ADDIS ABABA UNIVERSITY

ADDIS ABABA INSTITUTE OF TECHNOLOGY

Evaluation of the nature of porosity in carbonate rock of Hamanlei formation, Ogaden Basin, Ethiopia: implications for prediction of reservoir quality

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A Thesis submitted as partial fulfillment to the requirements for the award of the degree of the Master of Science in Petroleum Engineering

Submitted to

Center of Ethio-Mines Development

Addis Ababa Institute of Technology

June, 2023

Addis Ababa, Ehiopia

Declaration

This thesis work entitled **Evaluation of the nature of porosity in carbonate rock of Hamanlei formation, Ogaden Basin, Ethiopia: implications for prediction of reservoir quality, is** my original master's degree under the supervision of **Dr. Solomon Kassa**. I want to declare that this research work has not been presented or submitted for any degree at any University (institutions). All relevant source materials used for this thesis work have been duly acknowledged.

Name of Student	**Signature**	**Date**
Yimam Ali	____________	___________

Approval Page

This is to certify that the thesis prepared by **Yimam Ali** which is entitled **Evaluation of the nature of porosity in carbonate rock of Hamanlei formation, Ogaden Basin, Ethiopia: implications for prediction of reservoir quality,** is submitted as a partial fulfillment for the award of the degree of master of Petroleum Engineering compiles with the regulation of Addis Ababa University and meets the accepted standards with respect to originality, content, and quality.

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Abstract

The Ogaden basin is the largest sedimentary basin in Ethiopia having 350,000 km^2 areal coverage. It is also the most studied sedimentary basin in Ethiopia. Nonetheless, the amount of data gathered from this baisn is not enough to better comprehend the petroleum system of the basin. The Hamanlei carbonate rock in the basin makes good reservoir rock. The nature of this reservoir rock is complex owing to various factors. Despite detail studies were conducted to understand the reservoir property, particularly core and wireline log study, further studies are needed for better characterization of this reservoir rock. To further characterize the reservoir property, i.e. porosity, of this rock and prediction for reservoir quality, petrographic and image analysis were performed. The outcome of this study provides valuable insights into the mineralogy and texture of the studied rocks. Furthermore, it highlights the importance of understanding the different pore types that enables to better interpret the reservoir quality and potential flow characteristics of the studied rocks. Generally, the porosity value of the reservoir rock is too small which is caused by the dominant proportion of matrix and cement.

Acknowledgment

I would like to express my heartfelt gratitude to the Minister of Mines Ethiopia for providing me with the amazing opportunity to pursue my master's degree at Addis Ababa University. I am filled with immense appreciation for my advisor, Dr. Solomon Kassa, who has been instrumental in guiding, encouraging, and providing invaluable suggestions and advice throughout my research journey. I would also like to extend my thanks to Mr. Hailu Tsegaye, the director of the Mineral License Directorate at Addis Ababa Environmental Protection Authority (EPA), as well as Melkamu Sewunet, the Team Leader at the Mineral License Directorate, for creating favorable conditions that enabled me to attend Addis Ababa University. Furthermore, I am truly grateful to my family members who have played a significant role in supporting me throughout this endeavor. And lastly, I would like to express my appreciation to all my friends and extended family members who have directly or indirectly made sacrifices to contribute to the success of this project.

Table of Contents

List of Figures

List of Tables

Abbreviations

NE: North East

GSE: Geological Survey of Ethiopia

NW:North West

NNE: North East

NNW: North West

SW:South West

SSW: South West

CHAPTER 1

1. Introduction

In Ethiopia, sedimentary rocks are common and make up about 40% of the nation's total land area. In Ethiopia, there are five sedimentary basins: the largest is the Ogaden (350,000 km2), followed by the Blue Nile (Abay), Gambela, the Southern Rift, and Mekele (8000 km2) (Figure 1) (Hunegnaw, 1998; Ahmed, 2008). Geologically speaking, the origin of these sedimentary basins in Ethiopia is linked to an intra-continental rifting process (Russo et al., 1994; Hunegnaw et al., 1998). The most researched petroliferous basin of these is the Ogaden basin. In the basin, the reservoir rocks are sandstone and carbonate. Because carbonate reservoirs are frequently heterogeneous, describing and evaluating them may call for specialized approaches and techniques. The study of reservoir rocks, their petrophysical characteristics, the fluids they contain, or how they affect the movement of fluids underground is known as reservoir characterization. The description of the rocks and the pore network of a carbonate reservoir interval at the Calub Gas Field in the Ogaden Basin is the primary subject of this study. In order to understand how different factors affect reservoir quality, porosity has been studied.

While carbonate rocks have a variety of pores, including intragranular, interagranular, moldic, fracture, and vugy pores, siliciclastic rocks are characterized mostly by intergranular pores. As a result, carbonate pores are undoubtedly more varied than their siliciclastic equivalents. Both of these rocks can have their porosity identified by image analysis. Since solely intergranular porosity is considerably simpler to characterize than the various pore types that exist in carbonates, it appears that applying image analysis for porosity identification in siliciclastic rocks is easier than that in carbonate rocks. Because carbonate holes might represent several diagenetic alteration processes, it can be difficult to determine their origin and geometry.

The goal of this study is to evaluate the validity and use of carbonate pore digital image analysis as a predictor of reservoir quality and performance. This was done by classifying the carbonate pores according to size, shape, and abundance using thin section analysis. The categories were then put to the test to see how closely they matched up with other reservoir quality indicators like measured porosity and permeability. Pore data obtained by image analysis methods were categorized for pore categorization based on geometry and abundance. To find patterns in the porosity characteristics of the Calub field carbonate reservoir, pore facies were constructed.

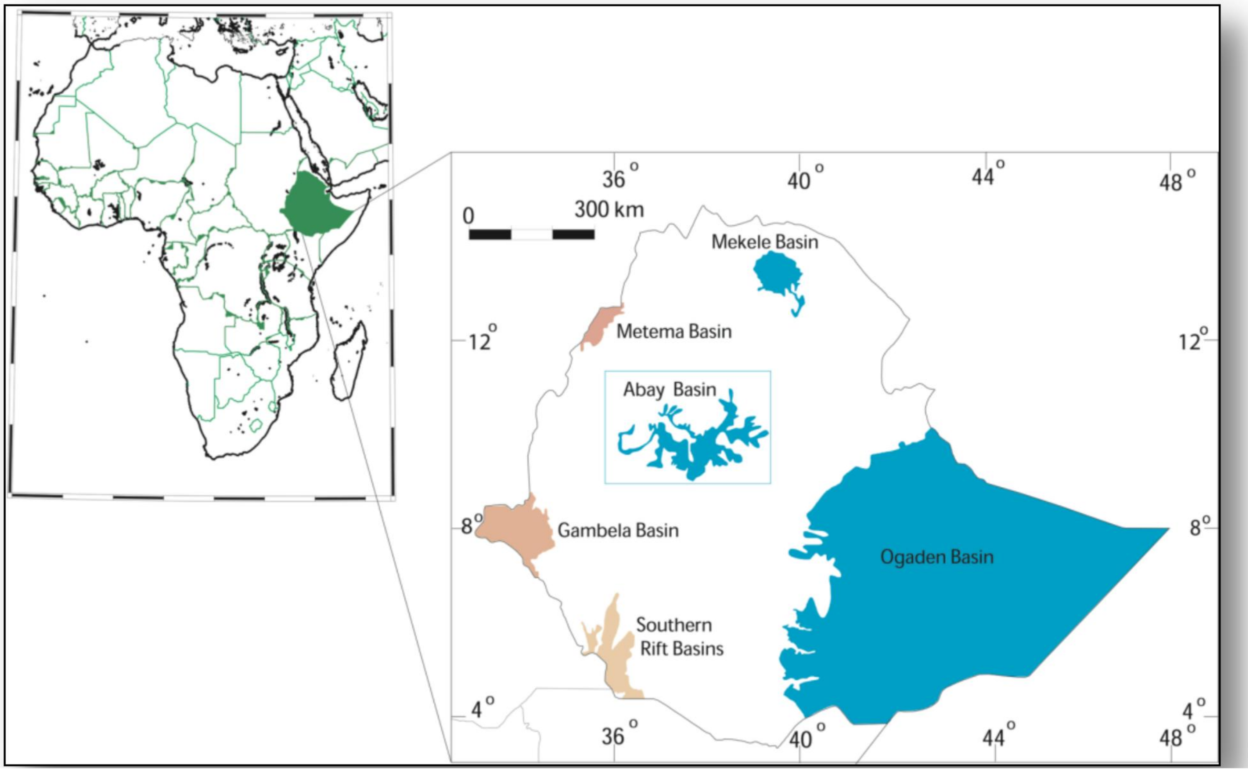

Figure1.1: Sedimentary basins of Ethiopia

1.1. Location of the Calub Gas field

The Calub Gas Field is found in the Ogaden basin, Somali regional state of Ethiopia. It is bounded by 6.3° N, 44°E and 5.2°N, 44.5°E. The core sample used in this study was taken from the well in the Calub gas field which is located approximately 700 km southeast of Addis Ababa, and is about 24 km west of Shilabo city, and also is about 60 km to Kebri Dehar (figure1).

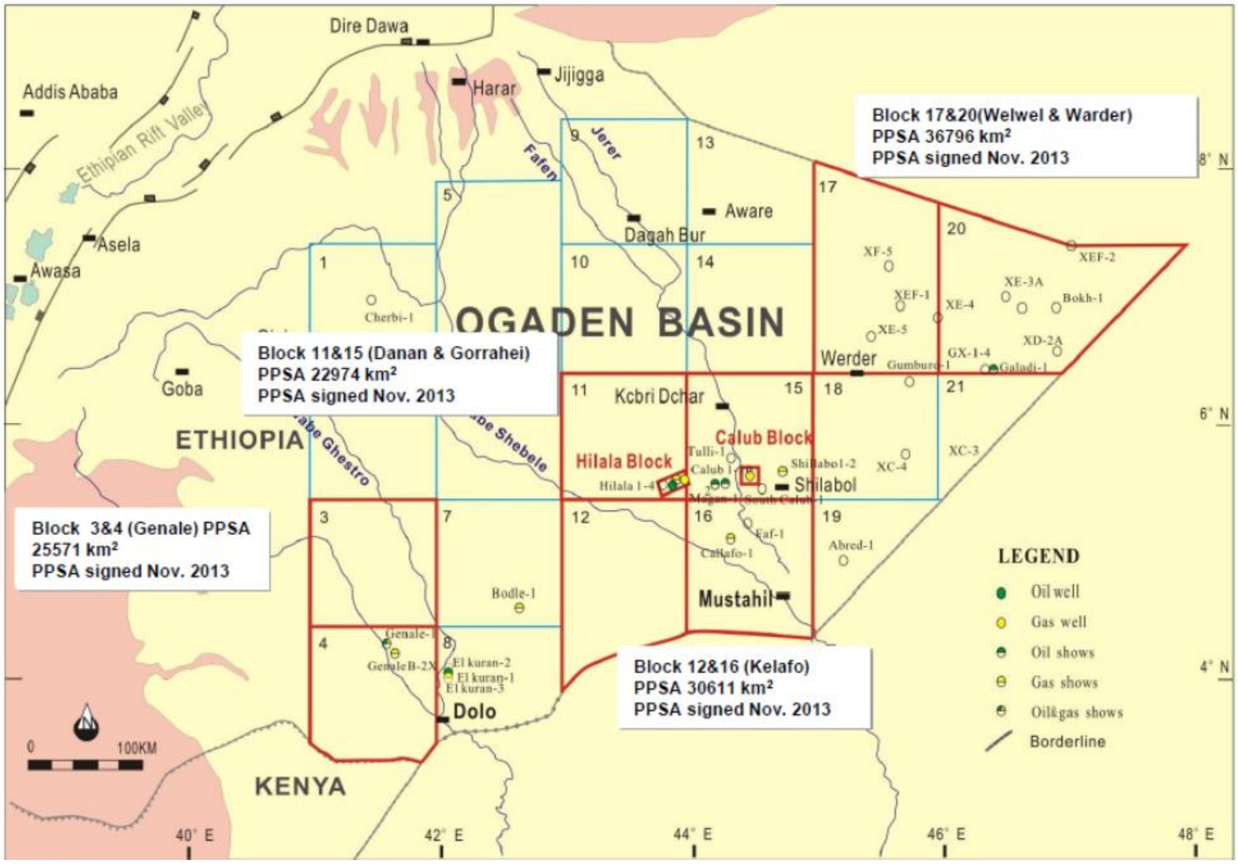

Figure1.2: Block of the study area (Luo yongsheng, 2017).

1.2. Problem statement

The Ogaden basin is a vast sedimentary basin having 350,000km^2 areal coverage. Although it is the most studied region in Ethiopia, so far 72 wells have been drilled in the area, i.e. the number of wells per area coverage is 4861 km^2. To better understand the nature of the reservoir rocks in undrilled areas, various studies should be conducted.

Hamanel formation is made from carbonate rocks, and previous study report showed that this formation bears oil and the reservoir rock is very tight; that is why oil extraction from this reservoir rock is believed to be difficult. Generally the formation is considered to be low porosity-low permeability reservoir rock. Considering the complex nature of this reservoir rock and the need for further characterization of this reservoir rock, there must be studies that depict nature of rock properties, i.e. porosity, and its effect on reservoir quality. Thus, with this in to consideration, this study tries to fill the aforementioned research gap with a different approach for pore identification.

1.3. Objectives

1.3.1. General objective

The general objective of this study is to evaluation the nature of porosity in carbonate rock of Hamaneli formation.

1.3.2. Specific objectives

- To identify vertical changes in porosity
- To highlight the nature of porosity destruction and enhancement
- To characterize pore types

1.4 Significance of the study

Through thin section examination and image analysis, the reservoir property of carbonate rock will be investigated in great detail by this study. In addition to the prior research conducted in this reservoir rock, the study's results will add to our knowledge of the reservoir quality of the carbonate rocks of the middle Hamanile formation. The findings will also act as a foundation for further research that will be done to understand the intricate makeup of the Hamanlei carbonate reservoir rock.

1.5 Thesis outline

Six chapters make up this research endeavor, each of which focuses on a different component of the investigation. A thorough overview is given in the first chapter, which also includes an introduction to the subject, the study's setting, its primary and particular goals, a problem statement, its importance, and an outline of the investigation. The discussion of major ideas and theories connected to the assessment of the understudied carbonate rocks is the main emphasis of chapter two's study of the literature. The strategies and resources employed in the study to accomplish the intended goals are described in detail in Chapter 3. Chapter 4, which combines the findings and comments, presents the study's conclusions and analyses. Chapter five presents the study's final conclusions as well as any relevant suggestions.

CHAPTER 2

2. Literature review

2.1. Regional Geologic setting

The sedimentary regions of Ethiopia cover a significant portion of the country and comprise five distinct sedimentary basins; namely: the Ogaden, Abay (Blue Nile), Mekele, Gambela and Rift Basins (Hunegnaw, 1998; Ahmed, 2008). The development of most of these basins is related to the extensional tectonic events that have taken place intermittently since the Late Paleozoic and continued up to Tertiary. The development of these sedimentary basins of Ethiopia is geologically interrelated; a process of intra-continental rifting is responsible for their formation (Russo et al., 1994; Hunegnaw et al., 1998). The evolution of sedimentary basins of Ethiopia is complex, but their tectonic setting and regional structural elements that control the basin styles and internal architecture readily understood. The Ogaden basin is a complex overprint of two (Permo-Triassic to Early Jurassic) rift basins which do not outcrop because they are overstepped by a passive marigin sag basin of a Late Jurassic age (Alconsult, 1996).

In Paleozoic-Mesozoic era the African plate and Arabian plate experienced a major events of continental rifting (Bosellini, 1989; Geleta, 1998). The Ogaden Basin is thought to have developed as a component of a triple-junction rift system during the Late Paleozoic Mesozoic, and the Blue Nile and Mekelle Outlier are believed to have formed as an intracontinental rift-related basin as a result of extensional stresses brought on by the breakup of Gondwanaland (figure 2.1a) starting in the Upper Paleozoic and continuing through the Tertiary Period. The result of the Gondwanaland breakup is equivalent to the early stage of Karoo rifting which is the late Paleozoic-Jurassic times. Continental rifts were developed especially along the border of the mega continent as a result of NW-SE tensional stresses. A correspondent thinning of the continental crust produced Graben and Half-Grabens which result in the Formation of several rift basins extending from South Africa to Eastern Ethiopia (Bosellini et al., 1989). The Ogaden Basin, located in the area extending from the east to southeast part of Ethiopia, is constituted of triaxially rifted troughs trending: NE-SW(Mandera-Bodle Rift), NW-SE (Blue Nile Rift), and ENE-WSW (North Shilabo Rift) (Ahmed, 1997; Hunegnaw et al., 1998). The extension dominating the African continents can be classified into three major episodes representing the evolutionary phase of intracontinental rift basins in the African continent (Assefa, 1991; Geleta, 1998).

After the creation of the Karoo rift in the early Mesozoic era, the Indian Ocean transgression from the southeast to northwest was a distinguishing characteristic (Assefa, 1991). Further indicated that the sedimentary history of horn of Africa's began during the late Carboniferous to Ordovician and Early Triassic periods, as a result of the development of NE and NW trending graben by continental sediment. During the Mesozoic era major and minor transgression and regression cycles occurred in Ethiopian Sedimentary Basins. The first and the major one cycle were responsible for the formation of the majority of Mesozoic sediments in Ethiopia in Mekele, Ogaden and Blue Nile Basins. Other minor cycles are recorded only in the Ogaden Basin (Geleta, 1998). The Permo-Triassic sediments, ranging from continental alluvial fan, fluviatile and deltaic clastics to lacustrine argillaceous types, were deposited in the Ogaden region in the Karoo rifting stage. The structures of Calub, Hilala and Shilabo gas fields are located in the Ogaden Subbasin of Somali Basin. The Somali Basin is located on the eastern side of the Ethiopian landmass, where the Paleozoic, Mesozoic and Cenozoic strata deposit on the Precambrian basement. The Somali Basin can be divided into 5 secondary tectonic units, i.e. Ogaden Subbasin, Nogal Uplift, Mudugh Subbasin, Mandera-Luga Subbasin and Mogadishu Subbasin. The Ogaden Subbasin, where Calub, Hilala and Shilabo gas fields are located, occupies an area of 3640 km2 and maximum deposition thickness of over 6,000 m, and the strata at the northern part are denuded completely where basement outcrops (POLY-GCL, 2017). This basin is influenced by the riftogenesis of the Paleozoic Karoo Rift System, and the Mesozoic and Cenozoic East African underlying Rift System and the Cenozoic Red Sea-East African Rift System, forming a large superimposed basin (POLY-GCL, 2017). With the evolution and tectonic movement of the basin, two sets of sedimentary strata are developed from the continental environment to the marine environment (POLY-GCL, 2017).

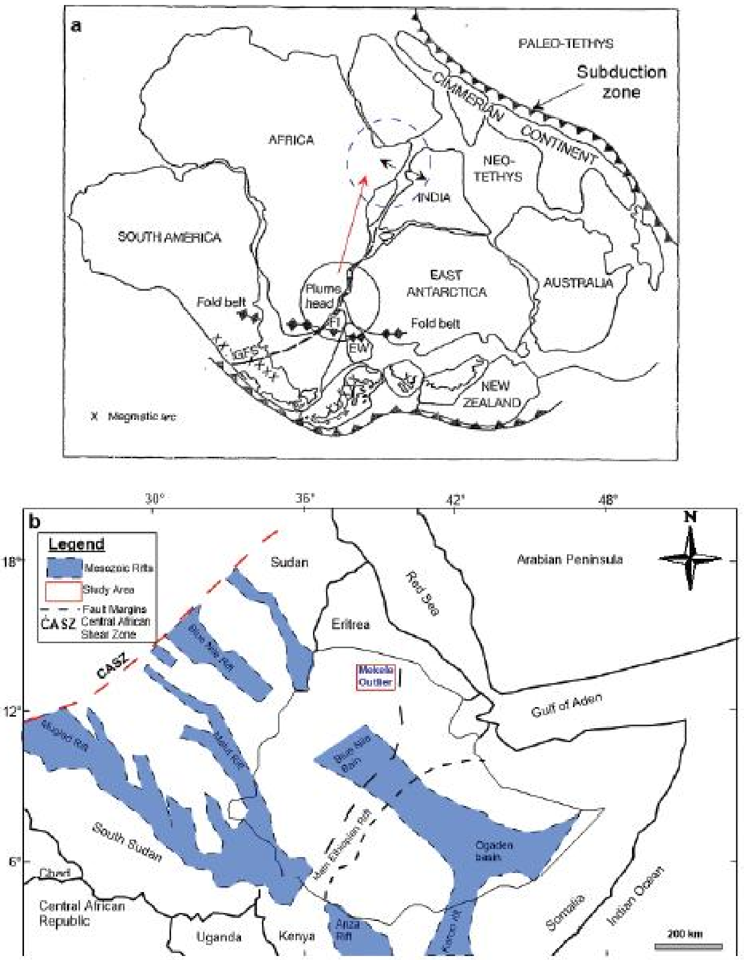

Figure2.1: a) Map showing Gondwana breakup, (b) Mesozoic rift basins of the Horn of Africa including Ethiopia (Adefris et al., 2022, and reference therein)

2.2 Stratigraphy

The Permian is the rifting-filling stage; mainly deposit the aliluvial fan and the fan delta. The Triassic-Early Jurassic is the rift spreading stage, mainly the lacustrine facies and the river delta facies. At the Early Jurassic Transition formation stratigraphic deposition stage, with the rift spreading further, the sea level rose and the large-scale transgression took place, then great thick marine sedimentary strata formed. At the late Cretaceous, the tectonic uplift, the sealevel fell and followed the large-scale regression (POLY-GCL, 2017).

The focus of this study in Calub fields, the M. Hamanlei formation is a set of marine deposition with a thickness of about 550 m, the lithology is mainly limestone, dolomite and anhydrite, and the oil and gas are mainly discovered in limestone and dolomite (table2.2). The region's sedimentation environment is composed of evaporative platform facies deposition, and the gypsum flats and dolomite-micrite flat deposition (POLY-GCL, 2017). Due to the influence of frequent sea level changes, the combination of multi-period anhydrite, limestone and dolomite is formed (POLY-GCL, 2017).

Table2.2: Stratigraphic column of Calub field (POLY-GCL 2017)

Era	System	Seires	Formation	Top Depth (m)	Thickness (m)	Lithology
Mesozoic	Jurassic	Upper	Gabredarre	1,070	240	Limestone mingled with mudstone
			Uarandab	1,310	150	Shale, marlstone
		Middle	U. Hamanlei	1,460	410	Granule limestone, marlstone
			M. Hamanlei	1,870	550	Dolomite, anhydrite, limestone
			L. Hamanlei	2,410	280	Marlstone
		Lower	Transition	2,690	60	Limestone, gypsum, mudstone in upper part, mudstone,shale in lower part
			Adgrat	2,750	100	Sandstone and mudstone interbedding

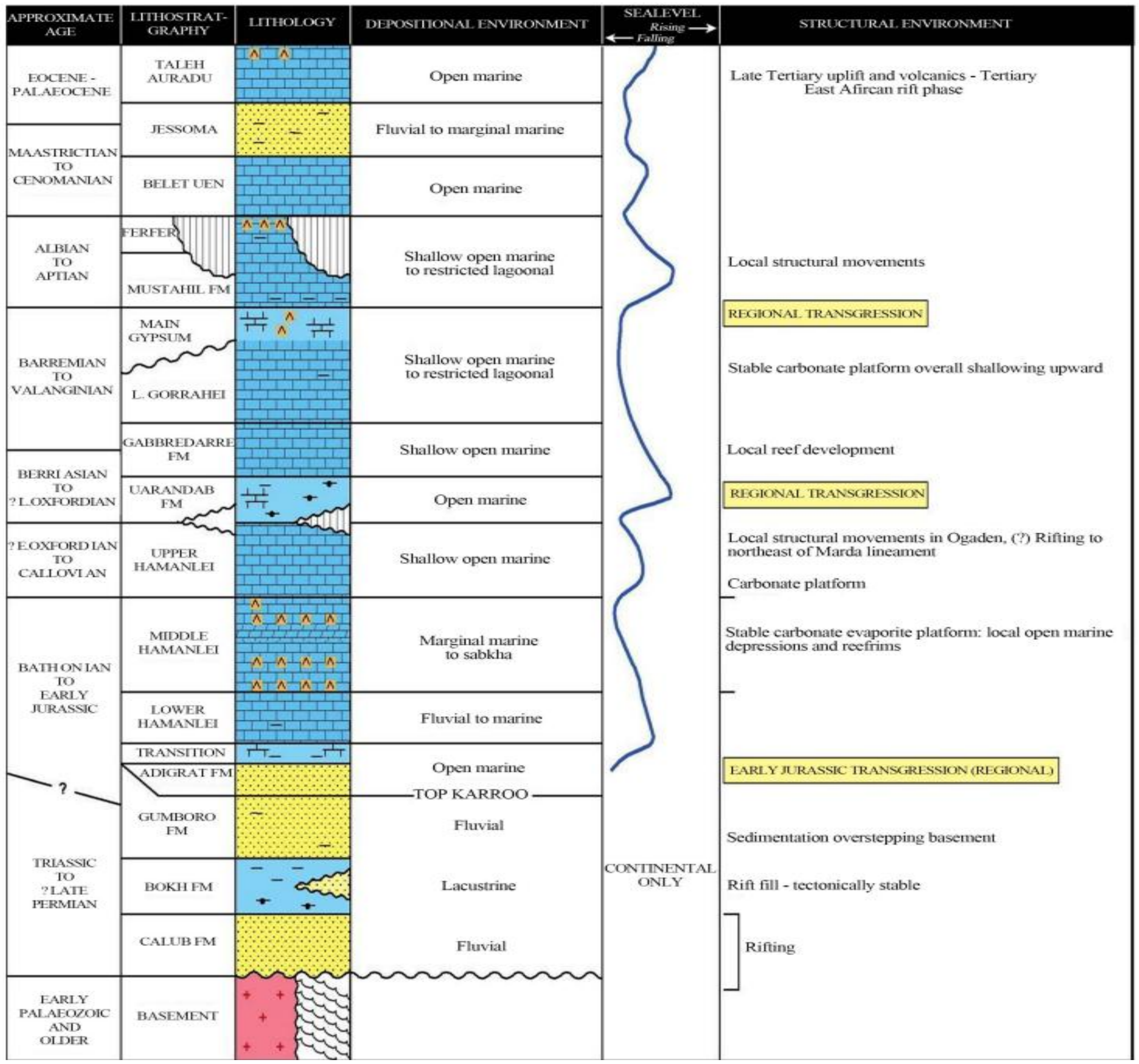

Figure2.2: stratigraphic and petroleum system of Ogaden basin (Getaneh, A., 1988)

2.3 Hamanlei Formation

The Calub gas field has 11 cored wells, from which 265 barrels of cores were taken. The footage is 1,082.5 m, the core length is 626.9 m, and the core recovery is 57.9% (Luo yongsheng, 2017). According to the core observation in this field, the Hamanlei formation is mainly composed of limestone, argillaceous limestone, dolomitic limestone and anhydrite in lithology (Figure 2.3).

When Mid-Jurasic Hamanlei is deposited, the basin's structural movement is relatively weak and it is overall marine deposition. Due to the cyclic eustatic changes, the basin undertakes deposition of a massive carbonate rocks and marine shale. Hamanlei group is divided into U. Hamanlei formation, M. Hamanlei formation and L. Hamanlei formation (POLY-GCL, 2017).

At the bottom part of L. Hamanlei formation, two sets of shallow marine carbonate rock and two sets of fine grained clastic rock are deposited, and the top part is shallow marine limestone deposition with oolitic carbonate rock in part which is high-energy open platform deposition; when M. Hamanlei formation is deposited, due to the existence of shoal which restricts the circulation of the marginal sea water, the water has relatively low energy, and thus the central uplift belt is supra tidal deposition with sabakha characteristics(POLY-GCL,2017). The lithology of M. Hamanlei is anhydrite interbedded with limestone and dolomite, and the presence of anhydrite indicates arid evaporated environment (POLY-GCL, 2017).

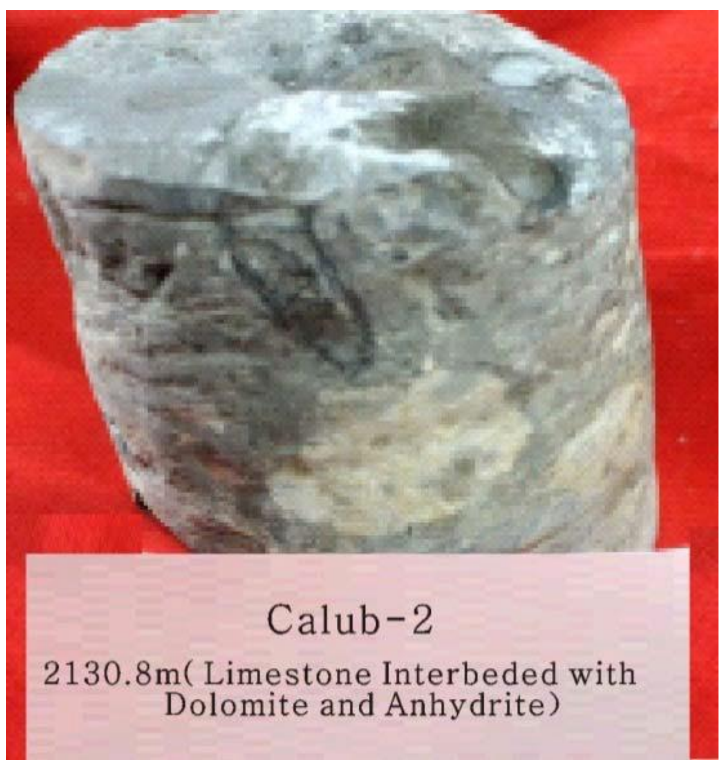

Figure2.3: Core Photos of M. Hamanlei Formation of Calub Gas Field.Core photo from 2130.8 m depth of Well Calub-2 shows interbedded limestone, dolomite, and anhydrite (POLY-GCL, 2017).

2.4 Core Descriptions

The Calub 2 core, extracted from Core No. 3 in the Calub Field, spans from a depth of 2126 meters to 2140 meters. The intervals within this core are described as follows: the initial 2 meters consist of anhydrite and white materials, followed by 10 meters of anhydrite and white. The subsequent 1 meter comprises dolomite and grey components. Lastly, the next 3 meters are characterized by anhydrite, lumpy texture, white color, and interbedded limestone.

Similarly, the Calub 2 core from Core No. 4 in the Calub Field covers a depth range of 2226 meters to 2242 meters. During this interval, there is a sequence of 16 meters consisting of dolomite, grey color, and limestone interbedded with anhydrite.

Table 2.4 Summary of calub 2 Core Description (modified from POLY GCL, 2017)

core No.3		
Depth(m)	Thickness(m)	description
2126	2	anhydrite, white
2136	10	anhydrite, white
2137	1	dolomite, grey
2140	3	anhydrite, lumpy, white, interbedded with limestone
core No.4		
2226	0.5	Dolomite, grey, limestone interbedded with anhydrite
2226.5	1	Dolomite, grey, limestone interbedded with anhydrite
2227.5	0.5	Dolomite, grey, limestone interbedded with anhydrite
2228	2	Dolomite, grey, limestone interbedded with anhydrite
2230	4	Dolomite, grey, limestone interbedded with anhydrite

2234	4	Dolomite, grey, limestone interbedded with anhydrite
2238	2	Dolomite, grey, limestone interbedded with anhydrite
2240	2	Dolomite, grey, limestone interbedded with anhydrite
2242	....	Dolomite, grey, limestone interbedded with anhydrite

2.5 Porosity classification

The geosciences and petrophysics have widely used image analysis to address problems with reservoir rock characterization. This method has been very useful for characterizing pore spaces, which can have complex geometries and connections. Several techniques, such as manual point counting, petrography, and image analysis, have been developed to precisely estimate porosity (McDaniel, 2014).

CHAPTER 3

3. METHODS

The following techniques were used to achieve the aforementioned goals of this study.

3.1. Primary Data

Fifteen (15) carbonate core samples, of Middle Hamanlei formation, from the Calub gas field were collected from the Ministry of Mines, Ethiopia. The samples were cut and thin sections prepared at GSE laboratory center.

3.2. Thin Section Preparation

Rock samples-typically cores or individual grab samples (Figure 3.1), require processing before they can be used for petrographic analysis by PLM (Polarizing Light Microscope). The sample has to be thin enough for light to pass through in a light microscope and have a polished surface for electron microscope studies.

In the Geological Survey of Ethiopia Laboratory, thin sections of rocks are typically cut perpendicular to the bedding plane or cleavage plane to capture the internal structure and composition of the rock. The thin section is cut from a larger rock sample using a rock saw or other cutting tool, and then ground and polished to a thickness of around 30 microns before being mounted on a glass slide.

A study of 15 thin sections of carbonate samples from Calub field was done to determine relationships between pore characteristics and reservoir quality to show that pore size, shape, and abundance.

Figure3.1: Core Photos of M. Hamanlei Formation of Calub Gas Field (ministry of mines)

3.3. Image Acquisition

Image acquisition from thin section is the process of taking pictures with a microscope or another imaging tool of thin slices of an object, such as a rock or biological tissue. Typically, thin sections are made by taking a thin slice of the material, putting it on a glass slide, and examining it under a microscope.

Thin section imaging can be used to capture pictures that can be utilized to characterize rock fabrics and detect mineral grains. The sample must be carefully prepared before picture acquisition from a thin segment in order for it to be placed and aligned with the imaging instrument. To guarantee that the photographs are of good quality and precisely depict the sample, imaging settings like the magnification, focus, and lighting must also be carefully calibrated. Several authors have employed image analysis to assess pore system features using images taken using various microscopy methods, such as optical microscopy (Grove and Jerram, 2011). A number of trial methods were made to capture very representative images for further analysis and interpretation. Thus, fifteen (15) images were acquired for the aforementioned purpose.

3.4. Image Processing and Analysis

Analyzing digital images is nothing new. Analyzing the qualities of digital photographs after they have been captured is all that is required. In recent years, following the introduction of high-speed desktop computers, this has become a standard practice. Geoscientists today employ image acquisition and analysis tools for a wide range of petrographic applications, including as textural, mineralogical, fabric, and porosity investigations. On each thin segment, 200 points were counted to determine the size and shape of the pores. Under a polarized light microscope, 15 stained samples from the Calub 2 #3 and Calub 2 #4 wells were examined in total. To find apparent porosity, grains, cements, and matrix (lime mud), thin slices were studied.

ImageJ in its Fiji version was the program used for image analysis (Figure 3.4). For the purpose of identifying the grains, matrix, and cement, a petrographic microscope was utilized.

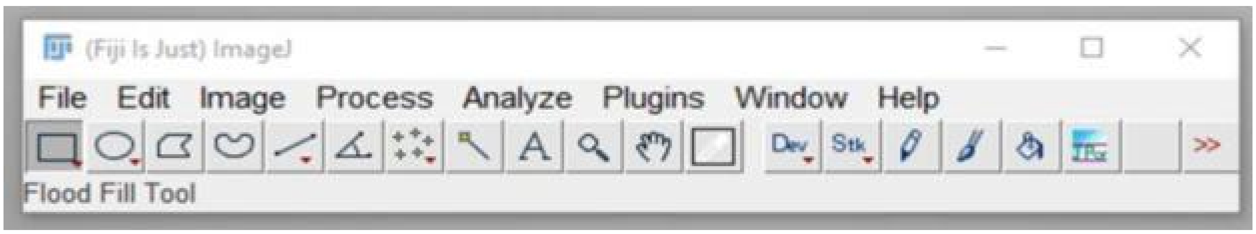

Figure 3.4: ImageJ software screenshot.

3.4.1. Pore Measurements

To ascertain constituent percentages and gather pore data, the thin-section samples were segmented by threshold (in the object extraction program). Select blue pixels on the second histogram to start measuring porosity. The proper sections for matrix, cement, and grit were then selected in the intensity histogram by using the inverse checkbox to select everything other than blue. The percentage of each component was next calculated. Finally, the pores were categorized using Ahr's genetic method. This makes it possible to identify different pore types at the field scale within the context of the larger stratigraphic architecture. Geologists can learn more about the history and evolution of various pore types to better understand the reservoir quality and prospective flow characteristics of a particular area.

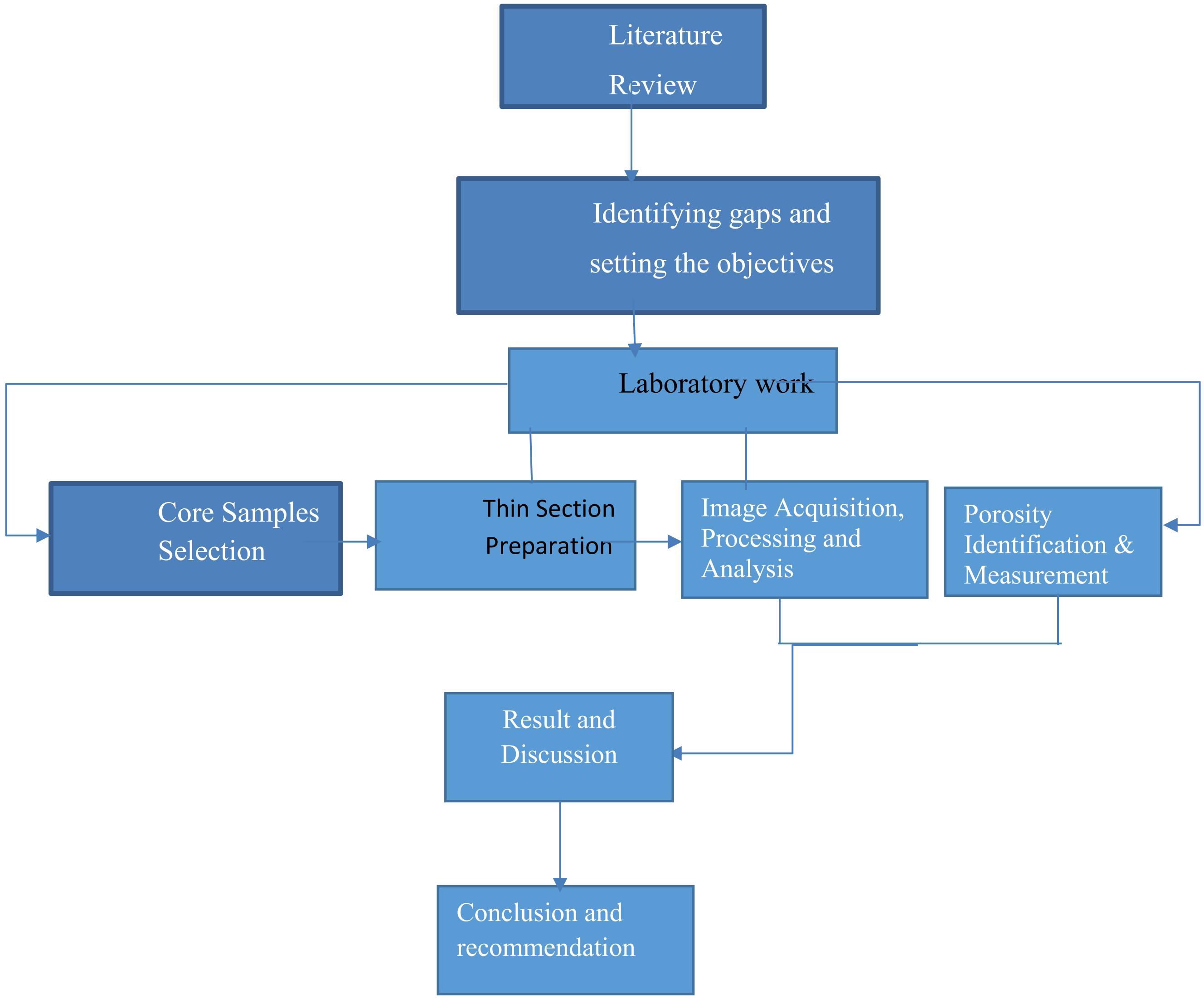

Figure3.3: Flow chart of the study

CHAPTER 4

4. Result and Discussion

4.1. Pore type

Moldic porosity, interparticle porosity, and intraparticle porosity were found to be three separate pore types within the Calub2 wells that contributed to the formation's composition. In the Calub field, this form of moldic porosity was discovered within the oolitic-skeletal grainstone and packstones facies. Moldic porosity is described as the selective removal of a single constituent of the rock, such as an oolith. Interparticle porosity, which was discovered in the siltstone facies, is characterized by original vacuum space between grains from original deposition. A characteristic of intraparticle porosity, which was discovered in the rudstone facies, is porosity within specific particles or grains.

4.1.1. Interparticle Porosity

The wackstone facies contains the first pore type, interparticle porosity (Figure 4.1). The wackstone has a relatively low porosity because to the tiny grain size and moderate cement content.

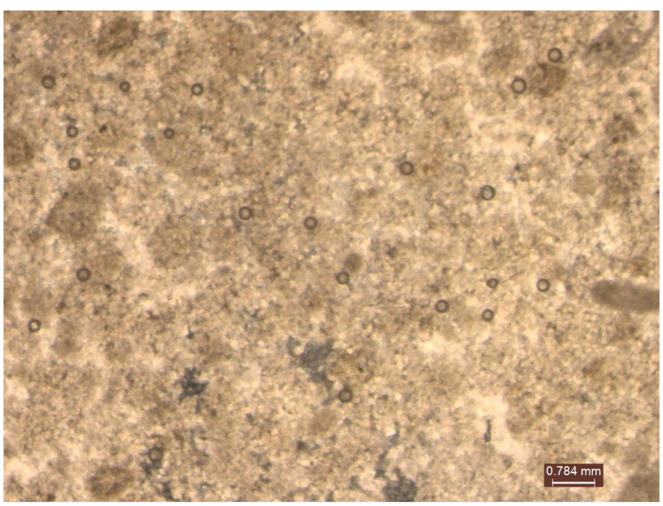

Figure4.1: Thin section image from well, Calub2, 2240m.

4.1.1.1. Grain Moldic (M)

Molds resulted from the stable grains' diagenetic breakdown. Ooids and skeleton remnants are frequently found in molds. Sharp, clear grain outlines can be seen in moldy pores. Moldic are the main contributors to the field's overall pore volume and predominate the oolitic skeleton grainstone packstone facies (Figure 4.2).

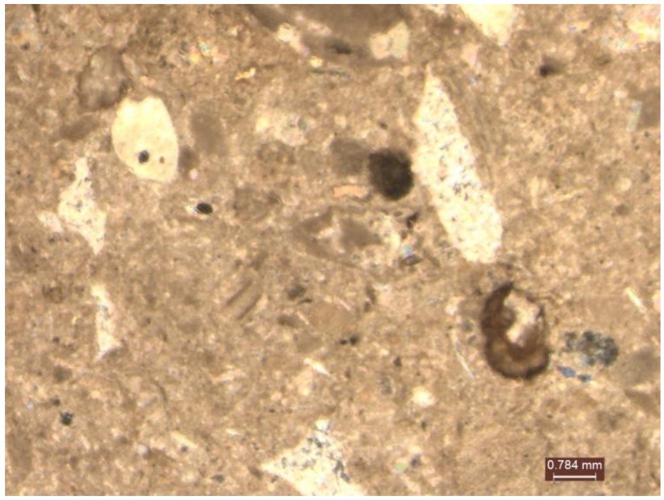

Figure4.2: Photo Optical microscopes of moldic pores. Samples from Calub Core No. 4, 2228m.

4.1.1.2. Intraparticle Porosity

The third form of pore is intraparticle porosity, which is present in rudstones, floatstones, and in situ tubiphytes bindstones (Figure 4.3). The interior chambers or apertures within the clasts or skeletal organisms that have or are in the process of dissolving are what caused this porosity to arise. Facies with this pore type have porosity values that range from moderate to high.

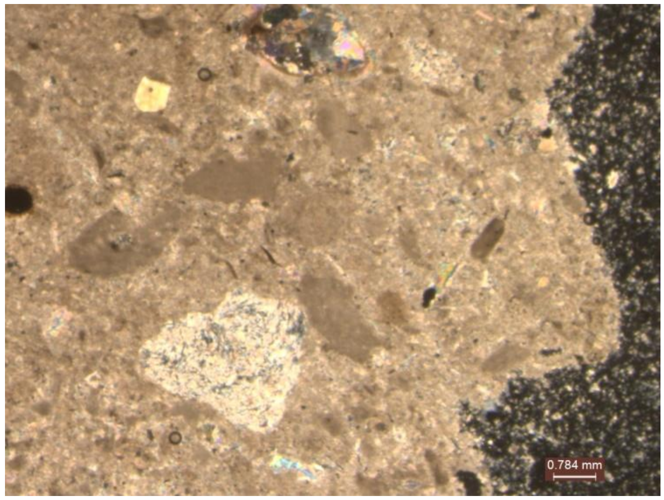

Figure 4.3: Thin section image from well Calub2 at 2227.5m

4.2 Component and porosity quantification

Table 2 shows quantitative image analysis information obtained from thin sections of wells cores 3 and 4 in the Calub field that were examined under an optical microscope. The statistics show that the carbonate rock has poor porosity, which is caused by the rock's predominate cement content. Due to this, carbonate rock is a subpar reservoir rock. The low quality of the carbonate reservoir rock was caused by the presence of intercalating anhydrite in the examined cores, low porosity dolomite, matrix, and cement-dominated limestone. To increase the porosity of this reservoir rock, any hydrocarbon exploitation plan must first take into account cementation and matrix effect.

Table 2: Carbonate components and identified amount of porosity

quantitative image analysis data							
Thin-section No.	Box No.	Slide	Depth(m)	Average Porosity	Matrix	Cement	Grain
1	11	CA2-1	2226	1.2	22	63	14
2	11	CA2-2	2230	4	26	70	0
3	11	CA2-3	2234	4	21	75	0
4	11	CA2-4	2238	1	34	59	6
5	11	CA2-5	2240	3	8	72	17
6	11	CA2-6	2226.5	2	21	60	17

7	11	CA2-7	2227.5	7	8	76	8
8	11	CA2-8	2228	1	3	82	14
9	8	CA2-9	2137	0	0	0	0
10	8	CA2-10	2126	0	0	0	0
11	8	CA2-11	2140	2	4	88	6
12	11	CA2-12	2226	3	14	81	2
13	8	CA2-13	2136	6	27	66	1
14	8	CA2-14	2137	4	6	86	4
15	11	CA2-15	2242	4	6	87	3

CHAPTER 5

5. Conclusion and Recommendation

5.1. Conclusion

The results of these measurements provide valuable insights into the mineralogy, texture, and structure of the studied rocks. By identifying and quantifying these components, geologists can better understand the formation and evolution of sedimentary rocks, as well as their potential as hydrocarbon reservoirs.

Petrographic image analysis is a faster method than any other standard petrographic analyses methods, but it has certain downfalls that can affect the results, such as, poor quality images and systematic human error. These findings highlight the importance of understanding the different pore types and their relationships to the depositional and diagenetic processes in order to better interpret the reservoir quality and potential flow characteristics of the studied rocks.

The porosity value of the carbonate reservoir rock is generally very low owing to the presence of intercalating anhydrite in the studied cores, the low porosity dolomite and matrix and cement dominated limestone. Nonetheless, moldic porosity, interparticle porosity, and intraparticle porosity are most observed pore types in different intervals of the studied cores. Overall, this study demonstrates the significance of pore type characterization in the field of geology, particularly in the exploration and exploitation of hydrocarbon reservoirs.

5.2. Recommendation

As this project work was conducted in a very limited time, detail investigation of the core samples, particularly the impact of depositional environment for the poor nature of the reservoir rock, could not be conducted. Similarly, the observed very low porosity value consistency in different well that hit the Hamanlei formation was not made to infer the poor nature of the carbonate reservoir rock in the Ogaden basin. Hence, it is recommended for further study, i.e. petrographic and image analysis, to be conducted for the rest wells besides the one studied in this work, so that a wealth of information, that can supplement the extant wireline log data, can be obtained.

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