LOWER BAB MEMBER (A0): A STUDY OF SEQUENCE STRATIGRAPHY,
POROSITY CHARACTERIZATION AND TIGHT RESERVOIR
DEVELOPMENT, ABU DHABI, UAE

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ABSTRACT

The Aptian-aged Shu’aiba Formation carbonate platform is one of the most hydrocarbon-productive formations in the Middle East. Equivalent to the Shu’aiba formation is the Lower Bab Member (A0) that comprises the basinal facies in the intra-shelf Bab basin. The Lower Bab Member (A0) has shown hydrocarbon potential in fields located in the southeastern part of the UAE. The A0 potential comes from its high storage capacity that comes from microporosity in the matrix reaching up to 25% but low permeability (up to 3mD). This study goals focus on (1) understanding of the relationship between the Shu’aiba Formation and the Lower Bab Member stratigraphically using the existing core descriptions, well logs, stable isotopes and seismic; (2) characterization of porosity and permeability to identify potential target production zones; and (3) suggest best practices for future development plans to produce the hydrocarbon from this tight carbonate reservoir. Results of this thesis include significant findings about the A0. Three lithofacies have been identified with carbonate texture of wackestone-mudstones. The carbon isotope record was a useful tool for interfield and global correlations, while the oxygen isotope record helped for intrafield correlations as well as providing information about diagenesis. Reservoir rock characterization of the A0 showed that the majority of the porosity comes from the interparticle porosity in the micrite. QEMSCAN and SEM have shown that there is significant isolated porosity in lithofacies 1 that is not contributing to the effective porosity. This isolated porosity comes from the coccoliths and foraminifera. These microfossils were not destroyed due to the early cementation that held their morphology intact. Clay-rich seams and stylolites formed vertical flow barriers by dissolving micrite and re-precipitation into diffused cement. The A0 contains light oil that makes it feasible to develop, hence, more dynamic data are required for full field development.
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1. CHAPTER 1: INTRODUCTION

One of the most hydrocarbon productive groups of formations in the Middle East, and the world, is the Lower Cretaceous Thamama Group. The Aptian-aged Shu’aiba Formation is a carbonate formation that produces significant volumes of hydrocarbons in the area. In recent years, the Shu’aiba Formation has been well studied in terms of sedimentology and stratigraphy. The Bab Member comprises the basinal facies in the intra-shelf Bab basin that is equivalent to the shallow carbonate platform of the Shu’aiba Formation. The Bab Member has shown hydrocarbon potential in fields located in the southeastern part of the UAE. It overlies the low-angle carbonate ramps of the other Thamama Group formations that show much better reservoir properties. The Shu’aiba Formation contains prograding clinoform geometries in some of the fields in the United Arab Emirates such as Bu Hasa. The Bab Member is more homogeneous compared to Shu’aiba, and has not yet been studied as thoroughly as the Shu’aiba Formation.

Due to the low permeability in the Bab Member, that is less than 3 mD, it is considered part of the undeveloped reservoirs managed by the Abu Dhabi National Oil Company (ADNOC). The majority of the storage capacity in the Bab Member comes from microporosity in the matrix with porosity reaching up to 25%. This study focuses on the lower Bab Member (A0), which shows a higher potential for hydrocarbon than the upper part, especially in structural traps. The upper Bab Member is important as well but has a lower reservoir quality and is stratigraphically separated from the lower Bab by a sequence boundary. This study aims to improve (1) understanding of the relationship between the Shu’aiba Formation and the Lower Bab Member stratigraphically using the existing core descriptions, well logs, stable isotopes and seismic; (2) characterization of porosity and permeability to identify potential target production zones; and (3) suggest best
practices for future development plans to produce the hydrocarbon from this tight carbonate reservoir.

1.1. Thesis Organization

This thesis is organized into chapters that deal with different objectives of the study. Chapter 1 is an introduction and general information of the study area including: location and history, scientific importance, background information about regional stratigraphy, research objectives and tools, scope and data. Chapter 2 covers the sedimentology and facies description of the Lower Bab Member A0, which includes facies description and their depositional environments. Chapter 3 is a chemostratigraphy study of the Bab basin and focuses on high resolution regional isotopic data. Chapter 4 describes a reservoir characterization and pore architecture study of the Lower Bab Member A0 in Asab field, onshore Abu Dhabi. Chapter 5 covers a potential development plan for the tight carbonate reservoir of the A0 in the same field. Chapter 6 summarizes the previous chapters and provides conclusions.

1.2. Location and History

The United Arab Emirates (UAE) lies in the southeastern part of the Arabian basin between latitudes 22°40’ and 26°00’ and longitudes 51°35’ and 56°22’. The UAE consists of seven Emirates: Abu Dhabi (the capital), Dubai, Sharjah, Ajman, Umm al Qaiwain, Ras Al Khaimah and Fujairah. Abu Dhabi has approximately 10% of the world's proven oil reserves and 5% of the gas (Nairn and Alsharhan (1997)). According to the U.S. Energy Information Administration, (EIA) (2011) the UAE has proven oil reserves of 97.8 billion barrels, and its oil production is approximately 2.81 million barrels per day, of which 2.3 million is crude oil.

As stated by Nairn and Alsharhan (1997), the UAE lies within the interior platform of the Arabian Shield bounded by Qatar-South Fars Arch in the northwest and by the foreland basin,
adjacent foreland fold and the thrust belt of Oman to the northeast (Figure 1.1). Exploration for hydrocarbons in the UAE began in 1936 with surface geologic reconnaissance, gravity, magnetic, and seismic surveys. The first commercial hydrocarbon in the UAE was discovered in 1959 in Abu Dhabi Umm Shaif field in the offshore. This was followed by the discovery of commercial oil in Bab field in 1960 in the onshore, and many subsequent discoveries have made the UAE one of the richest hydrocarbon-producing countries in the world.

Most of the research data comes from Asab field, onshore Abu Dhabi (Figure 1.2). According to Alsharhan (1993) Asab field is located approximately 95 mi (150 km) southwest of Abu Dhabi Island. The field lies currently in the concession area granted to Abu Dhabi Company for Onshore Oil Operations (ADCO) since 1939. Oil was discovered in this field in May 1965 after the drilling of Asab 1 (SB-001) and after running seismic surveys in early 1960s. Asab field is a northeast-southwest trending elongated double plunging domal anticline, 16 mi (26 km) long and 6 mi (9 km) wide. The anticline has a structure relief of more than 600 feet (183 m) at the top of the Lower Cretaceous level and an areal closure of about 90 mi² (230 km²) (ADCO staff, 1986) (Figure 1.3). Structure contour maps of Asab field show the western flank dips 3° to 4° and the eastern flank dips 2° to 3°. The Asab structure is thought to be a result of the movement of the Infracambrian Hormuz salt. Timing of the structure evolution started during Late Cretaceous in the Cenomanian and ended during the Neogene-aged Alpine orogeny. The structure contains extensional faults and fractures, most concentrated at the crest. Most of the faults encountered in Asab field are normal faults with a maximum throw of 90 feet (27 m). Some of these faults might cause lateral and vertical fluid communication between different reservoir units.
Figure 1.1: A regional tectonic map showing the location of the United Arab Emirates (UAE) bounded by Qatar-Fars Arch in the northwest to west and by the Oman Mountains (and their foreland basin) from the northeast to east (after Nairn and Alsharhan (1997))
Figure 1.2: Location map of UAE showing the major oil and gas fields. Asab Field is located in the southeastern part of Abu Dhabi Emirate. (after Granier et al. (2003)).

Figure 1.3: A seismic surface map showing the Lower Bab Member (A0) top surface, the hotter the color, the shallower. Asab structure is a double plunging anticline. Arrow points to the north.
1.3. Regional Cretaceous Stratigraphy

According to Nairn and Alsharhan (1997) and Alsharhan (1993), the Late Paleozoic to Recent sedimentary section reaches a thickness of about 21,230 feet (6500 m) in the southeast and thickens toward the foreland basin in the north and northeast in the UAE. This sedimentary section is dominated by shelf carbonates with evaporites, minor argillaceous, and rare arenaceous siliciclastics. This section will describe the Cretaceous period formations shown in Figure 1.4.

During the Early Cretaceous an alternation of oolitic, dolomitic limestones and lime mudstones form the Habshan Formation. This was followed by a long period of cyclic deposition of shelf limestones and deep-water (low energy) limestones of the Lekhwair and Kharaib formations.

During the Aptian, an intrashelf basin (Bab basin) was situated in central Abu Dhabi where the Bab Member is composed of argillaceous limestones and shale. The Shu’aiba Formation was deposited at the basin margins forming carbonate platforms with algal and rudist buildups. The Shu’aiba and the previous formations make up the Thamama Group. Overlying the Thamama Group, the Wasia Group consists of the Nahr Umr Formation, comprising transgressive shale, and followed by the gradual diminishing of these shale, and a transition into shallow marine carbonates of the Mauddud Formation. Subsequently a basin developed again in central Abu Dhabi forming the Pithonella limestones of the Shilaif/Khatiyah Formation. At the basin margin, foraminiferal-algal-rudist wackestones/packstones/grainstones of the Mishrif Formation were deposited. This ends the deposition of Wasia Group and is followed by a major unconformity at the end of Cenomanian time. The Aruma Group overlies this unconformity and starts with the transgressive shale of the Laffan Formation, followed by the shallow shelf carbonates of the Halul Formation. This was succeeded by renewed subsidence, allowing the basinal shale and limestones of the Fiqa Formation to be deposited. These basinal shales shallowed into the
shallow shelf carbonate of the Simsima Formation. A major late Maastrichtian regression resulted in non-deposition at the end of the Cretaceous.

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Figure 1.4: Cretaceous stratigraphic column showing all formations in Abu Dhabi showing reservoirs, source rocks and seal distribution in the UAE (after Nairn and Alsharhan (1997)). Data of this study comes from the Aptian Lower Bab Member (A0), the basinal deposits that are equivalent to the Shu’aiba Formation carbonate platform.

1.4. Scientific Importance

Hydrocarbon is produced from the Shu’aiba Formation, from platform margin carbonates that were deposited on the margin of the Bab basin during the Aptian. Moreover, the basinal deposits of the Lower Bab Member in the Bab basin have shown hydrocarbon potential worth millions of barrels in fields in onshore Abu Dhabi. However, development has not been established yet, due to the low permeability of the Bab Member, though porosity in the Lower Bab Member is reasonably high in some zones. The Shu’aiba Formation forms a major reservoir in Bu Hasa field. Build-ups of Lithocodium-Bacinella and rudist float/grainstones comprise the Shu’aiba reservoir at Bu Hasa and laterally equivalent prograding clinoforms extend into the
basin, with their distal toes extending into the Bab basin. Understanding the Bab Member reservoir potential includes defining reservoir geometry and its stratigraphic relationship to the Shu’aiba shelf carbonates. Studying the nature of porosity and permeability will help identify potential target production zones within the Lower Bab Member.

1.5. Background Information

This section includes information from literature about regional sequence stratigraphy, nomenclatures of Aptian formations in the area, lithofacies in these formations, applications of biostratigraphy and chemostratigraphy in identifying sequences of the Aptian, and finally applications on reservoir characterization.

1.5.1. Regional Sequence-Stratigraphic Synthesis

Van Buchem et al. (2010), have synthesized the sequence stratigraphy of the Barremian-Aptian. They used an integrated data set that presents a time-constrained model based on biostratigraphy, chemostratigraphy and cyclostratigraphy modeling, and the use of many studies that have been published in GeoArabia Special Publication 4 (2010). Based on regional datasets, this sequence stratigraphic model is subdivided into three supersequences that have been divided into third-order sequences (generally 0.5-5MY in duration) (Figure 1.5): the Barremian Supersequence (divided in two third-order sequences), the Aptian Supersequence (divided into four third-order sequences, containing the units of this study) and the Upper Aptian-Lower Albian Supersequence (divided into four third-order sequences). During the Barremian-Aptian time interval, most benthic organisms had slow evolutionary rates, reducing their value for high-resolution age-dating in shallow water deposits, except for the orbitolinid foraminifers and the rudists. The Bab basin sediments do contain some nannofossils useful in age dating even though there is a lack of large benthic organisms in these intra-shelf basin deposits. Chemostratigraphy
uses a more environment-independent method based on the changing isotopic signature of the ocean water through time (e.g., carbon and strontium isotopes). Diagenetic resetting, reworking of sediments, and variations in the sedimentation rate can alter the nature of these curves and lead to miscorrelations if not constrained by other methods. Cyclostratigraphy is the third technique that has been developed for the Barremian through Aptian strata by referencing the sequences to the orbital cycles of the Earth.

Figure 1.6 shows the most recent sequence framework of Barremian-Albian strata of the southeastern Arabian Plate. It shows a comparison between lithostratigraphic nomenclature and the sequence stratigraphic synthesis built in GeoArabia SP4 (Van Buchem et al., 2010). The Lower Bab Member (A0) in the onshore Abu Dhabi corresponds to the Thamama IB in the offshore Abu Dhabi (Aldabal and Alsharhan, 1989). In Zakum offshore field, Thamama IB is subdivided into three units, which are from bottom upward: Tar (Bitumen) unit, IX unit, and

1.5.2. Nomenclature of Aptian Formations and Geographic Differences
Dolomite unit. All of these units have dolomite compared to Asab field, which lacks dolomite in equivalent units. Zakum is situated near the depocenter of the Bab Member basin (Aldabal and Alsharhan, 1989; Alsharhan, 1990).

1.5.3. Lithofacies of the Aptian in Eastern Arabian Plate

In describing the formations in this study, UAE (ADCO/ADNOC) nomenclature will be used as the reference, as this study encompasses fields that are part of ADCO/ADNOC concession. The Aptian stage encompasses the time from 125.0 ± 1.0 Ma to 112 ± 1.0 Ma (Van Buchem et al., 2010). The Aptian Supersequence is divided into four 3rd order sequences and encompasses the time from 125 ± 1.0 Ma to 118 ± 1.0 Ma (Van Buchem et al., 2010). It starts with the orbitolinid dominated, wackestone/packstone facies of Dense A (Figure 1.6). The Dense A extends below the Shu’aiba Platform wells and the Bab basin wells. This marks the early transgressive systems tract in the Aptian Supersequence and is called the Aptian 1 sequence. It indicates a uniformly thick ramp system that covered the whole southeastern Arabian Plate. The Dense A unit acts as a top seal for hydrocarbons trapped in the Thamama B below. The Dense A is followed by a late transgressive systems tract that is called the Aptian 2 sequence (i.e. 3rd order sequence). This was an important change in the sedimentary system and coincides with the formation of two sub-basins: the Bab basin in the south (UAE and Oman) and the Kazhdumi basin in the north (Iran). There was clear differentiation between the aggrading shallow-water carbonates and the starved, organic-rich, intrashelf basinal sediments (Van Buchem et al., 2010). Around the Bab basin, shallow-water carbonates are dominated by Lithocodium Bacinella microbialite boundstones. Based on seismic geometries observed in Bu Hasa field, (Yose et al., 2010) the water depth in the Bab basin at this time was estimated to be approximately 45 meters.
The early highstand systems tract during the Aptian supersequence resulted in the aggradation and progradation of rudist-dominated platform along the basin margin, and composes the Aptian 3 sequence. This marked an overall deepening in the basin and the depth of platform-to-basin relief in Bu Hasa field is approximately 75 meters (Yose et al., 2010). According to Yose et al. (2010), the organic-rich basinal mudstone facies of the Lower Bab Member is time-equivalent to the Aptian sequences 2 and 3. The late highstand during the Aptian was characterized by a relative sea-level standstill and resulted in prograding clinoforms in Bu Hasa Field, comprising the Aptian 4 sequence. This was followed by a sequence boundary that ended the deposition of the Aptian Supersequence and formed the incised valley incision observed in Qatar and the downward stepping of the sedimentary system along the southern Bab basin margins, with an estimated relative sea level drop of 30-40 meters (Maurer et al., 2012; Van Buchem et al., 2010). The Bab Shale and the Upper Bab Member were deposited during the Aptian 5 third-order sequence near the platform margin in the Bab basin, east of Bu Hasa Field, and is considered a part of the Upper-Aptian –Lower Albian Supersequence (encompasses the time from 118 ± 1.0 Ma to 109 ± 1.0 Ma (Van Buchem et al., 2010)). The Upper Bab Member low-stand clinoforms were deposited during this time in the southeast area of the UAE and are younger than the clinoforms in Bu Hasa field (Maurer et al., 2012; Van Buchem et al., 2010).

1.5.4. Application of Chemostratigraphy in Defining the Sequence Stratigraphy Framework of Aptian

Vahrenkamp (2010) has conducted a comprehensive chemostratigraphic analysis of the Shu’aiba Formation using carbon isotope curves in Oman and Abu Dhabi by compiling a database of carbon and oxygen isotope samples. These samples were compiled from the author’s data from several companies (Shell (1992), ADCO (1995), PDO (2006)) and from literature
1.5.5. Application of Biostratigraphy in Defining the Sequence Stratigraphy

Framework of Aptian

Yose et al. (2010) built an age model for the Aptian in Bu Hasa field using a set of data including: rudists, benthic foraminifera, calcareous nannofossils and stable isotopes summarized in Figure 1.7. Rudists are abundant in Aptian sequences 3, 4a and 4b sequences. The Early Aptian age sequences were defined by the presence of Agriopleura and Offneria in sequence 3. Late Aptian age sequences were defined by the presence of Eoradiolites and Horiopleura in sequences 4a and 4b. Benthic foraminifera provided higher resolution in differentiation of Lower and Upper Aptian sequences. Paleorbitolina in sequences 2 and 3 confirms the Early Aptian Age, and Mesorbitolina in sequence 4b and 5 confirm the Late Aptian Age. Nannofossils also confirmed the age of Aptian sequences 2 and 3 to be lower Ap3. Also, they confirmed that sequence 4a is Ap4 age but were not clear for the age of sequence 4b. It could be of Ap4 or Ap5 age. Sequence 5 could be Ap5 or Ap6 age, based on nannofossils. Rudists and benthic foraminifera are environmentally controlled.
(Budd (1989), Moshier (1989a), Wagner (1990), Vahrenkamp (1996), Van Buchem et al. (2002), Hillgärtner et al. (2003) and Immenhauser et al. (2004)). Vahrenkamp’s (2010) main conclusion is that the negative trends in the Early Aptian $\delta^{13}C$ can be interpreted to be related to the catastrophic release of methane from methane hydrate deposits due to ocean temperature warming (Jahren et al. (2001), Wissler et al. (2003), Beerling et al. (2002), Weisset and Erba (2004), and Renard et al. (2005)). This had a significant impact on the bio-composition and lithology of the Shu’aiba Formation with the widespread presence of *Lithocodium-Bacinella* microbialite boundstones during the Early Aptian.

Carbon isotope analysis across Bu Hasa Field is shown in Figure 1.8. However, Bu Hasa field is more than 100 km away from the Bab basin center and Bab Member deposits in Bu Hasa field onlap directly on the platform margin as the Aptian 5 sequence. The Bab Member deposits in Bu Hasa field at the platform margin have been dated by biostratigraphy using nannofossils as early to mid-late Aptian with orbitolinids giving an early Late Aptian age. Vahrenkamp (2010) concluded that the Hawar member (Dense A) has an earliest Aptian age, the overlying aggrading and prograding units in the center of the platform are early Aptian, there is a progressively younger Late Aptian age for units prograding in the Bab basin, and finally, the first progrades of the siliciclastic-rich Bab Member are mid-Late Aptian in age.

1.6. Application to Reservoir Characterization

Abu Dhabi Company for Onshore Oil Operations (ADCO, 2010) has used the sequence stratigraphic model of the Aptian to constrain the porosity model in Bu Hasa field. It takes into account the interface between Aptian sequences with the aid of seismic inversion. This has significantly helped in the field development of Bu Hasa field, especially in placing horizontal producer wells as well as the water injectors aligned with the clinoform geometry. Figure 1.9
shows a cross section across Bu Hasa field, showing pseudo porosity derived from inverted acoustic impedance from the field seismic data, and marks clearly the clinoforms of the Aptian Shu’aiba sequences.

Figure 1.7: Summary of age data compiled from many sources, including biostratigraphy and stable isotopes. OAE1a is globally recognized anoxic event (after Yose et al. (2010)).

1.7. Case Study of Tight Reservoir in Abu Dhabi

The Lower Bab Member (A0) shows high hydrocarbon potential in Asab field, Abu Dhabi. According to a stratigraphic section provided by ADCO (2006), A0 is divided into A01, A02 and A03 sequences divided by sequence boundaries as shown in Figure 1.10. Porosities in A0 can reach up to 30% in A02 with the highest permeability of about 1 mD. The Lower Bab member contains organic-rich clay seams that appear every 1 to 2 feet as shown in Figure 1.11. These
Figure 1.8: Carbon isotope analysis and gamma ray logs of wells across Bu Hasa Field (Vahrenkamp, 2010).
Figure 1.9: A cross section of Bu Hasa Field showing pseudo porosity derived from inverted acoustic impedance from seismic data, which marks clearly the clinoforms of Shu'aiba sequences (after ADCO (2010))
organic-rich clay seams were studied by Alsharhan and Sadd (2000). These authors indicated that the importance of these clay seams (or so-called stylolites by the authors) to reservoir geology is their association with a significant reduction in porosity and permeability and their effects on hydrocarbon fluid flow and migration. Also, they described the stylolites in Bab Member to occur mostly in the lime mudstone and wackestone intervals of the deep and open marine facies. Wave-like or sutured stylolite types were reported to be oriented parallel to bedding (stratiform stylolites). This indicates that the origin of these stylolites is not due to tectonic pressure, but probably due to compaction and pressure solution. The chemical composition of these stylolites includes: organic matter, clay, pyrite and quartz.

The seismic data from Asab field shows three clinoforms in the Upper Bab Member (Aptian 5) that are the thickest over the crest of Asab Anticline (Figure 1.12). The apparent thickness observed in the seismic could be due to the effects of fluids or diagenesis in the crest slowing down the seismic reflection. These clinothems downlap onto the Lower Bab Member (A0). The nature of the A0 is not fully understood. Three potential models for the A0 include: (1) units in A0 represent the toes of pre-Ap5 platform margin clinoforms observed in Bu Hasa, (2) they are a separate basin floor unit or (3) they are a separate carbonate build up on the topography high of Asab anticline.

Understanding the depositional model for the A0 could be helpful in predicting the hydrocarbon extent in such structures. For instance, if the A0 represent the toes of the clinothems from the platform margin, then it will be beneficial to extend the hydrocarbon potential parallel to the clinoforms. If A0 is a separate build up, then the hydrocarbon accumulation will be limited only to the extent of the build-up (i.e. Asab field anticline). Moreover, the clay seams observed
Figure 1.10: A Stratigraphic section provided by ADCO (2006), A0 is divided into A01, A02 and A03 sequences divided by sequence boundaries.
could represent either shutdown in carbonate production or the shaliest part of the clinothem
toes. This would help in predicting the role and extent of these potential flow barriers and the
hydrocarbon distribution in the Lower Bab Member (A0).

![Image](image1.png)

**Figure 1.11:** A photo shows organic-rich clay seams from the Lower Bab Member in Asab Field.

![Image](image2.png)

**Figure 1.12:** A time-thickness cross section (NNE-SSW) of Asab Field seismic data showing three
clinotheams in Upper Bab Member. (provided by ADCO (2010)).
1.8. Research Objectives and Tools

This study has the following objectives:

1- Define the stratigraphic character of the Lower Bab Member (A0), and how it correlates to the platform Shu’aiba Formation.

2- Identify the depositional processes and environment for the Lower Bab Member (A0).

3- Define porosity evolution and identify potential target zones and their geological extent and variations within the Lower Bab Member (A0).

4- Define the diagenetic alteration that affected the reservoir quality of Lower Bab Member (A0).

5- Suggest the best practices for the Lower Bab Member (A0) to build a development plan.

Tools and analytical techniques that were used in this research in order to achieve its objectives. Each number below refers to its numbered objective above.

1- Stable isotope and well log correlation on the scale of Asab field and adjacent fields, and integrated with regional seismic profiles.

2- Thin section description, chemostratigraphy, core description, SEM analysis.

3- Thin section description, QEMSCAN, SEM, mercury porosimetry and helium or nitrogen injection to obtain more detailed porosity distribution, permeability, and pore throat characterization. Results will be compared to conventional core analysis.

4- Tools as in number 3 above.

5- Results of reservoir characterization study and available dynamic data.

1.9. Data Sets

The data of this research includes but not limited to access to three cored wells in Asab field, more than fifty plugs and thin sections from one of the three wells, the Petrel® project of Asab
field including most of the well logs, image and sonic logs from all available wells in Asab field, 3D seismic project and four regional seismic lines in the area west of Asab field between Asab and Bu Hasa field.

1.10. References


ADCO, A. D. C. f. O. O. O., 2006, Regional stratigraphic columns.


Aldabal, M., and A. Alsharhan, 1989, Geological model and reservoir evaluation of the Lower Cretaceous Bab Member in the Zakum Field, Abu Dhabi, UAE, Middle East Oil Technical Conference, Manama, Bahrain, SPE.


2. CHAPTER 2: SEDIMENTOLOGY

2.1. Introduction

The purpose of this chapter is to provide sedimentological descriptions of the Lower Bab Member A0 and propose a depositional model. This is to better understand the texture and the parameters that affect flow capacities in the formation of interest. Understanding the constituents of the rock provides a context for describing the nature of the pore architecture in the rock, and testing the concept that pore architecture is related to depositional texture. Analytical tools used in this study include core description, thin section description, scanning electron microscope (SEM), QEMSCAN® imagery and special core analysis (SCAL), and well log analysis. Core description, thin section description and SEM were used to assign facies, while the other techniques were used for reservoir characterization. The A0 is divided into three lithofacies based on similar sedimentological features.

2.2. Core Description

Three wells were selected from the field for core description that covered the entire A0 and parts of the upper and lower formations. Figure 2.1 shows the location of the three wells (SB-359, SB-322 and SB-347) that have been studied. Moreover, they were selected from the crest of the anticline to avoid any excess diagenetic overprint at the free-water zone on the flanks. Core description included information about: depth, lithology, texture, sedimentary structures, fossils, fractures, stylolites and hydrocarbon stain.

Figure 2.2 shows an example of core description of well A (SB359) with core porosity and permeability.
Figure 2.1: A map showing Asab Field with all wells that have been cored in the A0. Three wells have been described in this study (Sb-359, Sb-322, and SB347). The three wells are all crestal wells, and were chosen in order to avoid any diagenetic overprint in the water leg. The light blue contour shows the oil water contact at the top of Thamama Zone A1. Light grey lines represent major faults.
Figure 2.2: An example of core description of well Sb-359. It includes mineralogy, texture, sedimentary structures, stylolites and plug porosity and permeability.
2.3. Thin Section Description

A total of fifty-five thin sections from one well were prepared for this study, and ten of them had duplicates for other analysis (SEM and SCAL). Three-centimeter diameter slices of cylindrical core plugs were trimmed and polished into 30 micrometer thickness and prepared without a coverslip. The samples were sent to Spectrum Petrographics Inc. in Vancouver, Washington. All samples were impregnated with blue epoxy for porosity visualization. Also, they were stained with Alizarin Red for differentiation of calcite/dolomite. Thin sections were observed using a binocular microscope that has an installed digital camera to take photos of the samples. Information obtained from thin section description included: lithological description, skeletal and non-skeletal grains, matrix, cement, pore system, and reservoir quality. A paragenetic sequence was interpreted for each thin section to provide a sequence of diagenetic events that had affected these samples.

2.4. Scanning Electron Microscopy (SEM)

Porosity in the A0 is dominated by microporosity and pore sizes are generally smaller than the resolution of the optical microscope. Scanning Electron Microscope (SEM) has been used to study twenty-three samples at the Petroleum Institute in Abu Dhabi (Figure 2.3) to understand the relationship of the relatively high porosity (up to 25%) and low permeability (up to 3mD) of the A0. The SEM has provided qualitative pictures of micrite particles with high magnifications up to half a micrometer scale. Also, the SEM provided elemental spectrum of the samples indicating that the dominant mineralogy of the samples is calcite. Micrite particles were described following Deville de Periere et al. (2011) description of porous and tight micrites.
Figure 2.3: A photo showing the Scanning Electron Microscope that has been used at the Petroleum Institute for this study. Samples were coated with gold to reach the maximum magnification.

2.5. Facies in the Lower Bab Member (A0)

Due to the lack of macro-size particles in the rock, and the dominant carbonate mud content and the minor sedimentary changes, only three lithofacies have been identified from the Lower Bab Member A0 using the Dunham (1962) classification with Embry III and Klovan (1971) and Wright (1992) modifications as described by Scholle and Ulmer-Scholle (2003). Core descriptions of wells Sb-359, Sb-322, and Sb-347 and thin section descriptions of well Sb-359 show the following lithofacies:

2.5.1. Lithofacies 1:

Skeletal mudstone to wackestone. Lithofacies 1 (Figure 2.4) is dominantly a light brown mudstone to wackestone and occasionally floatstone with fine-grained microporosity (9 to 30%) and low matrix permeability (0.1 to 3mD). Bed thickness of this lithofacies ranges from 3-15 ft. These mud-rich rocks are poorly sorted, burrowed, and are rich in bivalve and gastropod
fragments, and foraminifera. The dominant mineral is calcite. Skeletal allochems are fully recrystallized and some have developed micrite envelopes. Common bioclasts include: planktonic foraminifera, echinoderms, thin-shelled bivalves, and sponge spicules. Most of the bioclasts are fragmented into pieces. Non-skeletal allochems include peloids. The matrix is composed of very fine micrite with almost no macroporosity. Porosity types include: microporosity and micro-moldic and micro-vuggy porosity. Coccoliths are abundant in this lithofacies but not continually over the thickness. Fragmented coccoliths are contributing to the effective microporosity whereas intact ones seem to be part of the isolated microporosity (see discussion in chapter 4). The major type of porosity is microporosity in the matrix and some intraparticle porosity inside the foraminifera and coccoliths. Micro-size veins and micro fractures are common. This lithofacies show high hydrocarbon stain that becomes less with increasing cementation. Bioturbation is not common but it is present locally. The nature of the microporosity comes from poorly sorted scalenohedral micrite particles, which provided the best reservoir properties compared to the other two lithofacies.

The depositional environment of this lithofacies is subtidal, low-energy open marine due to the presence of the planktonic foraminifera. The presence of fragments of bioclasts and the presence of carbonate mud suggests that it is below fair weather wave base and probably below storm weather wave base due to the absence of storm related sedimentary structures. Lithofacies 1 is interpreted to have been deposited in the lower ramp to the basin environment as a result of dominantly rapid storm and plume deposition, which is indicated by less bioturbation compared to other lithofacies. Another interpretation regarding bioturbation, is that lithofacies 1 has lower bioturbation observed from core as it could have been homogenized sediments by extensive bioturbation.
Figure 2.4: Photos showing Lithofacies 1 at different scales. Each yellow box corresponds to the area imaged in the next photo. A) A photograph taken by a digital camera of the core. B, C and D) photos of thin sections at different magnifications. The scale bar is shown on the left top corner (B: 1 mm, C: 0.1 mm, and D: 0.1 mm). E and F) Photos of the same sample under the SEM as small rock chip. SEM shows clearly the microspores that range from less than a micrometer to a few micrometers.
2.5.2. Lithofacies 2:

**Burrowed argillaceous skeletal wackestone to mudstone.** Lithofacies 2 (Figure 2.5) is dominantly a wackestone to mudstone with medium porosity (<10%) and very low permeability (<1mD). It represents the relatively dense intervals within the Lower Bab Member and is greyish in color with limited or no hydrocarbon stain. This lithofacies has lower diversity and abundance of skeletal material and smaller size of skeletal fragments than Lithofacies 1. Lithofacies 2 contains planktonic foraminifera. Quartz is present within the matrix (<5%). Pyrite also is present around the organic rich seams. The key to its low permeability is that this lithofacies is composed of 70% to 95% micrite, which lowers the matrix permeability. Moreover, the presence of argillaceous matters in this lithofacies has contributed to the chemical compaction. Coccoliths are present occasionally in this lithofacies. Bioturbation is more intense than in lithofacies 1. The nature of the microporosity comes from the abundance of micrite particles that are scalenohedral in crystal shape with component of fused anhedral cement. The fused anhedral cement lowered porosity and permeability compared to lithofacies 1.

The depositional environment of this lithofacies is deep subtidal, low-energy open marine, below storm wave base. The low energy environment and the abundant oxygen are responsible for the intensified bioturbation, where organisms were not disturbed frequently with storms. Quartz is believed to have been brought into the system by dust storms (aeolian); and is abundant due to the relatively slow sedimentation rate of carbonate in this deep setting. It is interpreted to have been deposited in the lower ramp to basin environment, in a deeper position down ramp from Lithofacies 1. This lithofacies is more bioturbated than lithofacies 1 as it is less affected by storm and plume deposits that disturbs burrowing organisms.
Figure 2.5 A panel of photos showing Lithofacies 2 at different scales. Every yellow box corresponds to the area of the next photo. A) photograph taken by a digital camera of the core. B, C and D) photos of thin sections at different magnifications. The scale bar is shown on the left top corner (B: 1 mm, C: 0.1mm, and D: 0.1 mm). E and F) Photos of the same sample under the SEM as small rock chip. SEM shows this facies to be finer crystalline, fused micrite compared to Lithofacies 1.
2.5.3. Lithofacies 3:

Burrowed clay-rich skeletal wackestone to mudstone (clay-rich seams): The presence of clay-rich wispy seams a few millimeters to a few centimeters thick that are dark and organic-rich is the only difference in this lithofacies compared to Lithofacies 2 (Figure 2.6). This lithofacies is a burrowed, skeletal wackestone to mudstone. Bioturbation is limited and is deformed around the seams. The presence of the clay-rich seams is as frequent as one or two seams per foot. They are usually parallel to bedding plane. Pyrite is noticeably present in this lithofacies, which indicates lowered oxygen level, probably due to the oxidation of the organic matters.

The depositional environment of this lithofacies is deep, subtidal, low-energy open marine, below storm wave base in the lower ramp to the basin, and deeper than depositional environment of Lithofacies 1 and 2. The clay-rich dark seams are interpreted to represent a slowdown in the carbonate production and high rate of organic matter preservation due perhaps to reduced oxygen. This low oxygen level is caused by the consumption of oxygen by oxidizing organic matter for certain limit, once oxygen is consumed from oxidizing organic matter and there is no more supply of oxygen due to lower circulation, unoxidized organic matter is preserved. This lithofacies could represent the residue of dissolved carbonates that is resulting from chemical compaction.

2.6. Facies Association (Lower Ramp to Basin):

Due to the similarities between the lithofacies and the similar depositional environment, only one facies association has been identified for the Lower Bab Member A0. Based on the rare, fragmented bioclasts, high content of carbonate mud, presence of the clay and organic, matter content, and its position relative to the basin-margin Shu’aiba platform, it is suggested here that
this environment is at least tens of kilometers away from the platform margin in a lower ramp to basin position as shown in Figure 2.7. Lithofacies depositional environments could be oxic (in lithofacies 1 and 2) to perhaps slightly dysoxic (in lithofacies 3). Based on observation under the SEM, micrite in these lithofacies can be considered allomicrite (deposition of disintegrated skeletal material). This means that micrite could be deposited due to the possible processes (based on Flügel (2010) origin of micrite classification) such as disintegration of pelagic and benthic biota where disintegrated benthic algae or *Lithocodium Bacinella* which is abundant at the carbonate platform accumulates downslope, and is mixed with planktonic microfossils, such as coccoliths producing nanomicrites.

![Figure 2.6 A panel of photos showing Lithofacies 3 at different scales. Every yellow box corresponds to the area imaged in the next photo. A, B and C) core photographs taken by a digital camera. This Lithofacies is similar to Lithofacies 2, but has addition of clay-seams that are organic-rich. Abundant pyrite indicates reduced oxygen level at this lithofacies.](image-url)
Figure 2.7: A paleobathymetric profile showing the interpretation of the depositional environment for the lithofacies in the Lower Bab Member A0. Modified from Strohmenger et al. (2010).
2.7. References


3. CHAPTER 3: CARBON AND OXYGEN STABLE ISOTOPE STUDY IN A REGIONAL CONTEXT – APTIAN AGE CARBONATES FROM AN INTRASELF BASIN, ABU DHABI, UAE.

3.1. Abstract

The chemostratigraphic record of the Aptian formations has been extensively documented for carbonate platforms in the Middle East. This study aims to enhance the existing data set with new data from the time-equivalent basinal deposits from the intrashelf Bab basin. Two crestal wells have been analyzed from a large anticlinal onshore field in Abu Dhabi. This study confirms that carbon isotope curves can be considered a reliable correlation tool at regional scale and agree with the global signature. Trends in the carbon isotope curves were helpful in interfield correlation rather than absolute values of the carbon isotope ratios. Carbon isotope results from this study were correlated with data from carbonate platforms of Shu’aiba Formation (Strohmenger et al., 2010) and from the center of the basin of the Bab basin (Jobe, 2013). This study shows that δ^{18}O curves can be a useful tool for intrafield correlation as they correlate similar diagenetic environments. There is a weak correlation between porosity and δ^{18}O values, specifically for porosities higher than 5%, while highly cemented samples have a large range of δ^{18}O values, probably due to different cement generations or compaction. It is estimated that diagenetic fluid that generated the cement had a temperature 50-54°C, based on some assumptions and a correlation that uses δ^{18}O as a paleothermometer. The negative excursion in the δ^{13}C curve marks the beginning of the OAE 1a. It is interpreted to be caused by volcanism, enhanced CO₂ and/or the catastrophic release of methane. These conditions subsequently resulted in global warming and degassing of oceans, leading to mass storage of light carbon in
the organic matter in anoxic ocean waters that is the result of the positive $\delta^{13}$C excursion that follows the negative excursion.

### 3.2. Introduction

Carbon isotope stratigraphy has been widely used as a correlation tool for pelagic and shallow water sediments (Scholle and Arthur (1980), Weissert and Lini (1991), Lini et al. (1992), Jenkyns et al. (1994), and Vahrenkamp (2010)). It is based on the assumption that pelagic sediments are less susceptible to diagenetic alterations of their primary geochemical signature compared to shallow-water sediments. However, in other studies (Vahrenkamp (1994), Vahrenkamp (1996) and Jenkyns (1995)) it was found that pelagic sediments can be correlated with shallow-water sediments of the same age using their carbon isotope signature. Other authors have determined that shallow-water sediments have a similar isotopic signature as other time-equivalent shallow water sediments (Grötsch et al. (1998), Jenkyns and Wilson (1999), Bralower et al. (1999), Wissler et al. (2003), and many others). On the other hand, the oxygen isotopic composition shows a higher tendency to be affected by diagenesis when compared with carbon isotopes, due to the high molecule-to-molecule ratio of oxygen in water-rock interactions during diagenesis. Thus, $\delta^{18}$O can be potentially used for correlation where diagenetic environments are similar (i.e. intra-field scale). According to Herrle et al. (2004), carbon isotope records can be a useful tool for long-distance short-term correlation of different marine and terrestrial environments.

The Aptian Shu’aiba Formation has been thoroughly studied and documented in terms of its carbon and oxygen isotopic signature by many studies (Budd (1989), Moshier (1989a), Wagner (1990), Vahrenkamp (1996), Van Buchem et al. (2002), Hillgärtner et al. (2003), Immenhauser et al. (2004) and Vahrenkamp (2010)). This is due to its high hydrocarbon
productivity in the Middle East and its complex architecture of lithofacies dominated by rudist/\textit{Lithocodium-Bacinella} biofacies. On the other hand, there has been much less chemostratigraphic documentation of the basinal deposits in the Bab intrashelf basin that is time-equivalent to the Shu’aiba Formation. This study aims to document the carbon and oxygen isotopic signature in the Lower Bab Member (A0) and the Thamama Zone A down to the Hawar Member (Dense A) in a field that is located in the Bab basin. This study supports and complements the study conducted by Jobe (2013), which recorded a similar range of strata in the depocenter of the Bab basin. Also, this study will help to identify how the thin basinal deposits correlate to the different clinoforms at the platform margin adjacent to the Bab basin. The location of the field in this study is believed to be further away from the depocenter, and closer to the platform margin (Figure 3.1) than the field studied by (Jobe, 2013).

![Figure 3.1: A Late Early Aptian paleogeographic map showing the different interpreted depositional environments. Two fields are shown in red stars: the northwestern offshore field was studied by Jobe (2013), while the southeastern is the onshore field in this study. The three colored cross sections will have the same color code in the results figures of the carbon isotope curves in Figure 3.4 and Figure 3.5. The two fields are situated in the United Arab Emirates. Figure is modified after Jobe (2013).](image-url)
Large changes in the carbon isotopic signature in the coupled system ocean-atmosphere (greater than + 1.5 per mil) are frequently related to oceanic anoxic events (OAEs). Usually they reflect global events where ocean bottom water lacks dissolved oxygen and organic carbon is preserved and accumulated. The studied formation includes the OAE 1a that is believed to have caused major changes in the depositional trends from rudist-rich carbonate ramps into patchy Lithocodium-Bacinella algal buildups that developed later into a platform and intrashelf basin system, and in some locations resulted in a biocalcification crisis (Méhay et al. (2009), Vahrenkamp (2010) and Jobe (2013)).

In general, significant changes in the $^{13}$C/$^{12}$C ratio of marine carbonates indicate changes in the global carbon cycle. Photosynthesis is the dominant control on the distribution of carbon in the sedimentary record. Organic carbon is usually highly depleted in $^{13}$C compared to the oxidized carbon of the atmospheric (CO$_2$), or in marine carbonates, as organisms prefer lighter carbon isotopes during photosynthesis. Positive excursions in the carbon isotope curve occur for the following reasons:

- Positive excursions in the carbon-isotope signature can be due to the storage of organic matter in the geologic record (i.e. organic-rich shales) that incorporate lighter carbon isotopes in their composition. This results in increasing the ratio of $^{13}$C/$^{12}$C in the remaining carbon of the ocean and atmosphere.

- Another possible reason is due to the isotope fractionation between methane and residual solution that is caused by biological methane generation. Methane is the carbon compound that is most depleted in $^{13}$C. Generating it will increase the heavier carbon in residual solution leading to a more positive excursion, however, this will only be of local significance.
The Early Aptian is characterized by a large positive shift of the carbon isotope excursion and reflects changes in the global carbon cycle. This excursion is usually related to OAE 1a that indicates large-scale climate change and increased marine organic carbon burial. These events are usually associated with black shale deposits in deep ocean basins (Sliter, 1989). Also, this event may control the lower biodiversity of rudists bivalves and the shifts to *Lithocodium-Bacinella* as the main carbonate producers following these events (Van Buchem et al., 2010).

The OAE 1a is characterized by a negative excursion followed by a positive excursion of carbon-isotope ratio. The negative excursion is thought to be related to volcanism and enhanced CO₂ and possibly to the catastrophic release of methane gas hydrates (Vahrenkamp, 2010). Large-scale methane release could have been the reason of negative excursion in the carbon-isotope record, as methane has a highly negative carbon isotope signature. Followed by the release of methane, global warming has led to increase water temperature and high atmospheric CO₂ has led to increasing in the sea water acidity and sea level rise (Haq et al., 1987). This resulted in drowned carbonate platforms, and highly affected the dominant platform organism builders. This led to the spread of the *Lithocodium-Bacinella* facies for some time before the taxonomic turnover into the calcite-rich rudists (Skelton and Gili, 2012). These ocean water conditions favored an increase in nutrient flux and paleoproductivity resulting in expansion of the intermediate water oxygen-minimum zones (Vahrenkamp, 2010). The preservation of light carbon organic matter due to anoxic conditions in the basin eventually led to the subsequent positive excursions.

Several studies have concluded that during the deposition of the Kharaib and the Shu’aiba formations, a differentiation occurred on the Arabian platform from an overall shallow-water, open-marine carbonate deposition (Kharaib Formation) to the development of an intra-shelf basin surrounded by a shallow carbonate shelf (Shu’aiba Formation) as shown in Figure
3.2. This started after the marine reflooding recorded in Thamama Zone B and the deposition of the Hawar Member (part of Kharaib Formation) that is composed of shallow-water, argillaceous *Orbitolinid*-rich limestones (Dense A). This was followed by the deposition of the shallow-marine carbonate sediments in areas of relative topographic highs, and carbonate production slowed in other areas of the platform. During later stages, the Bab basin became starved of sediments due to the water depth that is unfavorable for shallow-marine deposits. Finally, the Bab intrashelf basin was filled with prograding pure carbonate wedges and organic-rich and argillaceous basinal deposits (Murris (1984), Vahrenkamp (1996), Vahrenkamp (2010), Van Buchem et al. (2010); Van Buchem et al. (2002), Droste (2010); Droste and Van Steenwinkel (2004)).

![Figure 3.2: Schematic lithostratigraphic scheme for the Barremian and Aptian strata of the southeastern Arabian Plate with facies change from platform to basin in the Aptian strata. Note different nomenclatures in different geographic areas, in this study UAE nomenclature is used (edited after Van Buchem et al. (2010))](image-url)
3.3. Data and Methods

Data for this study includes two cored wells from the crestal area of a large anticlinal oil field in onshore Abu Dhabi (Figure 3.1). Well cores were sampled at 1-foot intervals in the stratigraphic interval from the Aptian Hawar Member up to the top of Lower Bab Member (A0). Samples were drilled from the fine-grained lime mud matrix using a dental drill. Cements and recrystallized fossils were avoided to eliminate any material with major diagenetic overprint. Samples were transferred into sampling vials in an amount of a few milligrams powder per sample. They were analyzed for carbon and oxygen stable isotopes at the Colorado School of Mines Stable Isotope Laboratory in Golden, Colorado, USA. Carbonate samples for stable carbon and oxygen isotope analysis were weighed to the equivalent of 90 μg CaCO₃. Sample powders were reacted on-line at 90°C in a GV Instruments MultiPrep preparation device. The resulting CO₂ was cryogenically purified and analyzed by standard dual-inlet techniques on a GV Instruments IsoPrime stable isotope ratio mass spectrometer. Corrections of Craig (1953) were applied for the contribution of ¹⁷O, and all data are reported as a per mille difference from the Vienna PeeDee Belemnite (VPDB) international reference standard. Repeated analyses of blind sample duplicates and an in-house carbonate standard, calibrated to VPDB via NBS and IAEA standards, have yielded an external precision of ±0.03‰ δ¹³C and ±0.06‰ δ¹⁸O for this study.

3.4. Results and Discussion

This section includes results and discussion about the overall ranges of data, interfield correlation, intrafield correlation and diagenesis.
3.4.1. Overall Ranges of Carbon and Oxygen Isotopes

Well log analysis of the cored wells provided by Abu Dhabi Company for Onshore Oil Operations (ADCO) shows that the sampled interval is composed of more than 97% calcite with minor siliciclastics, dolomite and shale. Organic matter is localized around the clay-rich seams where pyrite is also present. The δ¹⁸O and δ¹³C values are plotted in Figure 3.3. The δ¹³C values vary between 1.3‰ and 4.3‰ and the δ¹⁸O values range from -7.5‰ and -4.6‰ VPDB. The data plot also shows the isotope ratios of oxygen and carbon of the low-latitude marine carbonates compiled by Prokoph et al. (2008). The results of this study have lower δ¹⁸O values, compared to the Aptian carbonates reported by Prokoph et al. (2008) probably due to warmer diagenetic fluids at the greater depths of the reservoir. The data plot range agrees with ranges reported by Vahrenkamp (2010) and others for the Shu’aiba carbonates in the Gulf region. According to Grötsch et al. (1998), Skelton (2003) and Strohmenger et al. (2010) the Shu’aiba Platform was located at low latitudes during the Aptian.

![Figure 3.3: Carbon versus oxygen isotope cross-plot of all measured samples in this study (n = 283). In this study, the δ¹³C values vary between 1.3‰ and 4.3‰ and the δ¹⁸O values range from -7.5‰ and -4.6‰. The isotope value ranges for low latitude Aptian carbonates (Prokoph et al. 2008) (red box) is shown as well as for Shu’aiba carbonates (Vahrenkamp, 2010) (blue box). Note there is significant deviation of the δ¹⁸O values from Cretaceous marine sea water (red box) indicating that there is a diagenetic overprint in this study area (Modified after Jobe, 2013).](image-url)
3.4.2. Interfield Correlation

Results from this study, which is situated in the Bab basin closer to the carbonate platform than the study area of Jobe, 2013, adds to the correlation done by Jobe (2013), where samples were obtained from the Bab basin depocenter, and compared to the well-studied carbonate platform by Strohmenger et al. (2010) as shown in Figure 3.4 and Figure 3.5. It fills the geographic area between the two previous studies.

When comparing δ13C curves provided by Strohmenger et al. (2010) in Figure 3.4 with data provided by Jobe (2013) and data from this study shown in Figure 3.5, there is a good match and correlation between the three fields. Compared to the platform deposits (in Figure 3.4), the Hawar Member, Thamama Zone A, and the Lower Bab Member A0 (in Figure 3.5) represent a condensed section that is equivalent to the third-order sequences of Apt2, Apt3 and Apt4 (a, and b) as subdivided by (Vahrenkamp, 2010). These sequences were defined in Chapter 1 in the background information section. In Figure 3.4, Hawar Member correlates to Apt 2 sequence, Thamama Zone A correlates to the lower part of Apt3 sequence. Moreover, reservoir zones of the A0 correlate to the Shu’aiba sequences as follow: zones A03, and A02 are time equivalent to the upper Ap3, zone A01 is time equivalent to the Ap4 sequence. It was noticed that time equivalence correlation (chronostratigraphic) is not necessary a facies (lithostratigraphic) correlation. It has been the tradition to correlate formations based on their lithological features, especially in carbonates, as lateral changes in carbonate facies are noticed over large distances, not like siliciclastic systems. Correlation using carbon isotope will be helpful in creating paleomaps of time equivalent facies, rather than to assume that formations with similar facies are time equivalent. The Lower Bab Member A0 thickens towards the northeast, which is believed to be towards the geographic center of the Bab basin, away from the Shu’aiba carbonate
platform. This means that some of the micrite has bypassed the platform margin toward the deeper Bab basin depocenter.

The $\delta^{13}C$ values tend to become more negative into the depocenter of the Bab basin. Also, it is worth mentioning that the total vertical depth (TVD) becomes greater as we move towards the NW towards the depocenter with a net of more than 3000 feet difference. Also, there could be another explanation for this trend into the basin, a decreasing aragonite content which has higher $\delta^{13}C$ than calcite, would result in a more negative $\delta^{13}C$ (Jobe (2013) and Kimbell and Humphrey (1994)). Moreover, an increase in organic matter towards the depocenter of the basin could be held responsible for decreasing $\delta^{13}C$ in the basin.

3.4.3. Intrafield Correlation and Diagenesis

The $\delta^{18}O$ curve is also a useful tool for correlation at the intra-field scale as shown in Figure 3.6. Overall the carbon and oxygen curves reflect that the carbon signature can be interpreted as representing geologic correlation timelines, and that the oxygen signature follows the carbon signature in similar diagenetic environments. Major trends in the $\delta^{18}O$ curve were used as correlation guidelines and might indicate similar diagenetic environments. Figure 3.7 shows that there is a correlation between the oxygen isotope curve and porosity. High oxygen-isotope values correspond to more porous intervals. In order to better understand and to quantify how diagenesis affects the $\delta^{18}O$ values, plug porosity versus $\delta^{18}O$ were plotted in Figure 3.8. These plugs come from the Hawar Member, Thamama Zone A, and the Lower Bab Member A0. They include facies of different texture (rudist and Bacinella biofacies included) and fine basinal deposits. The reason for including other facies in this plot is to increase data points, as removing the other facies will increase the error in calculating the best fit function, due
Figure 3.4: Carbon isotope analysis of Strohmenger et al, 2010. It was combined with strontium isotope analysis to provide absolute age dates as marked in Wells C and D. The curve on the right hand side to the yellow box comes from well 2 of this study. The dashed lines represent correlation lines between carbon curves (i.e., chronostratigraphic correlation). Red dashed line mark the boundaries of the OAE 1a. From the graph it is estimated that the Hawar is time equivalent to Ap2 Sequence, Thamama Zone A is time equivalent to lower Ap3 sequence and Zone A03, and A02 are time equivalent to the upper Ap3, and Zone A01 is time equivalent to Ap4 sequence. Note that time equivalence correlation (chronostratigraphic) is not necessarily a facies (lithostratigraphic) correlation.
Figure 3.5: Correlation panel through two anticlinal oil fields onshore (this study) and offshore (Jobe, 2013) Abu Dhabi in Bab basin. Vertical profiles are datumed at the top of the Lower Bab Member A0 at the Bab Shale (green line), the range between the upper and the lower red lines represent the OAE1a equivalent. The blue lines correlate similar features of carbon isotopes (chronological lines). Depths displayed here are true vertical depths. Formations are highlighted in different shades and their information is between wells 1 and 2 (onshore). Note that chronological lines are representing time at which these sediments were deposited, and don’t necessarily follow lithostratigraphic correlations (shaded). The core data for this study come from an anticlinal feature and depending on the position of the well the stratigraphy can be slightly stretched. Vertical wells on the flanks display slightly stretched stratigraphy relative to wells on the crest. Depth gridlines represent 20 feet.
to the small number of points. Data on the two plots comes from Well 1 (onshore) only. Figure 3.8a shows that there is a polynomial relationship between porosity and $\delta^{18}O$. The polynomial best fit function provided the highest coefficient of determination $R^2$. However, as oxygen signature is mass dependent, the oxygen signature should follow a linear best fit function, which in this case provided a lower $R^2$. Porosities lower than 10% and permeabilities less than 0.1 mD tend to have a wide range of $\delta^{18}O$ values. If only values greater than 5% porosity are considered, a more accurate best-fit function is evident, as data in the smaller values range tend to be more scattered. A new best fit function was calculated, excluding data with less than 5% of porosity and is shown in Figure 3.8b. The scattering of points less than 5% porosity can be interpreted to be caused by more extensive cementation or compaction in the lower porosity samples, whether it was syndepositional or post-depositional cements.

A simple calculation from porosity and $\delta^{18}O$ was performed to estimate water temperature of the original carbonate particles and the diagenetic fluid temperature of the cement. This calculation uses the assumption that the original porosity at the time of deposition is about 50% based on abundant literature including Terzaghi (1940) and Stockman et al. (1967). Another assumption is that the pore water is ocean water and not meteoric water that are usually depleted with $^{18}O$. Assuming porosity as 50% in the polynomial best fit function in Figure 3.8a, $\delta^{18}O$ will be equal to -3.45‰ VPDB. Using a correlation made by (Steuber et al., 2005), water temperature at time of deposition will be around 27°C for the 50% original porosity after extrapolation of the best-fit function. The cement will occlude this 50% porosity and when porosity value is zero, so it is important to take into account the mass balance into the calculation for the cement as shown in Figure 3.9. Using the best fit function, which is a polynomial, $\delta^{18}O$ is
Figure 3.6: Carbon and oxygen isotope analysis was used for intrafield correlation of two wells onshore Abu Dhabi showing a thickening trend to the NE towards the depocenter of the Bab basin. The lines are correlation lines (solid red: top of Dense A or Hawar Member, different reservoir and non-reservoir zones are shaded in different colors, and green line: Bab Shale that marks the top of the lower Bab Member A0). Red dashed lines mark the OAE 1a and the blue lines are chronostratigraphic correlation lines using carbon and oxygen isotopes. Well 1 is well Sb-359 and Well 2 is well Sb-322 from Figure 2.1.
Figure 3.7: Composite plot showing plug porosity (red curve) against clay rich seam thickness (blue bars) and the oxygen isotope results of the same well. There is a correlation between the oxygen isotope curve and the degree of cementation. High oxygen values correspond to more porous intervals.
Figure 3.8: A cross plot of core plug porosity versus the $\delta^{18}$O in per mil VPDB. Two best-fit functions were calculated: polynomial-scale (A) and linear scale (B). Data come from the Hawar Member, Thamama Zone A, and the Lower Bab Member A0 from well 1 in Figure 3.6. They include facies of different texture (rudists and Bacinella biofacies) and fine basinal deposits. There is a weak correlation that the $\delta^{18}$O values become more positive with increasing porosity. At low porosity, there is a cloud scatter of $\delta^{18}$O values, probably due to different generations of cements or due to compaction; where no chemical reaction affected the oxygen isotope, but rather mechanical compaction lowered porosity (n=113).
Figure 3.9: A diagram showing how the cement oxygen signature was extracted by using mass balance calculation. The unknown in this equation is the oxygen isotope value of the cement by extrapolating the best fit function we can calculate the known for the original sediments (around 50% porosity) and the known of the fully occluded rock (around 0%) we can mass balance the knowns to get the unknown.
about -5.78‰ VPDB. Using the mass balance calculation of original carbonate (50% porosity) and the (zero % porosity), δ¹⁸O is estimated to be -8.1‰ VPDB. This indicates that the diagenetic fluid had a temperature of about 50°C, assuming that the fluid was Cretaceous seawater. The same calculation was performed using the linear best fit function in Figure 3.8b and provided higher temperatures: water temperature at time of deposition of 33°C and diagenetic fluid temperature of about 54°C. Having diagenetic fluid temperature in the range of 50-54°C indicates that the burial depth at which cementation occurred is not deep and if we assume that the geothermal gradient is about 25°C/Km and annual surface temperature of 27°C, burial depth will be less than 500m. This could explain why microporosity of the micrite and microfossils was preserved leading to the high storage capacity of the A0.

3.5. Conclusions

The chemostratigraphic record of the Aptian-aged formations has been enhanced with a new set of data. Two wells have been analyzed from the crestal region of a large anticlinal onshore field in Abu Dhabi. It complements data from the carbonate platform of the Shu’aiba Formation by recording the time-equivalent Lower Bab Member A0 basinal deposits. This study has confirmed that carbon isotopes curve can be considered a reliable correlation tool at regional and global scales. Carbon isotope results from this study were correlated with data from the carbonate platform (Strohmenger et al. (2010)) and from the depocenter of the paleo-Bab basin (Jobe (2013)). Results of this study can be summarized in the following points:

- The δ¹³C values vary between 1.3‰ and 4.3‰ and the δ¹⁸O values range from -7.5‰ and -4.6‰ VPDB.
• The δ\(^{18}\)O curve was a useful tool for intra-field correlation as it correlates similar diagenetic environments and that the δ\(^{18}\)O curve is consistent with the δ\(^{13}\)C curve and maintains a correlative pattern even though it has a diagenetic overprint.

• The Lower Bab Member (A0) deposits tend to thicken towards the depocenter of the basin, based on the δ\(^{13}\)C curve of the inter-field correlation.

• Based on the δ\(^{13}\)C inter-field correlation, the Hawar Member, Thamama Zone A and the Lower Bab Member A0 in this study represent a condensed section that is equivalent to the third-order sequences of Apt2, Apt3 and Apt4 (a, and b). In more detail, the Hawar Member correlates to the Apt 2 sequence, Thamama Zone A correlates to the lower part of the Apt3 sequence. Moreover, reservoir zones of the A0 correlate to the Shu’aiba sequences as follow: zones A03, and A02 are time equivalent to the upper Ap3, and zone A01 is time equivalent to Ap4 sequence.

• Time equivalence correlation (chronostratigraphic) is not necessary a facies (lithostratigraphic) correlation. It has been the tradition to correlate formations based on their lithological features especially in carbonates, as lateral changes in carbonate facies are noticed over large distances, not like siliciclastic systems. Correlation using carbon isotope will be helpful in creating paleomaps of time equivalent facies.

• There is a correlation between porosity with δ\(^{18}\)O values, correlation is stronger for higher porosities and permeabilities.

• Based on simple calculations, the temperature of marine water while depositing the studied samples ranges from 27-34°C. The temperature of the diagenetic fluid that caused cementation is interpreted to be about 50-54°C.
• The $\delta^{13}$C values become more negative moving toward the depocenter, that could be the result of higher temperature due to greater burial (TVD), an increase in organic matter in the depocenter, and/or the result of the aragonite-rich carbonate platform compared to the calcite-rich basin.

3.6. References


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4. CHAPTER 4: PORE ARCHITECTURE CHARACTERIZATION OF A BASINAL TIGHT CARBONATE: AN APTIAN RESERVOIR IN THE BAB BASIN OF THE MIDDLE EAST

4.1. Abstract

Most carbonate reservoir rocks have been developed using conventional development schemes, due to the presence of macropores that are responsible for high porosity and permeability. The main focus of this study are basinal carbonate reservoir rocks that lack macropores, but contain pores that are less than a micrometer in size. These rocks have high hydrocarbon saturation within the matrix microporosity, and are found in a structural trap in the Middle East. The study data comes from the Lower Bab Member (A0) that is the basinal carbonate deposit equivalent to the Aptian Shu’aiba Formation. The Lower Bab Member (A0) was deposited in the intrashelf Bab basin of Abu Dhabi.

Permeability can reach a maximum of 3 mD, as a result of the small pore sizes while porosity can range up to 24%. This study tests different techniques to characterize the nature of the porosity and permeability. These techniques have different capabilities and resolution limitations and include: seismic interpretation to observe depositional geometries, well log analysis, core description, QEMSCAN® (quantitative evaluation of minerals and porosity by scanning electron microscopy), SEM (scanning electron microscopy), CMS 300® (core measurement system), mercury porosimetry, and nitrogen gas adsorption. Integrating these techniques across different scales has helped characterize the pore architecture at different pore scales.

Lithofacies analysis has shown a very small change in texture and the dominant facies varies between wackestone to mudstone. The Lower Bab Member (A0) has significant storage
for hydrocarbons, dominated by the microporosity in micrite. The degree of cementation in the matrix is the main control on the microporosity readings. Clay rich seams and stylolites are associated with excess cementation that lowers porosity. Pore size and shape distribution helps explain lower permeability values, even though storage capacity is high.

4.2. Introduction

Most productive carbonate reservoir rocks have been developed using conventional development schemes. In recent years, as technologies have advanced (e.g. hydraulic fracking techniques) there has been a shift in focus toward tighter reservoir rocks. Carbonate rocks are heterogeneous and their reservoir properties can range from a highly productive reservoir rock to a highly cemented seal. The main two controls on these reservoir properties are sedimentology and diagenesis that control rock texture, pore architecture, and how the rock behaves under fluid flow. This study focuses on a low permeability carbonate reservoir. The prolific Aptian Shu’aiba Formation has been on production for a long time, due to the high porosity and permeability that resulted from the high-energy platform rudist/Lithocodium-Bacinella rich carbonates. Equivalent to the Shu’aiba Formation are the basinal deposits of the Bab Member that were deposited in the Bab intrashelf basin. The Bab Member has been divided into Lower and Upper Bab Members. The Lower Bab Member represents the time equivalent of the aggradational/progradational sequences of the Shu’aiba Formation during highstand in sea level during the Apt2, Apt3, Apt 4a and Apt4b sequences, as reported in Chapter 3. The Upper Bab Member occurs as part of a wedge that onlaps the erosional surface at the top of the Shu’aiba clinoforms at the carbonate platform. It is equivalent to the progradational lowstand systems tract of the Apt5 sequence that fills the remaining accommodation space in the Bab basin.
The Lower Bab Member (A0) has very good oil saturations in the Asab field onshore Abu Dhabi. In this study, the main concentration is on basinal carbonate reservoir rocks that lack macropores, but contain pores that are micrometers in scale or less. These rocks have high hydrocarbon saturation within the matrix microporosity, and are found in a structural trap. This study uses different techniques that have different capabilities and resolution limitations, to characterize the nature of the porosity and permeability in the A0.

A very important aim of this study is to characterize the reservoir rock that has high storage capacity for fluids but very low permeability. The A0 is considered a conventional system due to its structural trap in an anticline, but as it has a low-permeability texture, applying unconventional techniques might be the right direction for development. Unconventional systems usually occur over broad regional areas and are commonly independent of structural and stratigraphic traps. In comparison to other current unconventional systems, the Lower Bab Member is an oil-prone tight carbonate reservoir compared to a majority of gas prone systems. The size of the Bab basin (intrashelf) is considered local over 10s of kilometers compared to huge shale plays around the world. Porosity in the A0 can reach up to 25% and permeability can reach 3 mD in high permeability zones, which is a better reservoir quality than most unconventional systems.

The Bab Member has been described as a source rock by many studies (Aldabal and Alsharhan (1989), Alsharhan et al. (2000) and Nairn and Alsharhan (1997)). The Bab Member basinal facies consist of argillaceous lime mudstone and wackestones, dominated by pelagic and planktonic faunas, in which the total organic content TOC ranges between 1-6 wt% and pyrolysis yields reach 16 kg/ton (Nairn and Alsharhan (1997) and Alsharhan et al. (2000)). The relatively high TOC that can occasionally reach up to 10% (Taher (2010)) comes from the preservation of
algae and phytoplanktonic biota remains below the active wave base and in a restricted water body with anoxic conditions (Alsharhan et al. (2000)). Moreover, the Aptian marks the onset of the oceanic anoxic event 1a (OAE 1a) which can enhance the storage of organic matter in basins, as reported by many studies including but not limited to (Budd (1989), Moshier (1989a), Wagner (1990), Vahrenkamp (1996), Van Buchem et al. (2002), Hillgärtner et al. (2003), Immenhauser et al. (2004) Vahrenkamp (2010) Méhay et al. (2009), and Jobe (2013)). Anoxic events are usually associated with high stands in sea level, where sea level covers large terrestrial areas that provide organic-rich terrestrial and planktonic material that is deposited rapidly and consumes the oxygen dissolved in seawater, enhancing the preservation of organic matter (Jenkyns (1980)).

According to Deville de Periere et al. (2011) microporosity accounts for a significant part of the total porosity in most of the Cretaceous limestone reservoirs in the Middle East. The example of Ghaba North Field, Oman, is an excellent example of this (Al-Awar and Humphrey, 2000). Microporosity is the dominant porosity type accountable for holding the majority of the reserves (Moshier, 1989a). Identifying whether microporosity is effective or ineffective depends on pore-throat size, reservoir pressure and temperature, and viscosity of the oil and gas (Smith et al., 2003).

As stated by Moshier (1989a), the matrix in the Shu’aiba Formation in Sajaa field, North Eastern UAE, is composed of euhedral to subhedral, micro-rhombic that are associated usually with meteoric water, low-Mg calcite crystals with average diameter of 5μm. Moreover, the matrix is believed to be a result of the early diagenetic process that converted calcitic lime mud into micro-rhombic micrite and microspar, and resulted in microporosity in the matrix. This was based on trace element analysis conducted on samples from the Shu’aiba Formation in Sajaa field. The preservation of microporosity depended on the relatively quick stabilization of the
matrix that reduced matrix cementation without introducing outsourced calcite into the system (Moshier, 1989a; Moshier, 1989b). This result agrees with a study of mud deposition in a recent isolated carbonate platform that shows that the matrix can be recrystallized relatively early after deposition (Gischler and Zingeler, 2002). However, during burial, diagenesis can create porosity by dissolution of micrite (Lambert et al., 2006; Moshier, 1989b) or can be destroyed by dynamic cementation in response to oil charge (Cox et al., 2010).

4.3. Methodology

Porosity characterization data for this study come from subsurface well cores, and well logs from Asab field, onshore Abu Dhabi, United Arab Emirates, that is situated in the Bab basin. The first stage of this project was to identify lithofacies and describe their porosity using core description and petrographic analysis. Three lithofacies have been identified and described in Chapter 2. Point counting for porosity quantification was very challenging as the pore sizes of the Bab Member were lower than the resolution of the binocular microscope, and the microporosity appeared as blue-haze from the impregnated epoxy. As a result, other tools have been used. These tools include: (1) regional seismic lines in the area west of the field towards the platform margin of the Shu’aiba Formation to identify depositional geometries and how reservoir properties may change across the basin, (2) the field Petrel® project provided by the operating company that contains interpreted well logs from the field, (3) QEMSCAN® backscatter electron mode analysis, (4) conventional core analysis results of plug porosity and permeability provided by the operating company using the core measurement system CMS 300, (5) scanning electron microscopy SEM, (6) mercury porosimetry, and (7) nitrogen gas adsorption-desorption.
4.3.1. Regional Seismic Profiles

Six 2D seismic lines were provided by ADNOC for the area west of Asab field and east of Bu Hasa field, in the Al Falaha syncline. The main purpose of interpreting these lines is to capture any discontinuity or change in geometry between the two fields. Figure 4.1 shows the location of the 2D seismic lines. The top of the Bab Member horizon was picked on the six regional seismic lines. The closest offset between the Asab field 3D seismic cube and the regional 2D seismic lines is about 3 km, and allowed correlation of the Bab Member horizon between the field and the regional lines. However, two strong reflection horizons, which are above and below the top of Bab Member, were picked as control horizons to reduce any possible errors in picking the low-reflection top Bab Member horizon. Picking the reflectors was manual for the Bab Member due to some discontinuities in their reflectors.

Figure 4.1: Six 2D seismic lines of the area west of Asab field. Scale bar is 5 km and the arrow is towards the North.
4.3.2. Well Log Analysis

The field master Petrel® project was provided by the operating company. It included a complete data set of the field: well logs, cored intervals, reservoir static and dynamic models, plug data, and other important drilling information. The main producing formations in the field are stratigraphically below the Lower Bab Member (A0), allowing the majority of the wells in the field to have well logs that penetrate the A0. The completeness of this data set helped significantly in correlating over the field using the well logs from across the field. Six cross sections of well logs showing effective porosity (PHIE) in Asab Field were constructed across the field (Figure 4.2). Effective porosity (PHIE) corresponds to the porosity that is contributing to fluid flow and does not include isolated pores. The reason for choosing PHIE is that it corrects the total neutron porosity by removing the bound water volume in shaly sediments. Moreover, other well logs such as the Gamma Ray (GR) showed frequent spikes that were challenging to correlate across the field, and they were not used. Well logs have been datummed to the Bab Member Shale (top of A0) as the maximum flooding surface; as it is considered the shaliest part of the Bab Member.

4.3.3. QEMSCAN® (Quantitative Evaluation of Minerals and Porosity by Scanning Electron Microscopy).

The QEMSCAN®-BSE tool can quantify the porosity by measuring pore spaces from thin sections with up to 1 micrometer resolution. It was performed at the Electron Microscopy Laboratory at the Colorado School of Mines. The QEMSCAN® instrument consists of a custom-built Carl Zeiss EV050 electron beam platform equipped with four Bruker X275HR silicon drift energy dispersive x-ray spectrometers (EDS) and a four-quadrant semiconductor diode
backscatter electron (BSE) detector. Instrumentation is combined with a rotary stage capable of stepwise rastering of samples at pre-defined intervals.

**Figure 4.2:** Six cross-sections were created: west flank, east flank and the crest of Asab Field. Numbers 1-6 corresponds to the location of cross sections in Figure 4.5 and Figure 4.6.

This analysis was applied to 10 thin sections from core plugs that were duplicated for SEM image analysis. Mercury porosimetry, nitrogen gas adsorption-desorption, and conventional core analyses were also performed on samples from these plugs. Thin sections from the crestal well (Sb-359) were impregnated with blue epoxy to show porosity. Thin sections were taken from core plug trims with diameter of 1.5 inches. Thin sections were ground to 1 micron...
and a 250Å carbon coating was applied. Due to the abundant microporosity, the major porosity type in the samples in this study, three square areas from different places on the same thin section were imaged. Each square is 0.5 cm long by 0.5 cm wide. The BSE intensity can be scaled to identify minerals from non-mineral particles (porosity) with a resolution up to 1 micrometer. This is due to the fact that the size of the beam that scans the mineral is 1 micrometer in diameter. Backscattered electron (BSE) values were taken with a beam stepping interval (i.e., spacing between acquisition points) of 1 micrometer, an accelerating voltage of 25 keV, and a beam current of 5 nA. The BSE values were compared with values held in a look-up table allowing an assignment to be made at each acquisition point. This procedure allows a porosity map of the sample to be generated.

A trial imaging of two thin sections from two different lithofacies was done to test the range of heterogeneity in each sample. Measurements categorized: 1) mineral (BSE threshold 35+), 2) porosity (BSE threshold 0-27), and 3) porosity + mineral transition (BSE threshold 27-35). The mineral area indicates that it is occupied with mineral and we are 100% confident. The same with porosity; where we are 100% confident that this area is fully porosity. The third category represents areas where the resolution is lower than that can distinguish between the mineral and the porosity. Initially, the analysis of this imaging was to obtain a value for porosity and compare it to the conventional core analysis porosity. The BSE intensity of the scans of some individual pixels was examined to see if the thresholds that were set before provide realistic results compared to plug analysis. Using the recommended scale BSE intensity of 35 and above for carbonates provided values of lower porosity when compared to CMS300 plug porosity (4-12 porosity units lower). After testing new brightness values, calcite was very bright and so the scale of calcite was set to a BSE threshold of 40 and above, an increase from the
previous scale of 35 and above. The new thresholds for the tight carbonate, using QEMSCAN are:

- 0 - 27: Porosity (P)
- 27 - 35: Porosity to Mineral transition (PM)
- 35 - 40: Mineral to Porosity transition (MP)
- 40+: Mineral (M)

By applying the new scale for brightness, total porosity (any value below 40) is more reasonable and very close to the porosity from CMS300. The new scale works the best for tight carbonate rocks with pore spaces less than a micrometer in scale.

The results of the QEMSCAN®-BSE analysis are high-resolution digital images, from which every pixel represents 1 micrometer. These digital images were processed using iDiscover® software to calculate porosities and extract pore size and shape information, and calculated porosity includes P, PM and MP. Pixels that are categorized to be pores and forming clusters of porosity pixels (pore bodies) were extracted and pore sizes were assigned from the shortest axis of bore bodies. Similar, the long and short axes were used to calculate the aspect ratio that is measured by dividing the longest axis of pore spaces by the shortest axis.

**4.3.4. CMS 300® (Core Measurement System) and Clay Seam Documentation**

Core-plug porosity and permeability values were provided by Abu Dhabi Company for Onshore Oil Operations (ADCO). They were measured by Core Lab facility in Abu Dhabi using the core measurement system CMSTM-300. It followed the routine core analysis procedure to calculate porosity and permeability from standard core plugs from the same studied field.

Besides core description, clay rich seams/stylolites data were described from three crestal Asab wells, Sb-359, Sb-347, and Sb-322, in the Lower Bab Member and Thamama A unit. The
data included: depth, thickness, amplitude of deformation, and type of seams. Types of seams included: undeformed clay seams, stylolites, or mixture of both. The main reason for this documentation is to understand the role that these frequently occurring (every 1-2 feet) stylolites/clay seams have on reservoir properties, and to understand the origin of these sedimentary structures.

4.3.5. SEM

Scanning Electron Microscope (SEM) has been used to study twenty-three samples at the Petroleum Institute in Abu Dhabi to image the relatively high porosity (up to 25%) and to understand the low permeability (up to 3mD) of the A0. The SEM is equipped with analytical systems, which are: energy dispersive spectrometer, wavelength dispersive x-ray spectroscopy and electron backscatter diffraction. The samples were prepared from core plug broken chips with natural breakable surface and no polishing. Scanning electron microscopy often requires that specimens be coated with a conductive metal, such as gold as was done in this study. This helps prevent charging, ensures that the surface conducts evenly; to be able to get the highest signal with minimal noise (Miller et al. (2004); Leslie and Mitchell (2007), Jones et al. (2012)), and provides a reflective surface for translucent or transparent specimens (Purnell et al. (2012)).

Samples were placed in a chamber that was put under high vacuum with a movable stage. The SEM has provided qualitative pictures of micrite textures with high magnifications up to half a micrometer scale. The SEM also provided elemental spectrum of the samples confirming that the dominant mineralogy of the samples is calcite.

4.3.6. Mercury Porosimetry

Mercury porosimetry is one of the most frequently used tools in the oil industry in special core analysis for reservoir simulation, to obtain capillary pressure curves. The most commonly
measured process is Mercury Injection Capillary Pressure (MICP). MICP is based on the principle that mercury is a non-wetting liquid to pores, and non-wetting liquid cannot intrude pores spontaneously without applying pressure due to preventive physical parameters. This pressure should overcome the capillary pressure and is called the entry or threshold pressure. According to Webb (2001) the mercury intrusion porosimetry test involves placing a sample into a container, degassing the sample, allowing mercury to fill the container. Next, pressure is incrementally increased, and volume and pressure of the injected mercury are recorded. Total volume of the injected mercury reflects the volume of the effective porosity. Washburn’s equation is used to calculate pore diameters by linking the external pressure to the pore diameter (Washburn (1921)). Ten samples were sent to Micrometrics in Georgia to conduct mercury intrusion and extrusion analysis for a pore size range of 360 to 0.003 µm using the ISO 15901-1 method. Mercury intrusion and extrusion data were collected using a Micromeritics AutoPore IV 9500®. Sample masses used in this analysis ranged from 2-5 grams of plug trims. Mercury surface tension was 485 dyns/cm and contact angle was 130°. Samples were degassed at 50 µmHg evacuation pressure for 5 minutes. Total intrusion volume and incremental intrusion pressures were measured yielding effective pore volume and calculated pore diameters respectively. Extrusion part is essential to observe the hysteresis effect of mercury, which is indicated by a shifted curve of differential pressure between intrusion and extrusion parts.

4.3.7. Nitrogen Gas Adsorption-Desorption

Nitrogen gas adsorption-desorption analysis is used to obtain specific surface area, pore volume and average pore size of porous materials with pore diameter of less than 0.1 micrometer (Richards (2006)). When a gas or a vapor phase is brought into contact with a solid, part of it is taken up and remains on the outside attached to the surface. This attachment comes from weak
Van der Waals attraction between adsorbate and the solid surface. This process involves measuring the amount of gas adsorbed across a wide range of relative pressures at a constant temperature, creating an adsorption isotherm. Equally, when gas is removed as pressure is reduced, desorption isotherms are achieved by measuring the gas amount. These adsorption/desorption isotherms are controlled by the pore shape and surface area. The Brunauer, Emmett and Teller (BET) method is most commonly used to describe specific surface area and was used in this research. The pore size distribution curve from the nitrogen adsorption/desorption hysteresis shapes was done using the Barret-Joyner-Halenda (BJH) method that assumes a cylindrical pore geometry model and that the liquid will evacuate (desorption) pores according to the Kelvin equation. Ten samples were sent to Micrometrics in Georgia to conduct Nitrogen gas adsorption-desorption analysis using the ISO 15901-2 procedure. Experiments were conducted using a Micrometrics ASAP 2420® (Accelerated Surface Area and Porosimetry) system. Sample masses used in this analysis ranged from 2-5 grams. They were degassed at 105°C for 16 hours. Data for a 40-point adsorption isotherm as well as a 40-point desorption isotherm were collected and the BET surface area, BJH pore size distribution and total pore volume were calculated.

4.4. Results and Discussion

This section includes the following results: seismic profile results, well logs across the field, QEMSCAN results, comparison of QEMSCAN results and other porosity measuring tools, CMS300 and facies, SEM results, mercury porosimetry and nitrogen gas adsorption-desorption and finally reservoir rock development
4.4.1. Seismic Profile Results

The seismic line 85-20 shows that below the top Bab Member horizon clinothems are present that prograde toward what is thought to be the pre-Bab basin (Figure 4.3). These clinothems possibly occur in the Thamama B or Thamama C reservoir unit intervals, and suggests that Bab basin might have started earlier than Bab Member age. These geometries are progradational geometries toward the present Falaha syncline west of Asab Field. It appears that the center of the pre-Bab basin is closer to Asab Field than Bu Hasa Field. The Bab Member itself shows no change in depositional geometries, but rather looks like a carbonate ramp, which is probably due to the resolution of the seismic data and the relatively thin Bab Member deposits compared to the Shu’aiba carbonate platform.

![Seismic Profile](image)

Figure 4.3: Seismic line 85-20 showing internal geometries below the Bab Member prograding toward what is thought to be the pre-Bab basin. Light blue horizon is the top of Bab Member, light green and the pink horizons are control horizons.
Figure 4.4 shows the Asab Field with three clinoforms of the Upper Bab Member (Aptian 5) clay rich deposits that filled the remaining of the Bab basin during Aptian 5. Seismic resolution could not identify depositional geometries in the lower Bab Member. This indicates that the A0 was deposited as a condensed section in the deeper part of the ramp (lower sedimentation rate) during a sea level highstand.

![Time thickness analysis of Top BAB to Top C](image)

**Asab Field**

![Asab Field cross-section](image)

**Figure 4.4:** A time-thickness cross section (NNE-SSW) of the Asab Field showing three clinoforms in Bab Member (ADCO, 2010)

### 4.4.2. Well Logs across the Field

Six cross sections of well logs showing effective porosity (PHIE) in Asab Field have been plotted (Figure 4.2). PHIE logs are scaled from 0 to 45% in every plotted well. The Lower Bab Member is shaded in light orange in all of the cross sections (Figure 4.5 and Figure 4.6). The Lower Bab Member overlies the Thamama A reservoir unit.
The main findings from these cross sections, shown in Figure 4.5 and Figure 4.6 are as follows:

- When the wells are referenced or flattened on the Top of A0, Thamama A is a very gently dipping ramp towards the north to northwest. It is estimated that the dip angle of the map is less than 0.1° for the most northeastern five to six kilometers, and it becomes almost flat in the southwestern portion of the field. The Lower Bab Member is thickening over the ramp in the same direction. This agrees with the observed carbonate ramp geometry from the seismic interpretation.

- The highest effective porosity in the Lower Bab Member is located in the crest of the Asab Anticline, and the eastern flank shows better effective porosity than the western flank. These changes in effective porosity are interpreted to be due to: (1) the highest porosity in the crest is the result of hydrocarbons preserving porosity compared to the flanks where water saturation is high enough to cause cementation and occlude porosity. A contributing factor may also be that porosity on the structural flanks could be reduced as a result of compaction due to higher stress along the flanks in the process of folding the Asab anticline; and (2) the reason for the difference in effective porosity between the eastern and the western flanks may be controlled by the original depositional porosity; as the western flank was in a deeper down-ramp position than the eastern one. Another possible interpretation may be that the western flank has been under higher tectonic pressure, which resulted from the collision of the Arabian plate with the Eurasian plate.

- The overall geometry of high effective porosity zones is a progradational trend with minor aggradational trend. In Figure 4.5, cross sections 1, 2 and 3, which are running NNE to SSW, correlate these high effective porosity zones. These zones might be continuous across the
field, and are important due to the relatively high porosity, which qualify them to be target zones.

- Figure 4.6 illustrating cross-sections 4, 5 and 6, are oriented WNW to ESE, and show almost semi parallel geometry, but have a very gentle dip towards SE. These trends agree with the interpreted location of the Bab basin location in respect to Asab Field shown in the map in Chapter 3.

Figure 4.5: Three cross sections showing PHIE (0-45%) across Asab Field (NNE to SSW). The cross sections are flattened at the top of A0. They show a gently dipping carbonate ramp below the A0 that becomes flat moving to the north. The crest has the highest effective porosity due to oil preserving porosity. Porosity decreases toward the NNE towards the Bab basin depocenter.
Figure 4.6: Three cross sections showing PHIE across Asab Field (WNW to ESE) and PHIE (0-45%) across Asab Field. The cross sections are flattened at the top of A0. There is a gentle component of progradation towards the SE.

4.4.3. QEMSCAN Results

Figure 4.7 illustrates the results of scanning each thin section using QEMSCAN® BSE mode. First, three panels of 0.5 cm*0.5 cm area were scanned using the QEMSCAN® BSE mode.
Every pixel of the scan had the highest resolution of 1 micrometer, and was assigned a BSE intensity value. Pixels where assigned to groups (i.e. threshold ranges) based on their BSE intensity values as discussed previously in the methodology section. These groups were color-coded and their area percentage was created for each panel of a thin section. Next, all pore bodies were extracted to the iDiscover software for statistical analysis of pore size and shape. Figure 4.8 shows how all pore spaces were categorized and grouped according to pore size and shape factor, using sample 37 as an example. The observed overall trend is: the smaller the pore size, the smaller the aspect ratio and the majority of the pore size in most samples are less than 10 micrometer in size. The same figure shows the pore size distribution of the same panel with the volume percentage, and shows the aspect ratio versus the volume percentage.

Table 4-1 summarizes the different average porosity values calculated using: QEMSCAN® BSE mode, CMS300, mercury porosimetry, and well log calculated porosity. Nitrogen was used only for determination of smaller pore size distribution. Porosity was not calculated from nitrogen, as it would be relative and non-representative. The QEMSCAN® BSE mode column includes three porosity groups with their percent volume, each sample value in the table is an average of the three panels of each thin section. Since analyzed samples have very small pore sizes that are in general smaller than the QEMSCAN beam size, it would be reasonable to use the maximum porosity value (which is the sum of: POR, POR+MIN, and MIN+POR areas) to be compared to other tools. Table 4-2 shows the pore size distribution analysis created by pore body analysis using the iDiscover software. There is a general trend that the majority of the samples have their dominant sizes less than 10 micrometer in size. Sample 79 comes from the top of the Thamama Zone A at the base of the A0, and sample 117 belongs to the Hawar Member (Dense A).
Figure 4.7: Three panels of 0.5 cm*0.5 cm area were scanned using the QEMSCN® BSE mode. Every pixel of the scan had the highest resolution of 1 micrometer, and was assigned a BSE intensity value. Pixels where assigned to groups (i.e. threshold ranges) based on their BSE intensity values as discussed previously in the methodology section. These groups were color coded and their area percentage was created for each panel of a thin section.
Figure 4.8: All pore spaces were categorized and grouped according to pore size (shortest diameter length) and shape factor (aspect ratio). Right hand graphs show the volume percentage, versus pore size distribution and the aspect ratio.
Table 4-1: A summary of the porosity measured by QEMSCAN, CMS300, Mercury Porosimetry and porosity from well logs, along with the lithofacies. Samples 79 and 117 are not part of the A0, but from Thamama Zone A and the Hawar Member.

<table>
<thead>
<tr>
<th>Sample</th>
<th>Lithofacies</th>
<th>QEMSCAN® BSE mode</th>
<th>CMS®300</th>
<th>Mercury Porosimetry</th>
<th>Porosity well log</th>
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<tr>
<td></td>
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Table 4-2: Pore size distribution using the QEMSCAN® BSE mode after being analyzed by iDiscover software.

<table>
<thead>
<tr>
<th>Sample</th>
<th>Lithofacies</th>
<th>QEMSCAN® BSE mode (Area %)</th>
<th>CNMS®/300</th>
<th>CNMS®/400</th>
<th>Pore Size Distribution (μm) using QEMSCAN-BSE mode</th>
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<td>MIN+POR</td>
<td>MAX+POR</td>
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<td>26.07</td>
</tr>
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<td>10.18</td>
<td>16.37</td>
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</tr>
<tr>
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<td>12.36</td>
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</tr>
<tr>
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<td>1.74</td>
<td>11.86</td>
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</tr>
<tr>
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</tr>
<tr>
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<td>15.88</td>
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</tr>
<tr>
<td>117</td>
<td>(DA)</td>
<td>0.06</td>
<td>0.64</td>
<td>3.35</td>
<td>4.05</td>
</tr>
</tbody>
</table>
Table 4-3 shows the pore shape distribution analysis created by pore body analysis using the iDiscover software.

By observing table 4-2 and 4-3, samples that belong to lithofacies 1 show an increase in volume percentage with increasing pore size that peak at pore sizes (5-10 micrometers). The increase has a linear to exponential trend. The higher the percentage of 5-10 micrometers sized pores, the higher the MAX POR from QEMSCAN compared to POR from CMS300. This could indicate that the isolated pores that come from the coccoliths are abundant in lithofacies 1. Lithofacies 2 show a more normal distribution of pore sizes with majority of less than 10 micrometers. This indicates the lack of isolated porosity and that most of pores by volume is the effective interparticle porosity of micrite. Aspect ratios of pores in lithofacies 1 have a high percentage of the less than 10 aspect ratio. This indicates that pore shape are more spherical compared to the aspect ratio of lithofacies 2, which shows a variety of pore shape by having a variety of aspect ratios (including more elongated pores).

4.4.3.1. Comparison of QEMSCAN Porosities with other Tools

There is a general agreement of the CMS300 results with the MICP porosities. QEMSCAN® BSE mode measures one micrometer length by one micrometer width pixel in a two dimensional slice of the thin section, and maps connected and isolated pores. The MICP and the CMS300 measure effective (connected) porosity by injecting fluids. The QEMSCAN® BSE mode provides larger porosity values in some of the samples (especially from lithofacies 1) compared to MICP and CMS300. This may be due to significant volume of isolated pores within coccoliths or foraminifera that are 5-10 micrometer in diameter, and are not contributing to the effective porosity calculated by CMS300 and MICP.
Table 4-3: Pore shape distribution using the QEMSCAN® BSE mode after being analyzed by iDiscover software.

<table>
<thead>
<tr>
<th>Sample</th>
<th>Lignite</th>
<th>POR</th>
<th>POR+MIN</th>
<th>MIN+POR</th>
<th>MAX POR</th>
<th>K (MD)</th>
<th>Volume %</th>
</tr>
</thead>
<tbody>
<tr>
<td>7</td>
<td>3</td>
<td>0.17</td>
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</tr>
<tr>
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<td>14.7</td>
<td>22.22</td>
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<td>9.08</td>
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<td>15.88</td>
<td>38.88</td>
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<td>3.2</td>
</tr>
<tr>
<td>117 DA</td>
<td>3</td>
<td>0.06</td>
<td>0.64</td>
<td>3.35</td>
<td>4.05</td>
<td>1.20</td>
<td>0.03</td>
</tr>
</tbody>
</table>

Pore Shape Distribution – Shape factor/Aspect Ratio using QEMSCAN® BSE mode

<table>
<thead>
<tr>
<th>Volume %</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt;10</td>
</tr>
<tr>
<td>10-15</td>
</tr>
<tr>
<td>15-20</td>
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<tr>
<td>20-30</td>
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<td>50-100</td>
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<td>100-200</td>
</tr>
<tr>
<td>200-500</td>
</tr>
<tr>
<td>500-1000</td>
</tr>
</tbody>
</table>

84
Some support for this comes from the pore size and pore shape distributions for each sample. Sample 37 (lithofacies 2) has a Gaussian distribution of pore size below 10 micrometer and exponential decline of pore shape in Table 4-2. The pore sizes of 5-10 micrometers are minimal in sample 37 compared to other samples (lithofacies) that have larger porosity than the CMS300 and MICP calculated porosity. This specific sample lacks the isolated pores of the coccoliths or the foraminifera. In this case, there is excellent agreement between QEMSCAN, MICP and CMS300 porosity values.

Samples 17, 23 and 26 (lithofacies 1) have eight porosity units more from QEMSCAN compared to MICP and CMS300. The pore size distribution in shows a linear incline in pore sizes that peaks by the 5-10 micrometer category in all three samples (about 30-37 volume percent of the pore sizes are 5-10 micrometer). Moreover, samples 44 and 45 (lithofacies 1) have about 10 porosity units more in QEMSCAN than MICP and CMS300 porosities. There is a parabolic increase that peaks at the 5-10 micrometer range (about 45-46 volume percent of the pore sizes are 5-10 micrometer). This indicates that the higher 5-10 micrometer pore size range present, the higher the QEMSCAN® value compared to calculated effective porosity, as more of the isolated pores within the coccoliths and the foraminifera are included in the total porosity. Table 4-3 shows that the higher the aspect ratio volume percentage is, the higher the connected pores are controlled perhaps by the addition of elongated channel-like pore spaces. The more distributed pore shape, the higher the permeability value. It appears that the estimation of porosity from QEMSCAN analysis increases with increasing volume percentage of shape factor larger than the value 200. This indicates that pore shape plays an important role, the larger the channel width, the higher volume of pore is calculated from QEMSCAN.
In order to validate porosity values obtained from well logs, CMS300 have been plotted with the neutron porosity and porosity from density log Figure 4.9. All samples (17, 23, 26, 37, 44, 45, and 69) are located within the A0 and have reasonably good porosities. The plug porosities (using CMS300) have greater porosity than calculated using well logs. This means that the logs are underestimating porosities and thus, well logs should be calibrated to match CMS300.

Figure 4.9: A well log from well SB359. It shows neutron porosity (NPHI), porosity from density log (POR_DEN) and plug porosities using CMS300. Red points are showing the samples used in the QEMSCAN analyses, and the blue dots are the CMS300 plug porosity.
4.4.4. CMS 300 Results with Lithofacies

This section is divided into CMS300 results of core plug porosity and permeability, and clay seams documentation analysis.

4.4.4.1. Plug Porosity versus Permeability

Plug porosity and permeability have been plotted in Figure 4.10. All of the plotted points are from well Sb-359 and come from the Lower Bab Member A0. Porosity ranges from 0.1% up to 26.2%. However, permeability ranges from 0.02 mD up to approximately 1.5 mD and rarely to 2.9 mD across the lower Bab Member. To better understand these high porosity and low permeability values, lithofacies were included in the cross plot as shown in Figure 4.11. Lithofacies 1 and Lithofacies 2 have a similar slope relationship to permeability and porosity using a best fit, log function. Lithofacies 1 has a higher zero intersection than the lithofacies 2 (i.e. where permeability is as small as 0.01mD, porosity is higher in Lithofacies 1 than Lithofacies 2). Lithofacies 3 has only 5 data points. In addition, they are scattered and more data points are needed to establish a good relationship. The reason lithofacies 1 has better porosity than lithofacies 2 is that microporosity in lithofacies 2 has undergone relatively greater occlusion with calcite cement. The most likely explanation could be that dissolution –reprecipitation of micrite during diagenesis, where aragonite (unstable mineral) is dissolved and reprecipitated as low-Mg calcite overgrowths, occluding more microporosity (Volery et al., 2009). In addition, cementation was localized around clay seams/stylolites.

4.4.4.2. Clay Seams

After plotting all the amplitude and thickness data in Figure 4.12, the stylolites have the highest amplitudes and the lowest thickness, and the clay seams are thickest with lowest amplitude. Statistical analysis of the distribution of these seams shows that the most abundant
clay-seam occurrence is at the exact crest of the Asab anticline. As we move down the flanks, of the structure clay seam abundance decreases and stylolite abundance increases (Figure 4.13). The dashed purple line represents roughly where the exact crest of Asab anticline is situated. These observations agree with the conclusion of Alsharhan and Sadd (2000) that stylolites tend to be most common and abundant toward the flanks of the anticlines. Another finding of the study here is that porosity is significantly reduced when thick clay seams or stylolites appear. Also, if clay seam thickness is more than 25 mm, it might act as a flow barrier. This was noticed in the first 15 feet of the section (Figure 4.14) where a tight zone is bounded by two thick clay seams, an upper one that is 125 mm thick and a lower one that is 27 mm thick. This also agrees with Alsharhan and Sadd (2000) that suggested stylolite development act as effective barriers for petroleum migration.

Figure 4.10: Plug porosity versus plug permeability of the Lower Bab Member in well Sb-359
The organic rich clay seams are possibly structures that were formed as a result of mechanical compaction and pressure dissolution of calcite, especially in areas that were originally more argillaceous during burial diagenesis (Garrison and Kennedy, 1977). Also, some of the calcite which was dissolved might have been precipitated locally (Garrison and Kennedy, 1977) and is accountable for partial occlusion of matrix porosity in areas where stylolitization is common (Moshier, 1989a). Similarly, permeability is highly affected by the abundance of stylolites decreasing the overall permeability to 2 mD or less in the Lower Bab Member (Alsharhan et al., 2000) and (Alsharhan and Sadd, 2000). In the same context, depending on well logs alone (i.e. resistivity and neutron logs) to identify the water saturation in micritic limestone reservoir zones that are rich in stylolites may underestimate the hydrocarbon reserves (Petricola et al., 2002) and (Kieke and Hartmann, 1974).

Figure 4.11: Plug porosity versus plug permeability of the Lower Bab Member showing different lithofacies in well Sb-359. Lithofacies 1 has the best reservoir quality.
Figure 4.15 shows the oxygen isotope against core plug porosity and clay seam thickness obtained from Chapter 3. There is a weak correlation of $\delta^{18}O$ with the porosity, the higher the porosity, the higher the $\delta^{18}O$ as discussed in Chapter 3. A full analysis has been conducted to estimate temperature at which cementation occurred. It is estimated that this temperature ranges from 50-54 °C and based on geothermal gradient, the depth at which cementation occurred is shallower than 500 meter. This indicates that some of the skeletal grains were supported by cementation and were preserved from being mechanically broken. This is supported by the SEM images, where coccoliths seem to be in their original depositional morphology. This has allowed some samples, especially from lithofacies 1 to have higher contribution of isolated porosity (of coccoliths) to the total rock porosity.

![Diagram of Clay seams and stylolite in the Lower Bab Member](image)

**Figure 4.12: Thickness versus amplitude of clay seams (CS), stylolites (ST), and mix of both (MIX) in the Lower Bab Member from three different Asab crestal wells.**
Figure 4.13: Statistical analysis of the distribution of clay-rich seams from three different wells. The dashed purple line represents roughly where the exact crest of Asab anticline is situated. The further we move away from the crest, the clay seams are less abundant relative to stylolites.
Figure 4.14: Composite plot showing plug porosity in red curve, against the clay-rich seam thickness. The thicker the clay seam, the lower the porosity reading is.
4.4.5. SEM Image Analysis

The scanning electron microscope (SEM) is a powerful tool that helps explain the results from other pore characterization tools. It has helped to explain why QEMSCAN analysis may provide higher porosities compared to CMS300 and MICP porosities by visualizing the abundance of coccoliths in lithofacies 1. This has changed the original assumption that coccoliths were responsible for the high effective porosity measured using CMS300. The SEM shows that the more abundant micrite particles in the rock, the higher the porosity, the small pore throats between these particles has been responsible for the low permeability. The degree of cementation in the matrix is the main control on the microporosity readings. Figure 4.16, Figure
4.17, Figure 4.18, Figure 4.19 and Figure 4.20 are different examples of SEM photos showing different values of porosities and permeabilities associated with lithofacies 1 and 2 coupled with mercury porosimetry and nitrogen adsorption-desorption curves.

**Lithofacies 1**

As discussed in the previous sections, lithofacies 1 has been showing higher total porosity measured using the QEMSCAN than the effective porosity with 8-12 more porosity units. An explanation of this observation can be reached by examining lithofacies 1 SEM photos. Figure 4.16 (sample 26) and Figure 4.17 (sample 44) shows clearly the coccoliths embedded between micrite particles. If we compare pore size distribution obtained from MICP from the same figures to pore size distribution obtained by QEMSCAN from Table 4-2, the peak at 5-10 micrometers observed by the QEMSCAN, has not been captured using MICP, and supports the interpretation that the coccoliths are providing isolated porosity.

**Lithofacies 2**

Lithofacies 2 shows QEMSCAN porosity (total) similar to CMS300 and MICP calculated effective porosities. Figure 4.18 (sample 37) and Figure 4.19 (sample 69), show that the main constituents of lithofacies 2 are micrite particles, with minor broken coccoliths. This has minimized isolated porosity due to mechanical breakage of any coccoliths.

**Lithofacies 3**

Lithofacies 3 has shown very low porosities and permeabilities due to extensive cementation. Figure 4.20 (sample 7) shows micrite in the fused form due to reprecipitation into overgrowth calcite cement, occluding porosity. This is believed to be a result of mechanical and chemical compaction that resulted in the clay seams and stylolites.
Figure 4.16: A panel showing SEM photograph, mercury porosimetry with pore size distribution by MICP and N₂ gas adsorption-desorption of sample 26 (lithofacies 1). Table above shows the plug porosity and permeability, with BET surface area obtained by N₂ gas adsorption-desorption. Coccoliths can be clearly seen in this photo surrounded by micrite.
Figure 4.17: A panel showing SEM photograph, mercury porosimetry with pore size distribution by MICP and N$_2$ gas adsorption-desorption of sample 44 (lithofacies 1). Table above shows the plug porosity and permeability, with BET surface area obtained by N$_2$ gas adsorption-desorption. Coccoliths can be clearly seen in this photo surrounded by micrite.
Figure 4.18: A panel showing SEM photograph, mercury porosimetry with pore size distribution by MICP and N\textsubscript{2} gas adsorption-desorption of sample 37 (lithofacies 2). Table above shows the plug porosity and permeability, with BET surface area obtained by N\textsubscript{2} gas adsorption-desorption. This photo lacks coccoliths and contain broken pieces only, composed mainly of micrite.
Figure 4.19: A panel showing SEM photograph, mercury porosimetry with pore size distribution by MICP and \( \text{N}_2 \) gas adsorption-desorption of sample 69 (lithofacies 2). Table above shows the plug porosity and permeability, with BET surface area obtained by \( \text{N}_2 \) gas adsorption-desorption. This photograph lacks coccoliths and contains broken pieces only, forming micrite.
Figure 4.20: A panel showing SEM photograph, mercury porosimetry with pore size distribution by MICP and N₂ gas adsorption-desorption of sample 7 (lithofacies 3). Table above shows the plug porosity and permeability, with BET surface area obtained by N₂ gas adsorption-desorption. Fused micrite into calcite cement is clear in this photo, with no visible microporosity.
4.4.6. Mercury Porosimetry and Nitrogen Gas Adsorption

Results of the mercury porosimetry show a similar signature of all samples from A0. Mercury porosimetry intrusion-extrusion curves, and calculated pore size distribution are shown in Figure 4.21. Most samples show a bimodal distribution that peaks around 0.3-0.8 micrometer and a smaller peak (0.005 to 0.01 micrometer or 5-10 nanometer). Figure 4.22 shows the results of the nitrogen gas adsorption-desorption experiments, including isotherms, calculated BET surface areas, and BJH pore size distribution. The calculated surface area for A0 samples ranges from 0.96 to 1.2 m²/g indicating small grain sizes. Pore size distribution using the nitrogen desorption shows a bimodal distribution (0.15-0.08 micrometer) and a smaller peak (around 0.004 micrometer or 4 nanometers). Mercury injection pore throat size peaks at 0.5 micrometer. The QEMSCAN was able to identify a peak of pore size distribution around 5-10 micrometer that was not observed using the Mercury porosimetry. The reason again, might be that the 5-10 micrometer pore sizes are isolated and do not contribute to the effective porosity measured by CMS300 or Mercury porosimetry. This has made lithofacies 1 and 2 to have similar grain size distribution curve using the mercury injection, even though lithofacies 1 has more abundant coccoliths than lithofacies 2. Samples 7 and 117 (lithofacies 3) are behaving differently than the other samples due to the extensive cementation, and all micrite intraparticle microporosity has been occluded. The high peak at the pore size distribution represent the ratio at which smaller size (intracrystalline type) pores are contributing to the total measure very small porosity.

4.4.7. Summary of Reservoir Rock Development

Lithofacies 1, 2 and 3 share similar carbonate constituents of micrite, and microfossils such as coccoliths and foraminifera. They were deposited in the middle to lower ramp with high original microporosity. Early cementation at a temperature around 50-54°C at burial depth of less than
Figure 4.21: Results of the mercury porosimetry analysis. Intrusion and extrusion curves and the calculated pore size distribution for all 11 samples (10 of them have clones for other analyses). Porosity and permeability comes from CMS300 analysis. Pore size distribution shows a bimodal distribution that peaks around (0.3-0.8 micrometer) and a smaller peak (0.005 to 0.01 micrometer or 5-10 nanometer)
Figure 4.22: Results of the nitrogen gas adsorption-desorption analysis of the 11 samples including: calculated surface area (BET), adsorption-desorption isotherms, and calculated pore size distribution. Porosity and permeability in the table comes from CMS300 analysis. Pore size distribution shows a bimodal distribution (0.15-0.08 micrometer) and a smaller peak (around 0.004 micrometer or 4 nanometers).
500 meters helped in preserving the morphology of coccoliths that added isolated porosity to the total porosity. Clay rich seams formed as a result of chemical and mechanical compaction in weak zones that are rich with argillaceous materials. This compaction has crushed isolated pores in lithofacies 2 and made it mainly composed of micrite particles. This has enabled micrite to dissolve and reprecipitate into overgrowths of high-Mg calcite cement around the clay seams/stylolites, and is lithofacies 3. These zones can be considered as fluid barriers if highly cemented and divides the reservoir into subzones.

4.5. Conclusion

This study has tested a variety of techniques with different capabilities and resolutions to characterize the microporosity that is the major porosity type within the Aptian basinal carbonate of the Lower Bab Member (A0). Lithofacies analysis has shown a very small change in texture and the dominant facies varies between wackestone to mudstone. The main purpose of this investigation was to explain the reason for the high porosity and the low permeability in these rocks and to interpret the controls on porosity. The main findings of this study can be summarized in the following points:

1. Interpretation of regional seismic profiles in the Falaha syncline shows that there are progradational geometries below the Bab Member that prograde northwest towards the center of the syncline. Probably these are within the Thamama B and C reservoir/seal units. Also, in the studied field, three clinoforms have been identified and represent part of the Apt5 lowstand sequence that filled much of the remaining of the Bab basin.
2. Well log analysis across the studied field shows that the A0 is thickening in the direction of the depocenter of the Bab basin with progradational geometries. Porosity logs show that the higher porosities are at the crest of the field anticline.

3. QEMSCAN® BSE mode results has been a useful quantitative analysis of the pore bodies within the A0. Porosity obtained by this method agreed with CMS300 and Mercury porosimetry porosities in some samples, and indicates additional porosity not measured by these other methods in other samples. The reason for this difference is that the QEMSCAN measures total porosity (isolated and effective) while CMS300 and MICP use fluid injected to measure the effective porosity. The abundance of coccoliths (5-10 micrometer pore size) that could not be measured using fluid injection methods was the reason for the addition of isolated porosity using the QEMSCAN.

4. Well log porosities should be calibrated to match effective and total porosities as they underestimated both.

5. Mercury porosimetry experiments show that most analyzed samples from the A0 show a bimodal distribution that peaks around 0.3-0.8 micrometer and a smaller peak from 0.005 to 0.01 micrometer, or 5-10 nanometer.

6. Nitrogen gas adsorption-desorption experiments show that the calculated BET surface area ranges between 0.96 to 1.2 m²/g for samples from the A0 and indicates small grain sizes. Pore size distribution from nitrogen desorption show a bimodal distribution (0.15-0.08 micrometer) and a smaller peak around 0.004 micrometer (4 nanometers).
7. Mercury porosimetry pore size distribution did not show a peak at 5-10 micrometer in samples where coccoliths are abundant.

8. Diagenesis was the main control on the quality of reservoir rock properties in the A0.

4.6. References


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5. CHAPTER 5: IMPLICATIONS OF RESERVOIR
CHARACTERIZATION STUDY ON A FUTURE DEVELOPMENT
PLAN OF A TIGHT CARBONATE RESERVOIR

5.1. Abstract

The reservoir characterization study of the Lower Bab Member A0 indicates that it has a high storage capacity with porosity up to 24%, but it contains low permeability with maximum of 3 mD, making it a challenging reservoir to produce. Vertical variation in porosity and permeability in the A0 is controlled mainly by the varying abundance of stylolite/clay seams that could act as flow barriers for reservoir fluids. A well that has been drilled in this reservoir shows encouraging production rates. This well has shown that reservoir pressure should be supported by injector wells. Still, more dynamic data are required to minimize uncertainties for a full field development plan for this reservoir. Wells should be drilled to collect necessary data and to test the reservoir performance. These wells should include injectors, producers and monitoring wells. Due to the low permeability, injectors should be placed close to the producers. Enhanced oil recovery techniques can be tested in pilot wells to assess their hydrocarbon recovery. Hydraulic fracking can be performed but it should be contained and controlled to not affect other underlying reservoirs. It is recommended to monitor the performance of the planned wells without fracking.

5.2. Introduction

The key element in developing any reservoir is to maximize contact with the reservoir rock to reach reservoir fluids. Moreover, sustaining production by using techniques to increase hydrocarbon recovery and maintain reservoir pressure is essential. There has been a shift toward
exploring tighter reservoir rocks as technologies develop, and the price of oil has increased. This is achieved by drilling horizontal wells and hydraulic fracking in many cases, especially in unconventional plays. Nevertheless, hydraulic fracking and drilling through fractures can leave behind large volumes of reservoir fluid in the porous matrix of low permeability reservoirs, especially if injected fluids break through the fracture network. This paper aims to suggest the optimum development practice for tight carbonate reservoirs onshore Abu Dhabi. It will focus on reviewing fields with similar reservoir properties that have been developed, to learn from their lessons and experiences. It is important to highlight that in order to have a full field development plan, dynamic data are needed. For instance the A0 lacks detailed fluid and geomechanics data to start a development plan. Thus, this chapter will use all available information to suggest the best practices towards a future development plan. This chapter is not a development plan, but rather listing points that should be considered for future.

The Aptian Lower Bab Member A0 comprises the intrashelf basinal deposits in the Bab basin of Abu Dhabi and is composed of mudstones to wackestones. Chapter 4 presented a reservoir characterization study to understand the porosity of this tight carbonate reservoir. It showed that the Lower Bab Member (A0) has significant storage for hydrocarbons, dominated by the microporosity in micrite. The degree of cementation in the matrix is the main control on the microporosity readings. Clay-rich seams and stylolites are associated with excess cementation that lowers porosities, and can affect vertical flow. This is probably because the dissolution associated with compaction in clay seams and stylolites is the source of cementing fluids.

In the studied field, the Lower Bab Member A0 has not been fully studied for the purpose of a development plan yet. New pilot wells will be drilled including producers and injectors in
the near future to increase the understanding of the A0 reservoir performance. Data input for static and dynamic modeling are currently not sufficient and work has to be done in order to identify and mitigate uncertainties prior to the final decision on the full field development plan (FFDP). The necessary data input includes geo-mechanical data, fracture analysis, and fluid analysis. According to Abu Dhabi Company for Onshore Oil Operations (ADCO), there will be some drilling activities in the A0 in the next two years to evaluate the A0 performance, to collect necessary data, and to conduct the necessary well tests.

5.3. Literature Review

Many studies have tested different development schemes for tight carbonates that could be useful in providing guidance to move forward with the A0 reservoir development. Mostafa (1993) indicated that horizontal drilling is important to developing tight carbonate reservoirs. This is because horizontal wells increase contact with reservoir rocks and fluids. Moreover, it was found that water alternating gas injection (WAG) and water injection only showed higher ultimate recovery than gas injection alone. This is concluded after running the three cases and it was found that gas injection alone is an inefficient recovery mechanism in such strongly stratified reservoirs due to gas gravity segregation and poor vertical sweep. However, this could not be the case in A0, as thickness of A0 is not more than 60ft while the study by Mostafa (1993) was conducted on much thicker (150 feet) and higher permeability (1-30 mD) reservoir.

Another study by Manrique et al. (2004), provided a large data set of fields that have undergone enhanced oil recovery (EOR) in the USA and suggested that infill drilling of wells using gas and water shutoff, mitigates the early breakthrough of injected fluids and increases oil recovery. However, no more than 40 or 50% of the original oil in place is produced. A field that has similar reservoir lithology and properties to the Lower Bab Member A0 with permeability
ranging from 0.1 to 14 mD has been developed using water alternating with gas (WAG) injection to enhance recovery. Gomes et al. (2002) suggested miscible WAG in 1-10mD tight reservoirs after conducting a full field development plan. Another similar field studied by Benlacheheb et al. (2008) also suggested WAG for a tight carbonate reservoirs with average of 1mD and maximum of 6mD for development. The high amount of estimated STOIIP was the main driver for reservoir development.

Dello et al. (1996) conducted a simulation study on a low permeability carbonate reservoir with less than 5mD of permeability in offshore Abu Dhabi. The study concluded that low permeability carbonate reservoirs recovery could be improved by gas injection using an approximately 2 km long horizontal wells in a line drive configuration. The critical element for successful recovery was the linear flow, and large pressure gradient between injectors and producers. Simulation data has shown 30% OOIP recovery using this method compared to 0.3% recovery of OOIP using water injection in vertical wells.

Vertical permeability is always important to measure in these highly stratified reservoirs, as vertical flow barriers and baffles are common. Mostafa (1993) and Mitri and Abed (1991) concluded that stylolites and dense zones around them are key features that dominate the vertical sweep performance of stratified carbonate reservoirs, and they need special emphasis in development plans and simulation. Also, special care is required when analyzing stylolite plugs at the lab conditions, as lab-measured permeability can be misleading due to the presence of unloading fractures or tension gashes.

A similar study by Bigno et al. (2001) suggested that in a low permeability 1-10 mD carbonate reservoir, recovery increased by decreasing the spacing between the producers and injectors to as small as 40 meters to maintain pressure gradient. Moreover, wells that have been
drilled using fishbone technology (multilateral) have shown that they improved sweep efficiency by increasing the width of the swept area and contact with reservoir.

Li et al. (2009) recommended using borehole images, seismic, production data, well test data, mud logs and core data for fracture studies in tight carbonate reservoirs in Kuwait. The main purpose was to identify sealed fractures from open fractures and their effect on flow. The lesson learned from Rao et al. (2013) is that real time image logs are a must in fractured carbonate reservoirs. The main challenge is the ability of wells to access permeable vertical fractures in tight carbonate carbonates that are characterized by overall low porosity compared to the Lower Bab Member.

Geomechanics studies are valuable for tight reservoirs (Finkbeiner et al., 2010). For instance, permeability has a log-linear relationship with the rock minimum stress magnitude in tight reservoirs. Barzegar Alamdari et al. (2012), after conducting core-flooding experiments, showed that having open fractures might lower recovery in low permeability carbonate reservoirs, while having sealed or no fractures increase oil recovery and sweep efficiency. The reason for that is that sealed fractures confine and guide injected fluids, which increases sweep efficiency. Sirat et al. (2014), concluded that there are two fault trends in southeast onshore Abu Dhabi where the studied field is located, N75W and a less intense fracture trend of N45W. This study suggested that horizontal wells should be drilled away from these major fault corridors and from water legs to avoid water breakthrough into the oil producer wells.

Al-Hajeri et al. (2007) documented an example of successful production of a tight carbonate reservoir in the offshore Abu Dhabi. Success was achieved by horizontal drilling in a high permeability zone (as high as 1.8 mD) and produced at rates higher (1550 STBOPD) than
the simulation expectations (300 STBOPD). This is probably because they underestimated permeability due to the averaging (1mD) while upscaling for simulation.

5.4. Results and Discussion

5.4.1. Reservoir Zones

Figure 5.1 and 5.2 show that the sedimentary column of the A0 is divided into zones A01, A02 and A03. Lithofacies shown in Figure 5.1 and 5.2 were described using the company atlas for lithofacies in Thamama zones A, B and C (ADCO, 2011). The lithofacies in the A0 have very similar characteristics to the company’s atlas. A01 shows the lowest porosity values and is rich in clay seams and highly cemented zones. A02 is probably the thickest zone in the A0 and can be subdivided into three subzones that have stylolites causing a decrease in porosity between the subzones (Figure 5.3). There is a major decrease in porosity between zone A02 and A03, higher clay content and abundant sets of stylolites that lower porosity and permeability, and will probably act as a vertical flow barrier as shown in Figure 5.4 and the field cross section shown in Figure 5.5. This possible vertical barrier should be taken into account by confirming vertical permeabilities at these subzones transition. High permeability (as high as 2-3 mD) zones are on average 10-15 feet thick which will be a challenge for geo-steering while drilling and reliable LWD tools should be used.

5.4.2. Production Test

One well has been drilled and tested for production from the A0 in the studied field. The well is horizontal with about 3000 feet of open hole. At the beginning, the well had been on production for almost a month when it was noticed that the GOR was increasing in the produced oil from 75 SCF/STB to over 780 SCF/STB. This indicated that the reservoir pressure was decreasing due to hydrocarbon withdrawal without any injection activities to support reservoir
Figure 5.1: A stratigraphic column showing some reservoir units within the studied field. This study focuses on the Lower Bab Member A0 as shown by the red arrow. This figure shows a gamma ray log (GR), interpreted effective porosity (PHIE), and plug permeability. Facies legend provided by ADCO facies atlas in Figure 5.2.
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<td>BCSM</td>
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Figure 5.2: Facies Legend of the Thamama Reservoirs provided by ADCO 2011.
Figure 5.3: A well log displays porosity logs (RHOB and PHIE). Black points on the PHIE log are porosity values from core plugs. (ADCO, 2011)
Figure 5.4: Porosity from core plug analysis (using CMS300®) and thickness of clays seams/stylolites. Overall, the presence of thick clay seams lowers porosity significantly.
Figure 5.5: A cross section from southwest (right hand side) to northeast (left hand side) showing effective porosity logs (scaled 0-45%). Two high porosity zones should be targeted in the A0 include subzones A02 and A03 (highlighted with black dashed line) that are separated by stylolites or thick clay seams. Wells are datummed to the Top of A0 as it is considered the maximum flooding surface, showing that the Thamama Zone A is a gently dipping carbonate ramp. Porosity decreases moving deeper in the ramp.

pressure. Production tests using 20/64” choke showed that this well dropped production for solely this reason and there is no skin factor. This well is currently produced for 24-hour intervals every few months, showing an oil production rate (API=42) ranging between 400 to 800 STB/day, which is considered a very good production rate for such a tight formation. Consequently an injection mechanism is essential to maintain reservoir pressure. Moreover, due to the low permeability, spacing between injectors and producers should be optimized to increase sweep efficiency and avoid early water breakthrough.

5.4.3. Faults and Fractures

Most existing image logs are taken from other reservoir units and not from within the Lower Bab Member A0 interval. Wells that have image logs within the Thamama Zone A which is underlying the Lower Bab Member were used here to help understand regional fracture orientations (Sirat et al., 2014). A well (SB480) that was drilled in the Thamama Zone A, which underlies the A0 in the free water level on the southwestern flank of the field was studied. The
analysis of this well showed a dominant strike orientation of ESE-WNW of all fractures (Figure 5.6). Another well (SB484) on the southwestern mid-flank of the structure was used to analyze existing fracture and faults. This well showed a dominant strike orientation of conductive fractures of NE-SW orientation (n=20), while showing ENE-WSW dominant strike for resistive fracture data (n=59) (Figure 5.7). Two faults were crossed with ENE-WSW strike orientation (Figure 5.8). The results of these two wells agree with the regional study by Sirat et al. (2014) stating that there are two major fault trends, where fracture trends are not significantly different from fault trends.

Figure 5.6: Strike and azimuth histograms of continuous fractures (Schmidt lower hemisphere plots) in well SB-480 (6° Horizontal Hole). Green triangles represent resistive fractures, while blue triangles represent conductive fractures. (ADCO, 2011).
Figure 5.7: Strike and azimuth histograms of continuous fractures (Schmidt lower hemisphere plots) in well SB-484 (6° Horizontal Hole). Green triangles represent resistive fractures, while blue triangles represent conductive fractures. (ADCO, 2011).

Figure 5.8: Azimuth and strike histograms of faults identified in well SB-484 (Schmidt lower hemisphere plots) (ADCO, 2011).
5.4.4. Drilling

Based on discussion with ADCO/Asset team members, there were some concerns that fracking could go beyond the A0 reservoir and affect the currently developed Thamama Zone A reservoir unit. For instance, if fracture propagates through the Thamama Zone A, water might break through these fractures bypassing large volumes of hydrocarbon. Based on the literature review section in this chapter, and the reservoir character of the A0 defined in this study the following steps are proposed to develop the A0:

1. Drilling horizontal wells in blocks that are away from fault zones in the crest of the structure and away from the free water level at the flanks. This can be achieved by using seismic data, and the current static model.

2. Horizontal wells should be aligned in the direction of the minimum principal stress perpendicular to open fracture trends.

3. Proper LWD tools should be used to maximize the contact with the high permeability zones within the A0.

4. Wells should be in a pattern line drive (producer parallel to injectors).

5. Test the communication between A02 and A03 subzones:
   a. Based on the level of communication, it can be decided if injectors should be drilled in A02 or A03,
   b. And whether injectors and producers that are next to each other should be in the same zone or not, and
   c. To test if it is possible to drill a well in multi subzones.

6. Test the communication between the A0 and Thamama Zone A reservoir.
7. The most promising recovery mechanism could be water alternating with gas (WAG). More simulation should be conducted in addition to SCAL and reservoir fluid studies. Gas alone and water alone injections should be considered and used in feasibility studies.

8. A comprehensive rock mechanics study should be conducted on the A0.

9. Borehole imaging while drilling is a must to overcome challenges in geo-steering within the thin high permeability zones, and to clearly map and identify fractures.

10. There should be some pilot wells to test new EOR methods and compare recoveries.

11. Observation wells are essential to map the sweep efficiency and fluid fronts and breakthrough.

12. Fracking can be applied but should be contained to not affect the lower reservoir zones. Further studies are required to confirm fracking feasibility.

13. Stimulation methods should be tested to find the optimum production.

Figure 5.9 shows a suggested drilling pattern based on the points above. This initial plan will help in testing the performance of wells in term of injectivity and productivity. The wells are designed to be away from major fault corridors and are perpendicular to the trend of open fractures. It is expected that wells at the flanks will be more stylolite rich, and thus reservoir rock will show lower porosity due to cementation.

5.4.5. Collecting More Data

The key for a successful development plan is to gather as much data as possible to lower uncertainties. This can be achieved by routine core analysis studies on all of the well cores.
through the A0. The scope of this research allowed study of three well cores only. Special core analysis and reservoir fluid properties studies are essential to gather dynamic information for the fluid simulation. Geo-mechanics studies are necessary for drilling and completion parameters.

5.5. Conclusion

This chapter has covered some of the important aspects in developing the tight carbonate reservoir of the Lower Bab Member A0 in a field onshore Abu Dhabi. The A0 shows a high potential for development, as one horizontal well produced large volumes of oil. However, the lack or reservoir pressure support led to reaching the bubble point, increasing GOR and lowering oil production. Based on literature review, the A0 should be developed using closely spaced horizontal wells that are line configured with line drive and WAG injection to maintain reservoir pressure. Blocks of the reservoir that are away from fault corridors should be targeted to maintain the maximum sweep efficiency. Geo-steering within high permeability zones needs the use of sophisticated LWD tools, especially live borehole imaging tools. A trial drilling of producer and injector wells is advised to collect dynamic data and to test the initial performance. A thorough integrated study is necessary to produce a reliable static and dynamic model for the Lower Bab Member to achieve a successful full field development plan.
Figure 5.9: Areal map showing suggested pattern for horizontal wells. Red lines represent horizontal producer wells, whereas blue lines represent horizontal WAG injectors. These proposed wells should avoid fault corridors identified by seismic data (grey lines). The light blue polygon represents the oil water contact associated with the Thamama Zone A, which is underneath the A0.
5.6. References


Li, B., M. A. Al-Awadi, C. Perrin, M. Al-Khabbaz, S. Al-Ashwak, and B. Al-Qadeeri, 2009, Fracture and Sub-Seismic Fault Characterization for Tight Carbonates in Challenging Oil-Based Mud Environment—Case Study From North Kuwait Jurassic Reservoirs: SPE Middle East Oil and Gas Show and Conference.


Mostafa, I., 1993, Evaluation of water and gas pattern flooding using horizontal wells in tight carbonate reservoirs: Middle East Oil Show.


6. CHAPTER 6: CONCLUSIONS

The Aptian Lower Bab Member (A0) has been studied in one of Abu Dhabi’s onshore large oil fields. The A0 is the basinal deposits equivalent to the carbonate platform Shu’aiba Formation. The Bab Member has shown hydrocarbon potential in fields located in the southeastern part of the UAE. Due to the low permeability in the Bab Member, that is less than 3 mD, it is considered part of the undeveloped reservoirs managed by the Abu Dhabi National Oil Company (ADNOC). The majority of the storage capacity in the Bab Member comes from microporosity in the matrix with porosity reaching up to 25%.

This study aimed to improve (1) understanding of the relationship between the Shu’aiba Formation and the Lower Bab Member stratigraphically using the existing core descriptions, well logs, stable isotopes and seismic; (2) characterization of porosity and permeability to identify potential target production zones; and (3) suggest best practices for future development plans to produce the hydrocarbon from this tight carbonate reservoir.

This dissertation went through aspect of understanding the A0. First, chapter 1 was an introduction to the studied field and reservoir including: Location and history, regional Cretaceous stratigraphy, scientific importance, background information, research objectives and tools, and a list of data sets used.

Chapter 2 provided sedimentological descriptions of the Lower Bab Member A0 and proposed a depositional model. Core description, thin section description and SEM were used to assign facies, while the other techniques were used for reservoir characterization. The A0 is divided into three lithofacies based on similar sedimentological features. Lithofacies 1 is a skeletal mudstone to wackestone with high microporosity with abundant foraminifera and
coccoliths, Lithofacies 2 is a burrowed argillaceous skeletal wackestone to mudstone, and Lithofacies 3 is a burrowed clay-rich skeletal wackestone to mudstone that represent the stylolite/clay rich seams in the A0. Based on the lack of bioclasts, and high content of carbonate mud, presence of clay and organic matter, and its position relative to the basin margin Shu’aiba platform, it is suggested here that this environment is at least tens of kilometers away from the platform margin in a lower ramp to basin.

Chapter 3 was titled “Carbon and Oxygen Stable Isotope Study in a Regional Context”. The chemostratigraphic record (carbon and oxygen isotopes) of the Aptian formations of Abu Dhabi has been enhanced with a new set of data. This chapter concluded the following points:

- The $\delta^{13}C$ values vary between 1.3‰ and 4.3‰ and the $\delta^{18}O$ values range from -7.5‰ and -4.6‰ VPDB.
- The $\delta^{18}O$ curve is a useful tool for intra-field correlation as it correlates similar diagenetic environments. The $\delta^{18}O$ curve is consistent with the $\delta^{13}C$ curve and maintains a correlative pattern even though it has a diagenetic overprint.
- The Lower Bab Member (A0) deposits tend to thicken towards the depocenter of the basin, based on the $\delta^{13}C$ curve of the inter-field correlation.
- Based on the $\delta^{13}C$ inter-field correlation, the Hawar Member, Thamama Zone A and the Lower Bab Member A0 in this study represent a condensed section that is equivalent to the third-order sequences of Apt2, Apt3 and Apt4 (a, and b). In more detail, the Hawar Member correlates to the Apt 2 sequence, Thamama Zone A correlates to the lower part of the Apt3 sequence. Moreover, reservoir zones of the A0 correlate to the Shu’aiba sequences as follow: zones A03, and A02 are time equivalent to the upper Ap3, and zone A01 is time equivalent to Ap4 sequence.
• Time equivalence correlation (chronostratigraphic) is not necessary a facies (lithostratigraphic) correlation. It has been the tradition to correlate formations based on their lithological features especially in carbonates, as lateral changes in carbonate facies are noticed over large distances, not like siliciclastic systems. Correlation using carbon isotope will be helpful in creating paleomaps of time equivalent facies.

• It seems that there is a correlation between porosity with $\delta^{18}$O values, correlation is stronger for higher porosities and permeabilities.

• Based on simple calculations, the temperature of marine water while depositing the studied samples ranges from 27-34°C. The temperature of the diagenetic fluid that caused cementation is interpreted to be about 50-54°C, assuming Cretaceous seawater as the precipitating fluid.

• The $\delta^{13}$C values become more negative moving toward the depocenter. This could be the result of higher temperature due to greater burial (TVD), an increase in organic matter in the depocenter, and/or the result of the aragonite-rich carbonate platform compared to the calcite-rich basin.

Chapter 4 was titled “Pore Architecture Characterization of a Basinal Tight Carbonate: An Aptian Reservoir in the Bab Basin of the Middle East”. This chapter has tested a variety of techniques with different capabilities and resolutions to characterize the microporosity that is the major porosity type within the Lower Bab Member (A0). The main purpose of this investigation is to explain the reason for the high porosity and the low permeability in these rocks and to interpret the controls on porosity. The main findings of this study can be summarized in the following points:
• Seismic interpretation of regional seismic profiles in the Falaha syncline shows that there are progradational geometries below the Bab Member that prograde northwest towards the center of the syncline. Probably these are within the Thamama B and C reservoir/seal units. Also, in the studied field, three clinoforms have been identified and represent part of the Apt5 lowstand sequence that filled much of the remaining of the Bab basin.

• Well log analysis across the studied field shows that the A0 is thickening in the direction of the depocenter of the Bab basin with progradational geometries. Porosity logs show that the higher porosities are at the crest of the field anticline.

• QEMSCAN® BSE mode results has been a useful quantitative analysis of the pore bodies within the A0. Porosity obtained by this method agreed with CMS300 and Mercury porosimetry porosities in some samples, and indicates additional porosity not measured by these other methods in other samples. The reason for this difference is that the QEMSCAN measures total porosity (isolated and effective) while CMS300 and MICP use fluid injected to measure the effective porosity. The abundance of coccoliths (5-10 micrometer pore size) that could not be measured using fluid injection methods was the reason for the addition of isolated porosity using the QEMSCAN.

• Well log porosities should be calibrated to match effective and total porosities as they underestimated both.

• Mercury porosimetry experiments show that most analyzed samples from the A0 show a bimodal distribution that peaks around (0.3-0.8 micrometer) and a smaller peak (0.005 to 0.01 micrometer or 5-10 nanometer).

• Nitrogen gas adsorption-desorption experiments show that the calculated BET surface area ranges between 0.96 to 1.2 m²/g for samples from the A0 and indicates small grain
sizes. Pore size distribution using from the nitrogen desorption show a bimodal distribution (0.15-0.08 micrometer) and a smaller peak (around 0.004 micrometer or 4 nanometers).

- Mercury porosimetry pore size distribution did not show a peak at 5-10 micrometer at samples where coccoliths are abundant.
- Diagenesis was the main control on the quality of reservoir rock properties in the A0.

Chapter 5 was titled “Implications of Reservoir Characterization Study on a Future Development Plan of a Tight Carbonate Reservoir”. This chapter covered some of the important aspects in developing the tight carbonate reservoir of the Lower Bab Member A0 in a field onshore Abu Dhabi.

- The A0 shows a high potential for development, as one horizontal well produced large volumes of oil. However, the lack or reservoir pressure support led to reaching the bubble point, increasing GOR and lowering oil production.
- Based on literature review, the A0 should be developed using closely spaced horizontal wells that are line configured with line drive and WAG injection to maintain reservoir pressure.
- Blocks of the reservoir that are away from fault corridors should be targeted to maintain the maximum sweep efficiency.
- Geo-steering within high permeability zones needs the use of sophisticated LWD tools, especially live borehole imaging tools.
- A trial drilling of producer and injector wells is advised to collect dynamic data and to test the initial performance.
• A thorough integrated study is necessary to produce a reliable static and dynamic model for the Lower Bab Member to achieve a successful full field development plan.

All objectives of this research have been achieved within the scope of this thesis. Further work is suggested to focus on the best enhanced oil recovery (EOR) method that will recover the most oil using core flooding experiments. More reservoir data are required to better understand the fluid properties for full field development.

Finally contributions of this thesis to the research domain include:

– Filled a gap in the chemostratigraphic record of the lower Bab Member.
– Used Chemostratigraphy to interpret some of the reservoir characterization results, especially the timing of cementation.
– Used many techniques for porosity characterization and found that isolated porosity can be significant.