



ADDIS ABABA UNIVERSITY
SCHOOL OF GRADUATE STUDIES
DEPARTMENT OF EARTH SCIENCES

**Petroleum Source Rocks Analysis Based on Geochemical
Data: A Case Study in the Melut Oilfields, South Sudan.**



**A thesis submitted to the Department of Earth Sciences of Addis Ababa
University in partial fulfilment of the requirement for the Degree of Master
of Science
In
Earth Science (Petroleum and Coal Geology)**

By: Chuol Tap Thechuong
Advisor: Balemwal Atnafu (PhD)

October 2021
Addis Ababa, Ethiopia

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**PETROLEUM SOURCE ROCKS ANALYSIS BASED ON GEOCHEMICAL DATA: A
CASE STUDY IN THE MELUT OILFIELDS, SOUTH SUDAN.**

**BY
CHUOL TAP THECHUONG**

APPROVED BY EXAMINATION COMMITTEE AND DEPARTMENT CHAIRMAN

Name:	Signature	Date:
Dr. Balemwal Atnafu Head, School of Earth Sciences	_____	_____
Dr. Balewmal Atnafu Advisor	_____	_____
Dr. Mulugeta Fesseha Examiner I	_____	_____
Professor Dereje Examiner II	_____	_____

October 2021

Addis Ababa, Ethiopia

Declaration

I, Chuol Tap Thechuong, do hereby declaring that the thesis entitled “Petroleum Source Rocks Analysis Based on Geochemical Data: A Case Study in the Melut Oilfields, South Sudan.” is submitted to the School of Earth Sciences in Addis Ababa University in partial fulfilment for the requirement for the award of the Master of Science in Earth Science (Petroleum and Coal Geology) under supervision of Dr Balemwal Atnafu. I certify that this thesis work contains no data which have been accepted of any other degree as related to the content of this work. The data used to obtain the objectives of this thesis have not been previously published or written by any other researcher, with exception of the due reference made in the appropriate reference list.

Signature

Date

Chuol Tap Thechuong

Dr. Balemwal Atnafu

October 2021

Addis Ababa, Ethiopia

Abstract

The Melut Basin is an important petroliferous rift basin in Africa, and a large number of structural hydrocarbon accumulations have been discovered in it. In this paper, Rock-Eval 6 instrument was used as the main apparatus to achieve the objectives of this study. The general objective of this study is to characterize the petroleum source rock in the Melut Basin based on geochemical data. Geochemical parameters obtained from rock-eval 6 analysis was presented. The samples have been evaluated using geochemical analysis. Following the temperature program and taking into account all measurement and assumptions, S1, S2, S3, TOM, TOC, HI, OI, PP, and Tmax has been measured and calculated in this study. Other parameters include organic carbon content and source rock maturity are evaluated with various factors including quantity and quality of organic matter, petroleum potential, type of organic matter and thermal maturation were considered. For all the selected settings, 5 samples were collected from the Galhak formation, 4 from Al Gagyer and 4 from Melut formations. From all the selected samples, sample TNP011 have shown a considerable richness in total organic matter (TOC), which is 3.24wt.% indicating a very good rate for petroleum potential. The maturation possibility of these sequences is ranging between 423-436°C as indicated by the T_{max} values. Most of the above have shown immature, early and post maturities. For post, maturity samples are mentioned for sample TPW012 as its value equals 448°C. The lowest Tmax value equals 423°C for sample AMF013 which show an immature level. The criterion for determining kerogen type (quality) is usually depending on the value of the hydrogen index. The overall results show that the source rock quality range from fair to very good hydrocarbon potential stage, with kerogen confined, is encompassed into Type II that has the capability of generating oil and limited gas. Location-1 and location-2 samples have shown poor pair quantity of source rocks. Mostly, gas can be produced in these locations which correspond to type III kerogen. Type III kerogen is known for producing gas. The quality of kerogen in this study is ranging from kerogen type II, III and IV. Type IV kerogen cannot produce oil or gas. Oil and gas are produced from type II and Type III respectively. In this thesis work, the geochemical results have shown that S1 values are lower than S2 values in each source rock sample, which might be interpreted as hydrocarbons migrated out of the investigated source rocks into the traps system.

Keywords; *Rock-Eval 6, Source Rock, Parameters, TOC, Kerogen, Al Gayger, Type II, Migration.*

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List of Abbreviations

AU-Assessment Unit

CASZ-Central Africa Shear Zone

DPOC- Dar Petroleum Operating Company

CNPC; China National Petroleum Corporation

FID- Flame Ionization Detector

HI-Hydrogen index

SUDD- province encompasses parts of the Central African Republic, Chad, Kenya, Sudan, and Tanzania.

PP-Petroleum potential

S1- Value of free bitumen

S2-Hydrocarbon potential value

S3-CO₂ potential

PI-Production Index

TOM- Total Organic Matter

TOC-Total organic carbon

Tmax-Temp of Maximum generation rate (i.e., S2)

mD-millidarcies

OI-Oxygen index

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CHAPTER ONE

1. Introduction

Rift basins are rich in oil and gas resources. Among the 877 giant oil and gas fields discovered worldwide, 30.9% are located in rift basins (Mann et al., 2003; Jia et al., 2011). Some large rift basins have reserves exceeding 30 billion barrels, including the Sirte Basin in North Africa and the Songliao Basin in northeast China. The Central and West African Rift System is a well-known intra-continental rift system, where a series of petroliferous rift basins including the Termit, Bongor, Muglad, and Melut Basin (Fig. 1A) developed under the effect of crustal extension caused by dextral strike-slip motion along the Central African Shear Zone (CASZ) during the Late Jurassic to the Cretaceous (Fairhead, 1986; Binks and Fairhead, 1992; Guiraud and Maurin, 1992; McHargue et al., 1992).

Geochemical analysis of petroleum source rock is done by defining the properties of source samples extracted from sub-surface (cores) and analysed in the laboratory. Source rocks are sedimentary rocks that are deposited in very quiet water, usually in still swamps on land, shallow quiet marine bays, or deep submarine settings. They consist of very small mineral fragments which are remains of organic materials usually algae, tiny woody fragments, or pieces of the soft part of plants and animals (Hunt, 1995). Geochemical analysis of petroleum source rocks has effectively caught the attention of many Geologists particularly petroleum geologists in recent years because of the accuracy and efficiency of the analyzed data relating to the source rock maturation, quantity and quality.

Petroleum geochemistry is basic science to understand the characteristics of source rocks, productive and non-productive zones, oil migration all produce more efficient exploration, oilfield development and sustainable production. Due to the influence of time, temperature, and pressure, the mud sediment turns into sedimentary rock. Unconsolidated rock that comes from mud which contains oil spots is known as source rock. The parent rock is one of the main elements of the hydrocarbon system (Millayanti et al, 2019).

The research on Petroleum Source Rock in Melut Basin has received inadequate consideration in terms of petroleum geological literature.

Academics have studied various aspects in the basin with specific titles related to the petroleum accumulations and migration, Reservoir Characterization, and limited to an understanding of petroleum source rock in this basin. Therefore, this study will give more insights and understandings on the petroleum source rock that would help bridge the gap on defining the petroleum source rock in the basin.

1.1 Overviews on Melut Basin

Most of the world's petroliferous sedimentary basins instigate crudely in a rifting event and later pass through a syn-rift to post-rift evolution (Kingston et al. 1983). The Central and West African Rift System is a world-renowned Mesozoic-Cenozoic rift system, with several petroliferous rift basins, such as the Termit, Bongor, Muglad, and Melut Basins (Browne and Fairhead 1983; Bermingham et al. 1983; Genik 1992; Guiraud and Maurin 1992; Wilson and Guiraud 1992). The rift basins in the central African Rift System are known to contain Cretaceous to Paleogene lacustrine and marine source rocks that have generated hydrocarbons since the Late Cretaceous (Genik, 1992, 1993; Mohamed and others, 2002). Hydrocarbons migrated into Cretaceous and Paleogene reservoirs and trapped in structural traps. Melut Basin is the second-largest sedimentary basin of the Central African Rift System (**figure 1**) positioned in South Sudan, covering an area of 3.3×10^4 km² (Schull 1988; Jorgensen and Bosworth 1989; Mchargue et al. 1992; Genik 1993). Exploration activities in the Melut Basin began in the period between 1970 to 1974 after Chevron signed a concession contract with the Democratic Republic of Sudan covering an area of 516,000 km². Two large rift basins, Muglad and Melut Basins, were both inside the block. To discover large oil fields quickly and effectively is the major purpose of the overseas exploration project. The major drilling activities were concentrated in the Muglad Basin, where a series of oil fields had been discovered since 1979 (Schull, 1988; Dou et al., 2002; Tong et al., 2004). In the late months of 2000, four exploration wells and one appraisal well were drilled in Melut Basin, and as a result, only a small oilfield, the Adar-Yale field, was found in the basin (Schull 1988; Dou et al. 2007). In November 2000, China National Petroleum Corporation (CNPC) entered the Melut Basin, launching the major overseas exploration scheme of China at the time. Soon after, with scientific and reasonable exploration strategies and technical approaches, they had made a significant discovery in the basin. The primary field in the Melut Basin which is rated as a world-class is named the Great Palogue Field discovered in 2003 with an estimated recoverable oil reserve of over 900 million barrels of good-quality light crude (61.5° API) oil was discovered (Dou et al. 2007). From 2004 to 2007 China National Petroleum Corporation (CNPC) has been particularly active in the Melut Basin, having been awarded the concession for two producing blocks (block 3 and 7) in the Western part of the Upper Nile Region.

Exploration practices in the basins of China have revealed that a petroliferous basin usually undergoes three exploration stages: regional exploration, key play exploration, and fine exploration (Zhao et al., 2005). During the regional exploration stage, the large regional structural traps are the main drilling targets to confirm the petroleum geological conditions and

hydrocarbon potential of the basin. If the basin is shown to be oil-rich, exploration will focus on structural traps in the key plays. And after most structural traps in the key plays have been drilled, the basin will enter a fine exploration stage focusing on stratigraphic traps. The yearly reserves of stratigraphic hydrocarbon accumulations may account for more than 40% of the total reserves in the fine exploration stage (Jia et al., 2007). Therefore, the investigation on the stratigraphic hydrocarbon accumulations is important to promote the increasing exploration in the mature Northern Sub-basin. The Melut Basin is a passive rift basin and has different sedimentary filling and hydrocarbon accumulation characteristics from the active rift basins in China (Shi et al., 2019). The Melut Basin develops regional and thick sandstones above the primary source rocks (Dou et al., 2007; Shi et al., 2019), and the hydrocarbon generated by the Lower Cretaceous source rocks migrated upward and accumulated in the Paleogene Yabus and Samma sandstones. The hydrocarbon accumulations in the Melut Basin have higher risk of hydrocarbon charge and more complicated formation conditions, especially for the stratigraphic hydrocarbon accumulations.

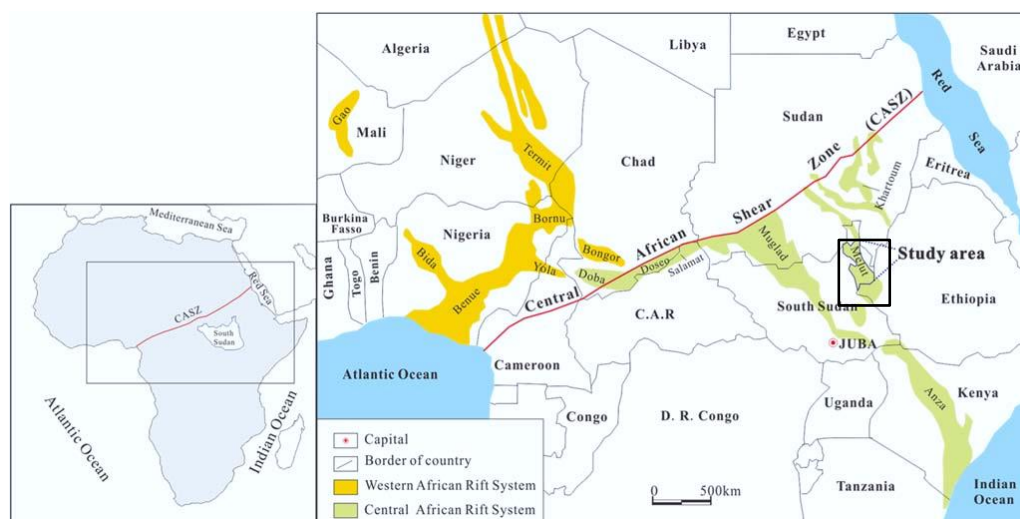


Figure 1. Distribution of the Central African Shear Zone and Central and West African Rift Systems (modified after Genik, 1993)

5.3 Petroleum Geology History in Melut Basin

5.3.1 Reservoir Rocks

The primary reservoirs of the Melut Basin are the Paleogene and Upper Cretaceous sandstones where commercial oil flows have been tested from. The sandstones reservoirs studied in Melut Basin (Dou., 2007) exhibit good reservoir quality (both in porosity and permeability) at varying depths. However, the difference in settings and tectonic history resulted in the major pay zones and features changes with time and space in Sudan. In the Melut Basin, about 95% of oil

reserves are accumulated in the Yabus and Samma sandstones (Dou, 2004). The relatively weak rifting episode during the Late Cretaceous resulted in the sand-dominant sediments, no thick shales can provide a good regional seal within the Cretaceous strata. As a result, oil and gas generated and expelled from the Lower Cretaceous Al Gayger source rocks migrated to and accumulated in the Yabus and Samma sandstones. The reservoir quality of the Melut sands is lithofacies dependent. Porosities of the reservoir sandstones of the Melut Formation range from 8–25%, averaging 20%, and permeabilities range from 0.1 to 300 mD. Lab analyses of cores from the Melut Sand intervals show that the average porosity of reservoirs is 20.15% and the average permeability is 9 mD. Calibrated by core study, well logging data indicate that the Upper Cretaceous reservoirs belong to medium porosity and low permeability reservoirs based on the Chinese lacustrine reservoir evaluation standard.

5.3.2 Seal and Charge System

The Adar Formation has a sand net-to-gross ratio of less than 20%. The accumulated thickness of mudstones penetrated by study wells is 128–507 m and up to 900 m in basin depocenter as interpreted from seismic profiles, substitute as a regional seal for the underlying Yabus and Samma Formations. These mudstones have moderate to good sealing quality, with mercury-injection capillary pressure of 0.6–2 MPa. Despite late tectonic movements, the Adar seal contributed a strong fault sealing capacity for the juxtaposition of fault blocks and lithological column (Dou et al, 2007, Mohammed., 2016). In addition, the mudstones within the Melut Formation can serve as a local top seal and fault sealing for the antithetic fault-blocks, for example, at the Palogue South-2 well commercial oil flow was obtained from the Melut sandstone reservoirs.

5.3.3 Oil-Source Correlation

Oil–source rock correlations attempt to determine the specific source facies that gave rise to an oil. Correlation studies endeavour to establish the original genetic relationship of geologic samples rather than a mere matching of bulk properties or chemical compositions. In Melut Basin, the basic crude oil properties include a specific gravity (d_4^{20}) ranging from 8.87–61.51 API. The viscosity at 50°C is 3.93–2467 mPas, while the pour point is 1–120°F. The oils are high wax sweet crudes, with a wax content of 2.62–45.24%, a Sulphur of 0.035–0.21% and a lower oil/gas ratio at 26–90 scf/bbl. The total acid number (TAN) of these oils is changed greatly, from less than 0.01 to 10.6 mgKOH/g. Compared with the geochemical data of source rocks displays that the oils from the Yabus, Samma and Melut reservoirs show similar levels of maturation, which is higher than that of the source rocks penetrated in Palogue-1 and Fal-1.

The studied oils belong to one family (Dou et al, 2007), based on their bulk chemical compositions and biomarker fingerprints.

5.3.4 Trap Type

According to a study conducted by Lirong Dou and others (2007) in the Melut Basin, the major type traps and the age of core pay zones are faulted anticline and Paleogene, respectively.

I. Faulted Anticline

During the Early Cretaceous, the steep planar boundary faults resulted in few large rollover anticlines on the hanging wall of the boundary faults. The half-graben framework decides that the several normal faults dipping to the basin centre are developed on the gentle slopes. The sand dominated sequences of the Upper Cretaceous could not generate large-scale drape-anticlines (Figure 17).

Faulted anticlinal oil fields found up to now include Palogue-Fal drape-anticline, Jamous-1 faulted-anticline, Longyang-1 collapse-anticline, Bong West faulted anticline and Adar-Yale faulted anticline. The anticlines developed during the Paleogene rifting stages account for about 95% of proven oil reserves (Mohammed, 2016).

II. Antithetic Tilted-blocks

Tilted blocks are formed by simple block rotation along a normal plane. When the dip of a fault plane is contrary to the dip of formations, which is called an antithetic tilted block, the shale at and cross-fault will act as a seal for the closure of footwalls. For instance, the Adar Formation, acting as a regional seal, provided a good top seal and fault sealing capacity for the Yabus and Samma Formations. This type of structure is very common throughout the basin, similar to the Muglad basin (Schull, 1988). By the end of 2005, the proven oil-in-place volume in this type accounts for 5% of oil in place in the basin (Dou et al, 2007).

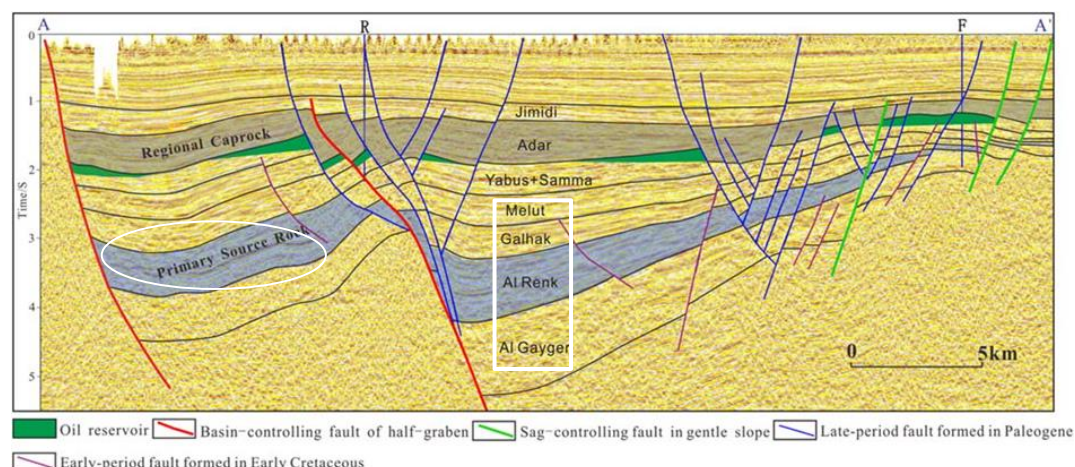


Figure 2. Seismic profile B–B’ across the Northern Sub-basin showing the basin framework and stratigraphic units of the Melut Basin.

1.2 Location, Accessibility and Climate of the Study Area

The Melut rift basin is located in the North-Eastern part of South Sudan's Upper Nile Region, close to the borders of South Sudan with the Republic of Sudan and Federal Democratic of Ethiopia. The basin is confined between longitudes ranges from **31°0'0"E** and **35°0'0"E** to latitudes of **9°0'0"N** through **11°0'0"N**. The landscape of Melut Basin and its surroundings is flat and at an altitude of about 400 m above sea level (GPS readings). The area is covered by unconsolidated alluvial sediments of recent age and the basin is bounded by outcrops of the basement to the east, southeast and northwest (Whiteman, 1971). The basin extending is about 310 km in an NNW direction with an average width of 100 km.

The main drainage system in the basin is characterized by the White Nile River which interconnects with the Blue Nile in Khartoum. This river runs toward the North-East of the Melut Basin and it represents the main drainage elements.

The Melut Basin is accessed via various means of transport within the routes connecting Upper Nile Regional State. The transportation means to depend on two seasons; during the wet season, the road is usually muddy and murky which usually made it difficult for some cars to reach the key town, while in the dry season the cars can easily pass. Therefore, air and river transports are the best options for researchers to reach the Melut Basin during the wet season.

The climatic condition of the study area is attributed to the tropical climate of South Sudan. People experience hot weather during the day while it is moderately cold at night hours.

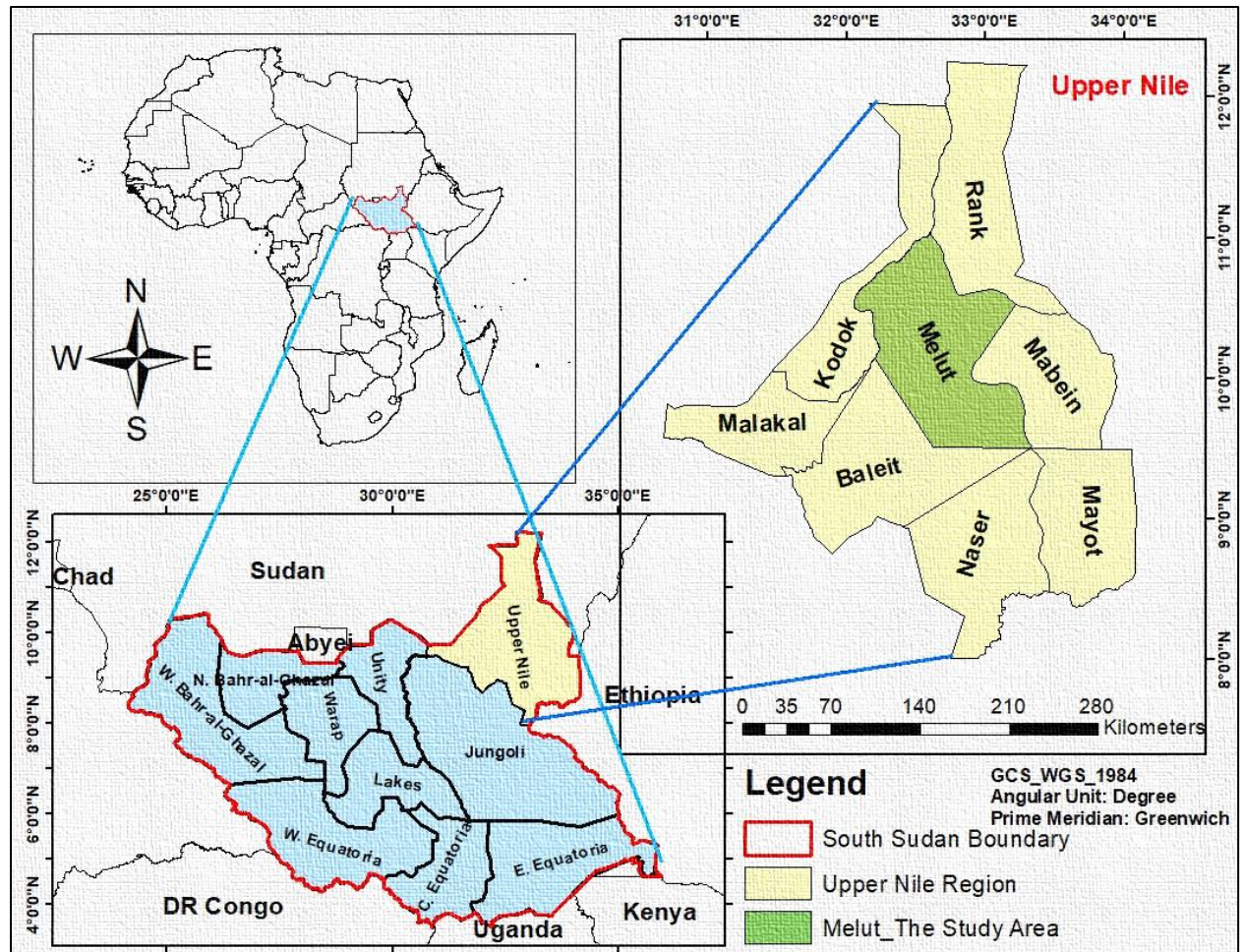


Figure 3. Location map of South Sudan (in red boundary) and the Study Area (in green).

1.3 Objectives

The objective of this study is divided into general and specific objectives as described below;

1.3.1 General Objective

The general objective of this study is to characterize the petroleum source rock in the Melut Basin.

1.3.2 Specific Objectives

- To evaluate the quantity of Organic Matter.
- To determine the quality of Organic Matter.
- To define the role of the source rock in an understanding of the petroleum system in the basin.

CHAPTER TWO

2. Geological Setting and Structural Framework

The geological setting of Melut Basin has been systematically described and included in the scientific kinds of literature (Guiraud and Maurin, 1992; McHargue et al., 1992., Patton et al., 1994., Dou et al.,2007). The basin is situated in the far South of Central Africa Shear Zone (CASZ). It covers an area of 33,200 km², and is up to 100 km wide, is over 310 km long and locally contains up to 10 km of Cretaceous-Tertiary sediments deposits. This basin is classified as an intra-continental rift basin formed on consolidated craton due to the strike-slip and extension of the Central Africa Shear Zone during the Early Cretaceous (Guiraud and Maurin, 1992; McHargue et al., 1992; Dou et al., 2007).

The basin is characterized by a passive rift with half-graben being a dominant form of deformation (Fairhead, 1988; Wilson and Guriad, 1992; Jorgensen and Bosworth, 1997).

Due to this evolution, the basin has formed five sub-basins and one uplift that have been recognized. These sub-basins include the Northern, the Eastern, the Central, the Western, and the Southern sub-basins and the Central uplift. The main explorations in the Melut Basin are concentrated in the Northern sub-basin which covers a vast area of nearly 10,000km². So far, almost all the discovered reservoirs are located in the Northern sub-basin, including the world-class Great Palogue oilfield (fig 3).

The other four sub-basins are smaller and mainly situated in the Southern part of the Melut Basin. Due to the swampy and muddy environments surrounding these sub-basins on the surface and other safety reasons, they have little exploration level, and there is scarcely any discovery except the small oil reservoir in the Miyan area of the Central subbasin (Dou et al.,2007, Bentao et al.,2020).

The seismic profiles displayed that, volcanic and magmatic rocks are associated with the Late Cretaceous to Tertiary which indicated that rifting is missed in the northern part of the Melut Basin.

In the southern subbasin, the volcanic rock distribution can be traced on seismic profiles as a very strong event. Volcanic rocks have been penetrated by several exploration wells, for example, Sobat-1, Miyan-1, Agordeed-1, Nal-1 and Adar-1(Dou 2007). They are mostly basalt of Senonian age, which has been confirmed by the widely dispersed volcanic outcrops in Sudan (Vail, 1989) and is of a similar age to the dolerite sill described from the Muglad Basin (McHargue et al., 1992). for over 90% of discoveries (Tong et al., 2006).

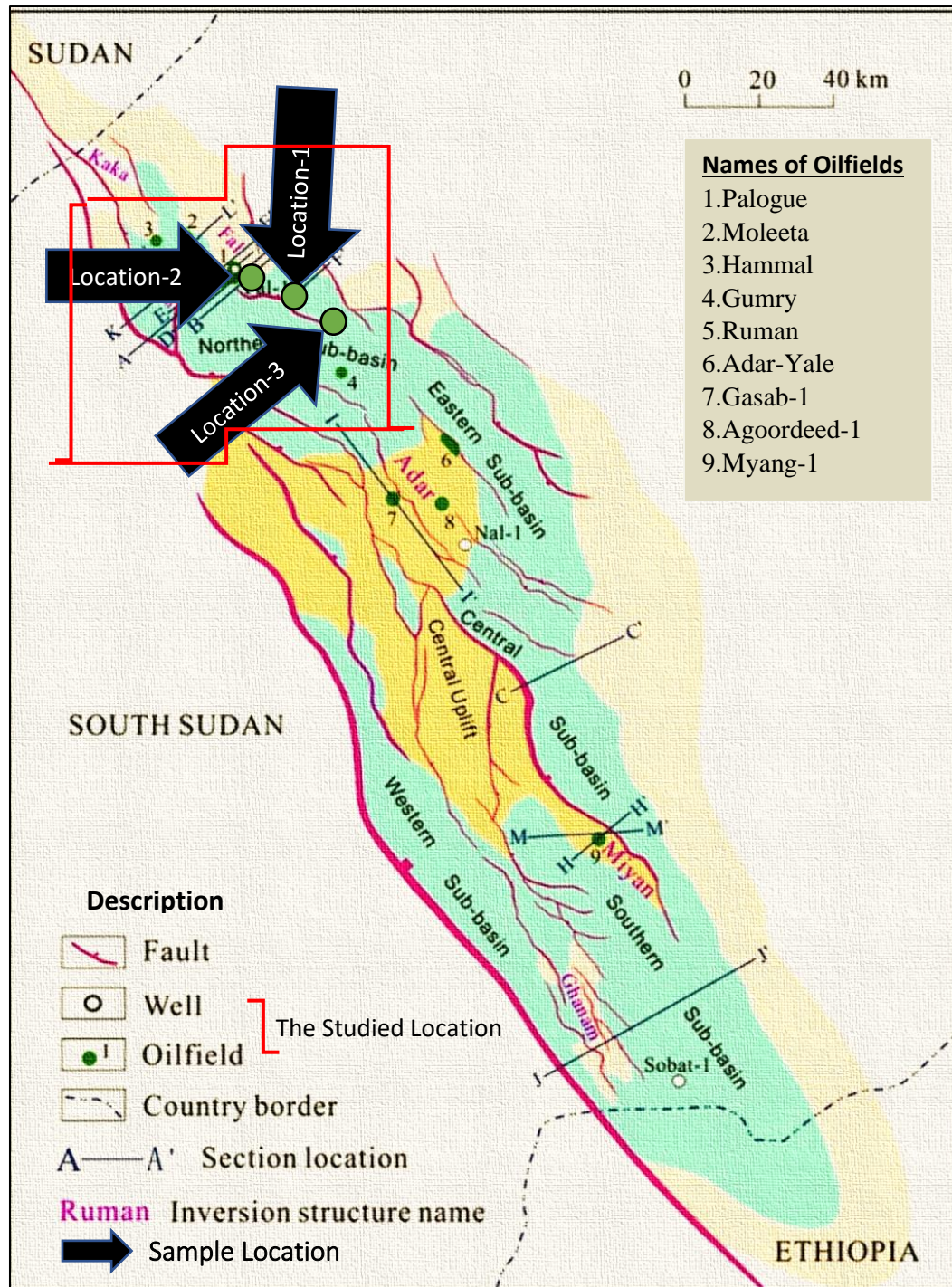


Figure 4: Location of Sub-basins in Melut Oilfields, Southern Subbasin in red block modified after Mohammed (2016).

2.1 Stratigraphy

The stratigraphy sequence of Melut Basin is related to the sequence studied in the interior Sudan (Mohammed.,2002, Dou et al., 2007). The main source of sediments deposition in the Melut Basin studied is Precambrian schist, gneiss and Cambrian granite. The outcrops surrounding the basin is distinguished to be similar to the outcrops recorded in the basement of

the basin and have been confirmed by the drilling activities in the basin. The basement complex in the basin has received limited attention due to the lack of adequate data in the reference. In exploration works, only one well in the Northern Subbasin, Fal-1, penetrated the basement in which quartzite of unknown age has been located.

In the Melut basin, four main stratigraphic sequences separated by unconformities have been determined by seismic, drilling and paleontological facts; these are Lower Cretaceous, Upper Cretaceous, Paleogene and Neogene Quaternary (Dou et al., 2007).

2.1.1 Lower Cretaceous

The lower cretaceous consist of Gayger Formation at the depth ranging from 2130-2270m and 1990-2110m of Fal-1 well confirmed from drilling data of the well. Al Gayger formation is divided into upper and lower intervals; the lower interval is dominated by thin sandstone interbedded with thin claystone of sedimentary environment ranging from fluvial-deltaic to shallow lacustrine facies upwards. The upper portion consists of dark grey and black, thick shales interbedded with thin sandstones. The major sedimentary environment hosting this interval is ranging from semi-deep and deep lacustrine facies. The nature of this unit was undoubtedly the result of a humid climate and lack of external drainage, indicating that the basins were tectonically divided by rises during Aptian-early Albain time. The thickness of Al Gayger Formation is 1124m in the Fal-1 well and estimated to be 3000m thick at the depocenter (Mohammed.,2002).

2.1.2 Upper Cretaceous

Galhak and Melut Formations are contained at the Upper Cretaceous sequences. Galhak sediments are characterized by the predominance of medium to fine-grained sandstone and claystone of Senomania-Turonian age with a thickness of 290m (Mohammed et al.,2016). Their sedimentary environments are braided delta and shallow lakes.

On the other hand, Melut Formation is characterized by the domination of thick sandstones interbedded with thin claystone indicating the water become shallower with time. The deposition of coarse-grained sediments increased at the end of the Late Cretaceous. The Upper Cretaceous is up to 1593m thick (**Fig 7**).

The Adar formation is sparsely distributed in the basin. Its sample can be found everywhere in the basin and it is deposited in shallow to semi-deep lacustrine environments. It is also

characterized by dominant shales with fine-grained siltstones and sandstones in the basin's interior.

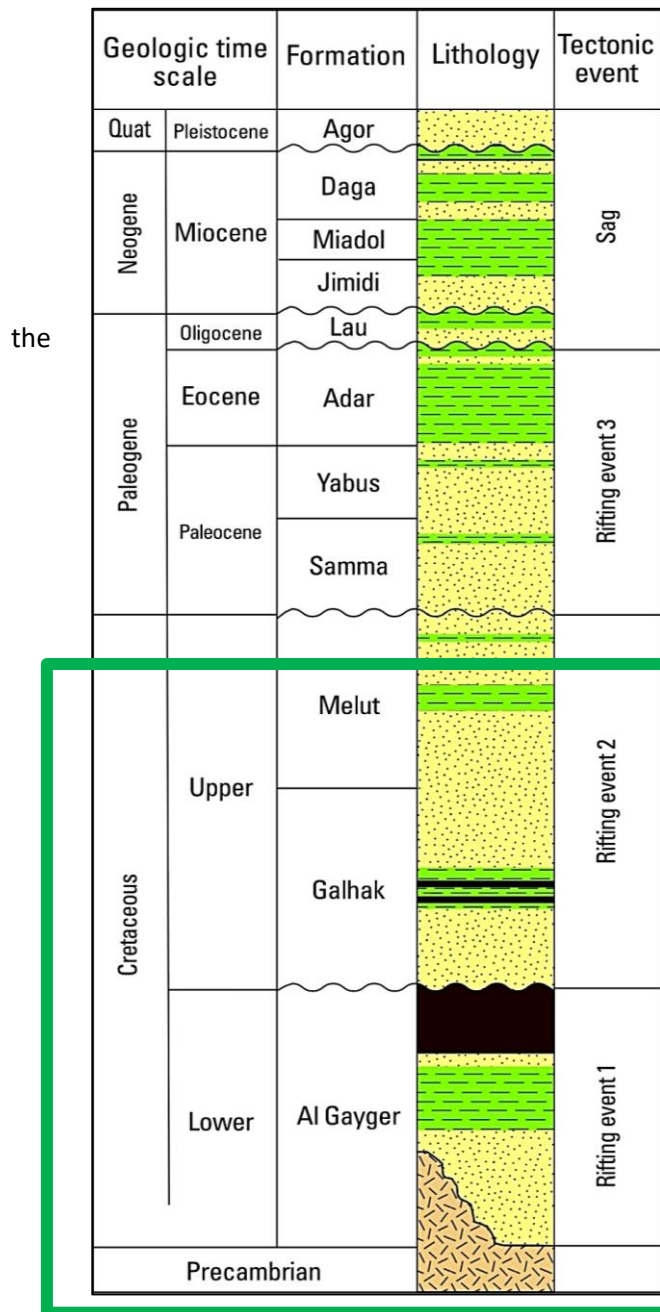


Figure 5. Generalized Stratigraphic Summary of Melut Basin, South Sudan. Modified from Dou et al (2007) and Mohammed (2016). In this summary, petroleum source rocks are found to be in cretaceous sequences of Al Renk and Al Gayger sequences. These sequences are affected by the first and second rifting in basin.

Legend

- Sandstone and siltstone
- Shale-Claystone—Minor Type I and Type III source rocks
- Lacustrine source rock
- Precambrian basement
- Unconformity

Green line showing the studied sequences (Source rocks) described in this thesis work

In Melut Basin, three main rifting episodes of extensional tectonism have been identified. These include ‘Early Cretaceous’ estimated to be approximately 140-95 Ma; ‘Late Cretaceous;’ 95 to 65 Ma, ‘Paleogene; 65-30 Ma, comparable to the Muglad Basin (McHargue et al., 1992). The acknowledgement of the above three distinct rifting events is based on the identification of three regional correlative depositional cycles which are practically evident in the Melut Basin.

The tectonic subsidence rate curve derived from the 1-D subsidence modelling of pseudo well P-1 in the Northern Sub-basin centre is in a stepped shape and well corresponds to the four

tectonic evolution cycles of the Melut Basin. The first rifting cycle occurred in the Early Cretaceous and is characterized by a strong rifting activity and a high tectonic subsidence rate, which made the Northern Sub-basin deposit the primary mudstone source rocks of the Al Renk Formation.

The second rifting cycle occurred in the Late Cretaceous and is characterized by a relatively weak rifting activity and a low tectonic subsidence rate, which made the Northern Sub-basin deposit hundreds of meters of sand-rich sediments in the Galhak and Melut Formations. The third rifting cycle occurred in the Paleogene and included two sub-stages. In the early stage, the rifting activity was weak and the sand-rich Lower Yabus and Samma Formations were deposited, which acted as the primary reservoir rocks.

In the late stage, the rifting activity was strong and the thick mudstones of the Adar Formation were deposited, which acted as the primary regional top seal.

After the Paleogene, the Melut Basin entered the sagging stage with a low and stable tectonic subsidence rate. The relatively weak rifting activities of the Late Cretaceous and Early Paleogene made the Northern Sub-basin develop hundreds of meters of sand-rich sediments between the Lower Cretaceous source rocks and the Upper Paleogene regional seals. No thick and regional mudstones developed between the Al Renk source rocks and the primary producing layers of Samma and Lower Yabus Formations. Hence, the hydrocarbons generated by Al Renk source rocks migrated a long distance through the conduit faults in vertical and accumulated in the Yabus and Samma traps. Thus, the hydrocarbon accumulations in the Northern Sub-basin are characterized by a long-distance migration in vertical, which accounted for over 90% of discoveries (Tong et al., 2006).

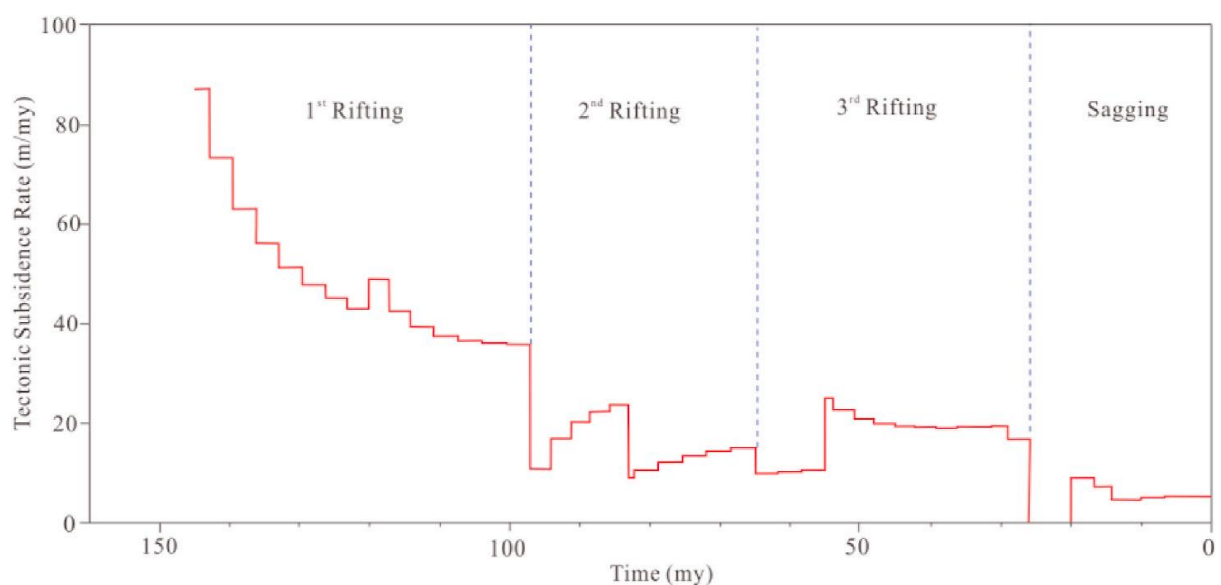


Figure 6. The tectonic subsidence rate curve is derived from the 1-D subsidence modelling of pseudo well P-1 in the Northern Sub-basin centre.

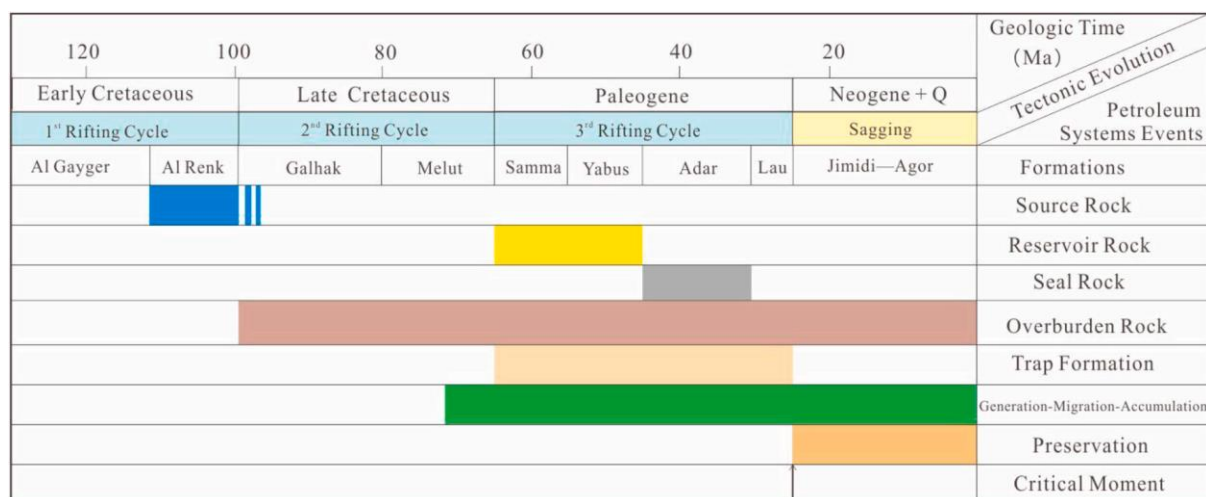


Figure 7. Events chart of the Cretaceous to Cenozoic petroleum system in the Melut Basin showing the essential elements and important processes (generation, migration, and accumulation) modified from Mohammed, (2016)

2.2 Regional Geology

2.2.1 Tectonic History and Petroleum Geology of Sud Province

The Sud Province encompasses parts of the Central African Republic, Chad, Ethiopia, Kenya, Sudan, and Tanzania. The Central African Rift system was initiated during the Early Cretaceous, at the instigation of regional northwest-southeast extension and the opening of the South Atlantic Ocean. The rifting continued into the Neogene and can be divided into two major rifting events in the western part and three rifting events in the eastern part.

The rift basins of Central Africa are linked along the Central African shear zone right-lateral fault system (Fig 4). Several thousand meters of Lower Cretaceous clastic sediment, mostly lacustrine shale, siltstone, and sandstone were deposited during this rifting phase (Genik, 1992, 1993). The Cretaceous-Tertiary rift basins of the western part of the Sud Province (fig. 1) are trans-tensional and are filled with Lower Cretaceous to Neogene sedimentary rocks, ranging in thickness from about 3,000 meters (m) to more than 7,500 m (figs. 4, 5), that were deposited in fluvial and lacustrine environments (Genik, 1992; 1993).

During the Early Cretaceous, the first rifting event allowed the deposition of fluvial and lacustrine rocks in rift basins of southern Chad and the Central African Republic (fig. 2). In the Late Cretaceous (Cenomanian to Turonian), a regional rifting event deposited thick continental clastic rocks in the eastern part of the province. During the Late Cretaceous and Paleogene, trans-tensional faulting and sag events in the western part of the Sud Province led to the deposition of fluvial and lacustrine rocks.

To Neogene sedimentary rocks (fig. 6) that range in thickness from 6,000 m to more than 13,000 m; these rocks were deposited in fluvial and lacustrine environments (Mohamed and

others, 2000, 2002; Dou and others, 2007). The initial rifting event began in the latest Jurassic and continued through the Early Cretaceous, resulting in the deposition of Lower Cretaceous lacustrine source rocks. The second rifting event began in the Turonian and continued into the Senonian, and the third rifting event occurred during the Paleogene, at the same time that the Red Sea rifting began (Mohamed and others, 2000). Each rifting event was followed by a sag event, during which thick continental clastic rocks were deposited. The central African rift basins are known to contain Cretaceous to Paleogene lacustrine and marine source rocks that have generated hydrocarbons since the Late Cretaceous (Genik, 1992, 1993; Mohamed and others, 2002). Hydrocarbons migrated into Cretaceous and Paleogene reservoirs and structural traps.

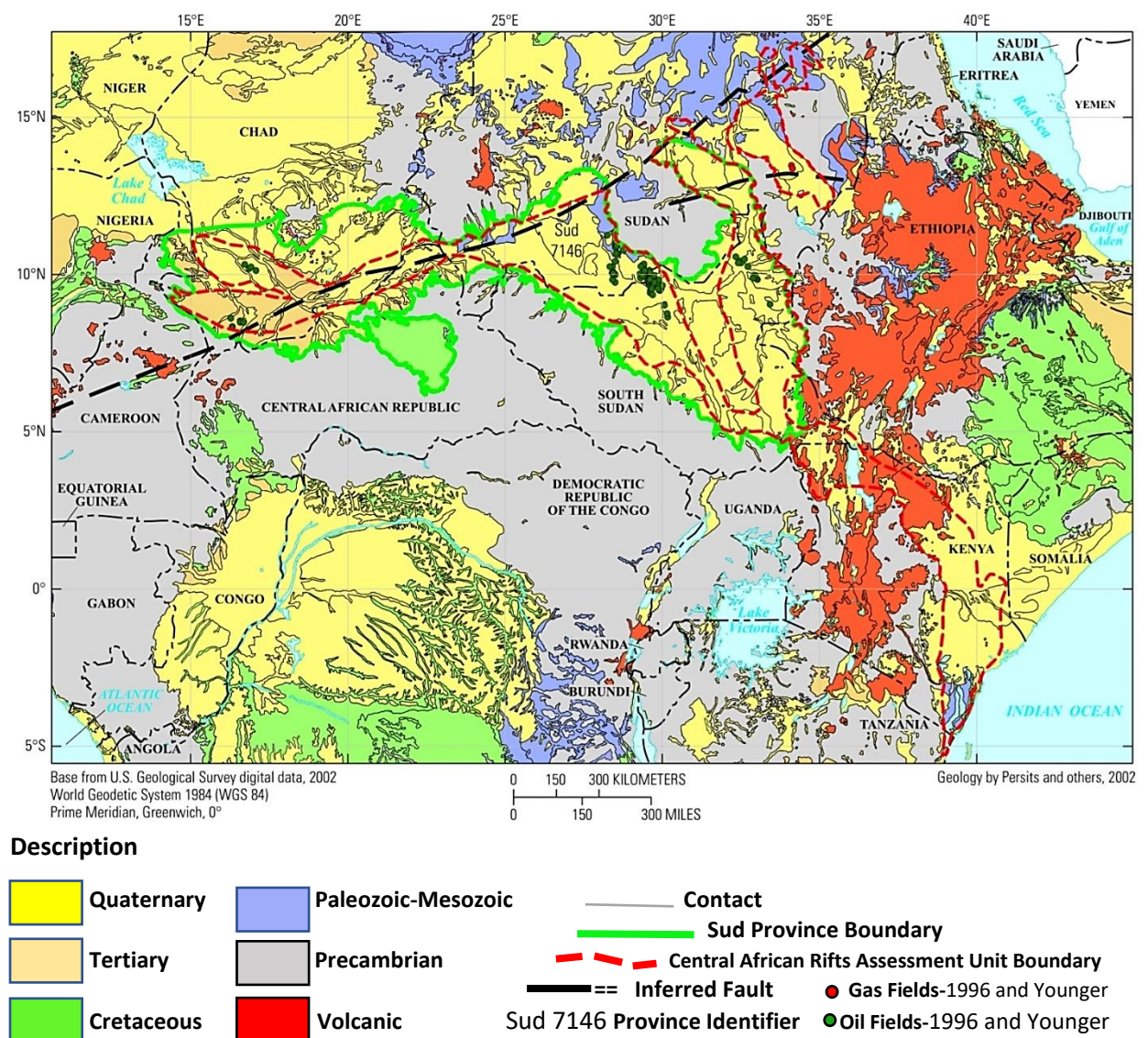


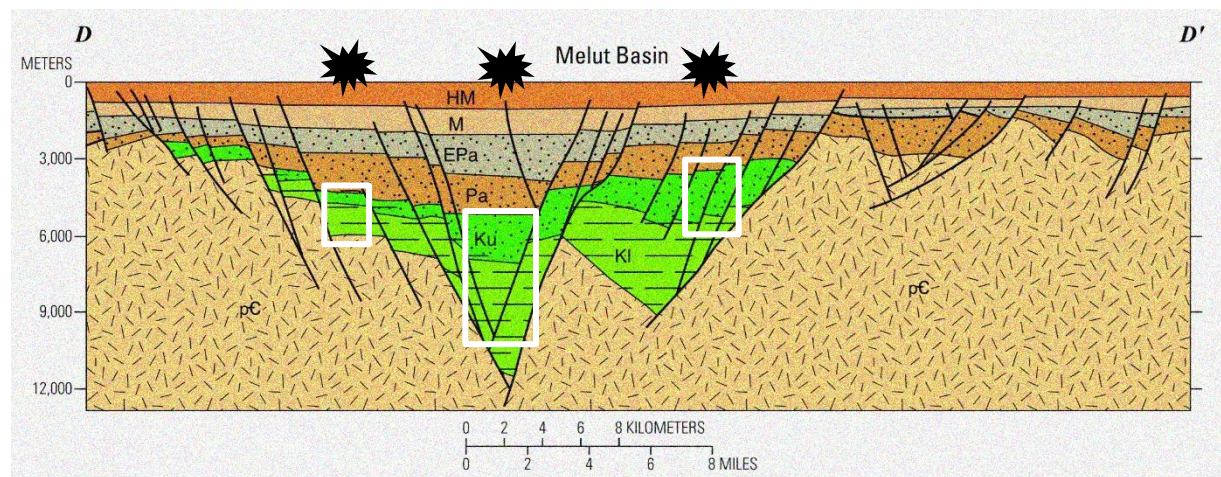
Figure 8. Generalize Geological Map of Central-East Africa (Adapted from Persits et al, 2002).

I. Source Rocks

Primary source rocks are Lower and Upper Cretaceous and Paleogene lacustrine rocks, ranging from 2,500 m to 5,000 m thick that was deposited in the rift basins (fig 6). Lacustrine source rocks range from 1 to more than 5 weight per cent total organic carbon (TOC) and average 2 to 3 weight per cent TOC; their hydrogen index (HI) values are greater than 600 milligrams per gram (mg/g) in the eastern part of the province (Schull, 1988; Mohamed and others, 2000; Dou and others, 2007). Some analyzed lacustrine samples in the Muglad Basin had TOC values as much as 9 weight percent TOC and an HI value of about 800 mg/g (Mohamed and others, 2002). Lacustrine source rocks in the western part of the province range from 1 weight percent of TOC to more than 14 weight percent of TOC and average 2 to 3 weight percent of TOC (Genik, 1993). Hydrogen Index (HI) values are greater than 600 mg/g for the lacustrine source rocks. The depth to the oil generation window in the Cretaceous-Tertiary rifts in the eastern part of the Sud Province averages about 2,050 m and ranges from 1,500 m to 5,300 m (Mohamed and others, 2000, 2002; Dou and others, 2007). In the Chad part of the Sud Province, the depth of the oil window ranges from 2,300 m to 5,000 m (Genik, 1993).

II. Reservoir, Traps and Seals

The Cretaceous and Paleogene sandstone reservoirs are located in the western part of the Central African Rifts. Assessment Unit (AU) is generally poorly defined in terms of their distribution and their net thickness. The reservoir quality is fair to good; porosities range from 12 to 32 percent and permeabilities from 10 millidarcies (mD) to 10 darcies (D) (Genik, 1993). These rocks were generally deposited in fluvial environments although some reservoirs contain lacustrine-delta sandstone. Reservoir characteristics are good to excellent in the Cretaceous fluvial sandstone reservoirs in the eastern part of the assessment unit and have excellent reservoir quality; porosities range from 8 to 25 percent and permeabilities are as much as 1,600 mD (Mohamed and others, 2000; Dou and others, 2007).



Explanation

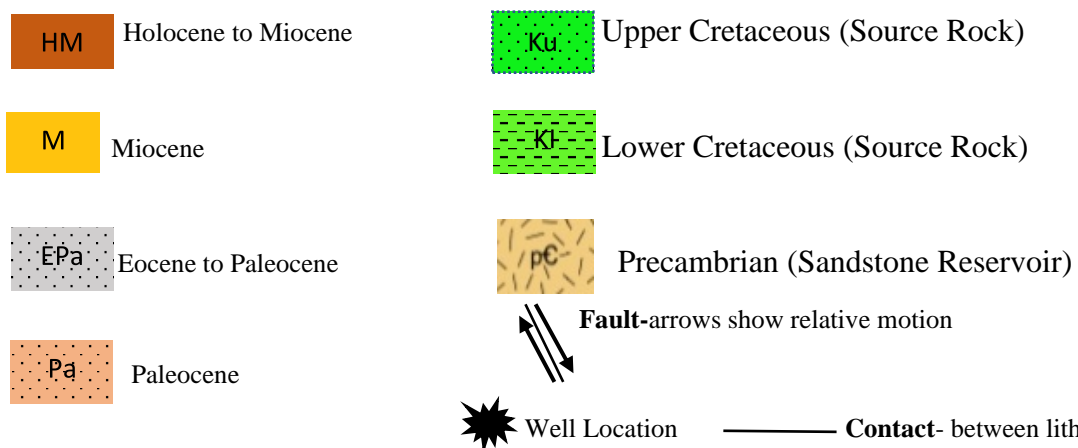


Figure 9. Schematic Map of Melut Basin showing the sedimentary basin fill in South Sudan (Dou et al). The Geological ages were compiled by Dou et al. (2007) and Persist (2015).

2.3 Description of Geological Map of South Sudan

South Sudan is underlain by metamorphic and granitic rocks belonging to the northern portion of the Tanganyika Craton bordered by gneissic rocks of heterogeneous Sudan that were deformed during the end-Precambrian Pan African orogenic event (Hunting,1980).

However, the Southern and Southwestern regions of Sudan are mainly underlain by Archaean and Proterozoic rocks which are generally of medium to high metamorphic grades (Hunting, 1976). The Basement Complex in these regions includes four major groups of rocks identified in the adjacent neighbouring countries and these regions can be discussed in four main contexts identified in the adjacent neighbouring countries.

a. The Madi Sequence

The Madi rock Sequence was documented by Berry and Whiteman in 1968 and by Hunting Geology in 1976. This Sequence was originally described in northern Uganda (Mathews, 1952,

Hepworth and Macdonald, 1966), in the Abu Satta Hills and to the northwest of Ragor along the boundary with the Central African Republic.

The Madi Sequence of Northern Uganda continues into South Sudan and is exposed on the Juba-Yei Road about 53 km Southwest of Nimule. Madi Sequence consists of muscovite quartzites interbedded with muscovite schists, quartz-feldspar-biotite-hornblende gneisses and amphibolite. It originated as a succession of arenaceous and argillaceous clastic sediments with minor calcareous beds and probably with some volcanic rocks.

b. Gneiss Group

According to Hunting Geology (1976), this group includes:

- i. massive weathered foliated granites and poorly banded gneisses,
- ii. biotite-hornblende gneisses with minor amphibolite and quartzite gneisses,
- iii. muscovite-biotite gneisses.

These gneissic rocks dominantly cover South Sudan and are mostly found in the basement complex.

c. Strongly banded rocks, gneisses, migmatites and locally metasedimentary rocks

This unit occurs in three areas to the east, north and west of the Imatong Mountains and occupies broad zones within the Raga region west of longitude $26^{\circ} 30' E$ (Hunting, 1976). The migmatitic rocks occur between Maridi and Mundri and the Southeast of Tambura. Rocks of this group include quartz-feldspar-biotite garnet gneisses, graphite-sill, ilmenite gneisses and migmatites, in addition to quartzites, schists, marbles, etc. of metasedimentary sequences.

According to Hunting 1980, the basement is under when four tectono-thermal activities. These include Watian 2.88 Ga, Aruan, Mirian and Chuan recognized in neighbouring Uganda.

d. Umm Rawaba Formation (UR)

The Umm Rawaba Formation is widely distributed in Central and South Sudan, almost totally covering the Upper Nile Province (*the study area*) and partly the Equatoria, Bahr el Ghazal, Darfur, Kordofan and Blue Nile Provinces (see fig 5).

The type-locality for these deposits is located at the Umm Rawaba village, in the Kordofan Province. This formation contains very few fossils and therefore not much can be said about age. It is considered of Quaternary to Tertiary age by Whiteman and as Quaternary by Vail. The sedimentary rocks of the formation consist of unconsolidated sands, locally gravelly, clayey sands and clays. Rapid facies changes are common in the Umm Rawaba Formation. Based on X-ray diffraction analysis, the dominant clayey material in the formation is montmorillonite. According to the heavy mineral fraction, the Umm Rawaba formation may be divided into three units (Shafie, 1975):

-Lower unit: some 99 m thick, it is characterized by individual grains of epidote. Authigenic minerals are represented by the presence of many limonite grains;

-Middle unit: some 149 m thick, it is characterized by abundant epidote, the increased quantity of which forms the bottom of the cross-section;

-Upper unit: some 157 m thick, the quantity of the epidote grains (in general) decreases in this unit.

The Umm Rawaba Formation is also characterized by the presence of a considerable number of feldspars which may reach up to 40 % of the light fraction, and ilmenite which reaches up to 77 % of the heavy fraction. Much of the area overlain by the Umm Rawaba Formation has surface deposits consisting of heavy clays, dark grey to chocolate in colour with kankar nodules. In the Muglad and Umm Rawaba area, sands directly overlie the clays. According to oil exploration data from central and Southern Sudan, the maximum drilled thickness of the Umm Rawaba Formation is higher than 15,000 feet (about 4,570 m). According to geophysical data, the maximum recorded thickness is higher than 27,000 feet (about 8,225 m) in some places.

The Umm Rawaba deposits are thought to have been deposited in a series of land deltas similar to the Gash delta of the Kassala Province and the Sudd region of Southern Sudan (Berry and Whiteman, 1968). Some geologists considered the Umm Rawaba deposits as fluvial and lacustrine. They may not have accumulated in one large and continuous lake extending as far north as the rocky area of Sabaloka, 45 miles north of Khartoum. According to Shafie (1975), the rocks of the Umm Rawaba Formation are ferruginous and partly lacustrine as shown from the upper unit (206 - 212 m) where 15 forms of diatoms were described as freshwater species in the water of very low salinity (0.5 %). The water reservoir of the ancient lake was not large.

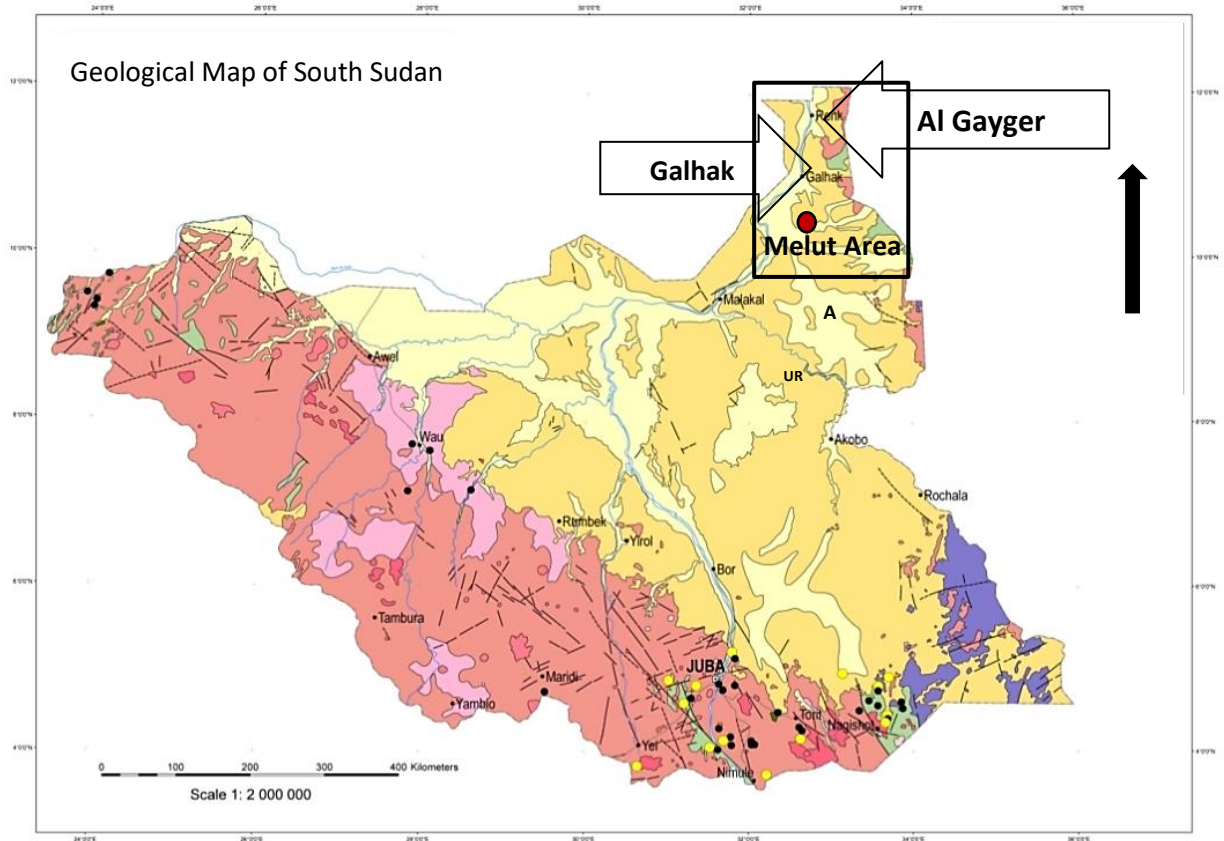


Figure 10. Geological Map of South Sudan (Simplified by the Ministry of Mines and Petroleum, RSS, 2016).

Legend

<table border="0"> <tr> <td style="border: 1px solid black; padding: 2px;">A</td> <td>Alluvium</td> </tr> <tr> <td style="border: 1px solid black; padding: 2px;">UR</td> <td>Umm Rawaba Formation</td> </tr> <tr> <td style="border: 1px solid black; padding: 2px;">B</td> <td>Basic Volcanic, Mainly Basalts</td> </tr> <tr> <td style="border: 1px solid black; padding: 2px;"></td> <td>Basement, dominantly Schists and Metasediments</td> </tr> <tr> <td style="border: 1px solid black; padding: 2px;"></td> <td>Basement, Banded Magmatic Gneiss</td> </tr> </table>	A	Alluvium	UR	Umm Rawaba Formation	B	Basic Volcanic, Mainly Basalts		Basement, dominantly Schists and Metasediments		Basement, Banded Magmatic Gneiss	<table border="0"> <tr> <td style="border: 1px solid black; padding: 2px;"></td> <td>Undifferentiated Basement</td> </tr> <tr> <td style="border: 1px solid black; padding: 2px;"></td> <td>Syenites</td> </tr> <tr> <td style="border: 1px solid black; padding: 2px;"></td> <td>Intrusive Rock, Gabbro</td> </tr> <tr> <td style="border: 1px solid black; padding: 2px;"></td> <td>Younger Granites</td> </tr> <tr> <td style="border: 1px solid black; padding: 2px;"></td> <td>Older Benthonic Grey Granites and Pegmatites</td> </tr> </table>		Undifferentiated Basement		Syenites		Intrusive Rock, Gabbro		Younger Granites		Older Benthonic Grey Granites and Pegmatites	<table border="0"> <tr> <td style="text-align: center;">●</td> <td>Gold</td> </tr> <tr> <td style="text-align: center;">●</td> <td>Other</td> </tr> <tr> <td style="text-align: center;">—</td> <td>Geology Boundary</td> </tr> <tr> <td style="text-align: center;">—</td> <td>Fault</td> </tr> <tr> <td style="text-align: center;">- - -</td> <td>Fault lineament</td> </tr> </table>	●	Gold	●	Other	—	Geology Boundary	—	Fault	- - -	Fault lineament
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2.4 Previous Studies

The study area has attracted many scholars to carry out several studies related to the petroleum deposits in the Melut Basin. The most dominant research in the Melut Basin was attributed to **Dou et al (2007)** titled ‘Petroleum geology of the Melut Basin and the Great Palogue field’, Sudan. This research has detailed insight on the understanding of the Petroleum Geology and the Petroleum System in the Melut Basin.

Others have also conducted systematic research that has also contributed to the understanding of the petroleum accumulation in the basin. These include **Tong XG et al** (2006) which explains the ‘Petroleum geologic property and reservoir-forming pattern’ of Melut Basin in Sudan.

Scholars like **Mohamed and others (2002 and 2016)** have immensely focused on an understanding of hydrocarbon generation and accumulation in the basin with his world-class research noticeably headed ‘Thermal modelling of the Melut basin Sudan and South Sudan: implications for hydrocarbon generation and migration’. It is also classified as one of the recent researches in the basin and it explains various aspects related to the thermal history in the basin encompassing South Sudan and North Sudan.

Wei Zhao and others (2020) have conducted new research in the Melut Basin published by the Arabia Journal of Geosciences (Springer) and this is projected to be among the noticeable research ever produced in the Basin. The ‘petroleum geological characteristics and hydrocarbon accumulation patterns’ was their heading. This emphasises the genesis and the characteristic of petroleum formation and its migration pathways.

In the study area, there was no research study conducted related to geochemical analysis which made this thesis work very unique and specialized.

CHAPTER THREE

3. Methodology

This chapter covers the material and method used to achieve the delineated objective of this thesis work. It also encompasses the analysis of geochemical parameters. These parameters include TOC from Rock-Eval pyrolysis data and another valuable parameter described in this chapter. All sample was analyzed using geochemical like TOC and Pyrolysis data that are defined below. The main apparatus used in this study is the Rock-Eval 6 Instrument for analysis of selected samples in China Key Petroleum for Reservoir Description. Petroleum source rock analysis based on Geochemical Data focuses on basics geochemical parameters analyzed in the Geochemistry Laboratory. These include Total Organic Carbon (TOC), Temperature of Maximum Generation (T_{max}), Quantity, Hydrogen Index (HI), Oxygen Index (OI), Petroleum Potential (PP). Other important parameters analyzed in the Geochemical Lab S_1 , S_2 and S_3 values represent Free Bitumen, Hydrocarbon Potential, and CO_2 Potential respectively. These parameters are also known as Source Rock Properties.

S_2 measures the number of hydrocarbons generated through thermal cracking of nonvolatile organic matter. S_2 is an indication of the number of hydrocarbons that the rock has the potential of producing should burial and maturation continue. S_3 is the amount of CO_2 (in milligrams CO_2 per gram of rock) produced during pyrolysis of kerogen. And T_{max} is the temperature at which the maximum release of hydrocarbons from cracking of kerogen occurs during pyrolysis (top of S_2 peak). The type and maturity of organic matter in petroleum source rocks can be characterized from Rock-Eval pyrolysis data. Using the following parameters: HI is a parameter used to characterize the origin of organic matter. PI is used to characterize the evolution level of organic matter.

3.1 Material

Following the field visit, 13 different samples of rock cores and cuttings were collected from three (3) different localities from Melut oil fields (fig 3 for sample locations). The samples are collected from three existing active wells which are currently operating under Dar Petroleum Operating Company (DPOC) and their potential for generating petroleum is measured in the laboratory. The collected samples were sent overseas for further analysis. Data used in this study include geological maps, seismic profiles and attribute maps, cores, thin sections, sample tests of source rocks, Geological maps and stratigraphic columns were used to illustrate the regional tectonic setting, major structural and stratigraphic units, tectonic evolution cycles, the intervals of source rocks, reservoir rocks and seals, and the contact style between formation

boundaries. Seismic profiles were used to illustrate the major structural units and basin framework.

3.2 Methods

The main method used in this study is a geochemical method. The methods used in this study includes Rock-Eval 6 procedures described as follow:

- The first procedure, the Core Sampling method was carried out and the extracted core samples were.
- Second, the extracted core cuttings from the boreholes were crushed to produce a rock powder.
- In the third step, the rock powder was weighed to 100mg. For the accuracy of the result, the rock-eval 6 instruments can weigh 100mg at a time.
- Lastly, the weighed rock powder sample is inserted into the oven and heated to a higher temperature up to 850°C controlled.

The collected data were analyzed by geochemical methods, covering a wide range of geochemical features of bulk rock samples. Petroleum software like Petrel 1D was used to construct and modify stratigraphy. Analysis like Rock-Eval 6 instrument was also used to perform most of the geochemical data presented in this study.

3.3 Rock Eval-Pyrolysis Analyses

Rock-Eval is a standardized routine analysis of source rocks, usually shales, to establish how much of the kerogen has been transformed into petroleum and how much can be transformed at a higher temperature. It allows the characterization of the organic matter and gives detailed information on the hydrocarbon generation potential, kerogen type and thermal maturation degree (Espitalié et al., 1985; Behar et al., 2001).

All 13 samples of dark shales were analyzed by Rock-Eval Pyrolysis (Rock-Eval VI instrument i.e., Rock-Eval 6 Analyzer), through DPOC in State China Petroleum Key Laboratory headquartered in China.

From all laboratory methods in the Geochemical industry, the Rock-Eval pyrolysis method has been widely used, throughout the world, for oil and gas analysis and exploration in sedimentary basins, as the method has been widely used in the industry as a standard method in petroleum evaluation. This method is used in determining kerogen heat maturation.

Behar et al. defined the heat parameters based on maximum temperature (T_{max}) which can be used to determine the dimensions of the oil window. According to that definition, the T_{max} value for the start of the oil window is usually 445-435 ° C, for the peak is 450-445 ° C, and

for the end is 470-450 ° C. The T_{max} parameter is used as a maturity parameter for fossil organic matter (Espitalié et al., 1985).

The primary data was given by Dar Petroleum Operating Company (DPOC) which is currently operating in the Melut Basin field and compared to other data obtained from the Ministry of Petroleum, Republic of South Sudan. To obtain accurate and precise result relating to analyses of Geochemical data of organic matter, the cores/cutting samples were sent overseas for analysis through DPOC and was analyzed in Key Laboratory of Petroleum Reservoir description and Prospecting, China. The analysis of the data is due to focus on Pyrolysis Analysis, Vitrinite content (T_{max}) of the total organic matter both in a quantity of the kerogen and is a type of quality of kerogen.

The other type of data which is secondary data was given by the Ministry of Petroleum of South Sudan in collaboration with Dar Petroleum Operating Company or DPOC.

3.4 Rock-Eval 6 Analyzer Description

3.4.1 Experimental Structures of Rock-Eval 6 Analyzer

a) Apparatus

Rock-Eval 6 Analyzer is designed to increase the domain of application of the method in the field of source rock characterization (improved kerogen analysis). The instrument is a completely automated device consisting of two micro-oven which can be heated up to 850°C controlled by a thermocouple junction located in contact with the sample.

Flame Ionization Detector (FID) detector measures the H/C gas released during the pyrolysis while an online infrared cell is used to measure the quantity of CO and CO₂ generated during pyrolysis and oxidation of samples. A new unified software (Rock six), supervises the analyzer and allows an easy interpretation of the data.

The Rock-Eval method consists of estimating the petroleum potential of sedimentary rocks by heating samples in an open pyrolysis system under non-isothermal conditions. The released hydrocarbons are monitored by a flame ionization detector (FID), forming the so-called peaks *S1* (thermo-vaporized free hydrocarbons) and *S2* (pyrolysis products from cracking of organic matter) (Espitalié et al., 1985).

b) Features

The novelties of the Rock-Eval 6 are:

- micro-ovens heating up to 800°C for pyrolysis and 850°C for combustion with probes in contact with the sample, allowing a better temperature control;
- infra-red cells for online continuous recording of CO₂ and CO production during pyrolysis and oxidation;

– an automatic sequenced sampler with a capacity of 48 samples, which allows running 24 hours a day, 7 days a week.

The Rock-Eval instrument subjects a crushed source rock sample to programmed temperature heating (under helium or Nitrogen gas) and measures the hydrocarbon and carbon dioxide that is released or generated by the sample during pyrolysis.

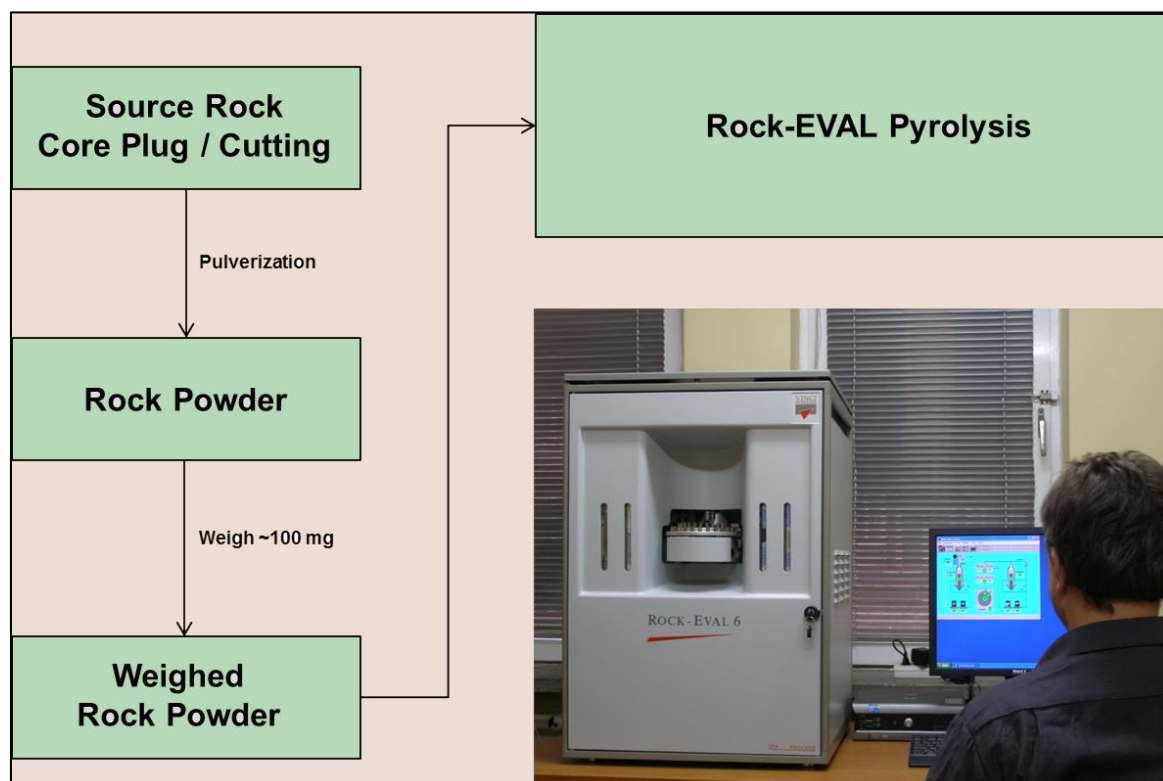


Figure 11. Rock-Eval 6 Analyzer process/ workflow from F.Behar et al(2015).

Rock-Eval instruments heating program is divided into three phases as described as Isothermal, ramped, and cooling phases. Each of these heating phases is designed to quantitatively and specific things as follows:

The Isothermal Phase (300°C)-S1:

- a. During this phase, free hydrocarbons (hydrocarbon that has already been generated, in nature, before pyrolysis, but is helping within the source rock) are volatilized and measured. The hydrocarbons associated with this phase are called S1 and are reported as milligrams of hydrocarbon per gram of rock (mg HC/g rock).

Theoretically, if a source rock sample is thermally immature, no hydrocarbons will be measured during this step (because the source rock sample hasn't generated any hydrocarbon yet). But realistically, even a completely immature source rock has a minor S1 peak.

The Ramped Phase (300-550°C)-S2:

- a. During this phase, the thermal cracking of kerogen (and large molecular weight hydrocarbons) within the source rock takes place, as the source rock is forced to thermal maturity during the pyrolysis procedure. The hydrocarbons that are generated during this phase are measured, are called S2, and are also reported as mg HC/g Rock.

The Cooling Phase-S3:

- a. During phase 2 (ramped phase), not only is the source rock being forced to thermal maturity to generate hydrocarbons, but also generates CO₂ during the thermal decomposition of the kerogen. While the CO₂ is generated during phase 2, it is held in a trap until phase 3 where it is released and measured. This is called S3 and is reported as mg CO₂/ g Rock.

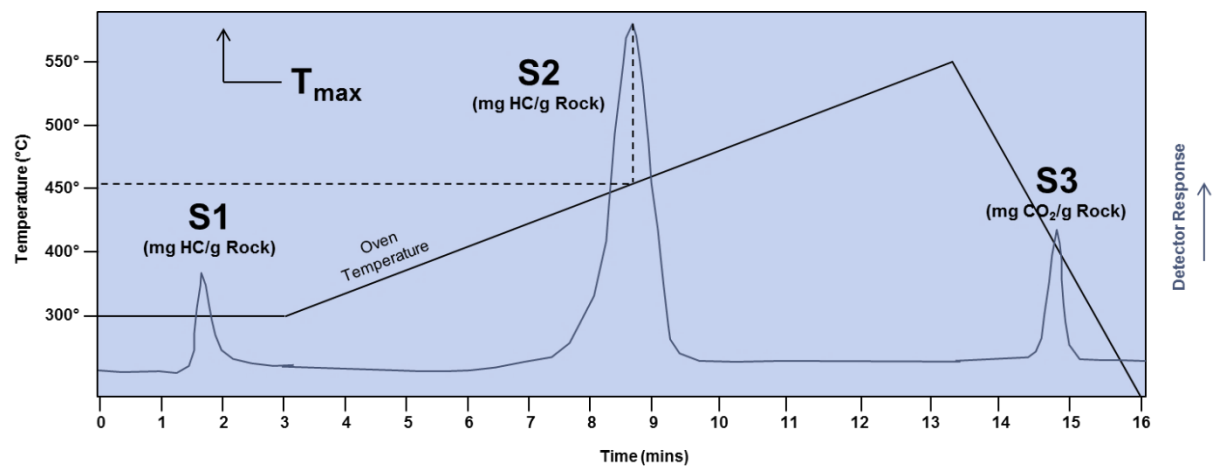


Figure 12. Schematic diagram showing S1, S2 and S3 processes with temperature peak by Espitalié et al., (1985).

3.4.2 Temperature Program and Rock-Eval Pyrolysis for Evaluation of Database

Rock-Eval is a standard routine analysis of source rocks, usually shales, to establish how much of the kerogen has been transformed into petroleum and how much can be transformed at a higher temperature. As explained by Bjørlykke (2015), temperature Maximum (T_{max}) is the temperature at which maximum hydrocarbon generation occurs during pyrolysis, and is a proxy for the thermal maturity of the analyzed source rock. During the ramped phase (fig 9), the kerogen in the source rock is thermally cracked to generate hydrocarbons which are then released from the rock and measured as the S₂ peak.

The sample of shale is crushed and heated to 300°C, at which point one measures the number of hydrocarbons that are already formed in the source rock but have not migrated out. The content of hydrocarbon with carbon numbers between C₁ and C₂₅ is called S₁. It is measured as the area beneath the peak S₁.

On further heating from 300 to 550–600°C, new petroleum is formed in the laboratory from the kerogen by heating (pyrolysis), and this amount is called S_2 . This is a measure of how much oil and gas could have been generated if the source rock had been buried deeper. The reason it requires such high temperatures is that the heating in the laboratory lasts just a few minutes or hours, instead of some millions of years (Bjørlykke, 2015). During heating from c. 300 to 550°C, CO_2 is also formed and is collected and measured separately as the S_3 peak (Fig. 10). Most of the CO_2 groups dissociate from the kerogen between 300 and 390°C. The generation of petroleum varies with temperature and reaches a peak corresponding to S_2 (Fig. 10). This temperature, which gives the maximum petroleum generation, is called T_{maks} and is typically in the range 420–460°C.

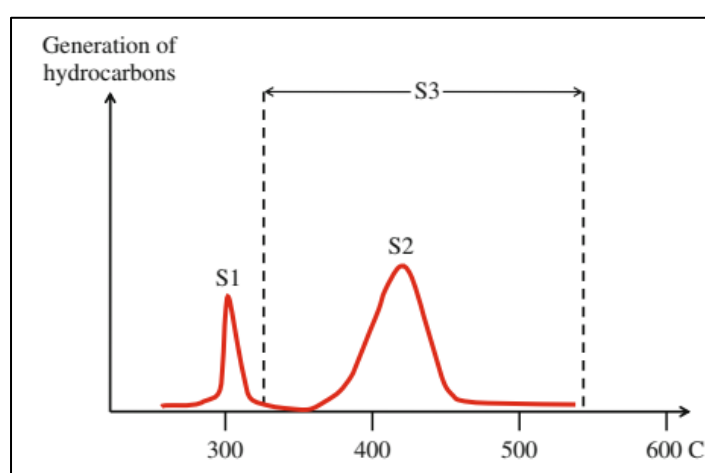


Figure 13. Showing T_{maks} ranges during Rock-Eval Process adapted from (Bjørlykke, 2015)

The ratio between the amount of petroleum generated (S_2) and the total content of organic material (TOC) is known as the Hydrogen Index (HI). The quantity of CO_2 which is formed (S_3), is limited by the oxygen content of the kerogen. The S_3/TOC ratio is the Oxygen Index (OI). The ratio between the quantity of free oil already formed (S_1) and the total amount of petroleum (S_1+S_2), is an expression of how much petroleum is still left about how much has already been generated. The $S_1/(S_1 + S_2)$ ratio is the Production Index (PI). Good source rocks have a high production index. Good source rocks are also the first prerequisite for finding oil and gas in a sedimentary basin.

For this reason, Total Organic Matter content (TOM) is the first geochemical parameter calculated as shown in Equation 1.

Total Organic Matter:

$$TOM (\%) = S_1 + S_2 + S_3 \quad (1)$$

Other geochemical parameters can also be calculated such as Petroleum Potential (PP), which describes the maximum amount of petroleum that a mature source rock might generate. PP is shown in Equations 2 (McCarthy et al., 2011).

Petroleum Potential:

$$PP \text{ (ton/kg of HC rock)} = S_1 + S_2 \quad (2)$$

Hydrogen Index (HI) and Oxygen Index (OI) are related to the Total Organic Carbon (TOC), as it is used for their calculation. Thus, a proper TOC determination is key to evaluating them. Hydrogen Index (HI) “is proportional to the amount of hydrogen contained within the kerogen”, high HI values indicate greater potential to generate oil.

Oxygen Index (OI) is related to the amount of oxygen contained within the kerogen. Both indices are used for defining the type of kerogen contained within the source rocks and their thermal maturation and are plotted in the Van Krevelen diagram (McCarthy et al., 2011). Equations 3 and 4 show HI and OI respectively (Behar et al., 2001).

Hydrogen Index:

$$HI \text{ (mg/g TOC HC)} = S_2/TOC * 100 \quad (3)$$

Oxygen Index:

$$OI \text{ (mg/g TOC CO}_2\text{)} = S_3/TOC * 100 \quad (4)$$

Vitrinite Reflectivity VRo%:

$$VRO\% = 0.018 * T_{maks} - 7.16 \quad (5)$$

Ro%:

$$Ro\% \text{ Measured} = Ro\% \text{ Calculated} \quad (6)$$

It is extremely important to mention that some assumptions must be considered when calculating Total Organic Carbon (TOC) values, due to Rock-Eval 6 limitations. To avoid such assumptions, further studies should be developed using different geochemical techniques, as it is explained in the seventh chapter of this thesis work. Thus, it should be noted that the results obtained as a consequence of the assumptions are merely indicative. Therefore, assuming these parameters, the organic matter characterization, the maturation definition and the petroleum potential determination can be calculated for each source rock sample. The method used for TOC calculation is called “The Basic Method” (Behar et al., 2001) which is used in Rock-Eval

analysis. It should be mentioned that the equations used in this study have been modified according to Rock-Eval 6 Standard measurements.

Parameter	Definition	Measurement	Application
TOC	Total organic carbon	Wt.% of Corg/rock	richness
S₁	Free bitumen	Wt.% of HC/rock	Oil or gas shows
S₂	Hydrocarbon potential	Wt.% of HC/rock	Richness/quality
S₃	CO ₂ potential	Wt.% of CO ₂ /rock	Quality
T_{max}	Temp of Maximum generation rate (i.e., S ₂)	°C	Maturity
HI	Hydrogen index	$100 \cdot S_2 / \text{TOC}$	Kerogen quality/typing
OI	Oxygen index	$100 \cdot S_3 / \text{TOC}$	Kerogen typing
PP	Petroleum potential	S ₁ +S ₂	Oil and gas potential
PI	Production Index	$S_1 / (S_1 + S_2)$	Maturity/transformation ratio

Table 1. Showing Rock-Eval pyrolysis parameters and Total organic Carbon (Behar et al., 2001).

CHAPTER FOUR

4. Source Rock Evaluation

This chapter explains and describe the standard procedures for the evaluation of source rock. the guidelines described below are used for accurate and precise references for the source rock evaluation based on geochemical analysis.

Five types of source rocks can be found in terms of petroleum generation potentiality (Tissot and Welte, 1984), as follow:

Effective Source rock; is generating or has generated and expelled petroleum.

Potential source rock; contains adequate quantities of organic matter to generate petroleum, but only becomes an effective source rock when it generates bacterial gas at low temperatures or it reaches the proper level of thermal maturity to generate petroleum.

Active Source rock; is generating and expelling petroleum at the critical moment, most commonly because it is within the oil window (Dow., 1977a).

An Inactive Source rock; has stopped generating petroleum, although it still shows petroleum potential (Barker., 1979).

A Spent oil source rock; has reached the postmature stage of maturity and is incapable of further oil generation, but may still be capable of generating wet and dry gas.

4.1 Formation of Kerogen

Petroleum geochemistry is basic science to understand the characteristics of source rocks, productive and non-productive zones, oil migration all produce more efficient exploration, oilfield development and sustainable production. Due to the influence of time, temperature, and pressure, the mud sediment turns into sedimentary rock. Soft rock that comes from mud which contains oil spots is known as source rock. The parent rock is one of the main elements of the hydrocarbon system (Bjørlykke, 2015). Petroleum is generated from organic matter which accumulates in sedimentary basins. Most of the organic matter is formed by photosynthesis producing algae (bacteria) and higher organisms that feed on algae.

The formation of rich source rocks requires that the organic matter is not diluted too much by deposition of clastic material or by precipitation of carbonates. The organic matter is altered into kerogen which consists of very large and complex molecules (Bjørlykke, 2015).

The organic matter may be derived from marine organisms, mostly algae, or from plants derived from land. The transformation of amino acids, carbohydrates, humic acids and other compounds into kerogen is achieved by the removal of functional groups such as acid groups, aldehydes and ketones. This involves a loss of oxygen from the organic material, also as nitrogen, water and CO₂.

It is also possible to separate kerogen by a density method, using heavy liquids, because kerogen is lighter than minerals. The resulting concentrate of kerogen can be studied microscopically using transmitted and reflected normal light, to identify the biological origin and the degree of thermal alteration. These phases of altered organic material are called macerals. Algal material has a dull appearance, while wood and material from higher plants is called vitrinite. Vitrinite becomes increasingly shiny when exposed to higher temperatures and by measuring the amount of reflected light in the microscope we obtain an expression for the degree of thermal alteration (Vitrinite index). Being a complex of very large molecules (polymer), kerogen is difficult to analyse, but upon heating to 350–450°C in an inert atmosphere (pyrolysis) it will break down into smaller components which can then be analyzed employing gas chromatography and mass spectrometry (Bjørlykke, 2015).

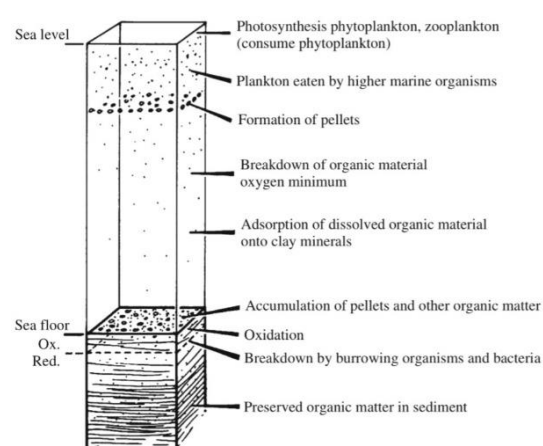


Figure 14. Formation of source rocks. Only a small fraction of the organic matter is preserved. The formation of organic-rich source rocks requires restricted water circulation and oxygen supply Modified from (Bjørlykke, 2015).

4.2 Types of Kerogens

Kerogen has a wide range of compositions, dependant on the original organic composition, but may be classified into 3 main types which may be plotted as a function of the H/C ratio and the O/C ratio (K. Bjørlykke, 2015).

Type I, Sapropelic Kerogen: is formed from organic material with a high content of lipids with long aliphatic/open chains. It consists of spores and planktonic algae, as well as animal matter, which has been broken down microbially after deposition in the sediment. According to Horsfield and Rullkotter (1989), sapropelic material which consists of fats, oils, waxes, etc., has a high H/C ratio, usually between 1.3 and 1.7. This kind of kerogen is often called Type I and contains little oxygen (O/C <0.1). It will provide mainly oil, with less gas (CH₄ and CO₂). Type I kerogen is typical of oil shales, especially in freshwater basins, but is also found in marine basins.

Type II, Kerogen: is a mechanically and chemically complex mixture of algae and other marine organisms and plant debris. The composition varies considerably, depending on the initial organic precursor materials which again may be linked to depositional facies. Type II kerogen represents a composition midway between types I and III but it does not represent a mixture of these end members. It has relatively high H/C, and low O/C, ratios, but contains more oxygen-containing compounds (ketones and carboxyl acid groups) than Type I. Esters and aliphatic chains are also common. This is the usual type of kerogen found in marine basins where mixtures of phytoplankton, zooplankton and micro-organisms have accumulated under reducing conditions, sometimes along with land-derived plant material. This type of kerogen is the most common source of *oil*.

Type III, Humic Kerogen: is derived from organic matter from land plants, such as lignin, and cellulose. This type has been studied to have a low initial H/C ratio, and a high initial O/C ratio, reflecting the composition of the precursor plant matter. In maturing (through the effect of temperature) this kerogen, which is often called Type III (Tissot and Welte, 1984), generates abundant water, CO₂ and methane (CH₄). Most coals have a composition and structure similar to Type III kerogens (fig 3).

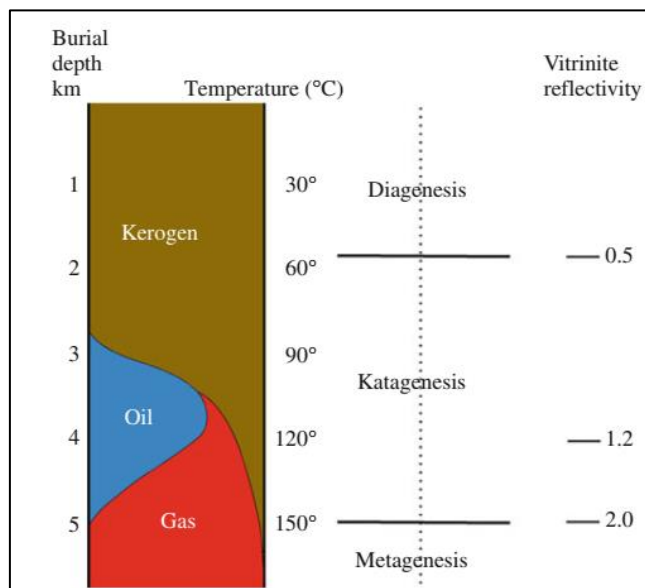


Figure 15. Alteration (maturation) of organic matter and generation of oil and gas as a function of temperature. The maturation is also a function of time and this can be determined by measuring the vitrinite reflectivity.

4.3 Maturation of Kerogen

The term “maturity” refers here to the degree of thermal transformation of kerogen into hydrocarbons and ultimately into gas and graphite (Figure 12). The conversion of kerogen into hydrocarbons is a chemical process that takes place with activation energies of around 50–60 kcal/mol. This energy is required to break chemical bonds in the kerogen which consists of

very large molecules (polymers) so that smaller hydrocarbon molecules can be formed (Mango, 1991). Temperature is the most important factor, and hydrocarbons can be produced experimentally from kerogen by heating it (pyrolysis).

I, Diagenesis: refers to all chemical, biological, and physical changes to organic matter during and after deposition of sediments but before reaching burial temperatures greater than about 60°-80°C. The quantity and quality of organic matter preserved and modified during diagenesis of sediment ultimately determine the petroleum potential of the rock (Horsfield and Rullkotter, 1989).

II, Catagenesis: can be divided into the oil zone, which corresponds to the oil window, where liquid oil generation is accompanied by gas formation, and the more mature wet gas zone, where light hydrocarbons are generated through cracking and their proportion increases rapidly (Tissot and Welte, 1984). Wet gas (<98% methane) contains methane and significant amounts of ethane, propane, and heavier hydrocarbons. The gas window corresponds to the interval from the top of the wet gas zone to the base of the dry gas zone.

III, Metagenesis: corresponds to the dry gas zone where dry gas is generated (2.0-4.0% Ro). Dry gas consists of 98% or more methane (Tissot and Welte, 1984). Dry gas is also found as deposits of bacterio-genic (microbial) gas generated during diagenesis of organic matter by methanogenic bacteria under anoxic conditions (Rice and Claypool, 1981).

IV, Thermal maturity: refers to the extent of temperature time-driven reactions that convert sedimentary organic matter (source rock) to oil, wet gas, and finally to dry gas and pyrobitumen (Tissot and Welte, 1984). Thermally, immature source rocks have been affected by diagenesis without a pronounced effect of temperature (<0.6% Ro) and are where microbial gas is produced. Thermally mature organic matter is (or was) in the oil window and has been affected by thermal processes covering the temperature range that generates oil (~0.6-1.35% Ro) or about 60°-150°C (Bjørlykke, 2015).

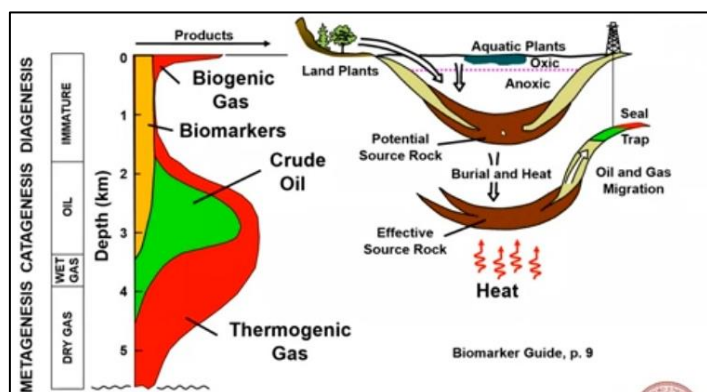


Figure 16. Explanation on stages of hydrocarbon maturation showing the primary composition of the different types of organic remains and the changes as a function of heating (maturation) during progressive burial (Bjørlykke, 2015).

4.4 Reference for determination of Quantity and Quality of Organic Matter

For this study to be accurate and specific, previously studied references recorded in the books of Magoon and Dow, (2009), and K. Bjørlykke et al., (2015) have been presented here in the tables below. This can be the main reference for any data discussed in this thesis work.

Property	TOC%	PP*	Rock-Eval Pyrolysis	
			S1	S2
Poor	0-0.05	0-2	0-0.5	0-2.5
Fair	0.5-1	2-6	0.5-1	2.5-5
Good	1-2	6-12	1-2	5-10
Very good	2-5	12-15	2-4	10-20
Excellent	>5	>15	>4	>20

Table 2. Interpretation of TOC and Rock-Eval Pyrolysis values (Magoon & Dow, 2009). PP* is petroleum potential (S1+S2).

Kerogen Type	HI (mg HC/g TOC)	Main Expelled Product
I	> 600	Oil
II	300-600	Oil
II/III	200-300	Mixed Oil and Gas
III	50-200	Gas
IV	< 50	None

Table 3. Geochemical Parameter Describing the Kerogen Type and the Expelled Product (Magoon & Dow, 2009).

Stage of Thermal Maturity	Tmax (°C)
Immature	< 435
Mature	---
<i>Early</i>	435-445
<i>Peak</i>	445-450
<i>Late</i>	450-470
Postmature	> 470

Table 4. Geochemical Parameter Describing the Level of Thermal Maturation (Magoon & Dow, 2009).

CHAPTER FIVE

5. Result

This chapter encompasses samples description and location, and rock-eval pyrolysis results obtained from source rock evaluation using Rock-Eval 6 apparatus. Following the temperature program and taking into account all measurement and assumptions, S1, S2, S3, TOM, TOC, HI, OI, PP, and T_{max} has been measured and calculated in this study. Therefore, the categorization of organic matter content, the quantity and quality of source rock, kerogen types, vitrinite contents and petroleum potential in the basin has been also determined for each sample using Rock-Eval 6 instrument in China Key Petroleum Laboratory for Reservoir Description. This apparatus uses a ramped temperature pyrolysis technique, whereby a small amount of sample (70–100 mg) is heated in an inert atmosphere (helium or nitrogen) and also combusted with air to obtain several key geochemical constraints relating to the hydrocarbon potential of the rock such as the total organic carbon (TOC), type or quality of organic matter and maturity level (Peters 1986; Lafargue et al. 1998) and (Behar et al, 2001).

5.1 Geochemical Data

Geochemical data have been continually used for analyses to achieve the main objectives of this thesis as well as the title of this study is focused. In this study, 13 samples were obtained from three different locations i.e., Al Gayger, Galhak and Melut Formations. For all the selected settings, 5 samples were collected from the Galhak formation, 4 from Al Gagyer and 4 from Melut formations locations. According to a comprehensive study by Lirong Dou and others., (2007) the age for this have been published in the Marine and Petroleum Geology journal. The dark lacustrine shale is indicated by early drilling activities. The result of that study indicated that Al Gayger formation is found within the lower cretaceous as explained in stratigraphical interpretations (figure7) (Dou et al., 2007).

Hence, the geochemical parameter from samples analysis is presented here. These include organic carbon content and source rock maturity evaluated with various factors including quantity and quality of organic matter, petroleum potential, type of organic matter and thermal maturation were considered. They are represented as Location-1, Location-2 and Location-3 correlating to well-1, well-2 and well-3 in the basin respectively.

5.2 Rock-Eval Pyrolysis

Rock-Eval Pyrolysis results were the main result this study particularly focuses on. The key data analysed from rock-eval pyrolysis are discussed in the sub-section below:

5.2.1 Quantity and Quality of Organic Matter

Organic matter richness, type, and thermal maturity are the three key geochemical indicators used for the evaluation of source rocks generation potentiality (Tissot and Welte, 1984). Different types of kerogens will produce different hydrocarbons. The results of this study are extracted from Rock-Eval Pyrolysis data described by Peters (1986). The parameter used for the determination of maturity level for this study was Tmax compared with vitrinite reflectance results extracted from Rock-Eval 6 instrument.

The geochemical result from Rock-Eval 6 apparatus, are plotted in a chart and also described on hydrocarbon generation using hydrogen Index as a role of Tmax, OI, TOC, etc. Tmax versus HI plots shows the different maturation pathways of different kerogen types. For this reason, the type and maturity of organic matter in petroleum source rocks of the three selected locations have been characterized from rock-eval 6 pyrolysis data as well as the important geochemical parameters like HI, OI, and PI have been calculated.

As shown in Table 5, the resulted data for TOC are calculated depending on a various formation that was analysed in the laboratory. These comprise Al Gayger, Galhak and Melut formations.

5.2.2 Samples Explanation and Locations.

The samples explained in this study are taken from three different wells in the Melut Basin. Well-1 and well-2 have slight similarities according to samples values and results presented.

The selected samples for this study mainly focused on the Northern Part of the Melut Basin, mostly in Greater Palogue Oilfields. The samples are collected from core cutting that was extracted during drillings and is analysed in Key Laboratory of Reservoir Description, China. The geochemical analysis for each sample is presented in the tables below.

According to the TOC and Rock-Eval pyrolysis data presented in this study, the samples are defined into three locations.

Location-1 comprises *NRV 01*, *SMY 02*, *CTP 03*, *BKC 04*, *KRY 05* samples as stated in table (5a).

Location-2 samples are depicted as *PTK 06*, *MNK 07*, *MBC 08*, *YMM 09*, which indicated four samples only (table 5b).

Location-3 also contain four samples collected which include *LYF 010*, *TNF 011*, *TPW 012*, *AMF 013* (table 5c).

Location-1

Sample	Formation	Depth(m)	TOC (%)	T _{max} °C	S1(m g/g)	S2(m g/g)	S3 (mg/g)	S1+S2(mg/g)	HI(mg/ g TOC)	OI(mg/ g TOC)	PP
NRV 01	Melut	1715–1725	0.72	437	0.16	0.46	1.7	0.62	64	236	0.62
SMY 02	Galhak	1970–1975	0.36	438	0.14	0.16	0.94	0.3	44	261	0.3
CTP 03	Galhak	1990–2000	0.5	435	0.19	0.24	0.97	0.43	48	194	0.43
BKC 04	Galhak	2150–2160	0.49	429	0.12	0.18	1.06	0.3	37	216	0.3
KRY 05	Galhak	2090-2100	0.49	435	0.26	0.35	0.85	0.61	71	173	0.61

Table 5a. Geochemical Parameters result for Location-1.**Location 2**

Sample	Formation	Depth(m)	TOC (%)	T _{max} °C	S1(mg/ g)	S2(m g/g)	S3 (mg/g)	S1+S2(mg/g)	HI(mg/ g TOC)	OI(mg/ g TOC)	PP
PTK 06	Melut	1990–1995	0.32	436	0.05	0.22	2.19	0.27	69	684	0.27
MNK 07	Galhak	2075–2080	0.12	433	0.02	0.02	0.53	0.04	17	442	0.04
MBC 08	Galhak	2080–2085	0.1	423	0.04	0.02	0.64	0.06	20	640	0.06
YMM 09	Galhak	2310–2315	0.2	432	0.03	0.01	0.49	0.04	5	245	0.04

Table 6a. Geochemical data for selected samples for Location-2.**Location-3**

Sample	Formation	Depth(m)	TOC (%)	T _{max} °C	S1(m g/g)	S2(m g/g)	S3 (mg/g)	S1+S2(mg/g)	HI (mg/ g TOC)	OI(mg/ g TOC)	PP
LYF 010	Melut	1820–1830	0.5	433	0.07	0.15	1.78	0.22	30	356	0.22
TNF 011	AlGayger	1990–2000	3.24	437	0.77	18.76	1.29	19.53	579	40	19.53
TPW 012	AlGayger	2170–2180	0.32	448	0.1	0.03	1.63	0.13	9	509	0.13
AMF 013	AlGayger	2220–2230	0.34	423	1.02	1.32	2	2.34	388	588	2.34

Table 7a. Geochemical parameters result for location-3

Table 8 (a, b, c). Showing the Result of the Geochemical parameters of the selected samples in Melut Basin.

The samples result from Rock-Eval pyrolysis data have been discussed below:

5.2.3 Location-1 Samples

In this location, five samples have shown TOC% values ranging from 0.36% to 0.72% at depth of 1990-1995m. The level of thermal maturity in these samples is ranging from 429-438°C which indicated peak maturity described by (Magoon & Dow, 2009). The formations found within this location are of Melut and Galhak formations. In the stratigraphic sequence studied and reported by Dou et al., 2007, Galhak formation were found underlying Melut formation in the upper cretaceous. The values (37-71mg/g TOC) for the HI index specified that these formations belong to non-source rock. As indicated by the hydrocarbon by S1 and S2 values is between 0.12 to 0.46 which show poor petroleum potential.

5.2.4 Location-2 Samples

The location-2 samples extracted from well-2 in the Melut basin are also corresponding to Melut and Galhak formation. Its depths range from 1990-2315m with a thickness of 129m for Galhak formation. These formations are formed during Upper Cretaceous (Mohamed., 2016). The results analyses from Rock-Eval 6 analysis of total organic carbon content indicated that the source rocks in this location are a poor-fair richness in organic matter. The maturation possibility of these sequences is ranging between 423-436°C as indicated by the T_{max} values. This means that the source found in this location is an immature one. According to these data, these source rocks have not expelled or slightly expelled little petroleum. The main sedimentary environment is a braided deltaic and shallow lake. The drilling or core samples have shown that the Galhak formation in this location has capped the underlying formation uncomfortably.

5.2.5 Location-3 Samples

The TOC values for Al Gayger source rocks are ranging from 0.32% to 3.24% demonstrating good-very good organic carbon as depicted in table 3. S1 and S2 values have shown 0.1 to 1.02mg/g that is fair-good as S1 value while S2 values are 0.03mg/g to 18.76mg/g representing good-very good on quality richness. In the table, the result for hydrogen Index is also calculated from equation (3) discussed earlier in chapter 4., computed results ranging from 9-579mg/g TOC which indicate type II Kerogen which is mostly an oil-prone region of Al Gayger formation. The Oxygen index computations for this formation is found to be low at 40 mg/g TOC and high at 588mg/g TOC, at a very accurate occurrence.

The data from the table was collected from the selected well-1, well-2, well-3. Their depth varies ranging from 1715-2315m (fig 17). This apparatus uses a ramped temperature pyrolysis technique, whereby a small amount of sample (70–100 mg) is heated in an inert atmosphere (helium or nitrogen) and also combusted with air to obtain several key geochemical constraints relating to the hydrocarbon potential of the rock such as the total organic carbon (TOC), type or quality of organic matter and maturity level (Peters 1986; Lafargue et al. 1998; Behar et al. 2001).

The geochemical result from Rock-Eval 6 apparatus, are plotted in a chart (figure 13 to14) and also described on hydrocarbon generation using hydrogen Index as a meaning of T_{max} , OI, TOC, etc. Temperature maximum contrasted with Hydrogen Index plots displays the different maturation pathways of different kerogen types (figure 15).

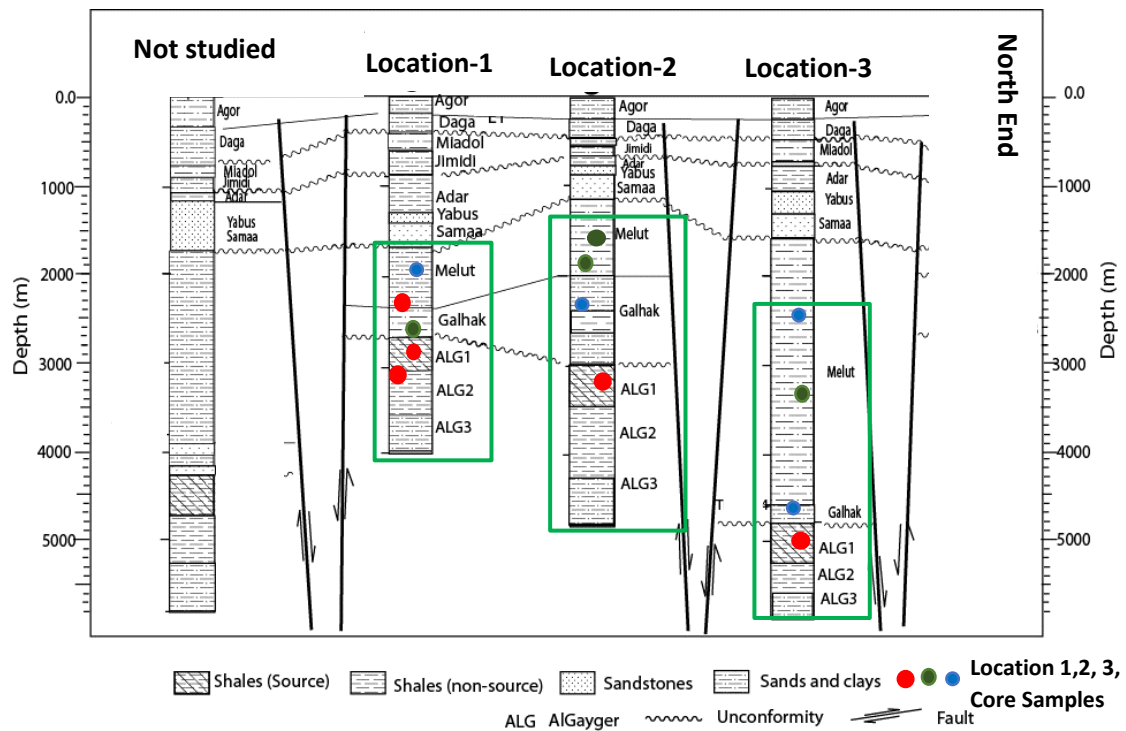


Figure 17. Composite Stratigraphic descriptions Relative to the studied Samples from three locations. The data was extracted from the depth ranging from 1715-2315m which is plotted in the picture above. The depth varies from location-1, location-2, and location-3.

In this composite stratigraphic, the Al Gayger Formation is divided into three layers. The information for the Al Gayger source rocks sequence was interpreted by researchers in collaboration with Lirong Dou (2007) and Mohammed et al (2016).

These are named (ALG1, ALG2 and ALG3 youngest to oldest) for source rock evaluation. These three layers and the other undivided five create eight layers of which four are of Cenozoic age and the remaining four are of Cretaceous (Figure 15). Vertical variation of the source rock lithologies is observed in published data, with the shales of the Aptian-Albian ALG-1 being the main hydrocarbon-rich source rock. The delineation explained in figure 15 are correlated to location-1, location-2, and location-3 as shown in the illustration (figure 15).

CHAPTER SIX

6. Discussion

In this chapter, a discussion of the results is explained. A proper source rock evaluation is also described. Rock-eval 6 apparatus data and its measurement is attained from pyrolyzed data and their diagram was plotted for more explanation and all were correlated to the standard analysis that was portrayed by (Peters 1986; Lafargue et al. 1998) and (Behar et al. 2001).

The geochemical parameters of the source rocks are presented in table 5 (**chapter 5**).

A complete and thorough analysis has been carried out in the laboratory to analyse each sample using Rock-Eval 6 apparatus. The values for total organic matter (TOM) calculated using equation (1) is ranging between 0.53-20.82wt. % for all 13 samples presented. From the same table 1, sample TPN011 has the highest values of total organic matter, whereas sample MBC08 has the lowest values of total organic matter which correlated as 0.01% and 3.24% individually. Free bitumen value (S_1), is low at 0.1mg/g for TPW012 and high at 1.02mg/g of rock. The number of hydrocarbon potential (S_2) is as low as 0.01mg/g for TPW012 and as high as 18.76mg/g for sample TPN011. S_3 values predict the carbon dioxide (CO_2) potential in the Basin which are recorded in this study ranging from 0.49mg/g to 2.19mg/g for PTK06 and YMM09 separately. The computed values for Hydrogen Index and Oxygen Index show the kerogen quality or typing measured in mg/g TOC of rock. The totalled values resulted as 5mg/g TOC for YMM09 and 579mg/g TOC for TPN011 representing hydrogen index values. The numbers for the oxygen index range from 40% to 684% for TPN011 and PTK06 respectively, not forgetting that petroleum potential value which predicts oil and gas potential is also calculated from summing the values of (S_1+S_2). These values are at low at 0.03 ton/kg of HC rock, and high at 19.53 ton/kg HC of rock respectively. The maximum temperature (T_{max}) for all samples is ranging from 423-448°C, which is lowest at the MBC08 location and highest at the TPW012 location.

6.1 Kerogen Type and Organic Richness for Petroleum Potential

The kerogen type and the richness of organic matter have been described by Hakimi and others (2012). Generally, Type I and II kerogens commonly derived from lacustrine and marine lower plankton are the best kerogen and are capable of generating liquid hydrocarbons (Hakimi et al., 2012) while Type III kerogen composed of terrestrial higher plants has the potential to generate gas (Behar et al., 2003; Ruble et al., 2001). Tissot and Welte, Peters and Cassa presented a measure for the assessment of source rock possibility based on the value of TOC% and Rock-Eval pyrolysis data, such as S_1 and S_2 .

From all the selected samples, sample TNP011 have shown a considerable richness in total organic matter (TOC), which is 3.24wt.% indicating a very good rate for petroleum potential. This sample has the highest petroleum potential in the basin. For this reason, TOC values have revealed that TPW011 can generate petroleum under higher temperature conditions.

The values of TOC used to interpret petroleum potential quantity are discussed in the table below:

Location	Sample	TOC%	Petroleum Potential (quantity)
Location-1	NRV 01	0.72	Fair
	SMY 02	0.36	Poor
	CTP 03	0.5	Fair
	BKC 04	0.49	Fair
	KRY 05	0.49	Fair
Location-2	PTK 06	0.32	Poor
	MNK 07	0.12	Fair
	MBC 08	0.1	Poor
	YMM 09	0.2	Poor
Location-3	LYF 010	0.5	Fair
	TNF 011	3.24	Very good
	TPW 012	0.32	Fair
	AMF 013	0.34	Fair

Table 9. The total organic carbon values for evaluating petroleum potential in Melut Basin.

The criterion for determining kerogen type (quality) is usually dependent on the value of the hydrogen index. The values present in **table 7** have shown different types of kerogens. These range from the ones producing oil or gas and others that cannot produce oil. The quality of kerogen in this study is ranging from kerogen type II, III and IV. Type III kerogen cannot produce oil or gas. Oil and gas are produced from type II and Type III respectively. The results show that the Source rock is fair to good hydrocarbon potential stage, with kerogen confined is encompassed into Type II and III that can generate gas and limited oil.

Many samples have also shown no possibility for the expulsion of oil. Oil can be only produced at a high HI value as indicated in table 7.

Location	Sample	HI (mg HC/g rock)	Kerogen Type (quality)	Main Product
Location-1	NRV 01	64	III	Gas
	SMY 02	44	IV	None
	CTP 03	48	IV	None
	BKC 04	37	IV	None
	KRY 05	71	III	Gas
Location-2	PTK 06	69	III	Gas
	MNK 07	17	IV	None
	MBC 08	20	IV	None
	YMM 09	5	IV	None
Location-3	LYF 010	30	IV	None
	TNF 011	579	II	Oil
	TPW 012	9	IV	None
	AMF 013	388	II	Oil

Table 10. Kerogen types and their HI values for the selected samples.

6.2 Thermal Maturity and Maturation Level

T_{max} is the temperature at which the maximum release of hydrocarbons from cracking of kerogen occurs during pyrolysis (top of S_2 peak). In the study area, maturity level increases with the rock stratigraphic position. This means that depth plays an important role in these samples. The type and maturity of organic matter in petroleum source rocks can be characterized from Rock-Eval pyrolysis data. On the other hand, the level of maturity can be determined based on the values of vitrinite content ($R_o\%$) extracted from rock-eval pyrolysis data. To determine maturation level, T_{max} results were used to predict the source rock's ability to generate petroleum. Therefore, T_{max} values have been extracted to explain the maturation level in this study.

As explained in table 8 below, T_{max} values have shown different maturation levels for the selected samples.

Location	Sample	T_{max} (°C)	Maturation Level
Location-1	NRV 01	437	Early Mature
	SMY 02	438	Early Mature
	CTP 03	435	Early Mature
	BKC 04	429	Immature
	KRY 05	435	Early Mature
Location-2	PTK 06	436	Early mature
	MNK 07	433	Immature
	MBC 08	423	Immature
	YMM 09	432	Immature
Location-3	LYF 010	433	Immature
	TNF 011	437	Early mature
	TPW 012	448	Late mature
	AMF 013	423	Immature

Table 11. Tmax and its maturation Levels for each selected sample in Melut Basin.

According to the samples explained in table (8), the maturity level can be traced from temperature results. Therefore, the temperature values (T_{max}) vary from sample to sample. Most of the above have shown immature to early maturity while postmature is hardly found in the selected samples. Some late maturity samples are mentioned for sample TPW012 as its value equals 448°C. The lowest T_{max} value equals 423°C for AMF013 which show an immature level. These two samples have the capability of producing oil as shown in the table. However, in location three, the most dominant kerogen type is type II, and it is correlated with the mature oil-producing area. For this reason, oil can only be produced in this particular location as is stated in the table.

The environmental variation of source rocks studied in this work is sensitive to various geochemical parameters, so that the original depositional environment and organic matter in the source rocks may be interpreted according to biomarker characteristics (Peters and Moldowan, 1993). The 18a (H)- oleanane is generally thought to be derived from Cretaceous or younger higher plants (Peters and Moldowan, 1993). A low content of oleanane was detected in the Upper Cretaceous sample of the Palogue-1; no oleanane was identified in the Lower Cretaceous shale sample of the Fal-1. This suggests that the Upper Cretaceous sample should be more abundant with terrestrial organic matters than those of Lower Cretaceous sample. The gamma cerane/C30 hopane ratio is thought to indicate the salinity of the depositional setting. As shown in Fig. 5, this ratio is higher than 0.1 for the Upper Cretaceous sample, but lower than 0.1 for the Lower Cretaceous sample, indicating that the salinity of the Early Cretaceous water body was lower than the Late Cretaceous.

6.3 Migration Pathways and Accumulations

The oils discovered in this basin were mostly heavy crudes and their °API increases with depth. Most reservoirs were found between depths of 800m and 1800m. Numerous faults were present in this basin, and the traps are fault related. These Cenozoic traps (Dou et al) were most likely formed during the last rifting events and controlled by the rejuvenation of the Cretaceous faults. Most hydrocarbons that were generated from the deepest source rocks (Alg1) of the basin were generated during the period 90 to 40 Ma(Dou et al, 2007, Mohammed, 2016) and shallower source rocks are still generating.

Most major faults were assumed to have been initiated during the first rifting event while others formed during the second and third phases. During syn-rift periods, faults can act as migration pathways depending on their Shale Gauge Ratio (e.g., active movement prevents mineralization and sealing of faults) but are assumed closed during the thermal sag phases. Therefore, the petroleum has migrated through a fault that has been initiated by the syn-rifting

period. The distance between the stratigraphic traps of the Upper Yabus Formation and the primary source rocks of the Al Renk Formation is over 2000 m in most areas of the Northern Sub-basin.

Hence, the vertical migration pathways are essential for the hydrocarbon charging of the Upper Yabus traps. The Melut Basin is a passive rift basin with multi-stage rifting cycles and developed abundant hydrocarbon conduit faults, which connected the Lower Cretaceous source rocks to the Paleogene traps and played an important role in the hydrocarbon charging of the Paleogene traps.

Driven by the multi-stage rifting cycles, the Melut Basin developed three types of faults: the basinal border faults, the intra-basinal early rifting faults and the intra-basinal late-rifting faults. The basinal border faults continuously moved from the Early Cretaceous to the Paleogene and connected the Samma and Yabus trap to the Al Renk source rocks, so they are favourable hydrocarbon conduit faults. The intra-basinal early-rifting faults mainly formed in the Early Cretaceous and most of them terminated in the Cretaceous formations. Therefore, the intra-basinal early-rifting faults are not effective vertical migration pathways for the hydrocarbon charging of the Paleogene traps. Compared to the intra-basinal early-rifting faults, the intra-basinal late rifting faults formed in the 3rd rifting cycle in the Paleogene were well developed and some of them penetrated the Al Renk source rocks and acted as the important hydrocarbon conduit faults for the charging of the Paleogene structural and stratigraphic traps. Although some late rifting faults only penetrated the Paleogene and the Upper Cretaceous formations, most of them connected with previous conduit faults and are also effective vertical migration pathways for the Paleogene traps. The abundant intra-basinal late-rifting faults made the Samma and Lower Yabus Formations developed numerous fault-block hydrocarbon accumulations, such as the Palogue Oilfield, Adar-1 Oilfield, Gasab-1 Oilfield (**fig 1**). Compared to the near-source hydrocarbon accumulations in the active rift basins in most Basins, the Paleogene far source hydrocarbon accumulations in the Melut Basin usually have shallower buried depth, good reservoir quality and high production. But due to the long migration distance from the Lower Cretaceous Al Renk source rocks to the Paleogene traps, the stratigraphic traps of the Upper Yabus Formation have a risk of being filled, and the stratigraphic traps associated with conduit faults have lower hydrocarbon charging risk and higher success rate than the pure sand lens and pure depositional pinch-out traps.

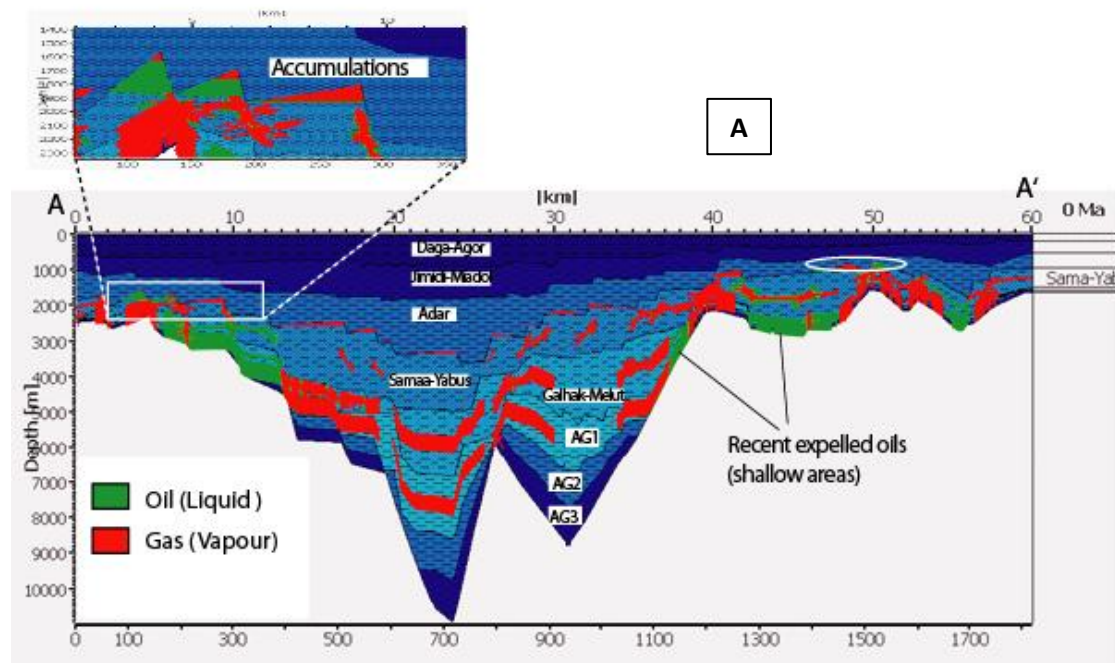
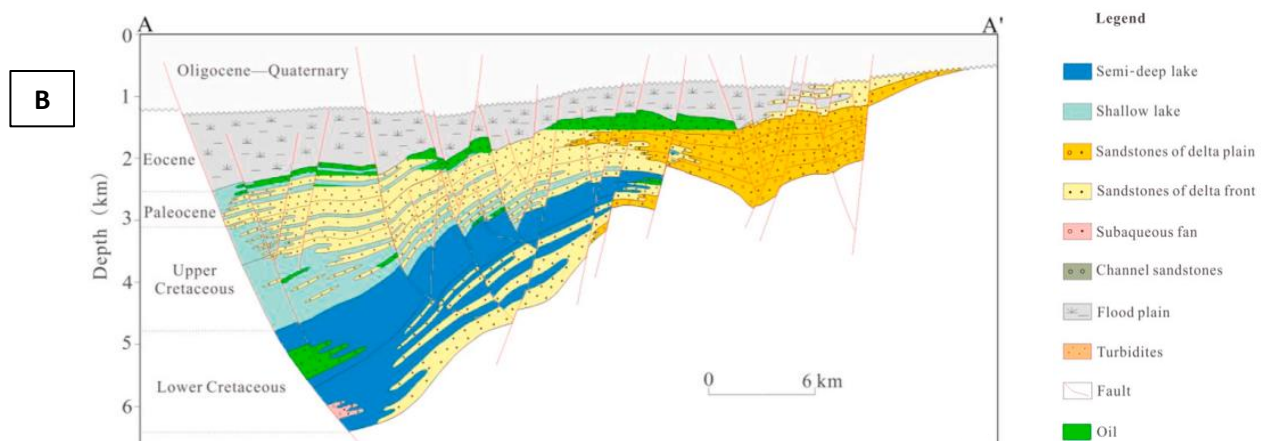


Figure 18. A) Migration and accumulation along cross-section A-A' using the Hybrid model (Darcy and flow path combined) and applying the plausible fault model with shale gauge ratio (SGR) of 50%. Accumulations bordered by a rectangle to the left and a semi-circle to the right are similar to the Palogue Fal and Adar-Yale oil fields when gas is removed. The top rectangular figure is an enlargement to the left accumulations. **B)** Sedimentary filling and hydrocarbon accumulation model of the Melut Basin (Modified from Shi et al, 2015).



6.3 Conclusion

The objective of this study is to evaluate the quality and quantity of organic matter in Melut Basin based on Geochemical Parameters. The analysis and the results are highlighted here. To obtain accurate and presentable results, various geochemical parameters were analysed in the lab and explained based on the geochemical results explained in chapter 5 of this study. The type of geochemical analysis used in this study is Rock-Eval 6 instrument. A complete and thorough analysis has been carried out in the laboratory to analyze each sample using Rock-Eval 6 apparatus. Data obtained from the rock-eval 6 apparatus was explained and compared with the standard data described by early researchers in the field of Petroleum Geosciences and they are presented in chapter four for an accurate and precise reference if needed. The following are the result key points covered in this study:

Geochemical data have been continually used for analyses to achieve the main objectives of this thesis as well as the title of this study is focused.

In this study, 13 samples were obtained from three different locations i.e., Al Gayger, Galhak and Melut Formations. For all the selected settings, 5 samples were collected from the Galhak formation, 4 from Al Gagyer and 4 from Melut formations. From all the selected samples, sample TNP011 have shown a considerable richness in total organic matter (TOC), which is 3.24wt.% indicating a very good rate for petroleum potential. This sample has the highest petroleum potential in the basin. For this reason, TOC values have revealed that TPW011 can generate oil and limited gas.

The TOC values for Al Gayger source rocks are ranging from 0.32% to 3.24% demonstrating good-very good organic carbon. S_1 and S_2 values have shown 0.1 to 1.02 mg/g that is fair-good as S_1 value while S_2 values are 0.03mg/g to 18.76mg/g representing good-very good on quality richness. The values for total organic matter (TOM) calculated using equation (1) is ranging between 0.53-20.82wt. % for all 13 samples presented. The maturation possibility of these sequences is ranging between 423-448°C as indicated by T_{max} values. Therefore, the maturity level is registered from immature, mature, and postmature.

The drilling or core samples have shown that the Galhak formation in this location has capped the underlying formation uncomfortably. The results show that the Source rock is fair to good hydrocarbon potential stage, with kerogen confined is included into Type II that has the capability of generating gas and limited oil for Al Galhak formation. In the other extension of the study area, maturity level increases with the rock stratigraphic position. This means that depth plays an important role in these samples. The type and maturity of organic matter in

petroleum source rocks can be characterized from Rock-Eval pyrolysis data. To determine maturation level, Tmax results were used to define the source rock's ability to generate petroleum. Based on S2 values, excellent and very good petroleum potential have been shown for the source rock samples. S2 represents the amount of hydrocarbons that can still be generated if thermal maturation undergoes.

During syn-rift periods, faults can act as migration pathways depending on their Shale Gauge Ratio (e.g., active movement prevents mineralization and sealing of faults) but are assumed closed during the thermal sag phases.

The overall conclusion explains that Al Gayger source rocks explained in location-3 has a very good storage of organic matter which made this location to be unique and have a high potentiality of producing hydrocarbon. They can generate oil and insufficient gas. Location-1 and location-2 samples have shown poor pair quantity of source rocks. Mostly, gas can be produced in these locations which correspond to type III kerogen. Type three kerogen is known for producing gas. The type of sources found in the Melut Basin is categorized as active, inactive and potential types.

The Melut Basin developed two sets of source rocks: the Al Renk Formation source rocks in the Lower Cretaceous and the Galhak Formation source rocks in the Upper Cretaceous. The Al Renk Formation comprises the primary source rocks deposited in the first rifting cycle and is dominated by deep and semi-deep thick lacustrine mudstones. The thickness map of Al Renk source rocks, derived from seismic interpretation of 5000 km² 3D and 2000 km 2D lines and lithology data of 60 wells in the Northern Sub-basin, indicated that the thickness of Al Renk source rocks ranged from several hundred to more than 1000 m thick. The kerogen elemental analysis showed that the Al Renk source rocks mainly developed type II kerogen prone to generating oil. Moreover, the research from Dou et al. (2007) and Mohamed et al. (2016) indicated that the TOC content of Al Renk source rocks has good to very good levels, with a maximum value of 3.24% and an average value of 2.08% wt. The value of S1+S2 ranged from 0.25 to 19.53 mgHC/g rock (mean, 9.96 mgHC/g rock). The hydrogen index (HI) ranged from 273 to 579 mgHC/g TOC (mean, 428 mgHC/g TOC), and the oxygen index (OI) ranged from 40 to 181 mgCO₂/g TOC (mean, 93 mgCO₂/g TOC).

In summary, the multi-stage rifting cycles promoted the development of hydrocarbon conduit faults connecting the Lower Cretaceous source rocks to the Paleogene traps, and these hydrocarbon conduit faults provided essential vertical migration pathways for the hydrocarbon charge of the Samma and Yabus traps. Among these faults, the basinal border faults and the intra-basinal late-rifting faults are favourable vertical migration pathways. The abundant oil

source faults derived from the multi-stage rifting cycles provided essential vertical migration pathways for the hydrocarbon accumulation of the Paleogene stratigraphic traps. In this thesis work, the geochemical results have shown that S1 values are lower than S2 values in each source rock sample, which might be interpreted as hydrocarbons migrated out of the investigated source rocks into the traps system. Compared to the near-source hydrocarbon accumulations in the active rift basins in most Basins, the Paleogene far source hydrocarbon accumulations in the Melut Basin usually have shallower buried depth, good reservoir quality and high production. But due to the long migration distance from the Lower Cretaceous Al Renk source rocks to the Paleogene traps, the stratigraphic traps of the Upper Yabus Formation have a risk of being filled, and the stratigraphic traps associated with conduit faults have lower hydrocarbon charging risk and higher success rate than the pure sand lens and pure depositional pinch-out traps.

6.4 References

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Appendix

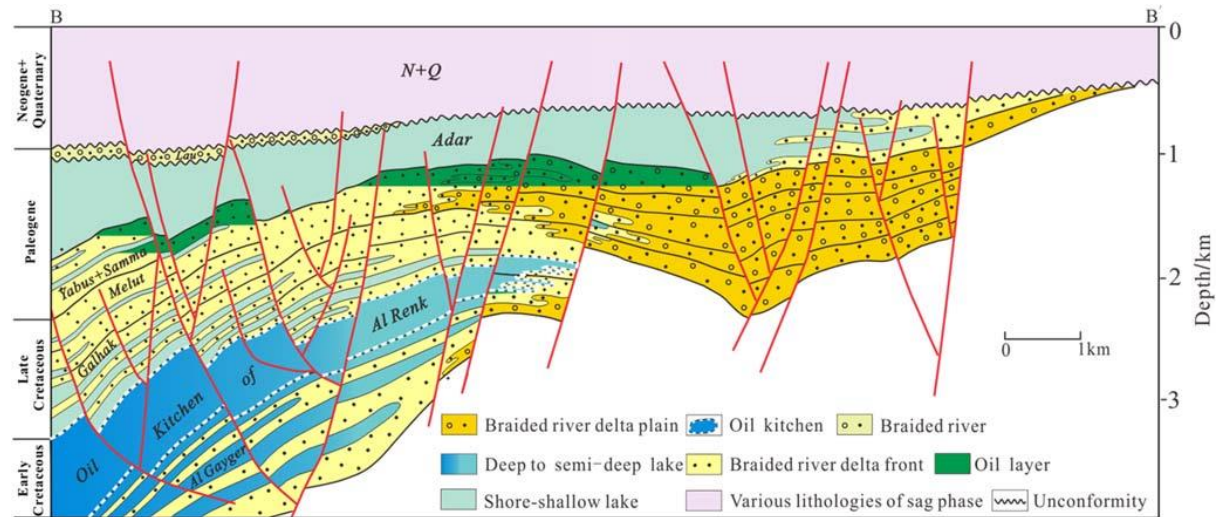
Appendix 1. Showing Geochemical parameter and results cutting of dark shales.

Sample	Formation	Depth(m)	TOC (%)	T _{max} °C	S1(m g/g)	S2(m g/g)	S3 (mg/g)	S1+S2(mg/g)	HI(mg/ g TOC)	OI(mg/ g TOC)	PP
NRV 01	Melut	1715–1725	0.72	437	0.16	0.46	1.7	0.62	64	236	0.62
SMY 02	Galhak	1970–1975	0.36	438	0.14	0.16	0.94	0.3	44	261	0.3
CTP 03	Galhak	1990–2000	0.5	435	0.19	0.24	0.97	0.43	48	194	0.43
BKC 04	Galhak	2150–2160	0.49	429	0.12	0.18	1.06	0.3	37	216	0.3
KRY 05	Galhak	2090-2100	0.49	435	0.26	0.35	0.85	0.61	71	173	0.61
PTK 06	Melut	1990–1995	0.32	436	0.05	0.22	2.19	0.27	69	684	0.27
MNK 07	Galhak	2075–2080	0.12	433	0.02	0.02	0.53	0.04	17	442	0.04
MBC 08	Galhak	2080–2085	0.1	423	0.04	0.02	0.64	0.06	20	640	0.06
YMM 09	Galhak	2310–2315	0.2	432	0.03	0.01	0.49	0.04	5	245	0.04
LYF 010	Melut	1820–1830	0.5	433	0.07	0.15	1.78	0.22	30	356	0.22
TNF 011	AlGayger	1990–2000	3.24	437	0.77	18.76	1.29	19.53	579	40	19.53
TPW 012	AlGayger	2170–2180	0.32	448	0.1	0.03	1.63	0.13	9	509	0.13
AMF 013	AlGayger	2220–2230	0.34	423	1.02	1.32	2	2.34	388	588	2.34

Appendix 2. Oil window depth and oil generation time of Well-1, Well-2, Well-3 in the Northern Sub-basin, Melut Basin (Mohammed, 2016).

Well		Well-1	Well-2	Well-3	Well
Oil Window Depth(m)	Onset	1727	1730	1619	2500
	Peak	3345	Not Reached	3211	3400
	End	3900	Not Reached	3715	4500
Oil Generation Time (Ma)	Start	84	51	86	66
	End	Generating	Generating	Generating	Generating

Appendix 3. Typical reservoir model of the far-source accumulation pattern of the Paleogene main producing layer in the Melut Basin(Dou et al, 2007).



Appendix 4. Depositional model (a) and hydrocarbon accumulation pattern (b) of the Abyat fan delta (Shi et al. 2015),

