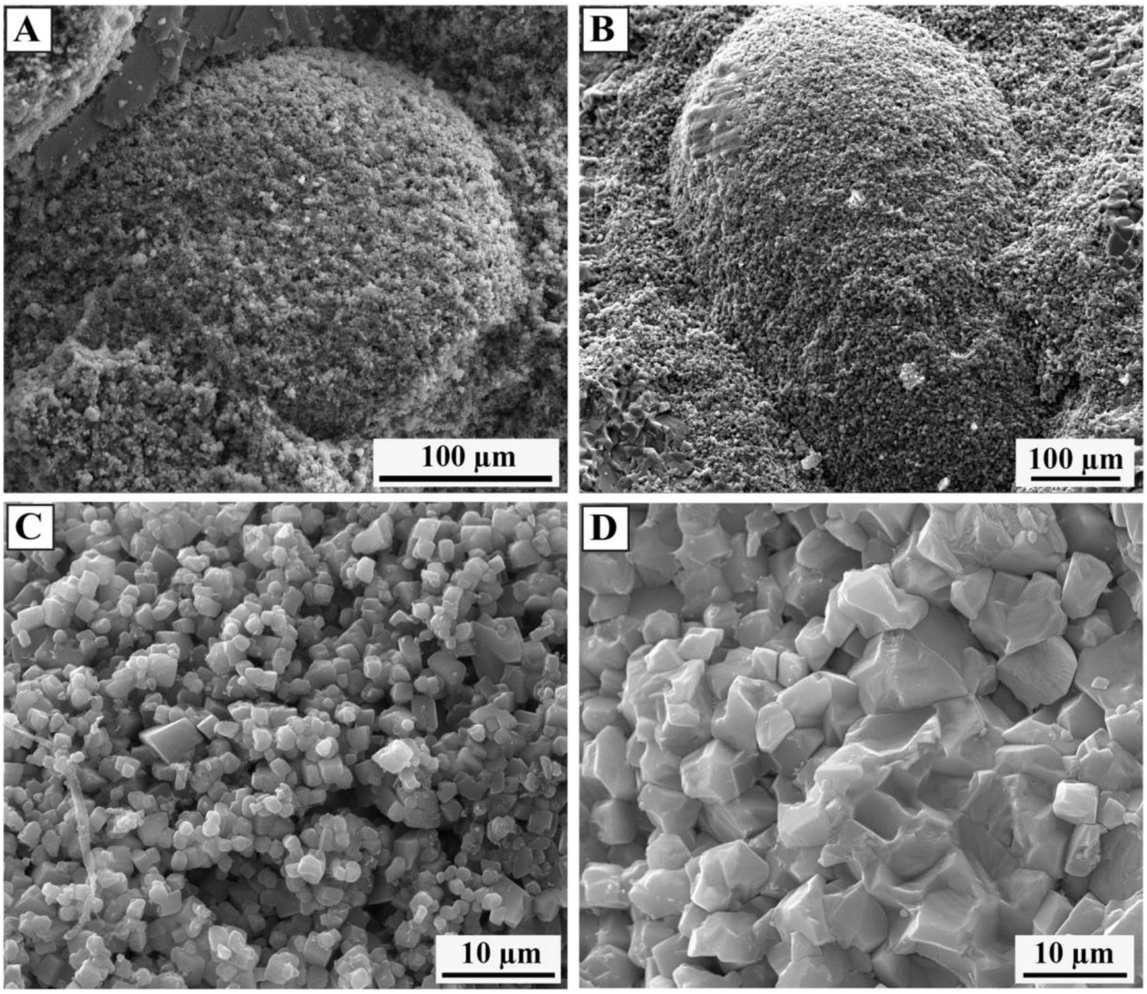

Figure 8: SEM images of peloids in the upper Arab D Member. (A) Peloid in the crest. (B) Peloid in the flank. (C) Higher magnification image of pleoid with microporosity in the crest (D) Higher magnification image of nearly completely cemented micropores in a peloid from the flank. (D. Morad et al., 2018)

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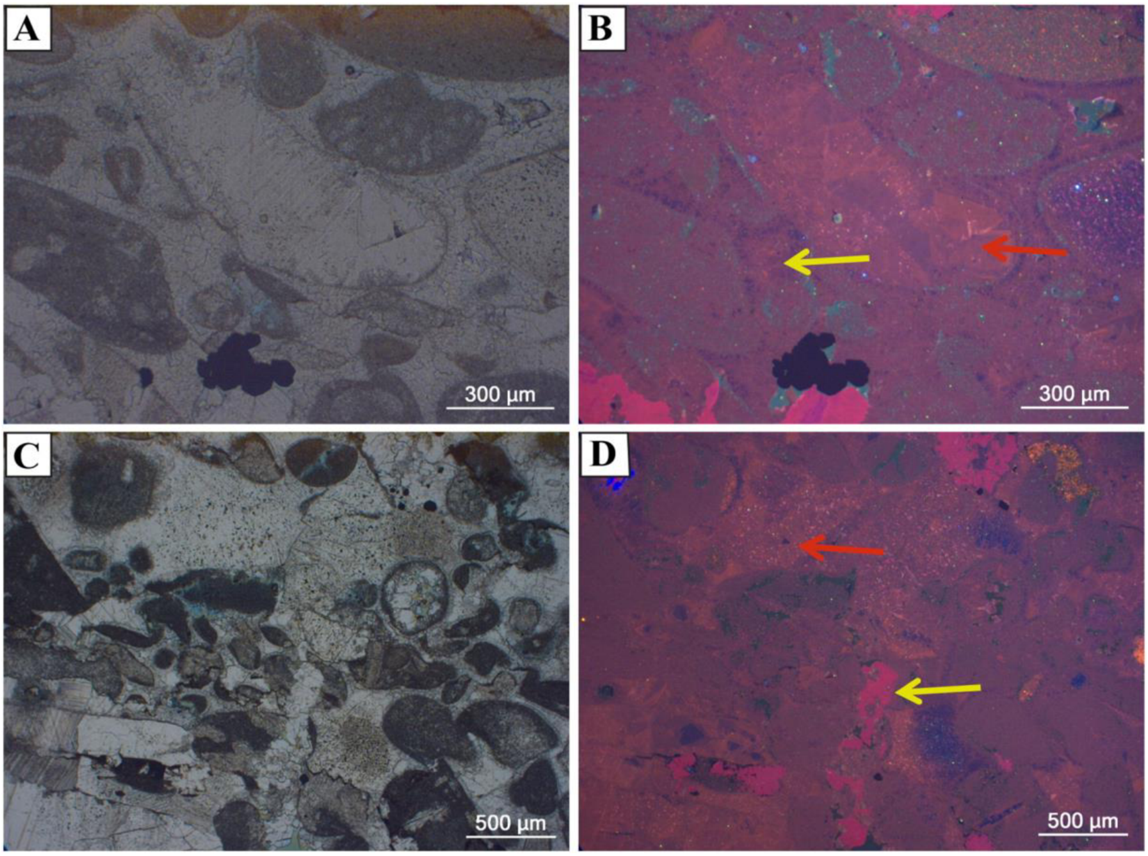

Figure 9: Optical and CL photomicrographs of grainstones in the crest. (A) and (B) Dull orange luminescent intergranular fine to medium equant (yellow arrow) and intragranular dull orange to yellow luminescence drusy (red arrow) calcite cements. Saddle dolomite cement is bright red luminescent. (C) and (D) Dull orange luminescent fine to medium equant (red arrow) calcite cements. Saddle dolomite cement has bright red CL colors (red arrow). (D. Morad et al., 2018).

The flanks compared to the crest, there is a higher frequency of cemented Moldic and intragranular pores and micro-vugs. Additionally, some mudstones in both the crest and flanks contain rare small (10 m) rhombic dolomite crystals. Euhedral micrite is a more common component of limestone samples from the flanks, whereas in the crest, coalescence is greater, resulting in lower porosity. This difference is particularly evident in the area around stylolites.

Contrasting the crest and flanks, a significant amount of fundamental water and a closed diagenetic system occur before oil emplacement (in both the crest and flanks). This is especially true in the highly impermeable mudstones where micropores dominate. According to Pingitore (1982), ionic diffusion is expected to be the dominant mass transfer mechanism rather than advection in these systems. Stylolites, which are essential features in the area, are more common and have a higher amplitude in the flanks compared to the crest. The presence of stylolites in the flank results in calcite cementation, negatively affecting the porosity and permeability of the water zone flank, particularly when compared to the oil zone crest.

Overall, the flanks exhibit more frequent cementation of Moldic and intragranular pores and micro-vugs, along with a higher occurrence of stylolites, which adversely affect porosity and permeability. In contrast, the crest experiences more remarkable coalescence, resulting in lower porosity. Irreducible water and a closed diagenetic system are observed in both the crest and flanks, with micropores dominating in impermeable mudstones.

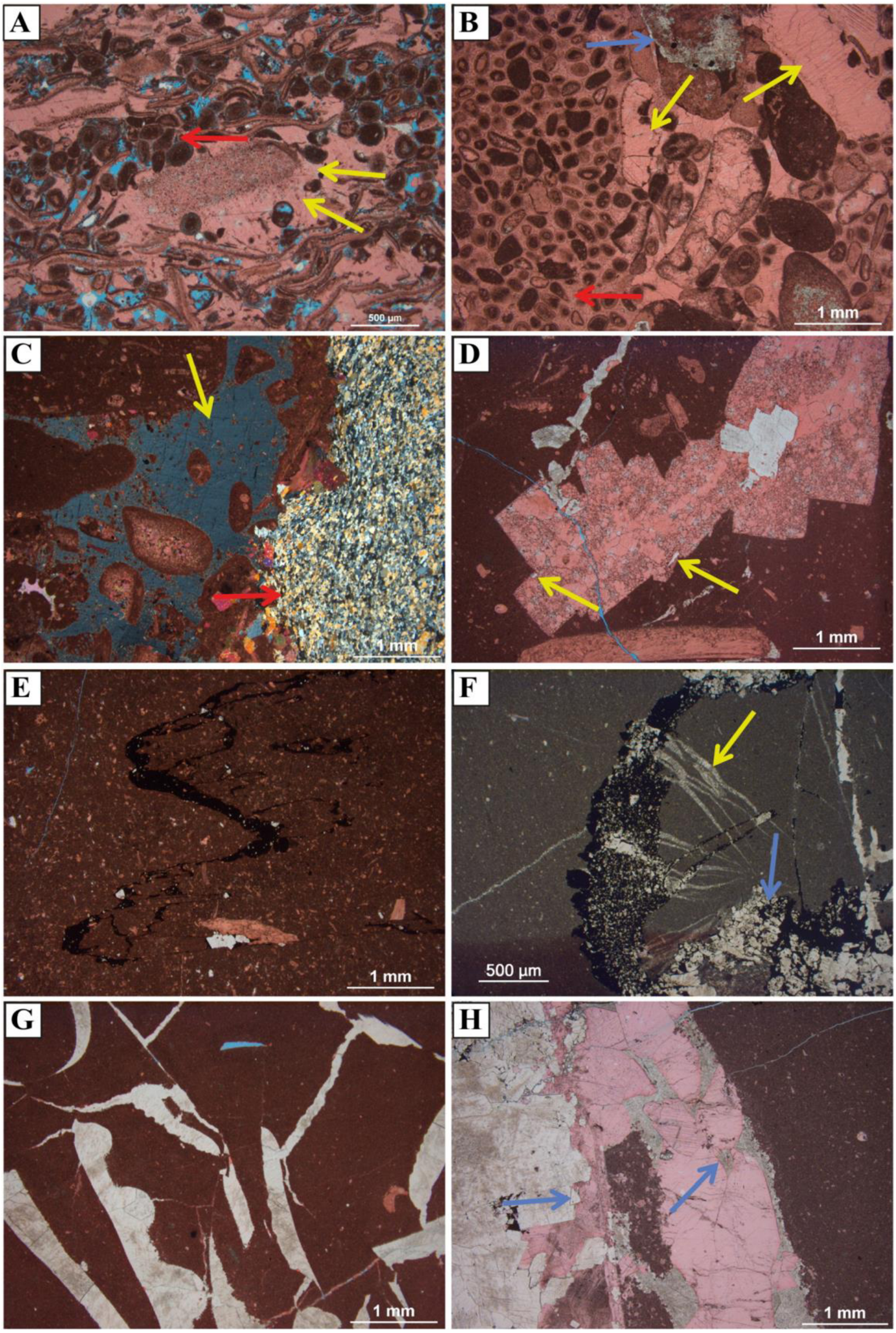
A
500 µm
B
1 mm
C
1 mm
D
1 mm
E
1 mm
F
500 µm
G
1 mm
H
1 mm

Figure 10: Optical photomicrographs showing: (A) Syntaxial calcite overgrowth around echinoderm fragment (PPL; crest; upper Arab D).Note the high and low intergranular volume between the peloids where syntaxial calcite cement is present (yellow arrows) and absent (red arrow), respectively. (B) Micritized grainstones with abundant fine to medium equant calcite (red arrow) and drusy calcite (yellow arrows) cements in intergranular and Moldic pores (PPL; flank; upper Arab D). Quartz cement has partly replaced a bioclast (blue arrow). (C) Celestine cement (yellow arrow) and anhydrite nodule (red arrow) that have replaced host limestone (XPL; crest; lower Arab D). (D) Calcite (stained pink) and saddle dolomite (unstained) that have replaced anhydrite (PPL; flank; lower Arab D). Small relicts of anhydrite is commonly observed in the calcite (arrows). (E) Low-amplitude stylolite with minor carbonate cements (PPL; crest; lower Arab D). (F) Microfractures associated with a stylolite are filled by fine to medium equant calcite cement (yellow arrow). Saddle dolomite is observed along the stylolite (blue arrow; PPL; flank; lower Arab D). (G) Floatstone with saddle dolomite in fractures and Moldic pores (PPL; crest; lower Arab D). (H) Blocky calcite cement engulfing and partly replacing saddle dolomite (arrows) along a stylolite (PPL; flank; lower Arab D). (D. Morad et al., 2018)

The porosity in the majority of samples is predominantly made up of micropores. However, the Upper Shu'aiba reservoirs in northwest Oman exhibit significant changes in total porosity across several lithofacies. In higher energy lithofacies, calcite cement, possibly originating from chemical compaction, fills previously abundant macropores. This preferential formation of cement in larger pores is due to the increased solubility of microcrystals and their limited growth in micropores. Consequently, as cementation fills micropores after macropores, the maximum pore-throat size decreases. The model proposed aims to demonstrate how increasing burial cementation affects the capillary pressure properties of microporous limestones.

On the other hand, Ehrenberg, and Wu (2019) propose a different perspective, arguing that porosity loss occurs before oil emplacement. This is evidenced by the absence of porosity variation between the crest and flanks in the extremely low-porosity dense zones surrounding the Thamama-B zone of field F. They suggest that chemical compaction is responsible for the decrease in both thickness and porosity. It is worth noting that higher porosity is typically associated with thicker reservoir zones. Therefore, the thickness of reservoirs plays a crucial role in estimating reserves. These findings highlight the complex nature of porosity variations and cementation processes in different lithofacies and their implications for reservoir characteristics and oil emplacement.

5 Discussion

When it comes to carbonates reservoirs, the distribution of reservoir quality mostly depends on how diagenetic processes have changed the microstructure of the rock, resulting in high variability and anisotropy. The pore network's size and connectivity may be increased by dissolution or decreased by cementation and compaction. Porosity variations in carbonate reservoirs result from the combined effects of depositional and diagenetic factors. The controlling mechanisms may be complex and difficult to resolve, but correlations between various measurable parameters (like stylolite frequency versus bed thickness, distance below a depositional surface, and intensity of dissolution effects) can provide insights into causal relationships. The most widely noted such correlation is the tendency for porosity to decrease with increasing burial depth in data from stratigraphic units of otherwise similar characteristics, as illustrated by the often-cited South Florida example of Schmoker and Halley (1982). Porosity-depth trends in sedimentary strata are generally explained as resulting from increased compaction and cementation as a function of increasing overburden pressure (effective stress) and temperature with increasing depth in a sedimentary basin (Choquette and James, 1987).

The discussed research on the comparison between anticline flanks (water zone) and crest (oil zone) regarding the case of cementation, reservoir quality, and diagenesis in carbonate rocks provides valuable insights into the factors influencing hydrocarbon reservoir properties. The results indicate that there are significant differences in the diagenetic processes and cementation between the two zones, leading to variations in reservoir quality.

One of the key findings is related to the impact of stylolites on reservoir quality. Stylolites are significant features that affect porosity, permeability, and fluid flow in carbonate rocks. The study demonstrates that the presence of stylolites is more common and pronounced in the flanks, leading to more extensive calcite cementation and reduced porosity and permeability compared to the crest. This difference is attributed to the delay effect of gas emplacement on diagenesis, indicating that oil presence may have a protective effect on porosity and cementation.

Furthermore, the results highlight the importance of understanding the timing of calcite cementation. The diagenetic history of sedimentary rocks can significantly impact reservoir quality, and the timing of cementation plays a crucial role in determining the porosity and permeability of the reservoir. Early cementation can result in stronger rock and better connectivity between pores, while late cementation may reduce overall porosity and restrict fluid flow.

The presence of micropores is a prominent feature in both the crest and flanks, leading to the dominance of microporosity in the reservoirs. However, there are differences in the distribution of cement in larger pores (macropores) between the two zones. The study indicates that higher-energy lithofacies exhibit calcite cement filling macropores, leading to a decrease in the maximum pore-throat size. This finding suggests that the burial cementation process affects the capillary pressure properties of microporous limestones.

The research also emphasizes the role of depositional environment and lithofacies in influencing reservoir quality. Different lithofacies exhibit varied diagenetic processes and cementation patterns, leading to variations in porosity and permeability. Understanding these variations is crucial for accurately estimating reserves and optimizing production strategies.

Overall, this review thesis provides valuable insights into the complex relationship between diagenesis, cementation, and reservoir quality in carbonate rocks. The results underscore the significance of considering multiple factors, such as stylolites, depositional environment, and timing of cementation, to understand the heterogeneity of carbonate reservoirs and optimize hydrocarbon production. Further research in this area will continue to enhance our understanding of these processes and their implications for oil and gas exploration and production.

6 Conclusions

The study's conclusion emphasizes the research on carbonate rocks found in the anticline crest and flanks have revealed important details about their diagenesis, cementation, and reservoir quality. These details provide information on the variables affecting the properties of hydrocarbon reservoirs. The study emphasizes the value of comprehending diagenetic process timing and nature, as well as the influence of stylolites, depositional environment, and lithofacies on reservoir quality.

Stylolites are a major factor influencing porosity, permeability, and fluid movement in carbonate rocks. According to many researchers, the flanks have more stylolites than the crest, which results in more widespread calcite cementation and decreased porosity and permeability. The difference is explained by diagenesis, suggesting that the presence of oil may have a protective impact on the crest's porosity and cementation.

Furthermore, the study also highlights how crucial it is to understand when calcite cementation occurs. While late cementation can reduce overall porosity and restrict fluid flow, early cementation can make rock stronger and improve the connection between pores. The distribution of cement in bigger pores (macropores), which differ between lithofacies, is influenced greatly by the diagenetic history of sedimentary rocks. In lithofacies with higher energy, macropores are filled with calcite cement, which reduces the maximum pore-throat size.

The study further highlights how lithofacies and the depositional environment have an impact on reservoir quality. Variations in porosity and permeability result from different lithofacies during different diagenetic processes and cementation patterns. For precise reserve estimation and production strategy optimization, it's essential to understand these variances. The research shows that the reservoir quality is generally higher on the crest than on the flanks, mostly because of the lower abundance and amplitude of stylolites and the lower level of calcite cementation.

It highlights the complicated relationship between diagenesis, cementation, and reservoir quality in carbonate rocks, as well as how multiple factors interact to affect the heterogeneity of carbonate reservoirs.

There are notable differences between the anticline's crest and flank with regard to diagenesis, cementation, and reservoir quality in carbonate rocks. These differences have an impact on the characteristics of hydrocarbon reservoirs. Similar diagenetic characteristics can be seen in both the crest and flank, such as calcite and dolomite cementation, mechanical and chemical compaction, and limited non-carbonate phase cementation. But between the two zones, the frequency and intensity of these diagenetic processes differ.

With almost 15% more core-plug porosity than the flank, the crest shows higher porosity values in both packstones and grainstones. Similar to this, the average core-plug porosity of the mudstones and wackestones in the crest is around 5% greater.

Stylolites, which are more prevalent and have greater amplitudes in the flank, can be blamed for the differences in reservoir quality. More calcite mass is released during stylolitization in the flank, and this eventually contributes to the decreased porosity seen in packstones, and grainstone mass is released during stylolites.

The crest, on the other hand, has superior reservoir quality as a result of smaller amplitudes and fewer stylolites. These discrepancies between the crest and flank of the anticline in stylolite features are explained by the delay effect of oil emplacement on diagenesis.

In comparison to the crest, the flanks exhibit a higher frequency of cemented Moldic, intragranular, and micro-vugs pores. Particularly in the water zone flank as opposed to the oil zone crest, stylolites are more frequent and have a higher amplitude in the flanks, causing calcite cementation and adversely reducing porosity and permeability. The absence of tiny rhombic dolomite crystals, which are present in a few mudstones, is another factor in the different reservoir qualities between the crest and flanks.

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