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COLLEGE OF BIOLOGICAL AND PHYSICAL SCIENCES
SCHOOL OF PHYSICAL SCIENCES
DEPARTMENT OF GEOLOGY

GEOCHEMICAL EVALUATION OF THE HYDROCARBON POTENTIAL OF SOURCE ROCKS IN THE ANZA BASIN

BY

BETT KIPNG'ETICH GILBERT

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This Dissertation is submitted for examination with my approval as a research supervisor.

1) Signature ……………………………… Date ……………………

Prof. Daniel O. Olago

Department of Geology,

University of Nairobi,

P.O. Box 30197-00100 Nairobi.

This Dissertation is submitted for examination with my approval as a research supervisor

2) Signature ……………………………… Date …………………..

Dr. Daniel W. Ichang'i

Department of Geology,

University of Nairobi,

P.O. Box 30197-00100 Nairobi.

This Dissertation is submitted for examination with my approval as a research supervisor

3) Signature …………………………….… Date …………………

Prof. Bernard K. Rop

Department of Mining, Materials and Petroleum Engineering,

Jomo Kenyatta University of Agriculture and Technology,

P.O. Box 62000-00200 Nairobi.

DECLARATION

I declare that this Dissertation is my original work and has not be presented elsewhere for examination for award of a degree or publication. Where other people (researchers') work or my own has been used, this has been acknowledged and cited in accordance with the University of Nairobi's requirement.

Signature …………………...........   Date …………………….

Bett Kipng'etich Gilbert

Reg. No.: I56/70102/2013

bett86.kip@gmail.com

Department of Geology,

University of Nairobi,

P.O. Box 30197-00100 Nairobi.

DECLARATION FORM FOR STUDENTS

I declare that this is my original work and has been prepared and presented for the Dissertation for award of a degree in Master of Science in Geology (Petroleum Geology) of the University of Nairobi.

Signature: .... Date: ....

Bett Kipng'etich Gilbert

Reg. No. I56/70102/2013

Department of Geology,

School of Physical Sciences,

College of Biological and Physical Sciences,

University of Nairobi

PO. Box 30197-00100 Nairobi.

DEDICATION

This research I dedicate to God, my family and the Department of Geology, University of Nairobi, for their unrelenting support and confidence in my ability to distinctively demonstrate scientific knowledge in the field of oil and gas.

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ABSTRACT

Geochemical analysis of source rocks is a method used to estimate and understand the formation of hydrocarbons (if any) in the rock samples. Over time, technology applied has improved and it is now possible to quantitatively and qualitatively determine the percentage of organic content, their maturity or immaturity as well as the migration paths. This study involved the use of Total Organic Content (TOC) and Rock-Eval pyrolysis methods to measure organic content and thermal maturity of hydrocarbon present in the source rock respectively. Geochemical analysis of sub-surface Cretaceous sedimentary rocks was undertaken in order to understand oil and gas potentiality of source rocks in Anza basin, based on a case study on the four wells namely; Chalbi-3, Siruis-1, Ndovu-1 and Kaisut-1. Anza basin is located on a fault block within a Paleocene–Cretaceous rift basin. The methodological approach used involved evaluation of source rocks through petrographical study of lithological features and geochemical evaluation of source rocks. The physical interpretation of depositional environments from lithologies and sedimentary structures as seen from the lithologs helped in elucidating the characteristics of the source rocks. Additionally, petrographical data provided valuable information such as provenance and depositional environments. Well sections with higher shale-volume ratio were selected for geochemical screening methods which included, TOC and Rock-Eval pyrolysis of well-logs to determine the quantity of organic matter and quality (kerogen type), and the thermal maturity of potential source rocks. TOC determination was used as a screening tool to identify intervals of organic richness. Those samples with satisfactory source rock richness ($\geq 0.5\%$) were evaluated further for their petroleum potential using petroleum indices (PI). Samples with TOC values greater than 0.5% for shales and 0.3% for carbonates were subjected to Rock-Eval pyrolysis to determine the level of thermal maturity of potential source rocks, migrated hydrocarbons and *in-situ* generated hydrocarbons present in sedimentary facies. The geochemical evaluation of rock cutting samples from the drilled wells' sections of Anza Basin confirmed both oil and gas potential. Sirius-1 proved to be the most oil-rich well. Gas Chromatography and Mass Spectrometry (GCMS) were used to characterize the biomarker signatures and oil-oil correlation of Sirius-1 samples. The results from this research-related work provided further understanding of hydrocarbon potentiality in Anza basin's four wells, namely; Chalbi-3, Siruis-1, Ndovu-1 and Kaisut-1. A predictive model was developed to further map the regional basin extension and thus exhaustively attempt to decipher the depths with high TOC and hydrocarbons' potential in the Anza basin; thus triggering future researches on oil and gas exploration rationale.

Keywords: geochemical evaluation, kerogen, maturity, petroleum potentiality, predictive model.

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LIST OF ABBREVIATIONS

OM - Organic Matter

API - American Petroleum Institute

GR - Gamma Ray

HC- Hydrocarbon

GC - Gas Chromatography

MS - Mass Spectrometry

TOC -Total Organic Carbon

nd – not determine

ppm - parts per million

wt. – weight

1 CHAPTER ONE: INTRODUCTION

1.1 Introduction

The purpose of the present research thesis work is to determine the hydrocarbon potentiality of four drilled wells (Chalbi-3, Siruis-1, Ndovu-1 and Kaisut-1) in the NW-SE trending Cretaceous-Tertiary Anza basin with the help both petrographical and geochemical analysis of source rocks. Anza basin evolved through extension tectonics that brought out continental rifting during the Gondwanaland breakup in the Late Paleozoic time, and continued in the Mesozoic and Tertiary (Rop, 2003). The research study involved determination of the quantity, quality, and thermal maturity of the source rocks in order to evaluate hydrocarbon occurrence, their commercial viability and further develop a predictive model for Anza basin. The great East Africa Rift System (EARS) is part of the Greater Rift Valley that runs from Red Sea through Ethiopia and Kenya up to the Tanzanian craton. The EARS is an active extensive fault-dominated rift with a chain of marginally down-warped depressions associated with active volcanism evidenced by early basalts and phonolite flood lava (Rop and Namwiba, 2018; Rop, 2013; Smith, 1994). EARS range from geological periods mid-Miocene to early Pliocene (Baker et al., 1972), followed by subsequent faulting that resulted in asymmetrical grabens and basins.

Therefore, the EARS region has witnessed and attracted intensive oil and gas exploration activities that are at different stages. Anza graben (where present study area is located in the northwest Anza basin extension) forms a minor rift to the east of EARS that extends to the South Sudan rift, where substantial oil discoveries have been made (Schull, 1988). The Anza basin, located in the southeast of Lake Turkana is dominantly marine and fluvial sediment provenance, with associated small lakes and dune fields (Rop and Namwiba, 2018; Rop, 2013; Bosworth and Morley, 1994). It borders Mandera basin to the East and Lamu basin to the southeast. Anza Basin has recently been a major target of oil and gas for many exploration companies such as Tullow Oil Incorporation, Total Kenya and other international companies. The Anza basin forms part of the termination rift of the Central African Rift System in Chalbi sub-basin in northern Kenya and an extension of the Melut and Muglad rift basins in South Sudan where working petroleum (hydrocarbons) systems have been proved and oil discovered (Rop, 2013; Schull, 1988; Atlas, 1990).

Hydrocarbons are organic compounds that are primarily composed of hydrogen and carbon elements, which may be monomeric or polymeric forms; for example, alkanes and naphthalene among other minor constituents. They are formed from organic matter that accumulated in a suitable depositional environment and underwent burial and subsequent sedimentation, diagenesis and mild metamorphism as the overlying loose sediments continued being deposited. Overlying weight exert heat and pressure upon the buried organic matter. However, hydrocarbon does not occur anywhere but only in mature source rocks such as laminated carbonates and shale. These source rocks possess definite characteristics that qualify them to become favorable for oil and gas accumulation, given the presence of good structural properties.

Petroleum processes of formation, generation and migration are guided by four main petroleum systems, namely: source rock, reservoir rock, trap and seal. These petroleum systems are interdependent (Magoon and Dow, 1991) for formation of oil and/or gas. All systems must exist simultaneously from organic matter to kerogen and then oil or gas accumulation in order to generate economically extractable hydrocarbon. The mechanisms of oil and gas generation vary from basin to basin depending on sedimentary facies, burial history, tectonic and other geological factors.

Petroleum geochemistry helps fundamentally to understand the properties of source rocks, producible and non-producible zones and source of organic matter based on depositional history. The term source rock refers to an organic-rich fine-grained sedimentary rock which can produce hydrocarbons due to thermal maturation (Rezaee, 2002). Hydrocarbon generation potential of a source rock is a calculated volume that utilizes multiple rock properties such as source rock volume, total organic carbon, kerogen types and pyrolysis (Espitalie et al., 1985).

1.2   Statement of the Problem

Petroleum geochemistry of different basins found with good depositional systems and generative potentiality of source rocks has not been studied quantitatively and qualitatively. This study intends to investigate two aspects regarding petroleum potentiality in Anza graben. The first aspect is to determine the generation and expulsion of hydrocarbon with the considerable depths of oil or gas windows. The second aspect is to establish whether well correlation models could provide a descriptive model that can be used for further and future researches.

1.3   Main Objective

The main objective of the project was to determine the hydrocarbon potentiality of drilled wells in Anza basin using both petrographical and geochemical analysis of source rocks. It involved determining the quantity, quality, and thermal maturity of the source rocks in order to assess hydrocarbon occurrence, their commercial viability and develop a predictive model for Anza basin.

1.4   Specific Objectives

1) To study the petrographical logs of the wells and determine the shale volume ratio for hydrocarbon generation potential.
2) To determine the geochemistry of the source rock samples from the drilled wells in order to establish their organic richness, maturity and kerogen types and their biomarker characterization to establish the hydrocarbon structures in the source rock.
3) To correlate the source rocks of the drilled wells using geochemical data and petrographical data (gamma rays data) and use this information to build a predictive model to guide future exploration.

1.5   Justification

East African countries, and particularly Kenya, have experienced escalated oil exploration activities that have led to discovery of economical mineable oil deposits in the Paleocene rift basin. Different geophysical and geochemical techniques have been employed with an aim of delineating and distinguishing hydrocarbon potential areas. Petroleum geochemistry provided the much-needed information on generation and expulsion of hydrocarbon. Geochemical evaluation of the wells under study, therefore, was used to determine whether Anza basin region can become part of Kenya's oil or gas producing zones in the near future. Kenya's neighbouring country, South Sudan has been producing its oil from near-similar geological rock formations and age at the Abu Gabra rifts (Schull, 1988) which prompted further research to be undertaken in Anza graben. Thus,

the paucity of the detailed geological, geochemical and geophysical data in the Anza basin in respect to petroleum prospectivity has necessitated this present research study. With the help of well-calculated and reliable data, a well correlation model was developed. This acted as predictive model for further exploration in the region; hence enhances knowledge to this little known basin in the exploration of oil and gas rationale.

1.6   Significance

The significance of this study was to unravel the mysteries of occurrence of oil or gas in this part of the Anza graben. The discovering of petroleum will increase socio-economic activities and development of the local community, county government and the country at large. Petroleum exploration and exploitation is a capital-intensive venture, that, demands a more sensitive and cautionary evaluation of every stage of exploratory and appraisal drilling and development. Further, geochemical evaluation can provide tangible knowledge for policy-decision making on the target field.

With the latest discovery and development of oil exploration in Kenya, it is important to provide dependable and detailed exploratory data from these virgin unexplored regions. Kenya's Vision 2030 is an ambitious approach to enhance development towards a middle-income economy that requires reliable energy sources.

1.7   Exploration history

In the mid-1970s, several oil companies started an intense exploration across Anza basin, both at the southern and northern part. The increased search for oil and gas is attributed to high (rising) oil prices in various markets across the world. The Texas Pacific, among other companies, drilled the Hargaso well while Chevron-Esso drilled two wells in South Anza basin, namely, Anza and Bahati wells with an objective of determining the Paleocene and Cretaceous rock properties. Results of the analyses were however disappointing due to the absence of well-defined source and reservoir rocks in the penetrated formations. As a result, exploration activities in Anza basin were temporarily stopped; but has recently picked up.

In 1987, TOTAL, AMOCO and Walter International drilled eight wells within the extensional North Anza Basin and South Anza Basin. Their objectives were to evaluate the lithostratigraphic arrangements of Late Jurassic through Paleocene fluvial and lacustrine sediments deposited within the rift basin environment. The Chevron's commercially extractable oil quantities of Abu Gabra Rift Basin in South Sudan, whose Lower Cretaceous sandstones formation sequences are similar to those of Anza Basin believed to be a continuation of the extensional intracontinental rifting, are said to have been deposited in the rift basins (Rop, 2013; Morley, 1999).

From biostratigraphic studies, these wells may not have been drilled to test Neocomian-Lower Albian sediments which comprise source rocks, reservoir rocks and traps/seals within the South Sudan rift basin (Atlas, 1990). Therefore, the potential reservoirs are untested but may exist in the Lower Cretaceous sections of the North Anza basin and its extensional sub-basins.

1.8   Literature Review and Geological Setting

Hydrocarbon exploration utilizes several tools both geophysical and geochemical in order to ascertain the occurrence of potential sites for development of oil and/or gas, or, abandoned wells' data. Rop (2013) opined that the geophysical methods used in exploration of hydrocarbons with the help of both gravity and seismic data are common and effective in delineating prospective subsurface structures. Petrographical study helps to categorically map well data along and around well bores. It is scaled down by well siting to areas with deep sedimentary units containing interlayered shales, compact sandstones, more porous, less compact reservoir quality sandstones and possible carbonate rocks with radioactive elements (Rop, 2003).

1.8.1 Petrographical and Gamma Ray Log Studies

Petrographical methods are very useful for subsurface evaluation for the hydrocarbon bearing zone, calculation of estimates of hydrocarbon volume (Asquith and Krygowski, 2004), and net gross of hydrocarbon using well-log data such as radioactivity (gamma rays), resistivity (self-potential), neutron porosity, etc. Gamma ray logs utilize the naturally occurring radioactive elements such as uranium, thorium and potassium (Serra et al., 1980). Potassium is the most abundant element in metamorphic and sedimentary rocks, especially in clay minerals compared to

thorium and uranium, which are dominant in volcanic rocks. Organic rich shales emit high radioactivity.

Therefore, petrographical studies could be helpful as a tool to determine and measure the shale volume along the well section. In shale, uranium suggests presence of a source rock, while thorium indicates the amount of degree of shalyness and potassium indicates clay type and mica. Gamma rays passing rocks are slowed and subsequently absorbed at a rate that depends on the formation density. Less dense formations, with the same quantities of radioactive materials per unit volume, exhibit more radioactivity than dense formations as illustrated in Figure 1 below.
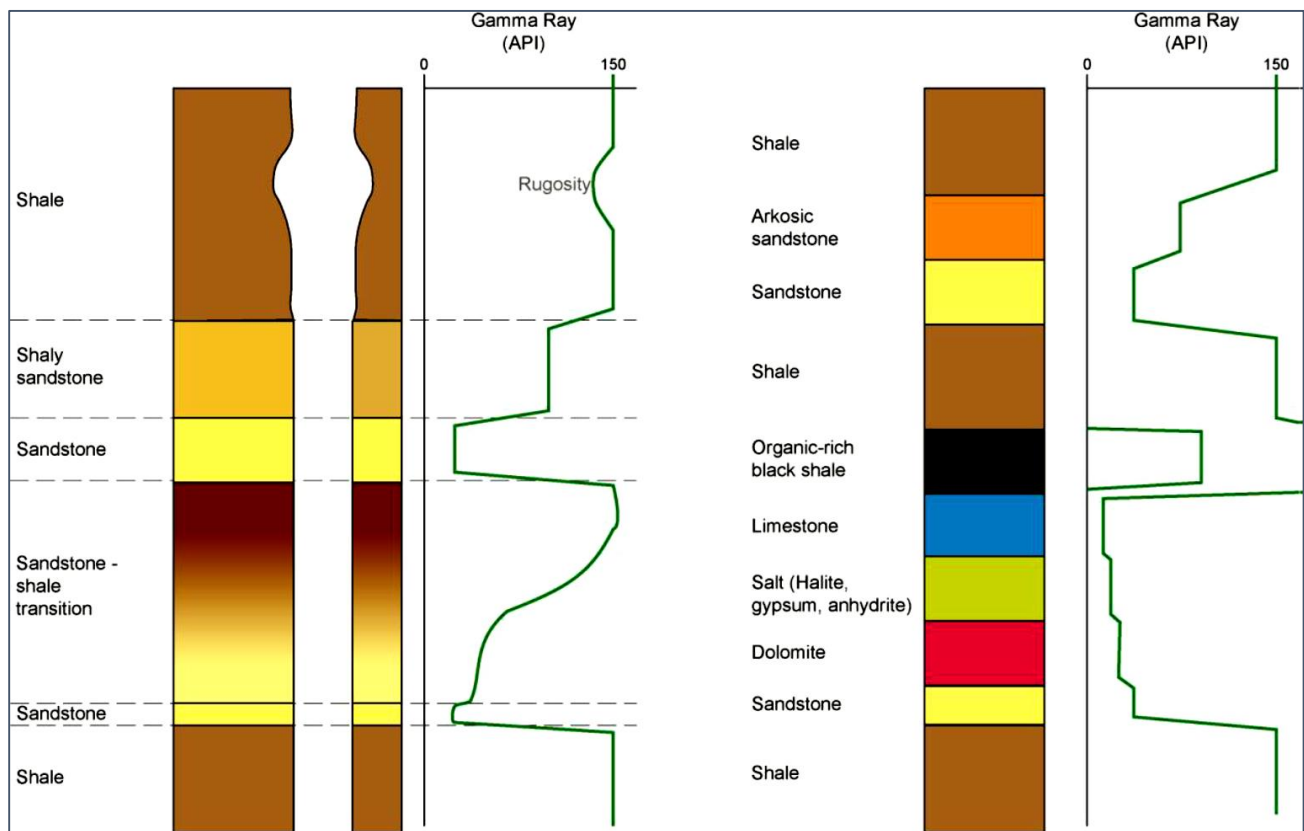
Figure 1: Relationship of Gamma ray log, lithological zoning and their interpretations.

The gamma ray log measures the natural radioactivity emanating from a formation split into contributions (Lyaka and Mulibo, 2018) from each of the major radio-isotopic sources such as potassium (K 40), uranium and thorium series. Analysis of the sources of the natural gamma radiation give lithology, depositional environments, shale types, identification of organic content,

geochemical logging, rock's diagenetic history and fracture identification analysis, based on the ratios of the main radioactive sources. Oxygenated environments are not conducive for the upkeep of natural material, while reducing environments not only favour the preservation of organic material, however also aid the conversion of the organic cloth to hydrocarbons. The source organic material for hydrocarbons in carbonate rocks is regularly algal materials, which have been integrated in the rocks deposited in a sub-sea (reducing) environment and include a vast quantity of uranium.

In clay-bearing carbonate rocks, high total gamma readings are no longer only associated to the clay fraction, but are additionally due to the presence of uranium-radium series isotopes of natural origin. High total gamma ray readings are consequently not reliable warning signs of the shalyness of a carbonate. However, if the spectral gamma ray log indicates the presence of K and Th collectively with the U, it does point out that the K and Th contributions are associated with the clay content of the shaly carbonate. Those of the U is associated with some organic source which used to be deposited in a decreasing environment that favours the conservation of organic material (Table 1-1). Similarly, excessive K and Th values collectively with low U indicate a shaly carbonate, deposited in an oxidizing surroundings which is not a favourable environment for the conservation of organic material.

Table 1-1: Natural radioactive elements and their geological interpretation using gamma ray tools.

K	Th	U	Interpretation
Low	Low	Low	Pure carbonate, no organic matter or oxidizing environment.
Low	Low	High	Pure carbonate, organic matter, reducing environment.
Low	High	Low	Not a carbonate, or shaly carbonate with rarer low K high Th clay minerals, no organic matter or oxidizing environment.
Low	High	High	Not a carbonate or shaly carbonate with rarer low K high Th clay minerals, organic matter, reducing environment.
High	Low	Low	Glauconite carbonate, no organic matter or oxidizing environment. Also consider K-bearing evaporites.
High	Low	High	Algal carbonate, or glauconite present, organic matter, reducing environment.
High	High	Low	Shaly carbonate, no organic matter or oxidizing environment.
High	High	High	Shaly carbonate, organic matter, reducing environment.
Note: Stylolites can locally concentrate U, clays and organic matter.			

Gamma Ray (GR) log measurements are calibrated to American Petroleum Institute (API) units. The total amount of gamma rays measured in the borehole is proportional to the concentration of radioactive elements in the formation (Lyaka and Mulibo, 2018). Shales, and mudstone, typically contain a larger concentration of radioactive elements than any other sedimentary rock. Consequently, shales will have high GR measurements of 80 API units, and above. A clean sandstone, limestone or dolomite will typically contain low to negligible concentrations of radioactive elements. Organic matter (OM) is excellent at concentrating uranium. If OM is deposited in a reducing environment, it can be preserved and thermally converted to hydrocarbons. Hence, there is a symbiotic relationship between the amount of uranium and hydrocarbon content as shown in Table 1:1 above. High potassium (K) in source rocks is characterized as having good ratio of shale deposits for hydrocarbon content. However, correction using the bit size and caliper tool should be considered to remove erroneous computation where there are bad-hole scenario such as swelling or collapse on the drill hole section as shown in Figure 2 below. For which zonation and analysis was used to map the potentially shale rich sections.

Porosity can range from 0 to 1 (0 to 100 % - *porosity can be stated as a percentage*). Well-consolidated sandstones can have a porosity of 0.1 – 0.2 (10 – 20 %), and unconsolidated sands may have a porosity greater than 0.3 (30 %). The maximum theoretical porosity, for material made of perfectly spherical beads, is 0.47 (47 %). A shale can have porosity greater than 0.4 (40 %), however, individual pores are so small that they do not allow fluid movement. Porosity is controlled by grain (or crystal) size, shape and packing. If the pore space exists only between matrix material (e.g., sand grains) the porosity is called *intergranular porosity*. *Primary porosity* was formed at time of sediment deposition, or formation. If porosity has been created, post-deposition by processes such as diagenesis (for instance, dissolution) or tectonics (such as fracturing), then the porosity is referred to as *secondary porosity*. *Total porosity* (Øt) refers to the total pore space, whether it is connected or isolated. Changes in grain size and the presence of clay minerals may result in small pore throats, so that the total pore space is not interconnected. *Effective porosity* (Øe) is the fractional volume of connected pore space, excluding clay and capillary bound water. It is the effective porosity, which contains moveable, or "free", fluids.

Each logging tool provide parameters in relation to the specific volume of rock against the depth under investigation. However, log measurements can be influenced by the competence of the well. Some of the factors that influence log measurement quality include bad-hole conditions such as shale sloughing and enlarged borehole (cave in or collapse), as well as mudcake and invasion. Borehole rugosity provides an understanding of how the drilled borehole diameter differs from the size of the drill bit. If the caliper is on gauge then the borehole diameter is comparable to the size of the drill bit. The caliper log may show the borehole diameter is larger than bit size indicating cave in in weak unconsolidated sands and brittle shale (Figure 2), or dissolved salt carbonate formations by fresh drilling mud. If the caliper shows a smaller borehole diameter than the bit size this could be the result of pronounced mudcake development on highly porous and permeable formations, or of hole sloughing caused by swollen shales (Figure 2).
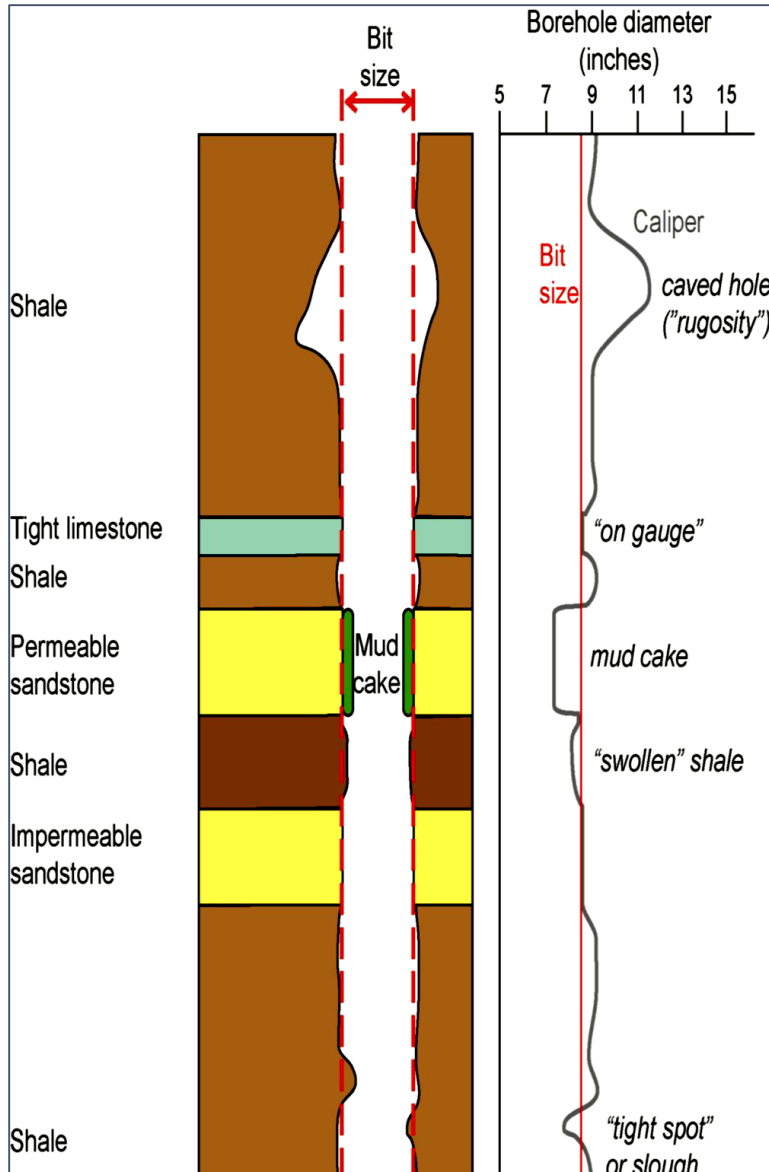
Figure 2: Correction and collation of data logging tools.

If not identified and corrected, the presence of caving will lead to an underestimation of bulk density or an overestimation of sonic (acoustic) travel time – both of which might lead to an overestimation of formation porosity.

1.8.2 Petroleum Geochemistry and Source Rocks Potential

Petroleum geochemistry is a vital device for lowering uncertainty inherent in exploration and production of hydrocarbon viable basins (Allan, 1990). It is used as the imperative science for understanding the properties of source rock indexed as volume and maturity of organic matter,

producible and non-producible, oil or gas migration pathways and suggestive sustainable production of resultant hydrocarbon (Hunt, 1979). Over time, the reliance on petroleum geochemistry has been steadily appreciated and has resulted in improved confidence on areas mapped for further exploration. The mechanisms was used to explain how oil and gas generated from organic remains portrayed certain paleo-parameters of a particular basin (Tissot, 1984) as result of sediments provenance, burial history, tectonics forces and other geologic processes that occurred in the basin (McCarthy, 2011).

To exhaustively determine the hydrocarbon potentiality of Anza basin, integrated study of both petrographical and geochemical studies of source rock samples (Togunwa et al., 2015) guarantees better understanding on formation, migration and possible accumulation of the hydrocarbon. Anza region is generally a product of rifting facies (Guihe, 2010) of basin development owing to it being an extension arm of the notable East African Rift System and the series of lakes in the EARS containing mineable salt deposits (Rop, 2013). Most of the probable reserves of recoverable hydrocarbons manifest in rifts with post-rift (Dindi, 1994) in the Kaisut and Ndovu sag sub-basins and in these sub-basins that bear marine sediments assemblages (Chand et al., 2012). The geological set up of the Anza basin include Precambrian basement rocks with Tertiary volcanics that have blanketed sedimentary sub-basins regarded as possible basins for exploration of oil and gas (Rop and Namwiba, 2018). Source rock is one of the four petroleum systems that is used as primary indicator for tracing any possible occurrence of hydrocarbon. It is the fine-grained sedimentary facies (Tissot, 1974) that can produce hydrocarbon. Therefore, in order to unravel the potentiality of hydrocarbon it is paramount to assess the source rocks using geochemical parameters (Gretskaya et al., 2008) universally acknowledged for petroleum discoveries. These geochemical analyses includes pyrolysis as total organic carbon (TOC %), generating source potential (S2), Production Index (PI), Oxygen Index (OI), Hydrogen Index (HI) and T-max (Tissot, 1984). This makes it possible to define oil source sequences and estimate quantitatively their hydrocarbon potentiality. Lithostratigraphic arrangement of rocks in this basin gives a predictive advantage of good Cretaceous source rocks (Abubakr et al., 2014) which is an extension of East African Rift System similar to the South Sudan arm of the rift basin. According to Rop (2013), the Cretaceous sedimentary sequences of the Anza Basin and those of the Abu Gabra (South Sudan) and Sharaf Formations (Sudan), both northwest of the Anza basin extension have similar counterparts in the intervening areas of the northern Kenya.

1.8.3 Recognition of Potential Source Rocks and Rock-Eval Pyrolysis

Total Organic Carbon (TOC) measurements provided evidence about the organic richness and spatial distribution (Bolandi et al., 2017) of organic components in the source rock that were vital for evaluating petroleum characterization (Rop, 2015). It was traditionally estimated by measuring cores, cuttings or sidewall cores (Barker, 1999a) in geochemistry laboratory with source rock evaluation instruments such as LECO and Rock-Eval apparatus. Resulting data should be integrated to the well log data to show the structural characteristics of a source rock bed otherwise it was unreliable (Bolandi et al., 2017). Continuous high resolution well logging (Bolandi et al., 2015) information from detailed petrological characteristics of core samples and side wall cuttings was incorporated to improve the data output for analysis (Sun, 2013).

Rock-Eval Pyrolysis technique was undertaken to establish the hydrocarbon originality at the selected stratigraphic signatures (Abubakr et al., 2014), kerogen type and thermal maturity of organic matter. This was used as a post-determination mechanism on good TOC percentages (Rop et al., 2015), such as > 0.5% TOC (Sharaf, 2003). In general, the suggestions for rating was developed with the aid of Peters (Peters, 1986a) whereby TOC values higher than 0.5% for shales and 0.3% for carbonates were regarded appropriate to progress for Rock-Eval pyrolysis to determine the stage of thermal maturity of possible source rocks, migrated hydrocarbons and *in situ* generated hydrocarbons existing in sedimentary facies. Pyrolysis process was performed as per (Espitalie et al., 1985) that involved programmed heating of source rock in order to break its complex composition into fragments in an inert atmosphere (Peters, 1986b). Hydrocarbon typing using pyrolysis (Hunt, 1979) is supported by the Visual Kerogen (Togunwa et al., 2015) descriptions completed at selected depths. The resultant parameters used in Rock-Eval analyses are expressed in mg/g of rock as follows: S1, S2, S3 and Tmax (Abubakr et al., 2014). The S1 is used to determine the amount of free (extractable) oil and/ or gas, S2 is a measure of converted hydrocarbon (Barker, 1999b) from kerogen through pyrolysis process, S3 represents amount of oxygen in the Kerogen, while Tmax is the temperature peak at which the maximum rate of thermal expulsion of hydrocarbon is recorded (Shalaby et al., 2011). In addition, petroleum indices, that is, Oxygen Index (OI) and Hydrogen Index (HI) explain the hydrocarbon maturation path (Mukhopadhyay et al., 1995, Nyantakyi, 2014).

1.8.4 Gas Chromatography-Mass Spectrometry and Basin Modeling

Gas Chromatography-Mass Spectrometry are predominantly referred by their abbreviated acronyms as GC-MS, respectively. The first component GC helps to detect, analyze and characterize the aromatic structure of hydrocarbon present in the source rocks. The second component, MS, measures (quantify) through electron ion count technique the amount of particular petroleum structure identified.

Basin modeling has been widely used to further demonstrate in 1D, 2D or 3D the nature and characteristics of the basin, especially with petroliferous basins (Abubakr et al., 2014). A good basin modelling system requires source rock kinetics to be able to reconstruct the hydrocarbon generation history (Chen et al., 2017). TOC and pyrolysis methods are used to provide tangible information of the basin that is then integrated into a model that help to predict other geological formations of similar or near similar characterization. Basin modeling is utilized to depict the sedimentation sequence of the basin based on stratigraphic geomorphology (Rop, 2003; Bloom, 2002) of the basin, geothermal history of the basin to ascertain the maturity layout of the source rocks (Hantschel and Kauerauf, 2009a) and the probable upward movement and entrapment of hydrocarbon in the basin.

In order to minimize investment risk in oil and gas exploration, a conscious study was done to ascertain the presence, kerogen types, and volumes of hydrocarbons in a prospective structure before drilling. Basin modeling helps in solving multifaceted problem of a petroliferous system. This system embodies the geologic factors and conditions that allowed for favourable accumulation of hydrocarbon.

Petroleum system modeling is an intrinsic process that encompass the following data sets: sediment facies, kinetics and migration channels (Mubarak et al., 2009). These complex sub-surface processes may be examined at staged levels, despite the inherent difficulty of combining heterogeneous data sets alongside their spatial dimensionality. One dimensional modeling (1D) is the simplest and is used to examine the depositional history at a single data viewing location. Two-dimensional modeling (2D), either in map or in cross section, can help visualize the processes of generation, migration and entrapment of hydrocarbon along a cross section. Three-dimensional

modeling (3D) utilizes the four petroleum systems that include the reservoir and extent of the basin (Mubarak et al., 2009) and incorporate all the dimensions in relationship with time.

The main concept in this research is to encompass geochemical models and construct petroleum generation (Welte et al., 2012) and expulsion model for the evaluation of source rock maturity. This encompasses catagenesis processes, the amount and OM attributes which are well defined as rock facies and organo-facies (Hantschel and Kauerauf, 2009a). A correlation model comprising of petrographical and geochemical logs (Schmoker, 1981) were utilized to create the predictive model.

1.8.5 Geological setting of the Anza basin study area

Anza basin has geological formations from Early Cretaceous till Neogene end (Guihe, 2010). The base of the basin is Precambrian crystalline basement with voluminous Tertiary volcanic lavas overlying thick sedimentary rocks (Rop and Namwiba, 2018). Strata deposited in the Anza basin are Middle to Upper Jurassic, Cretaceous, Paleocene and Quaternary in origin. Few drilled wells have provided distinct evidence of Lower Cretaceous, therefore throwing in a puzzle as to the age of the formation of the Anza basin (Atlas, 1990).

Sediments provenance (BEICIP, 1982) is described to contain fluvial and delta-plain facies developed in Palaeogene and lacustrine sediments source by shallow-half deep lake in northern part of Anza basin near Sirius-1(Rop, 2003). The sedimentary thickness of the basin is about 2,000m to 11,000m Anza basin is a rift basin characterized by the Cretaceous strata that was uplifted. Two other rifting system happened at the end of the Paleogene and Neogene (Guihe, 2010). The basin had an origin in rifting dominated by the Lagh Boghal fault (Figure 3). It is still uncertain as to whether the Lower Cretaceous rocks were deposited during active rifting, or, they were simultaneously down-faulted into the basin by younger rifting in the late Cretaceous. Rifting began in the Lower Cretaceous but became very widespread in the Upper Cretaceous and Paleocene (Bosworth, 1992). Winn et al. (1993) stated that rifting began in the Late Cretaceous and actively continued up to the Paleocene time (Morley, 1999).

The Anza basin extends northwest from its boundary with the Lamu basin, up to where it is intersected by the Eastern segment of the EARS (NOCK, 1990). The Lagh Boghal fault act as the eastern boundary and is a major fault that is down-thrown to the western side. The Western

boundary is on the stable basement platform. The Southern boundary of the Anza basin is a flexure zone with little faulting but in the northern boundary it is the major Chalbi fault. South Anza basin merges into the Lamu basin where the sedimentary thickness increases rapidly up to over 10,000m thick (Rop, 2003). Anza basin is a failed arm (Greene et al., 1991) that projected northward.

Anza basin is dominated by Proterozoic sedimentary and volcanic rocks, folded and metamorphosed during the late Proterozoic Cambrian Mozambiquan Orogeny. The lithology in this part of northern Kenya is altered psammite of the Kotim Gneisses (Key, 1987). At an early stage in the orogeny a regional, pro-grade granulite facies tectonic-thermal event (Samburuan) converted the psammites (Amoco, 2010) and related sedimentary rocks to quartzo-feldspathic and quartz-bearing gneisses (Winn, 1993), respectively, and produced local autochthonous granite melts. Following erosion, a succeeding major tectonic episode (Sabachian) produced recumbent, tight folds together with horizontal tectonic transport of crustal slices. The Korr complex was emplaced in the south-east and preserves a lower grade assemblage (Key, 1987) of sedimentary and igneous rocks including mafic lavas, peridotite, early granite, sheets and marbles.

The rock formations at the south-western part of Anza basin refolded in NNW- trending, upright folds plunging SSE and simultaneous cut by a parallel shears. During this (Baragoian) event the Korr complex was also cut by the shear zones. The major NNE-trending shear in the extreme south-west is the northern extremity of a major shear zone (Barsaloian) 180 km long. Minor intrusives mainly felsic veins accompanied these waning phases of the orogeny (Key, 1987). No significant metal mineralization is present in the Precambrian basement metamorphosed rocks (Figure 3).
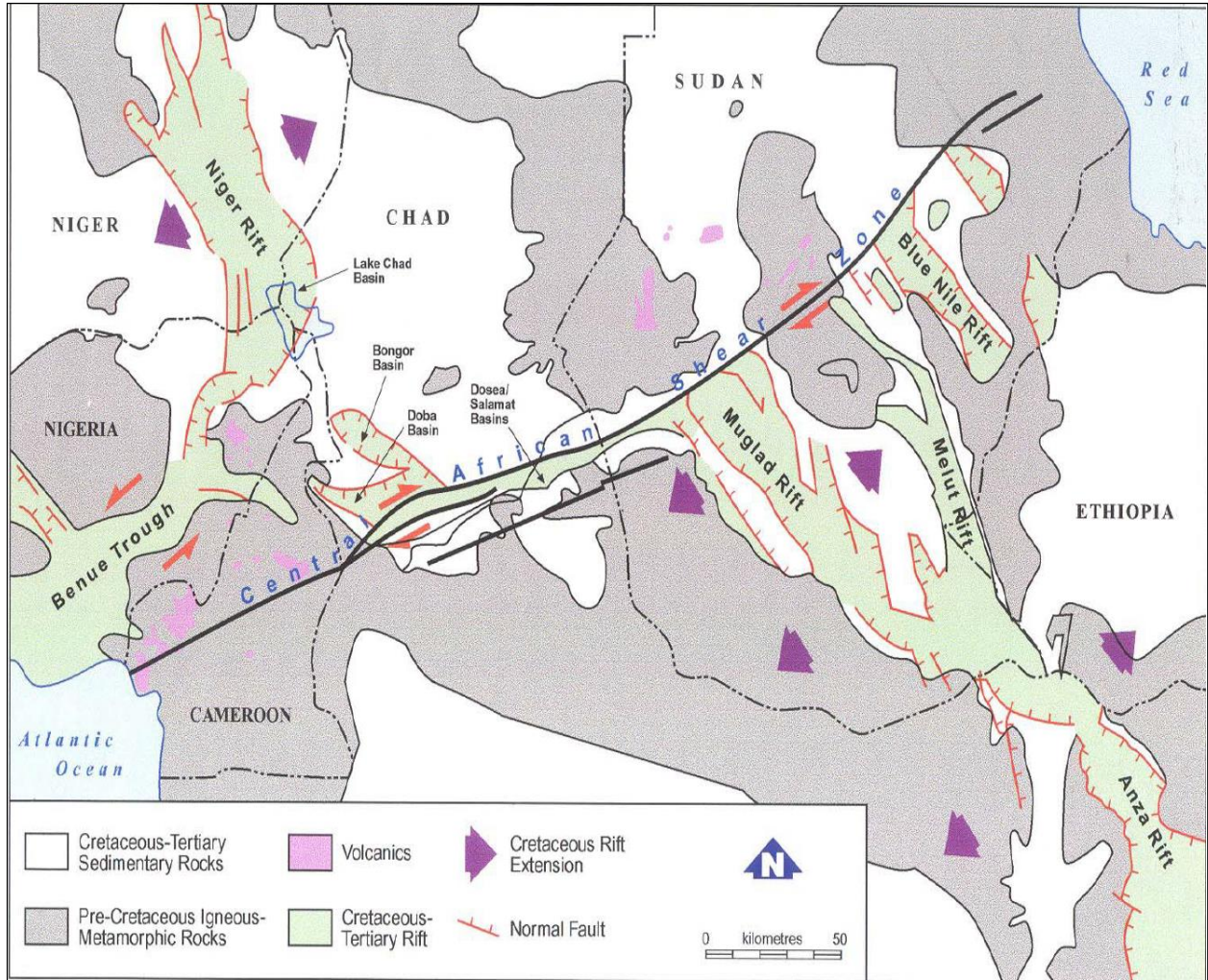
Figure 3: Regional geological map showing the geological ages of rocks in petroleum fields.

Post-Cambrian uplift and/or erosion produced a planar land surface upon which the coarse clastic sediments of the Maikona Formation was deposited. The sedimentation process in the NW-trending graben across the north-east of the area was as a result of streams from both the south-west and north-east parts of Anza graben. Present information is insufficient to state the exact age or maximum thickness of these sedimentary rocks. Lithological characterization of this basin is similar to the Cretaceous Turkana grits west of Lake Turkana (Rop, 2013; Rop and Partwardhan, 2013). They are economically important as a major aquifer and as well as potential hosts to hydrocarbons exploration.

Further erosion and regional warping produced the regional sub-Miocene planar surface, which defined the NW-trending Chalbi Basin. Fossiliferous lacustrine beds were deposited in this Basin during the Miocene (the Karole formation) on top of the Maikona formation (Key, 1987).

1.8.6 Petroleum Systems of the Anza Basin

Anza basin can be divided into three sub-basins that include North Anza Basin, North Anza Extension Basin and South Anza Basin (Figures 4 and 7). North Anza Basin is further divided into smaller sub-basins by Matasade High. The North Anza Basin and North Anza Extension have thickness of sediments that vary between 2,000 m to 8,000 m depth (Al Consult, 1987). Most of these sediments were deposited within continental, fluvial and lacustrine environments. Marine facies encroachment are often occasionally present, which indicate palaeoenvironment geology. The paleoclimatic conditions (Rop, 2013) with humid climate and heavy precipitations conducive for luxuriant thick vegetation during Cenomanian period; thus accompanied fluvial sedimentation of that period in the Anza basin under study.

1.9 Hydrocarbon Potential Characteristics

1.9.1 Source Rocks

Petroleum source rocks are fine grained (clay-rich) siliciclastic rocks (such as mudstones, shales) or dark coloured carbonate rocks (such as limestone, marlstones), that may have produced (thermally expelled) hydrocarbons (North, 1985). The source rocks of Upper Cretaceous are mainly distributed in Chalbi-Kaisut sub-basin (Figure 4) covering a total area of 7,000 square kilometers (Chalbi sub-basin: 2,700 km^2 and Kaisut sub-basin: 4,000 km^2) (Guihe, 2010). The thickness of Upper Cretaceous shale is about 1400m to 2800m (4593 – 9186ft) with Kaisut area described by less than 800m (2625ft) (Guihe, 2010). Throughout Anza basin, Neocomian to Lower Albian shales are the dominant source rocks. High heat flow was a significant geothermal that contributed favorably to the maturation of kerogen through rifting in the East African Rift System. Similar types of source rocks are an axiom within Lower Paleocene section where lacustrine source rocks have been identified (Atlas, 1990). However, the localities embodied with source rocks occur in the Upper Cretaceous stratigraphic segment in the Chalbi Basin in which higher gamma ray peaks (>80API) suggest the availability of radioactive elements with OM (shaly source rocks) which raises chance for conducive geothermal sufficient for HC generation (Rop, 2013).
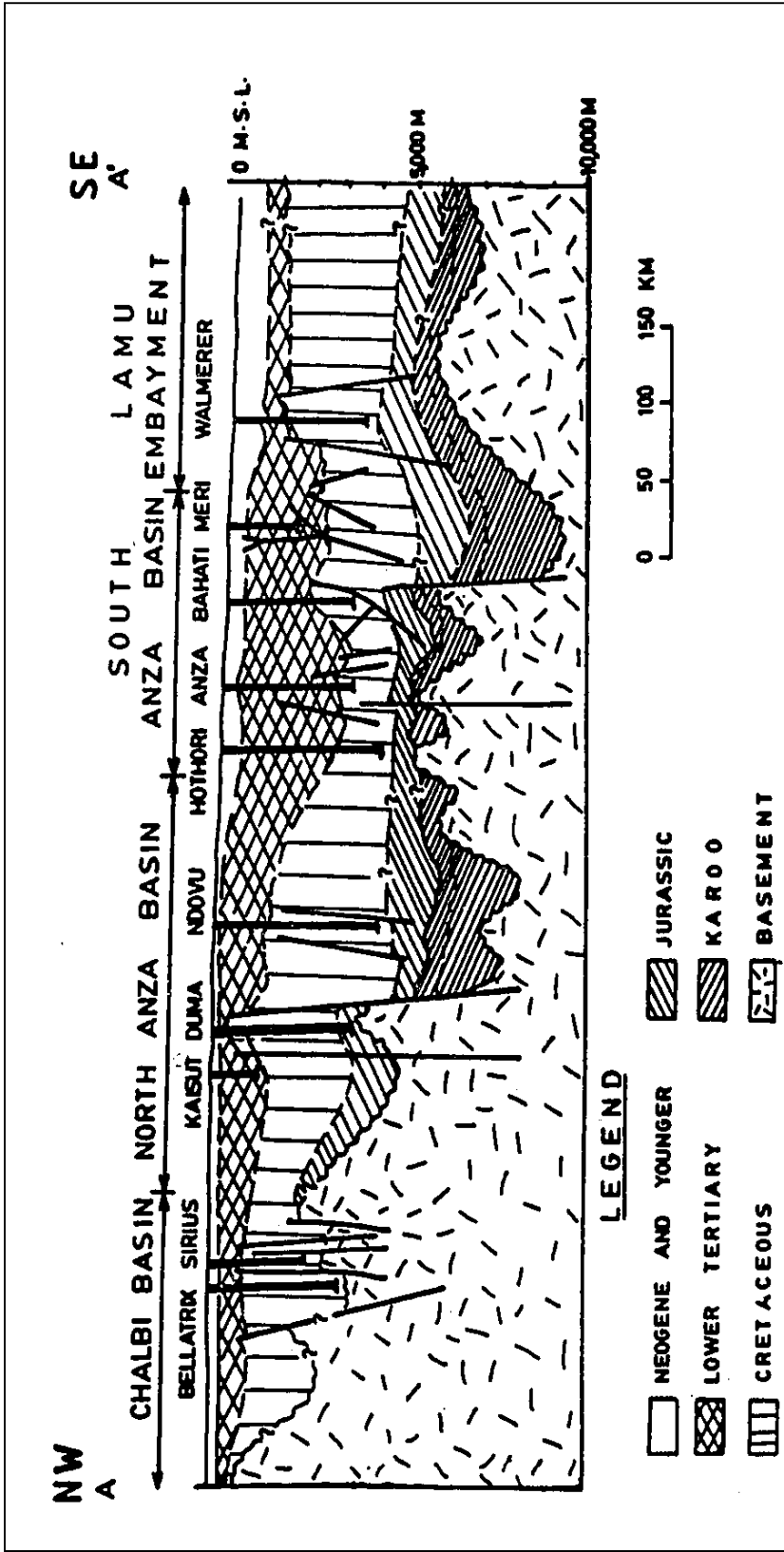
Figure 4: General geologic cross-section through Anza-Lamu basins. Source: NOCK (1990)

1.9.2 Reservoir Rocks

Both northern sub-basins (North Anza Basin and North Anza Extension Basin) have reservoir units that comprise continental fluvial and lacustrine sandstones of supposed Cretaceous to Paleocene geological time scale (Amoco, 2010). However, Neocomian Nubian continental sandstones are probable reservoir rocks that occur in the North Anza Extension Basin (Atlas, 1990).

1.9.3 Traps or Seals

Fault traps (structural traps) which are probably of Upper Cretaceous through Miocene section have been observed on seismic data within North Anza Extension. According to Rop (2013) the Abu Garb Basin rift sedimentation of South Sudan and those of the Anza Basin belonged to Late Jurassic to Cretaceous with thick sedimentary facies occurring in both sections.

Chevron Company that drilled several wells in South Sudan inspired enhanced prospect analogs in the North Anza and North Anza Extension Basins. However, these wells were not deep enough to penetrate the Neocomian to Lower Albian segments that comprised of the source rocks and reservoir rocks localities in the Unity field and Heglig field both of South Sudan (Guihe, 2010). Surface lithological characteristics (Rop, 2013) suggest presence of ambiguity in paleao-deposition which occurred during Cretaceous (or older times) required subsurface geophysical exploration to unearth the sediment facies (profiles) and provenances.

Jurassic evaporites as well as interbedded shales and volcanic of the Cretaceous provide effective seals for the reservoirs in these areas (Atlas, 1990).

1.10 Description of the wells

1.10.1 Ndovu-1 well

1.10.1.1 Location and Geological setting

The well is located North Anza Basin, Block 9 and was drilled by TEPMA operator for the TOTAL-Marathon –Mobil association. It lies in Yamicha Sub-basin. This well was drilled to a total depth (TD) of 4267m (13999ft) and was spudded on 23rd Aug 1987. Ndovu-1 was drilled to evaluate the Paleocene and Mesozoic section in the unexplored sedimentary basin (Atlas, 1990).

Ndovu-1 well was drilled in Yamicha Sub-basin which is in the Anza Rift of Cretaceous age. Based on the Matasada and Mandera Basin outcrops (Key, 1987), it was assumed that Jurassic marine deposits, possibly evaporates, could be present, overlain by lacustrine sediments of Cretaceous and Paleocene age, encompassing alluvial fans and turbidites (Source NOCK unpublished reports).

The present work was informed by commercial findings of oil deposits in similar conditions in Abu Gabra, Southern Sudan and the reported oil and gas indications in the Chalbi basin's Upper and Lower Cretaceous stratigraphic drilled wells (Sirius-1 and Bellatrix-1) although the Chalbi-3 well had gas shows indications only (Rop, 2013). TOTAL endeavoured to find equivalent non-marine source and reservoir rocks in Yamicha Sub-basin.

Ndovu-1 well is located in Block 9 limited by two almost parallel NW-SE faults, the Lagh Boghal faults to the north and the south-west fault, which limit the Yamicha Sub-basin (NOCK, 1987). Yamicha Sub-basin is believed to have been active during the late part of the Jurassic, the Cretaceous and Paleocene.

1.10.2 Sirius-1 well

1.10.2.1 Location and Geological setting

Sirius-1 well is located in the Chalbi sub-basin in the Anza graben of the North Anza basin. Studies done by AMOCO drilling company showed that Sirius-1 well penetrated the deep-end sedimentary segment encountered of Chalbi basin. The sedimentation in the Chalbi basin was guided by the intrabasinal and marginal faults (Rop, 2013). This was also encountered even at the basement whereby source rocks occur from 1500-1800m and 2300-2390m depths. The average porosity of the upper locality of source rock is 27% whereas lower section span from 10-15%. The OM in the sediments (with TOC > 5%) underwent necessary conversion under conducive environment, that included burial and good geothermal gradient (evidenced by numerous igneous intrusive activities), to become hydrocarbons potential area. The segment with reported oil and gas in the Sirius-1 well comprised of reservoir rocks with good average porosity (30%). However, previous work by Winn et al. (1993) when considering the subsurface formations and sedimentary

stratigraphic localities opined that petroleum system occurred in the study area, including the Sirius-1 well.

Sirius-1 well is thus located on a listric fault block within a Paleocene-Mesozoic rift basin. Rifting sequences begun during the Mesozoic, with later reactivation during the Paleocene. Fluvial and deltaic sands, located and overlying the Sirius extensional fault block, created a potential structural trap for any hydrocarbon migrating up-dip from fluvial-lacustrine source bed (Rop, 1995).

This geological setting (as shown in stratigraphic column, Figure 6) was believed to be similar to the Abu Gabra Rift Basin located Southern Sudan, whereby Chevron (oil producing company) are producing oil from Lower Cretaceous sandstones. In the Abu Gabra rift, an extension of Muglad basin, this is a probable reserve of approximately 300 million barrels of hydrocarbons (Mohamed, 2002), shown on Figure 5 below.

Figure 5: Abu Grabra basin (an extension of Muglad basin) in South Sudan (Modified from **(Mohamed, 2002)**).

Quaternary alluvial/dune sands and Calcrete Limestone

Miocene – Pliocene volcanics constituting five separate lava flows. The tops of the individual flows were weathered contained chert and loose sands. The flow texture and composition were uniformly black, grey to dark grey, very hard, aphanitic brittle, basaltic flows.

Miocene-Lower Tertiary (Maikona) sands and poorly consolidated sandstones with minor claystone horizons.

Lower Tertiary – Cretaceous sandstones with minor claystone/shale interbed. The Sandstones were predominantly medium to coarse grained and very loosely consolidated. The clays were usually light medium grey, soft, very plastic and amorphous. The shales were dark grey splintery, in part, fissile and firm with siltstone. The interbed Tertiary – Cretaceous boundary was a weathered zone which is apparently unconformity.

Upper cretaceous sandstone interbedded with claystone/clay and shale

Igneous extrusion body. The extrusion was black, dark grey to grey, mafic, aphanitic, magnetic basaltic flow. It was also locally quartz rich.

Sand/Sandstone/clay/claystone which become more shaly towards the bottom of the interval.

Gabbroic intrusion – dark green, black, spackled, aphanitic, blocky, hard and commonly very magnetic.

Lower cretaceous sediments comprising claystone-shale sequence with thin sandstone-interbeds.

Lower Cretaceous massive sandstones with thin very rare shale interbeds. The sandstone sequence had an excellent reservoir.

Lower Cretaceous – Jurassic? Dolomite and dolomitic limestone.

QUATERNARY

MIOCENE/PLIOCENE
1000'
(305m)

MIOCENE/LOWER / TERTIARY
2000'
(610m)

3000'
(915m)

LOWER TERTIARY/ CRETACEOUS
3860'
3870'
DST 5

UPPER CRETACEOUS
4000'
4210'
4977'
DST 4
4987'
DST 3
5446'
DST 2
5456'
5000'
(1525m)

6000'
(1830m)
6586'
6596'
DST 1

7000'
(2135m)

LOWER CRETACEOUS
3000'
(2440m)

Figure 6: Stratigraphic column of Sirius-1. Source: NOCK (1988)

1.10.3   Chalbi-3 Well

1.10.3.1 Location and Geological setting

The Chalbi-3 well is located in the Chalbi basin of northwestern Anza graben, Kenya. It is a Cretaceous-Paleocene age extension rift basin trending northwest- southeast direction. Sediments along this trend are primarily non-marine, and have been described as containing fluvial and lacustrine reservoir source and sealing lithologies (Rop, 1995).

The target objective of the Chalbi-3 well was to test Cretaceous age sediments for accumulations of trapped hydrocarbons. The stratigraphy of Chalbi-3 and sediment provenance was similar to those penetrated in Sirius-1 and Duma-1. However, a prognosis study illustrated that it was also characterized by Paleocene, Miocene sediments overlying fluvial-lacustrine Upper Cretaceous interbedded sandstones and shales.

The stratigraphy in the Chalbi-3 well consisted of 3643m (11952ft) of predominantly Paleocene-Cretaceous sandstones interbedded with thin intervals of siltstones, claystones and shales. The section was banded by five thin intrusive igneous intervals. Based on visual examination of the cuttings, the interval of the fine grain sediments, their organic richness and source potential appears to increase with depth. Visual porosity of the sandstones was varied but decreasing with depth.

The gas shows encountered in Chalbi-3 well were within the younger segment of the Upper Cretaceous (Rop, 2013) while both source rocks and reservoir rocks showing gas indications were found inside the Upper Cretaceous and Lower Cretaceous segments respectively. Chalbi-3 well was drilled in the northern area of the Chalbi Basin with locations of source rocks at depths ranging from 2300m to 3100m showing moderate gamma ray (from 60 API). The reservoir rocks are at shallow depths (1660-1700m and 1860-1960m) were characterized by reduced gamma ray (36-40 API).

1.10.4   Kaisut -1 well

1.10.4.1   Location and Geological setting

Kaisut-1 well was the third well drilled by TOTAL in block 9 after Ndovu-1 and Duma-1 in Yamicha basin and intermediate tilted blocks, respectively. The well was drilled into clastic sediment in Kaisut basin lying in the west part of the block, as shown on Figure 7 below. The well was drilled to total depth of 1450m (4757ft). The sediments encountered were mainly sandstones with thin alternatives of shales (Guihe, 2010). Kaisut-1 was drilled on an anticlinal structure to investigate the Cretaceous sandstones.

The Quaternary section penetrated by the Kaisut-1 well comprised mainly of sands with occasional stringers of sandstone (NOCK, 1990) from 200m to the surface. The sands are generally clear and transparent with traces of reddish-brown oxidation. Grains sizes range from fine to coarse with poor to moderate sorting. The grains are mostly angular with low sphericity. Traces of calcite, gypsum and anhydrite are present.

The Paleocene section is composed of alternating sands and thin beds of shale and clays at depths between 1450m and 200m. The sands are clear to translucent with reddish-brown oxidation staining in the upper parts of the section with greenish (chloritic) and pyritic sands in the lower parts (Guihe, 2010). Grain sizes are generally coarse to very coarse, sorting mostly good. These are loose sands, generally subangular to sub-rounded with low sphericity.

Sandstones stringers are more prevalent in the lower sections and are generally whitish with green staining (chlorite), medium grained, well sorted, friable and micaceous in part (NOCK, 1990). Clays are brown with grey, silty to sandy in part while shales are mostly greenish to grey, sub-fissile to blocky, micromicaceous, moderately firm. There are minor traces of lignite.
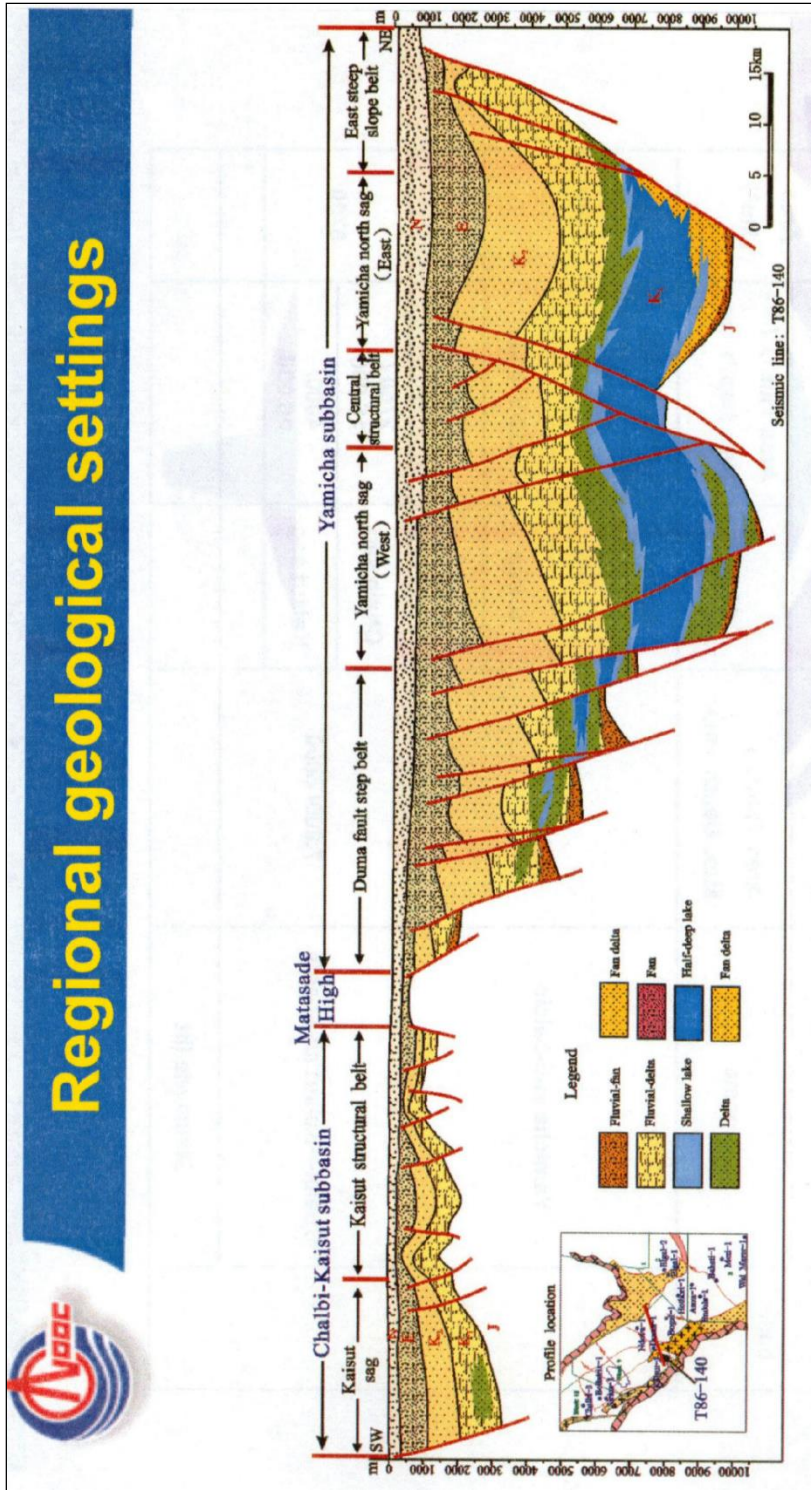
Figure 7: Regional geological cross-section setting of Chalbi-Kaisut sub-basin.   Courtesy of CNOOC Africa Ltd.

1.11 Summary of the literature review

The Anza basin has several sub-basins namely; Yamicha sub-basin in the Chalbi Basin of the North Anza Extension, Kaisut-sub-basin in the Kaisut Basin of the North Anza basin and the South Anza basin (Figure 7). The geological Time Scale of the target region for source rock evaluation lies between Paleocene–Cretaceous and predominantly sandstone sediments ranging from depth intervals of 2000m to 11000m. It has intervals of shale deposition that are potential catchment of source rocks for the HC exploration in the present study area.

The geological composition of the Anza graben has direct relationship with the regional crustal rift of the rift systems and an extension of the Muglad basin to Abu Gabbra of South Sudan. The Mesozoic to Cretaceous sediments in which Mesozoic source rocks were identified in South Sudan were encountered as prospective areas for hydrocarbons. Kenya's Anza graben requires further research studies in order to understand and unravel the sedimentation and depositional geo-dynamics conducive for petroleum systems exploration rationale.

CHAPTER TWO: STUDY AREA AND METHODS

2.1 Study Area Location and Climate

This study was undertaken in the Anza basin of Anza graben extensional rift. Due to limitation of time and finances, only four wells with high organic matter were selected for geochemical sampling within the Anza basin, which included: two (Chalbi-3 well and Sirius-1 well) in the North Anza Extension sub-basin (Chalbi Basin) and two (Kaisut-1 well and Ndovu-1 well) in the North Anza sub-basin (Figures 4, 5 and 7 of Chapter 1 above). The study area is located in a grossly underdeveloped semi- arid to arid climatic region in the northern part of Kenya, to the east of Lake Turkana and the extension arm of great East African Rift System. The Average temperatures during the day in the northern portion of study area extent from 20°C to 26°C. Occasionally, the temperature may rise to slightly above 30°C whereas the Chalbi desert and Hedad plains experience extremely high temperatures above 40°C (Key, 1987). Mt. Marsabit experience slightly lower temperature of between 17°C and 19°C. The study area receive bimodal rainfall pattern as follows: long rains fall during the months March and May while short rains is received in the months October and November. An average rainfall between 100mm to 150mm is received in the Chalbi desert. However, torrential rains is experienced at the range from 200mm to 300mm at the north-east, 300mm to 500mm (Key, 1987) in the south and along the north-west flanks of the present study area, whilst Mt. Marsabit slopes receive the highest amount of rainfall from 1000mm to 1200mm (Key, 1987).

2.1.1 Geological Setting of the Study Area

The Anza Basin (Figure 8) is one of the prospective sedimentary basins for hydrocarbons in the Kenya Rift systems. It trends in the northwest-southeast direction and extends towards Lake Turkana in the northern Kenya's extension arm of the East Africa Rift System (EARS) branch. Anza basin lies between latitudes 2°00'N and 3°30'N and longitudes 40°E and 36°E. It is sub-divided into three sub-basins, namely North Anza Extension, North and South Anza sub-basins (Figures 4, 5 and 7). North Anza and North Anza Extension contain sediments of variable thickness between 2,000 m to 8000 m (Atlas, 1990) and (Dindi, 1994). Most of these sediments were deposited within continental, fluvial and lacustrine environments. However, marine facies are occasionally present which explain further the possibility of the presence of paleoenvironmental and depositional setting of the sediments subsidence in the region.
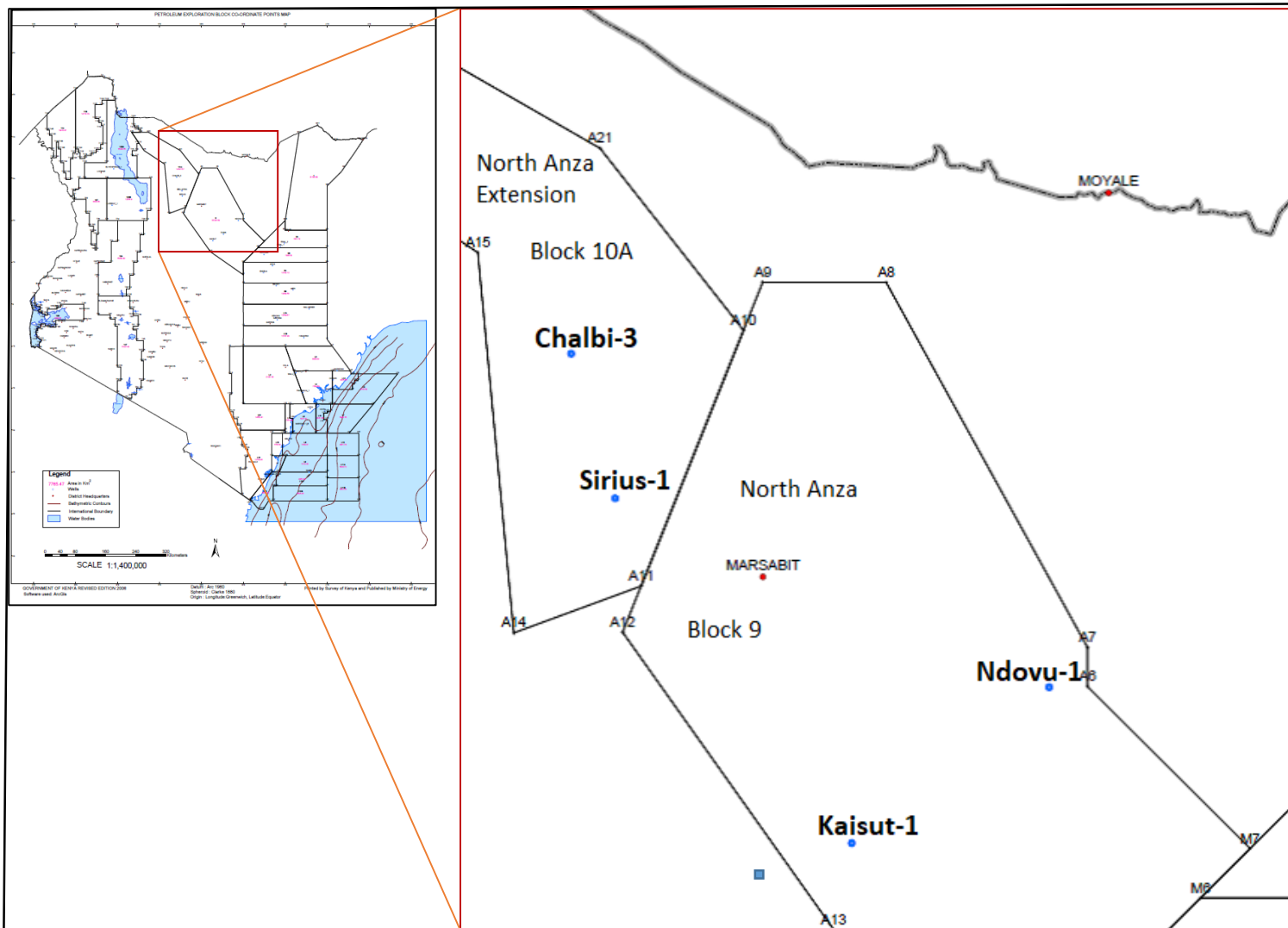
Figure 8: Location map of the present study area showing the four wells.

2.1.2 Physiography and drainage

The distinct physiographic and drainage features of the Anza basin study are comprised mainly of Precambrian basement ranges and inliers, Paleogene volcanic features (plateaus and lowlands) with alluvial plains and perennial water accumulations (e.g., the Chalbi Desert) and many radial and dendritic river-drainage systems. Some parts of the basin contain thick alluvial cover that hide the entire eroded surfaces of the older sedimentary sequences that, in turn, overly the basement Mozambique rocks (Barker, 1972; Key, 1987; Rop, 2013; Rop and Namwiba, 2018). The landscape show undulating features comprising of nearly-flat alluvial plains with intermittent elevated plateaus and ranges where faulting and rifting has occurred, thus indication block faulting that also control the drainage system in the study area. The potential petroliferous sedimentary rocks lie between the basement rocks and the Tertiary volcanic lavas.

Figure 9 shows the Chalbi graben with all drainage channels flowing into the playa (Rop, 2013). The principal watercourses are the Balesa River from the south, Laga Dambito from the Huri shield and Laga Sangarta from the Marsabit shield. All have well defined channels due to flash flooding. The south-east dune field is cut by several river channels that run parallel to sand dunes (Nyamweru, 1984). This suggested that during the dune formation the watercourses experienced perennially flowing water and were augmented by intermittent flash floods.
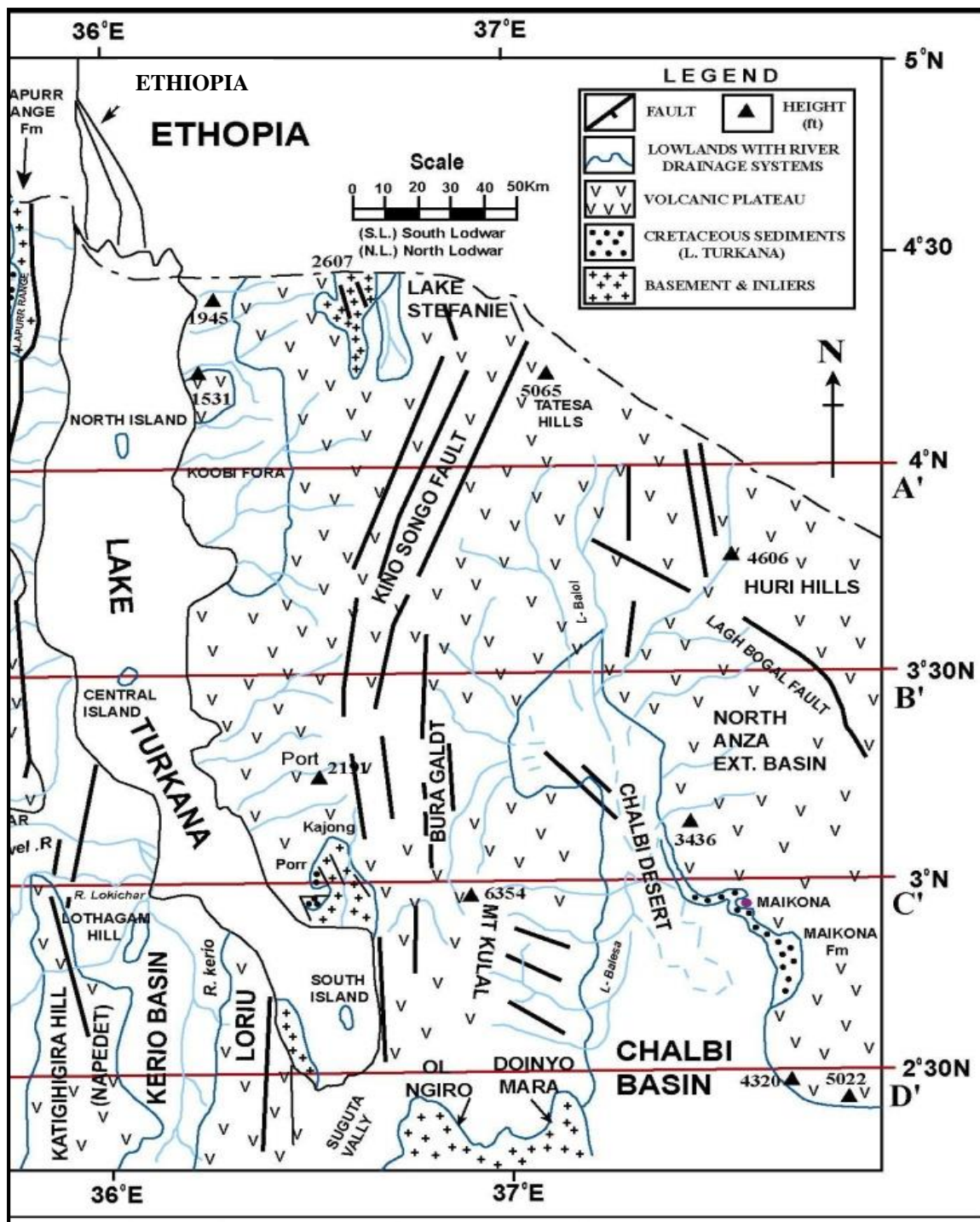
Figure 9: Physiographical and geological map of the Chalbi Basin region (adopted from Rop, 2013)

2.2   Methods

The geological information available especially through published and unpublished journals provided essential data for assessing further the viability of this research. They included previous publication, departmental reports such as at National Oil Corporation of Kenya (NOCK) and Mines and Geological Department. Geological reports of Marsabit area and North Horr explained the earlier geological exploration information such as formation, sedimentation of the region alongside palaeoclimatic influences that could have enhanced formation of hydrocarbon over given geological time scale.

Samples that were stored at NOCK laboratory depository were useful in the fulfillment of the research for petrographical study, geochemical analysis and creation of geochemical logs for the wells. Materials used to achieve the objectives of the research were cited with carefulness and in due respect of memorandum of understanding (MoU) between the University of Nairobi and NOCK.

2.2.1 Petrographical analysis

Objective one involved developing summary of shale volume and hydrocarbon potentiality of the source rocks using well log data. In objective two, visual inspection and sampling for geochemical analysis using source rock analyzer was undertaken to determine the TOCs, T-max, S1, S2, S3; and objective three depended on petrographical and geochemical logs in order to generated collated model for future prediction in hydrocarbon exploration.

Fundamental techniques were employed so as to accomplish the objectives of this present research, which included the following petrophyiscal studies of well log data with the help of well log data:

1) Formation temperature,
2) Water resistivity
3) Shale volume
4) Porosity and saturation
5) Generate a summary of the petrographical analysis.

2.2.1.1   Formation temperature

Geothermal gradient in sedimentary basin is fundamental aspect as a direct constituent for petroleum generation. Formation temperature helped in calculation for the kerogen maturity

and burial history. Temperature data was collected using a logging tool called "bottom-hole temperature" (BHT).

$$\text{Conductivity } (k) = Q/\nabla T \dots\dots\dots\dots\dots \text{Equation 1}$$

Where, Q - total heat flow in the basin; ∇T- the geothermal gradient and

k – The conductivity of the sediment calculated from the temperature log data.

2.2.1.2 Water Saturation

The most common technique for calculating water saturation, S_w, is the use of self- potential resistivity logs. Several data other sets may be used that included deep resistivity, neutron porosity, and shale-volume estimates using Archie's model.

$$F = \frac{R_O}{R_w} \dots\dots\dots\dots\dots\dots\dots \text{Equation 2}$$

Where, F = formation resistivity factor; R_o = resistivity of rock when 100% water saturated; R_w = resistivity of saturating water.

$$F = \frac{a}{\varphi^m} \dots\dots\dots\dots\dots\dots \text{Equation 3}$$

Where, Φ = porosity; a = empirical constant; m = cementation exponent.

To calculate for water saturation of the source rock (locality);

$$S_w{}^n = \frac{R_O}{R_t} \dots\dots\dots\dots\dots\dots \text{Equation 4}$$

Where, S_w = water saturation; R_t = resistivity of rock when $S_w < 1$; R_o = resistivity of rock when water saturation (100% saturated).

Joining the equations 2-5 result in Archie's equation, as shown in equation 6 below.

$$S_w{}^n = \frac{aR_w}{R_t \varphi^m} = \frac{FR_w}{R_t}.$$ …………………Equation 5

Archie's Equation (6) (Crain's, 2016a), shown below, was utilized to compute for the average water saturation of the source rocks.

$$S_w = \left[\frac{0.62 \times R_w}{\varphi^{2.15} \times R_t}\right]^{1/2}.$$ …………………Equation 6

2.2.1.3 Shale volume

Shale volume can be measured using gamma-ray logs, which quantify the natural radioactivity of elements in the sedimentary rocks. The most common elements include potassium, thorium and uranium. The ratio of elemental contribution in sedimentary rock radiation is such that one part per million (ppm) of uranium correlate to 3.65 ppm thorium and 27000 ppm (equivalent to 2.70%) potassium (Bjørlykke, 2010). Organic-rich source rocks with black shale contains the most of these elements and higher than that of sandstones. The Gamma Ray log was displayed in track one with the caliper, to the left of the log plot. Gamma Ray was plotted in API units, increasing from left to right. The scale will vary depending on the maximum radioactivity measured in the formation ranging from 0 – 150 API units (Figure 10).

The volume of shale was mathematically calculated as shown in equation 1 (Schlumberger, 1979) below, based on an assumption that only radioactive potassium elements contributed to the gamma ray signal.

$$I_{GR} = \frac{GR_{\log} - GR_{\min}}{GR_{\max} - GR_{\min}}$$ …………………Equation 7

Where, $GR_{\log}$ is the gamma reading from the log, $GR_{\max}$ Maximum gamma reading of the

well; $GR_{\min}$ Minimum gamma reading of the well

The volume of shale can be calculated using Larinor equation (Lyaka and Mulibo, 2018) shown below:

$$V_{sh} = 0.08\left(2^{3.7IGR} - 1\right)$$ …………………Equation 8
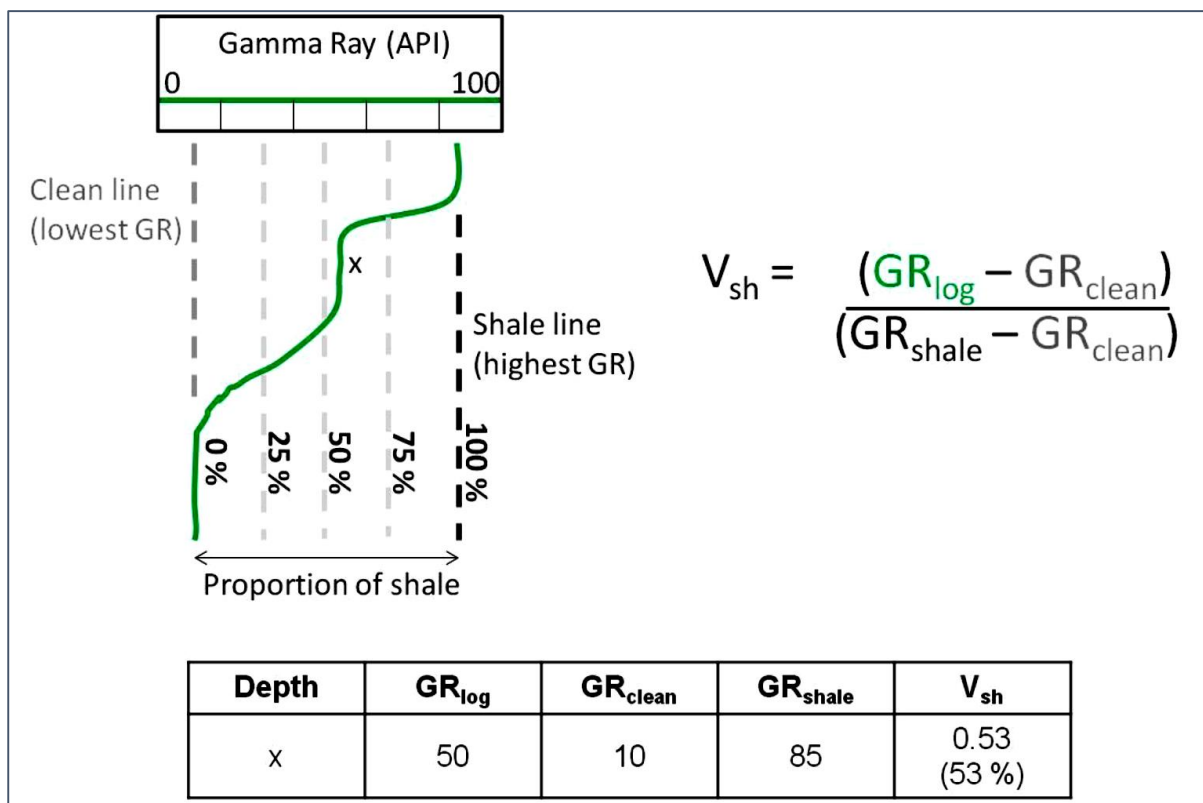
Figure 10: GR parameters for calculating for shale content in the source rocks.

2.2.1.4 Porosity and saturation

The porosity of a source rock is the ratio of the total pore space to the bulk volume of the sample, normally expressed as a percentage. Interconnected pore space provide the effective porosity of the rock. In calculating porosity of the source rocks from the well log data, the first step is to create depth plots and crossplots (Lyaka and Mulibo, 2018) of the core data against the various log data such as density log readings vs. neutron porosity data (Kumar et al., 2018). Neutron density logs provide the density parameters of the rocks and of the pore fluid by measuring the electron density of a rock (Bjørlykke, 2010). Density logs provide lithographic information based as factor of their densities.

$$\text{Porosity } (\varphi) = \frac{\rho_m - \rho_b}{\rho_b - \rho_f}$$

...............................Equation 9

Where, ρm – density of the minerals, ρb – the bulk rock density and ρf – the fluid density (oil, gas or water).

The average density of source rock also depends on the pore fluid (connate water, oil or gas) density occurring in the source rock.

a) Geochemical of the sections of potential source rock using Rock-Eval pyrolysis technique to determine the geochemical parameters that identify hydrocarbon potentiality of the source rocks, and expressed as wt. % TOC, T-max, S1, S2, S3 and kerogen types as shown in Figure 11 below.

Geochemical reports/ logs were developed for each well and compared to determine the TOC and t-max characterizations. Charts of the geochemical logs helped in explanation and interpretation, thus enabling correct stratigraphic sections and conclusions on the hydrocarbon potential in the analyzed wells.
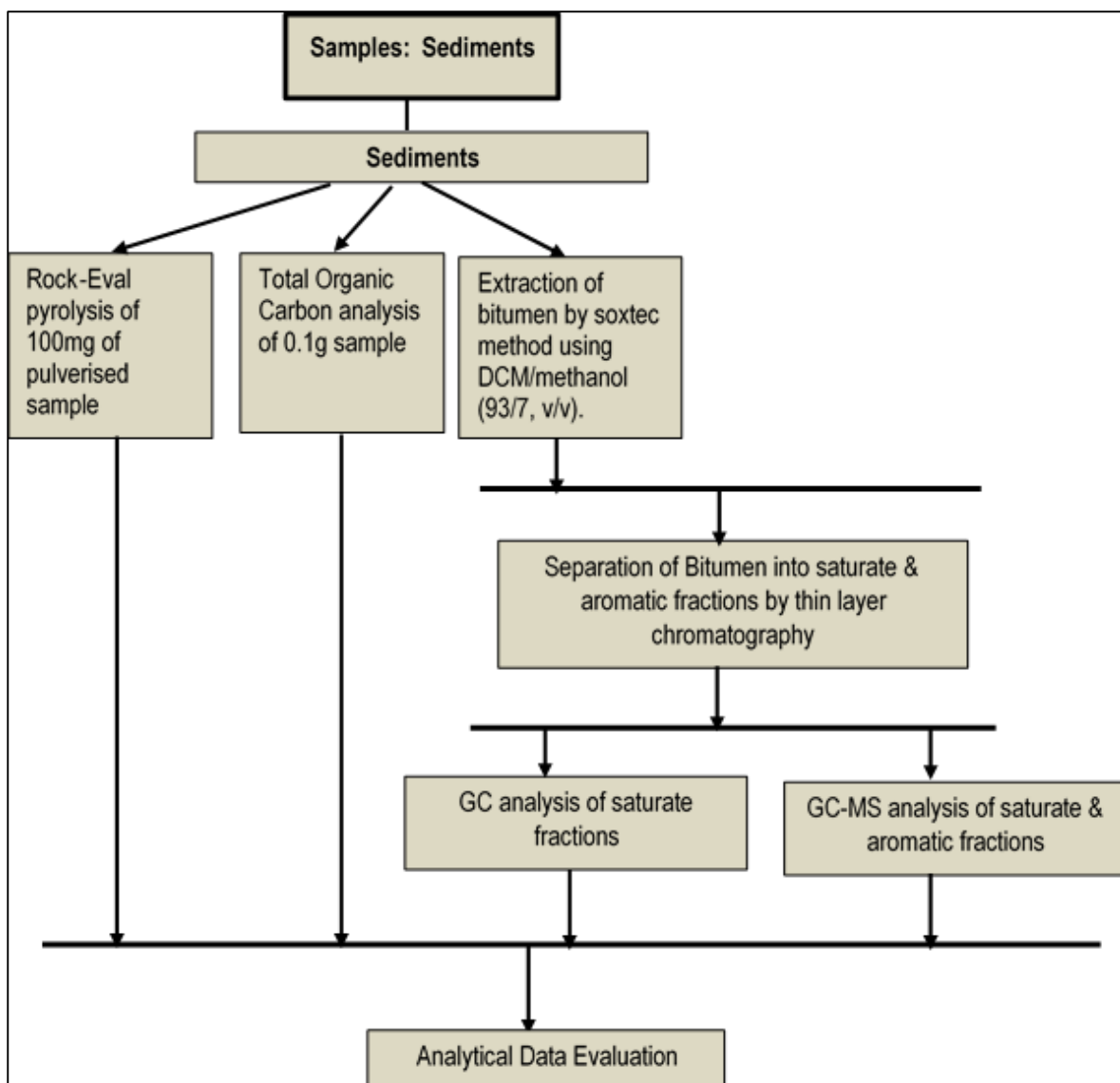
Figure 11: Schematic illustration of the geochemical analysis.

2.2.2 Sampling and data collection

Research activities were based on analyses of core samples from four wells namely Sirius -1, Chalbi-3, Ndovu-1 and Kaisut-1 all situated in Anza Basin. Samples were collected at NOCK laboratory offices for this research. Therefore, extensive work of assessing and mapping well sections with potentially shales or sandstones that are possible source rocks for hydrocarbon. Table 1:2 shows the well sections that were sampled for geochemical analysis.

Table 1-2: Sampled depths in the drilled wells.

Anza Basin			
Sr. No.	Name of the well	Depth intervals	Total number of sample per well
1.	Chalbi-3	1012m – 3584m (3320 – 11, 758 ft.)	10
2.	Sirius-1	1027m – 2017m (3370 – 6620 ft.)	14
3.	Ndovu-1	2664m – 3499m (8740 – 11479 ft.)	21
4.	Kaisut-1	950m - 1420m (3116 – 4659 ft.)	17
Total Number of Source Rock Samples			62

2.2.3 Geochemical Analysis

Drill and core cutting samples were studied to identify and deduce information on their geochemical properties that may have enabled storage and expulsion of organic matter and their maturity.

Total Organic Carbon (TOC) measurement was useful in source rock assessment. Other screening processes included pyrolysis and vitrinite reflectance analysis.

2.2.3.1 Total Organic Carbon analysis

TOC analysis was undertaken using Leco IR 212 Carbon Determinator equipment in which 1mg of core sample was pulverized and treated three times with hot 10% HC1 to remove carbonate contaminants. Then heated at 1200°C using a high frequency inducing furnace for 24 hours. During combustion, carbon content in the kerogen was thermally converted to CO and CO_2. The expelled carbon ratios fractions were detected and quantified in an infrared cell, computed as TOC data (wt. % of dry source rock sample) (Nyantakyi, 2013).

The TOC parameters were expressed in three distinct forms of carbon content:

a) Thermal cracking of kerogen – represents already generated but yet to be expelled HC in the source rock.

b) Residual carbon – illustrate kerogen with nil hydrocarbon generating potential. The source rock could be highly condensed chemical structure and with little hydrogen ratio.

c) Convertible – Is a conventional kerogen (in the source rock sample) that is capable of generating hydrocarbon.

2.2.3.2   Rock-Eval pyrolysis

Rock-Eval pyrolysis is a programmed heating technique (Hantschel and Kauerauf, 2009b) that subject rock samples to high temperatures to mimic subsurface geothermal parameters. The exercise encourages research in otherwise a process that ordinarily take millions of years in a conventional sedimentary basin (Welte et al., 2012). It is commonly applied in order to assess the source rock richness (OM) for petroleum potential (Espitalie et al., 1985a). It was used to further characterize source rock samples that had over 0.5% TOC analysis results (Nyantakyi, 2014; Rop, 2013). Rock-Eval device utilizes both regular pyrolysis and oxidation ovens (İnan et al., 2017) to heat source rock extracted samples in a staged heating process from 100ºC to 850ºC (212ºF to 1,562ºF) (McCarthy, 2011). Eight (8) sample from Chalbi-3 well and Sirius-1 well were analyzed and their results were computed, tabulated and output to a log (ASKIN, 1988).

 The method for Rock-Eval pyrolysis conducted in the NOCK laboratories incorporate; taking dried samples (of about 100 mg), which is placed in a flame ionization detector (FID) (Crain's, 2016). It is then heated in a stream of helium at comparatively low temperature (up to 300 ºC) (McCarthy, 2011) for the first five minutes, in order to remove free or absorbed HC (bitumen) that were present in the rock sample before pyrolysis (Figure 12). The investigation records two peaks, representing the volumes of two components of the OM. The expelled HCs, which typically volatilize under 300 ºC are represented by S1, which give already produced HCs data (bitumen). The S1 values, in most cases, show the occurrence of free hydrocarbons (bitumen) generated below 300 ºC while the S2 values >10 kg/g are meant to be of extra potential for HC (kerogen) generation (Nyantakyi, 2014; Rop, 2013). The results help geochemists characterize the kind of OM in a source rock and determine the thermal evolution of a sample and its residual HC generating potential.
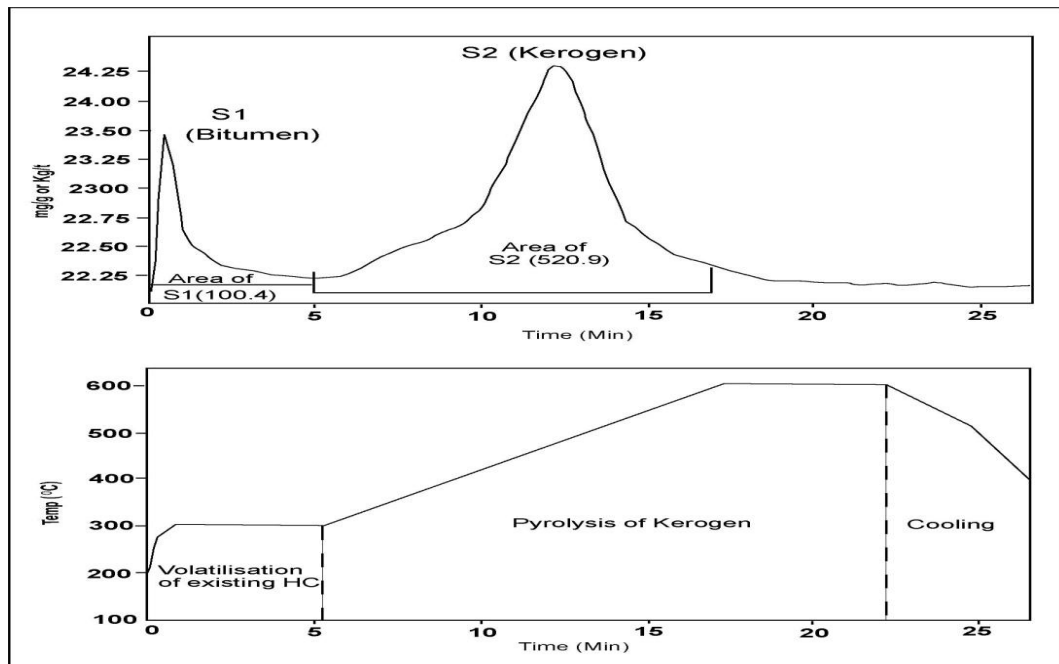
Figure 12: Schematic illustration of pyrolysis data of source rock sample (Adopted from Rop, 2013).

This controlled pyrolytic heating program in the present geochemical analysis study case was illustrated by a series of peaks (S1 and S2) which represent:

- ✓ The first peak (S1) corresponded to free oil and gas that evolved from the drill cut sample prior to thermal cracking the kerogen (up to 300°C). These generated HCs are only released from the rocks during pyrolysis. S1 represented the ratio of free HC per gram of the drill cut sample.

- ✓ The second peak (S2) represents a measure of the HC that were coverted from the OM rich drill cut samples during the main payrolitic thermal breakdown of kerogen. These HCs resulted from the cracking of heavy structured HCs and through thermally cracking of the kerogens. S2 symbolizes milligrams per gram of drill cut sample of residual HC (Rop, 2013). This provide information about the amount of HC that the source rock could produce if it proceed into thermal maturation; especially in the case of oil shales evaluation (McCarthy, 2011). However, Peters and Cassa (1994) did opine that S2 is a more realistic evaluation of TOC in organic-rich samples.

  Oxygenated compounds (such as CO_2) are separated via thermal conductivity detector, which then recorded as S3 data. Both S1 and S2 are either expressed in milligrams per gram (mg/g) or kilogrammes per tonne (kg/ton) of drill cut sample (original rock).

✓ The third peak S3 (not shown in Figure 12 above) corresponds to CO_2 that is produced from the heating conversion of the kerogen during pyrolysis, denoted as milligrams per grams of drill cut sample.

✓ Due to heating process, remnant organic carbon is often recommended for oxidation, which gives the S4 peaks as a product of carbon dioxide (CO_2) and carbon monoxide (CO) components. CO_2 peak, recorded as S4, represents carbon dioxide derived from decomposition of carbonate minerals in the drill cut sample (McCarthy, 2011).

According to Rop (2013), samples with S1 + S2 values < 2 kg/ton are not classified as potential source rocks for HC production. However, he noted that in source rocks samples with 2 to 5 kg/ton are recognizable but insignificant for HC expulsion. He also inferred that source rocks ranging from between 5 and 10 kg/ton have possible potential to expel some portion of the generated oil. Only source rocks with values >10 kg/ton are considered rich for sufficient oil expulsion. Thus, these rock samples observed in the study area, particularly those of the Chalbi-3 and Sirius-1 wells had the potential of oil generation as well as expulsion if the geothermal generation threshold temperature (60ºC) is reached; which also depends on the maturity level of kerogen, usually given by the temperature maximum (Tmax).

Pyrolysis temperatures were ecorded and produced at T_{max} peaks that corresponds to the heating oven temperatures during which maximum expulsion of HC are noted. T_{max} is denoted at the second heating stage, when thermal cracking of the kerogen and heavy HC generate the S2 peak. T_{max} is essentially the maturity value of the OM. The highest values of T_{max} were apparently obtained only from samples at deeper levels. Maturity level of organic-rich (kerogen) source rock sample is crucial for HC research process and exploration stage (Rop, 2013). Samples showing T_{max} values between range of 441 ºC - 444 ºC (J. Espitalie et al., 1985b) suggest that the source rocks are thermally mature and are within peak of oil generation /oil window – as in the case of Chalbi-3 and Sirius-1 wells of the present study area (Figures 21 and 24 of Chapter 4 below).

2.2.3.3 Temperature Maximum and Petroleum indices

The present study, because of the limited samples obtained, did not interpret the two paramaters namely; temperature maximum (T_{max}) and the petroleum indices (PI). They mainly depend on maturation level of OM in the drill cut samples, obtained for evaluation, as well as their respective lithological and stratigraphic depths. In most cases, T_{max} value increases with the maturity of the organic matter present in the analysed sample; although usually T_{max} varies with the type of OM and is directly related to the cracking kinetics of the OM. Achieving kerogen maturity level in an OM is very important for hydrocarbons exploration. The immature kerogen does not generate petroleum, but with increase in the maturity level, early gas and then oil is expected to be generated (Rop, 2013). T_{max} is a key identifier of the maturity of the source rock, whereby the higher the T_{max} value the higher the degree the source rock maturity. It should be noted also that the more complex kerogen type, the higher temperatures it requires to crack or break it.

However, other vital paramenters (discussed in details in Chapter 4) that are used in the assessment of petroleum potentiality in a given sub-basin depths' geological and geochemical analyses include;

1) Hydrogen index, HI, which is usually derived from the TOC (100 X S2/TOC) and this is proportional to the amount of hydrogen - and high HI confirms better chance to produce oil (Crain's, 2016b) and,

2) Oxygen index, OI, derived as percentage CO_2 to TOC (100 X S3/TOC - Macauley, 1985). OI is the indicator of the amount of oxygen inherent in the kerogen and is fundamental in determining the kerogen maturation or type.

Finally, the TOC value of 0.5% is commonly recognized as the minimum threshold for organic richness of a potential source rock. Anything below 0.5% is negligible for HC generation potential. Therefore, in the present study area, it is proposed that greater depths of the source rocks possess the good kerogen type that is denoted by higher T_{max} values. This is principal level for oil formation (see Chapter 4). Thus PI and HI play important role in oil generation in relation to the TOC of the sample.

The production index, PI, is a factor of HC generated during the first and second stages of heating program given by S1/(S1+S2). This depends on the evolution of the OM because PI tends to increase with depth for good source rock as well as with the depth of source rock maturation prior to HC expulsion; as thermally degradable components in kerogen are

converted to free hydrocarbons (Welte et al., 2012). In most cases, high values of S1 and PI could also help map out what could be HC accumulations or staining in the carrier beds. The overall petroleum potential of locality or source bed can be estimated from the amount of HC that mature source rocks could generate, that is obtained from S1+S2 (Macauley, 1985).

In summary, these indices, which have been used for interpretations and discussions in Chapter 4 of this present work, are fundamental in tracking kerogen type and their maturity level. Van Krevelin diagram is useful to classify kerogen types as follow: kerogens type I is demarctaed high HI and low OI (Mohammed, 2015), kerogen type III is synonymous with low HI and high OI while kerogen type II is the intermediate of the two kerogen types I and III. However, during maturation, the OI decline while HI remains almost constant. As the kerogen crosses the oil window, HI start to decline. PI increase simultaneously with increase in burial depth (Welte et al., 2012). Geochemical analysis contributes tangible information to ascertain the organic richness and maturity of the sources rocks which may encourage further research.

2.2.3.4   Gas Chromatography Mass Spectrometry

Gas chromatography mass spectrometry (GC/MS) is tier equipment of gas chromatograph (GC) coupled to a mass spectrometer (MS), by which biomarker signatures may be characterized and quantified. In order for a source rock sample to be analyzed by GC/MS it must be sufficiently volatile and thermally stable. Prior to analysis, samples were dried in an oven and weighed. Samples were then prepared for solvent extracted through soxhlet extraction processes. Four (4) samples from Sirius-1 well were analyzed for biomarker characterization using GCMS.

The soxhlet extracted sample solution was injected into the GC inlet where it was vaporized and swept onto a chromatographic column by the carrier gas (usually helium). The sample flows through the column and the compounds where it is liberated into respective phases of their relative interaction with the coating of the column (stationary phase) and the carrier gas (mobile phase) (McCarthy et al., 2011). The last portion of the column passes through a heated transfer line and ends at the entrance to ion source where compounds eluting from the column are converted to ions.

Two potential methods exist for ion production. The most frequently used method is electron ionization (EI) and the occasionally used alternative is chemical ionization (CI). Using electron ionization (EI) a beam of electrons ionize the solution sample molecules resulting in the loss

of one electron (Sharaf, 2003). The resultant ion generates a peak which is seen in a mass spectrum as the molecular weight of the compound.

Quantification of the elemental count of ion was done through a mass analyzer (Kaklamanos et al., 2012), which is biasely segregated based on their positively charged ions in relation to their mass related properties depending upon the analyzer used. Several types of analyzer exist that include quadrupoles, ion traps, magnetic sector, time-of-flight, radio frequency and cyclotron resonance (Breviere et al., 2002). The commonly used types are quadrupoles and ion traps. After the ions are separated it pass by a detector where the output is amplified to generate determinable signal (Kaklamanos et al., 2012). The detector communicate the results to the to a computer where all the data are recorded, computed into visual data displays for further analysis and storage in different devices.

CHAPTER THREE: PETROGRAPHICAL CHARACTERIZATION

3.1   General introduction

Well log data were used to determine the depth potential for hydrocarbon based on their shale volume, porosity and water saturation. Geological (well) reports informed the pre-computation parameters used to analyze the log data that included geothermal gradient, type of drilling mud, caliper data and bit size.

LAS files were available for Chalbi-3 and Sirius-1 only. The two data sets have been studied as shown below.

3.2   Petrographical characterization of well logs data

After plotting the raw data on the log view, it was noted that the caliper tool log had differential readings that distorted the ultimate results if not considered in the evaluations of the well section (e.g., Figure 2). The effects of caliper tool fluctuations can be an expression of irregular tool tension, competence of the rocks or cycle skipping (Kumar et al., 2018). To correct that, bit size log was side tracked with caliper log, whereby any collapse or swelling the well was noted for comparative illustration of the expected geological interpretation. Moreover, careful data observation of the log plots helped to pinpoint the erroneous data points and a crossplots of density logs and neutron porosity logs were used to improve the knowledge about the data quality in the well sections. The accuracy of formation and volumetric evaluation depended on the integrity of data sets that include porosity, density, gamma ray and their overall interpretation.

Using rock physics, evaluations of in situ rock parameters for their capability to host source rock material and their thermal cooking for generation of hydrocarbon; the following parameters were preferably considered porosity, fluid inclusions, resistivity and shalyness. For each data sets, gamma ray log was employed for shale volume, neutron-density log gave rock data for porosity calculation and the deep resistivity log was then used to compute for water saturation. The objective of formation evaluation using the petrographical study was to quantitatively locate and determine the shale volume, effective porosity and water saturation of the source rocks.
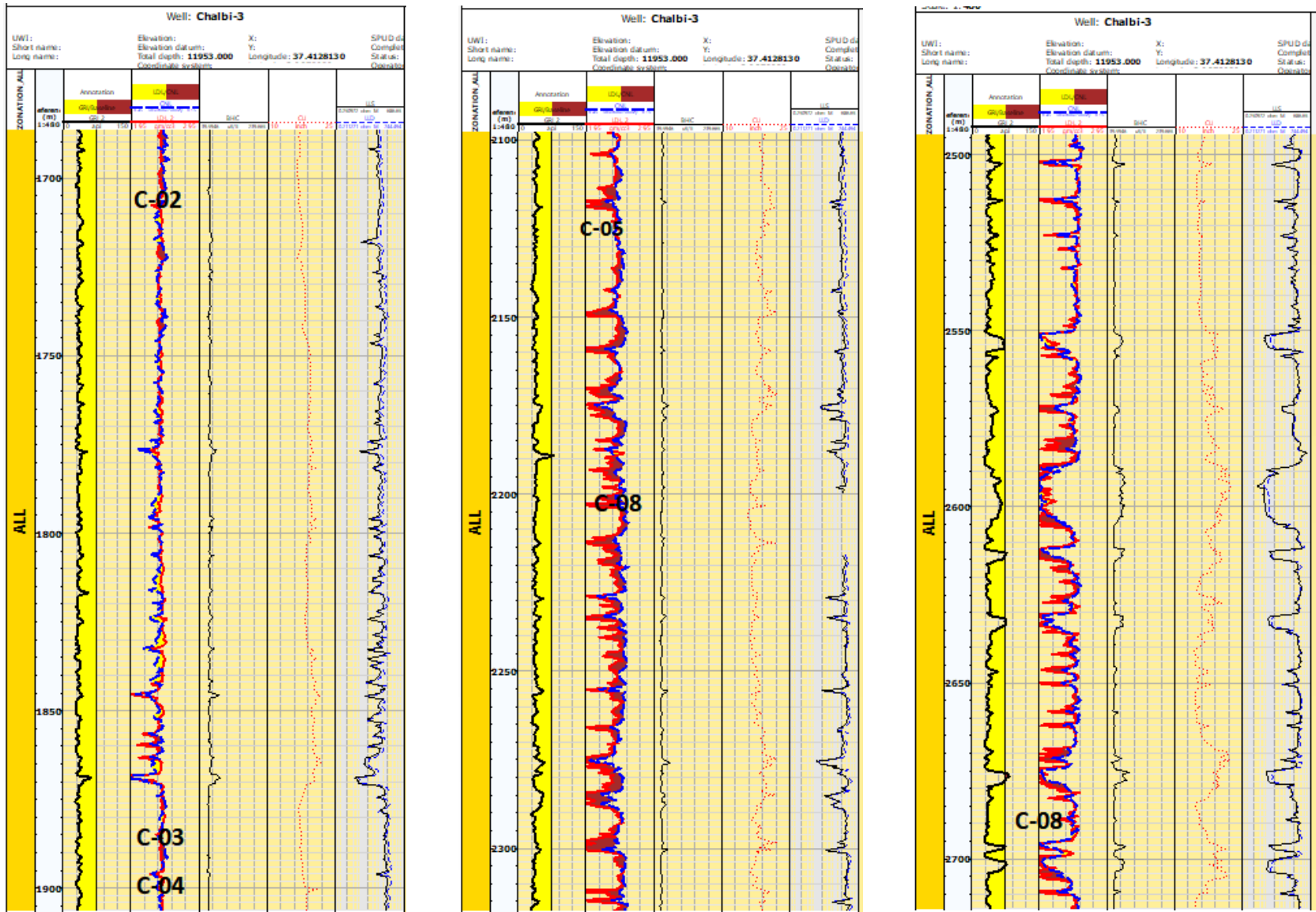
Figure 13: Chalbi-3 Petrographical logs (depths from 1690 – 1900m, 2100 – 2310m and 2500 – 2710m).

Figures 13-16 illustrate the shale occurrences in Chalbi-3 and Sirius-1 wells, as evaluated using gamma logging tool and sampled depths were similarly highlighted using sample reference numbers. There were several depth sections that indicated occurrences of shales as demonstrated by Gamma ray (GR) indices of over 80 API units. However, sandstone and siltstone were predominantly deposited in the Chalbi-3 well with small ratios of shale at several locations. Deeper cross-sections for both Chalbi-3 and Sirius-1 had greater depths enriched with shale that could act as source rocks for producible amount of hydrocarbon.
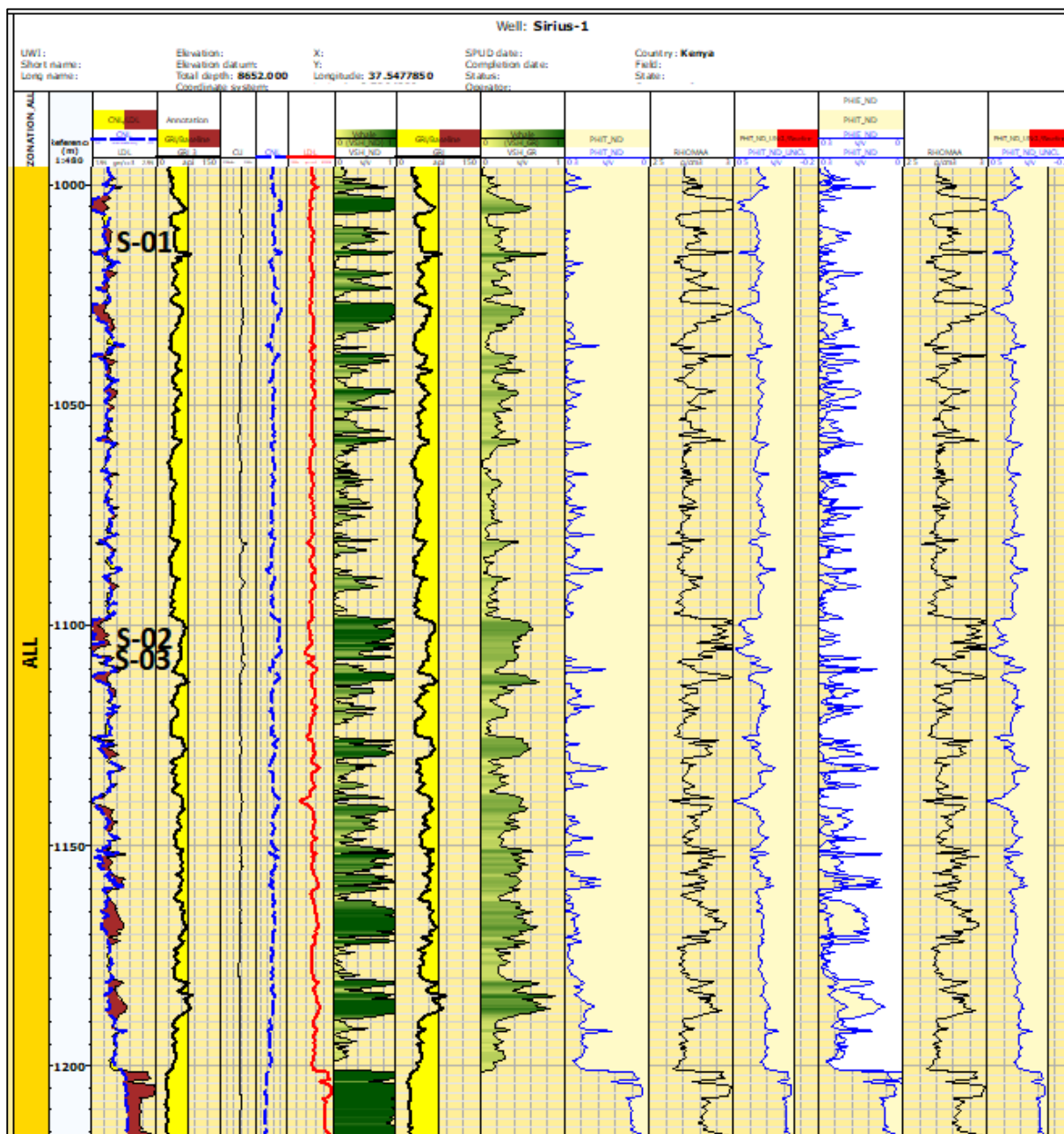
Figure 14: Sirius-1 Vshale at deeper depths 1450-1700m.
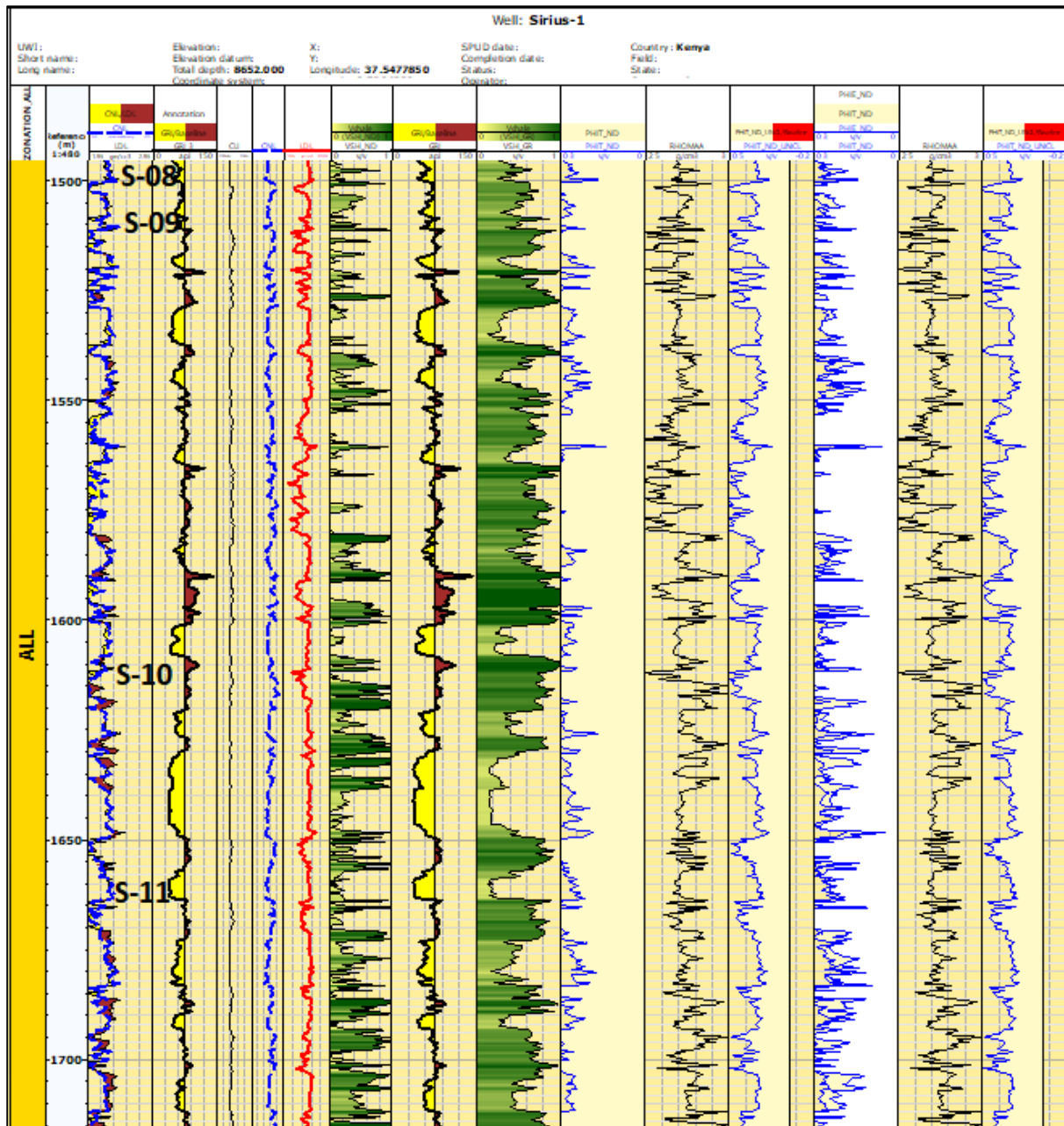
Figure 15: Sirius-1 Vshale at deeper depths 1500-1710m.

The strategic sampling was based on the lithological study of the geological well report of each well, that gave petrographic characterization of different rock and mineral structures. All the wells had thematic study to ascertain the depositional sequences and burial history of the sediments. Chalbi-3 and Sirius-1 wells were the only wells whose log data were available in data files that could be studied using Technlog petrographical software. In addition, several logging tools such as gamma log, caliper tool log, bit size were coalesced to determine shale signatures in the well logs. Neutron porosity and resistivity logs were used to compute effective porosity and water saturation respectively. The purpose for which was to understand the geological assemblages at several depths that could have allowed for accumulation and thermal

cooking of source rocks for occurrence of hydrocarbon. Gamma rays over 80 API mapped the potential sections (Figure 13-16) which were then calculated to determine their volume of shale and enrichment.
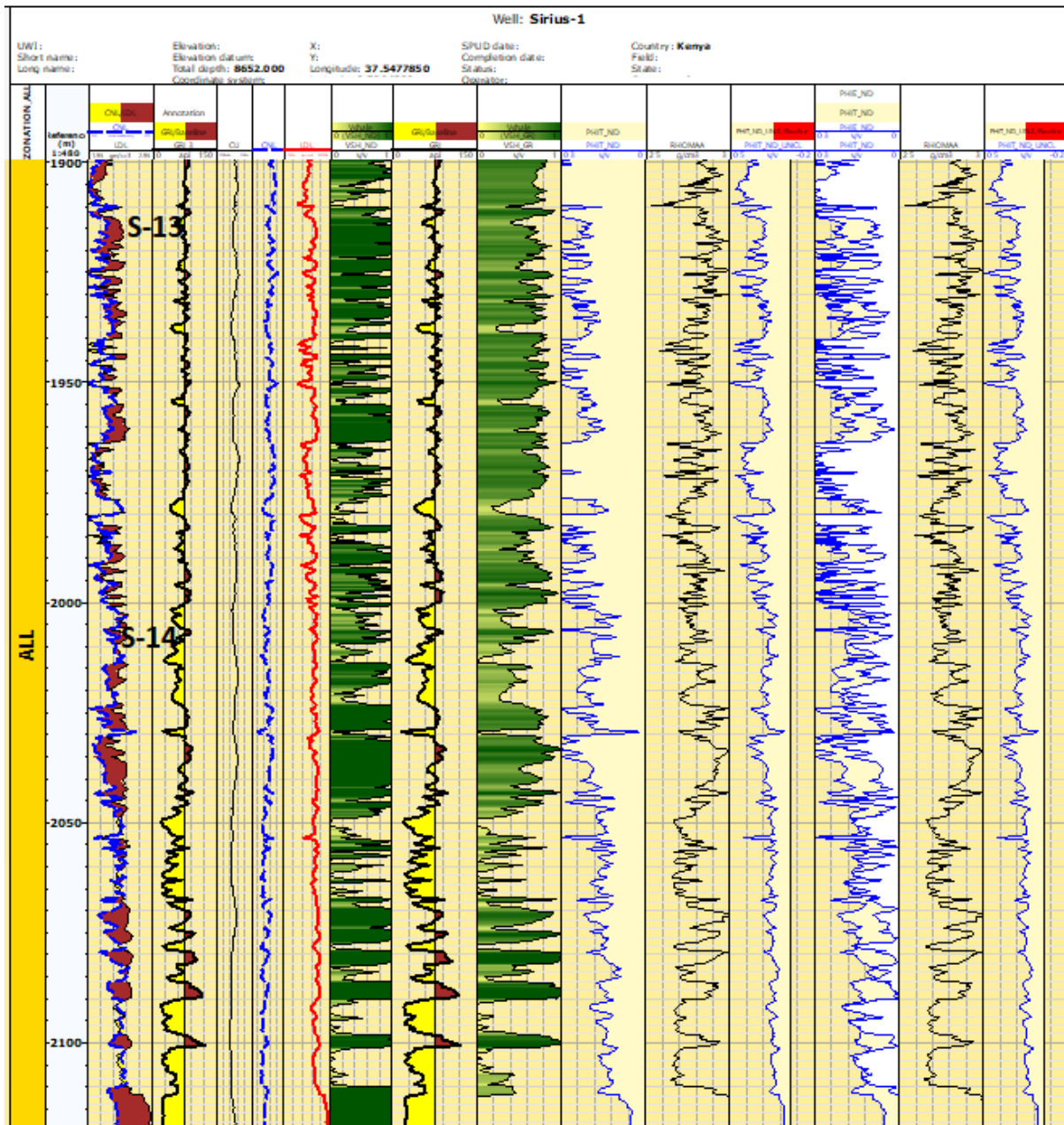
Figure 16: Sirius-1 Vshale at deeper depths 1900-2110m.

CHAPTER FOUR: TOTAL ORGANIC CARBON AND PYROLYSIS

4.1 Total Organic Carbon

Total organic content (TOC) evaluation provided the initial screening whereby the organic richness of source rocks were calculated as weighted percentage per gram of dry sample.

4.1.1 Kaisut-1 well

Kaisut-1 well (Figure 17) samples were majorly siliciclastic sediments with minimal amount (shading) of shale. It had the lowest percentages of TOC values as shown in Table 4-1 below. This appeared to be outside the margin of organogenic sedimentary rocks that could produce hydrocarbon.

Table 4-1: Kaisut-1 well lithology and Wt. % TOC

Sample Ref.	Depth (m)	Lithology	Wt.%TOC
K-02	1000	Loose unconsolidated sand, fine-med. Grained+ minor shale	0.03
K-04	1050	Loose unconsolidated sand, fine-med. Grained+ minor shale	0.06
K-05	1120	Loose unconsolidated sand, fine-med. Grained+ minor shale	0.05
K-08	1200	Loose unconsolidated sand, fine-med. Grained+ minor shale	0.06
K-10	1240	Loose unconsolidated sand, fine-med. Grained+ minor shale	0.04
K-11	1320	Loose unconsolidated sand, fine-med. Grained+ minor shale	0.08
K-13	1350	Loose unconsolidated sand, fine-med. Grained+ minor shale	0.06
K-14	1360	Loose unconsolidated sand, fine-med. Grained+ minor shale	0.03
K-17	1420	Loose unconsolidated sand, fine-med. Grained+ minor shale	0.06

The graph of wt. % TOC vs depth shown the variation of organic content. However, all selected samples did not surpass the 0.5% TOC threshold (Hunt, 1996; Tissot B, 1984) and were categorized a poor source rock types. Comparing with visual inspection of the samples, majority of the sampled depths had sandstone (loose and lump sand grains) with minimal ratio of shales. That had informed the decision to re-select samples for geochemical evaluation.
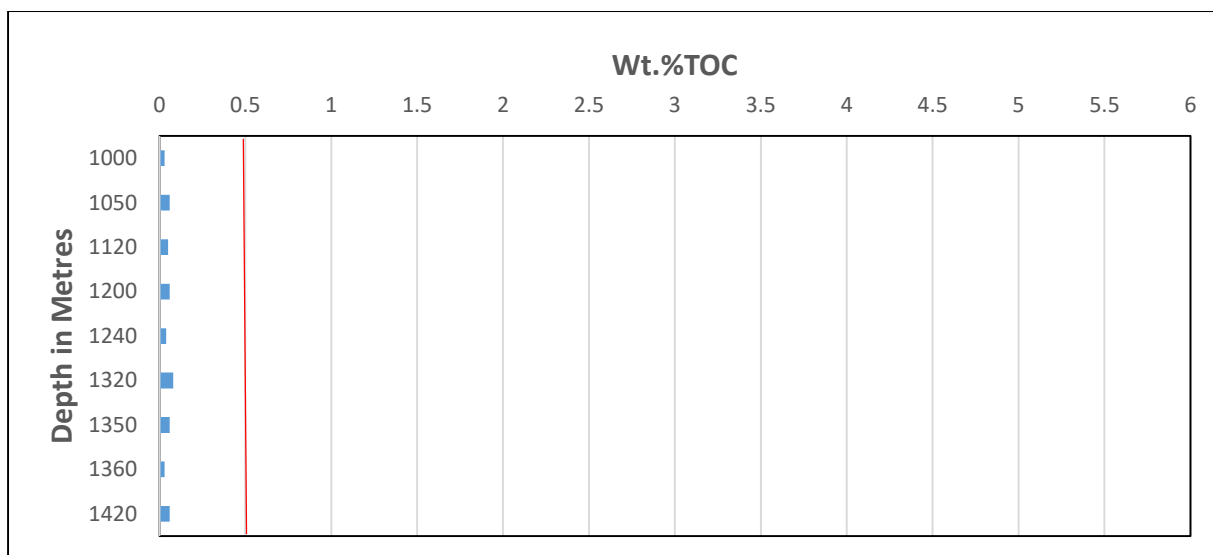
Figure 17: Kaisut-1 well TOC graph.

4.1.2 Ndovu-1 well

Ndovu-1 well has varied percentages of TOC values, see Table 4-2 below, from calcitic sediments from 2664 to 3141m and minor shale ratios from 3180m downwards from Palaeocene age (Figure 18).

Table 4-2: Ndovu-1 well lithology and Wt. % TOC values. Nd – not determined.

Sample Ref.	Depth (m)	Lithology	Wt.%TOC
N-01	2664	Drilling mud and N7 Calc. mudstone	0.04
N-02	2826	Drilling mud and N7 Calc. mudstone	0.07
N-03	2913	Drilling mud + minor calc. mudstone	0.10
N-04	2955	Drilling mud + minor calc. mudstone	0.07
N-06	3010	fine sand, unconsolidated, drilling mud, minor soft limestone and N5 shale	0.19
N-08	3066	Drilling mud + minor shale	Nd
N-O9	3093	Drilling mud + minor shale	0.04
N-11	3141	Drilling mud, loose fine sand, LCM and minor non calc N5 shale	0.14
N-12	3180	Drilling mud plus fine N4 shale	0.12
N-13	3201	Drilling mud + minor shale	0.16
N-14	3241	Drilling mud + minor shale	0.11
N-15	3280	Drilling mud + minor shale	0.12
N-16	3301	Drilling mud + minor shale	0.11
N-17	3361	Drilling mud + minor shale	0.15
N-18	3409	Drilling mud + minor shale	0.13
N-19	3439	Drilling mud + minor shale	0.06
N-20	3491	Drilling mud + minor shale	0.08
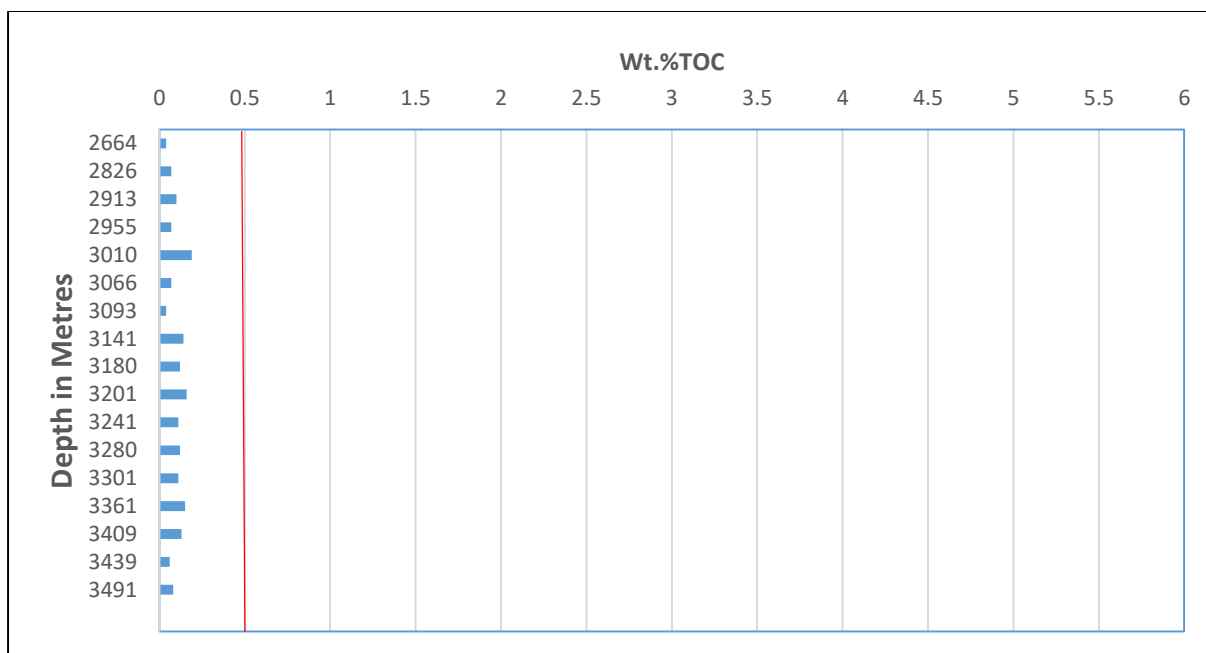
Figure 18: Ndovu-1 Well TOC graph.

4.1.3 Chalbi-3 well

Chalbi-3 (Figure 19) had sandstone with minor occurrence of shale (Table 4-3). TOC parameters of the Cretaceous source rocks shown the potential of fair to good source rocks. Two (1713m, 2680m) were selected for programmed pyrolysis to determine kerogen type and their maturity.

Table 4-3: Chalbi-3 lithology and wt. % TOC values.

Sample Ref.	Depth (M)	Lithology	Wt.% TOC
C-01	1012	Unconsolidated sand, fine to med. Very minor dark grey shale	0.42
C-02	1713	Unconsolidated sand, fine to med. Very minor dark grey shale	0.51
C-03	1871	Unconsolidated sand, fine to med. Very minor dark grey shale	0.49
C-04	1900	Unconsolidated sand, fine to med. Very minor dark grey shale	0.46
C-05	2150	Unconsolidated sand, fine to med. Very minor dark grey shale	0.43
C-06	2207	Unconsolidated sand, fine to med. Very minor dark grey shale	0.47
C-07	2365	drilling mud, sand and minor mid grey shale	0.53
C-08	2680	drilling mud, sand and minor mid grey shale	0.63
C-09	2905	Mostly drilling mud + fine unconsolidated sand. V. minor dark grey shale	0.41
C-10	3057	dominantly fine to med. Unconsolidated sand and drilling mud	0.39
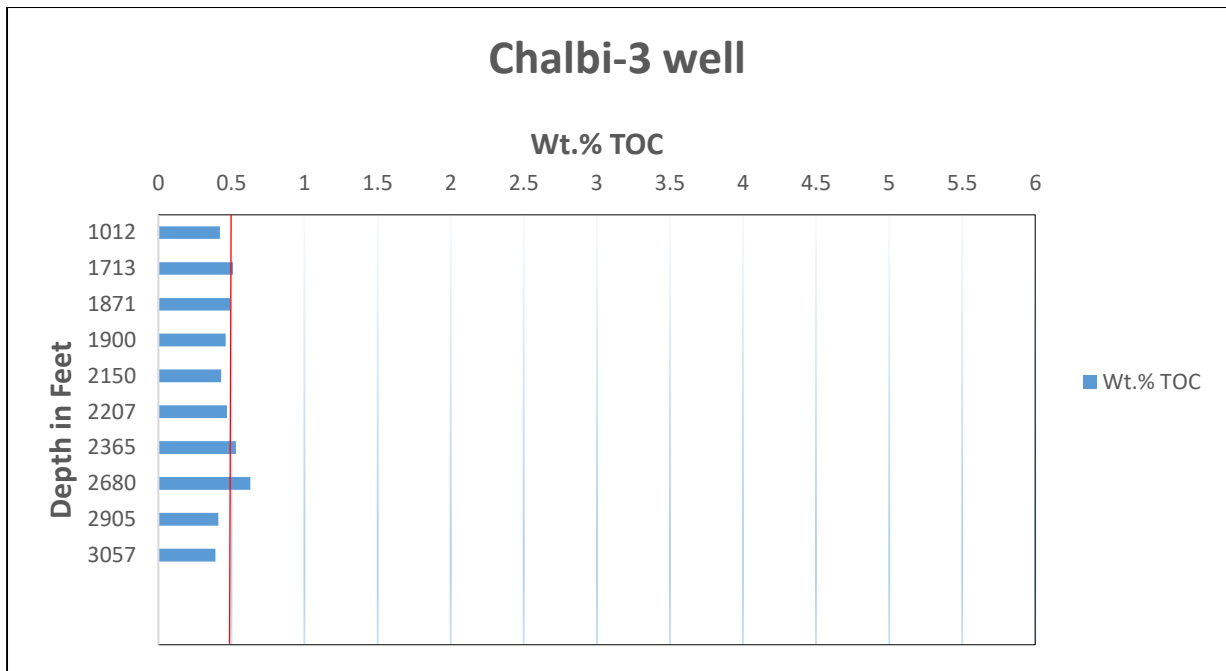
Figure 19: Chalbi-3 Well TOC graph.

4.1.4 Sirius -1 well

Sirius-1 well (Figure 20) demonstrated the highest percentages of TOC with oil shows at 1495-1510m (4905ft to 4954ft) depth as in Table 4-4. The target depth was upper Cretaceous and has good indication for oil potentiality.

Table 4-4: Sirius-1 lithology and Wt. % TOC values.

Sample Ref.	Depth(m)	Lithology	Wt.%TOC
S-01	1027	Dominantly unconsolidated sand, very minor shale	0.47
S-02	1106	dominantly drilling mud, minor shale and sand-very small sample	1.91
S-03	1109	dominantly drilling mud, minor shale and sand-very small sample	1.77
S-04	1335	drilling mud + dark grey shale and fine sand	2.50
S-06	1360	dominantly drilling mud plus fine sand	0.36
S-07	1495	dark grey shale, drilling mud and fine sand	5.94 oil shows
S-08	1500	as 4910'	4.34 oil shows
S-09	1520	shale, platy, dark grey + fins sand	3.20
S-10	1625	shale, platy, dark grey + fine sand	3.50
S-11	1673	sand and shale but mostly drilling mud-too small to analyze	NIL
S-12	1725	Shale, dark grey + drilling mud and minor sand	1.92
S-13	1930	sand and drilling mud plus minor shale	0.42
S-14	2018	Mostly sand and drilling mud.	0.31
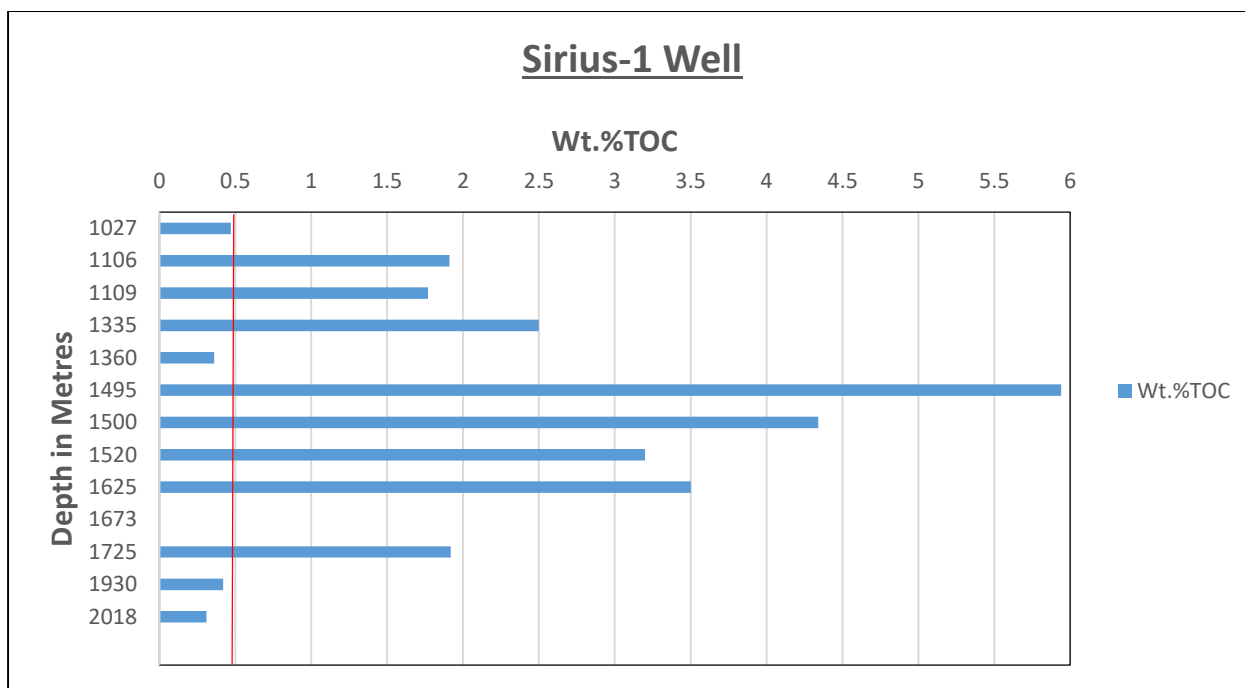
Figure 20: Sirius-1 Well TOC graph.

Several samples had good to excellent source rock types that were further analyzed to determine pyrolysable hydrocarbon as indicated wt. % TOC values, see Figure 20 above. In Sirius-1 well, the Cretaceous source rock had good deposition of shale content as earlier illustrated using petrographical study.

4.2   Rock-Eval Pyrolysis

Rock-Eval pyrolysis is an investigative process that helped to assess the maturity of hydrocarbon in the source rocks. The pyrolysable carbon content was computed using S1, S2, and S3 whereby S1 indicated the directly producible hydrocarbon at 350°C whereas S2 provided the extractable hydrocarbon content from the source rocks through thermal expulsion at 550°C (Lucas et al., 2015). S3 gave trapped carbon oxides released from pyrolysis at 390°C (carbon monoxide and carbon dioxides). The petroleum indices were calculated and displayed as cross-plots for further characterization of the source rocks.

Kaisut-1 and Ndovu-1 samples were below threshold value of 0.5% TOC (Hunt, 1996), therefore, it could proceed for rock-eval pyrolysis. Although visual inspection of the source rocks indicated the occurrence of black shale composite in the selected drill cuttings samples, the geochemical results illustrated that the percentages of the organic content for hydrocarbon generation were distributed in small ratios compared to the volume of the host (sedimentary) rock. Chalbi-3 and Sirius-1, however, gave good results at some depth sections that allowed for mounting of the pyrolysis program to determine their kerogen types and maturity. The results for Chalbi-3 and Sirius-1 were discussed below.

4.2.1 Chalbi-3 well

Chalbi-3 well sampled sections was dominated by Cretaceous sandstone bearing dark grey shale. However, the geochemical results as shown below indicated poor to fair organic composition of the source rocks potentially immature – mature and poor in hydrogen ratio that meant it was type III kerogen (Table 4-5).

Table 4-5: Pyrolysis data and computed petroleum Indices of Chalbi-3 1well. Nd – not determined.

Sample Ref. No.	Sample Depth (m)	TOC Wt. %	S1 mg/g	S2 mg/g	S3 mg/g	HI	OI	PI	Tmax °C	S1 / TOC
C-01	1012	0.42	nd	nd	nd	nd	nd	nd	nd	nd
C-02	1713	0.51	0.08	0.54	0.67	106	131	0.13	433	15.69
C-03	1871	0.49	nd	nd	nd	nd	nd	nd	nd	nd
C-04	1900	0.46	nd	nd	nd	nd	nd	nd	nd	nd
C-05	2150	0.43	nd	nd	nd	nd	nd	nd	nd	nd
C-06	2207	0.47	nd	nd	nd	nd	nd	nd	nd	nd
C-07	2365	0.53	nd	nd	nd	nd	nd	nd	nd	nd
C-08	2680	0.63	0.11	0.31	0.50	49	79	0.26	441	17.46
C-09	2905	0.41	nd	nd	nd	nd	nd	nd	nd	nd
C-10	3057	0.39	nd	nd	nd	nd	nd	nd	nd	nd

The TOC% of the dry weight (wt.) of the sampled depth portrayed a varied enrichment of organic content with negligible to fair percentages of TOC (0.39 wt.% to 0.63 wt.%). The deposition of shale content against the host (sandstone) rock instantiate the sediment provenance and burial history of the organic matter.

Cross plots of T-max (°C) versus hydrogen index (HI mgHC/gm of TOC) (Figure 21) and hydrogen index (HI) against oxygen index (OI), as shown in Figure 22 below, from pyolizable sample extracts to investigate for the kerogen type (source rock quality)as well as their generation potential. T-max (°C) gave the maturity signatures of the source rock (drill/ core samples).
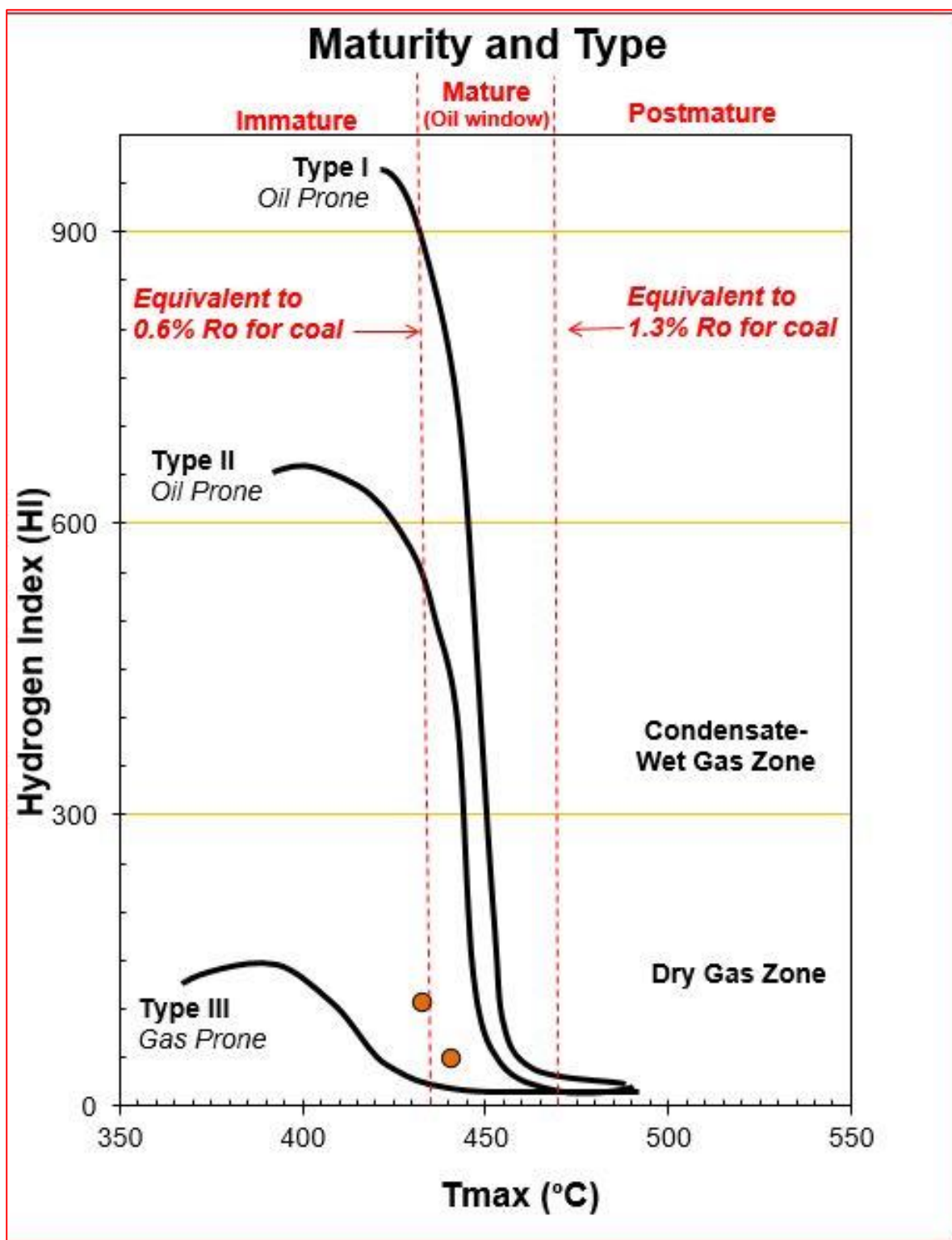
Figure 21: Chalbi-3 Maturity and Kerogen types

Analyzed (two) samples gave low indices of hydrogen ratios while also exhibiting low T-max values of 433°C and 441°C. However, the samples originated from kerogen type III (early gas) (Hunt, 1996) but immature source rocks (Espitalie et al., 1985).
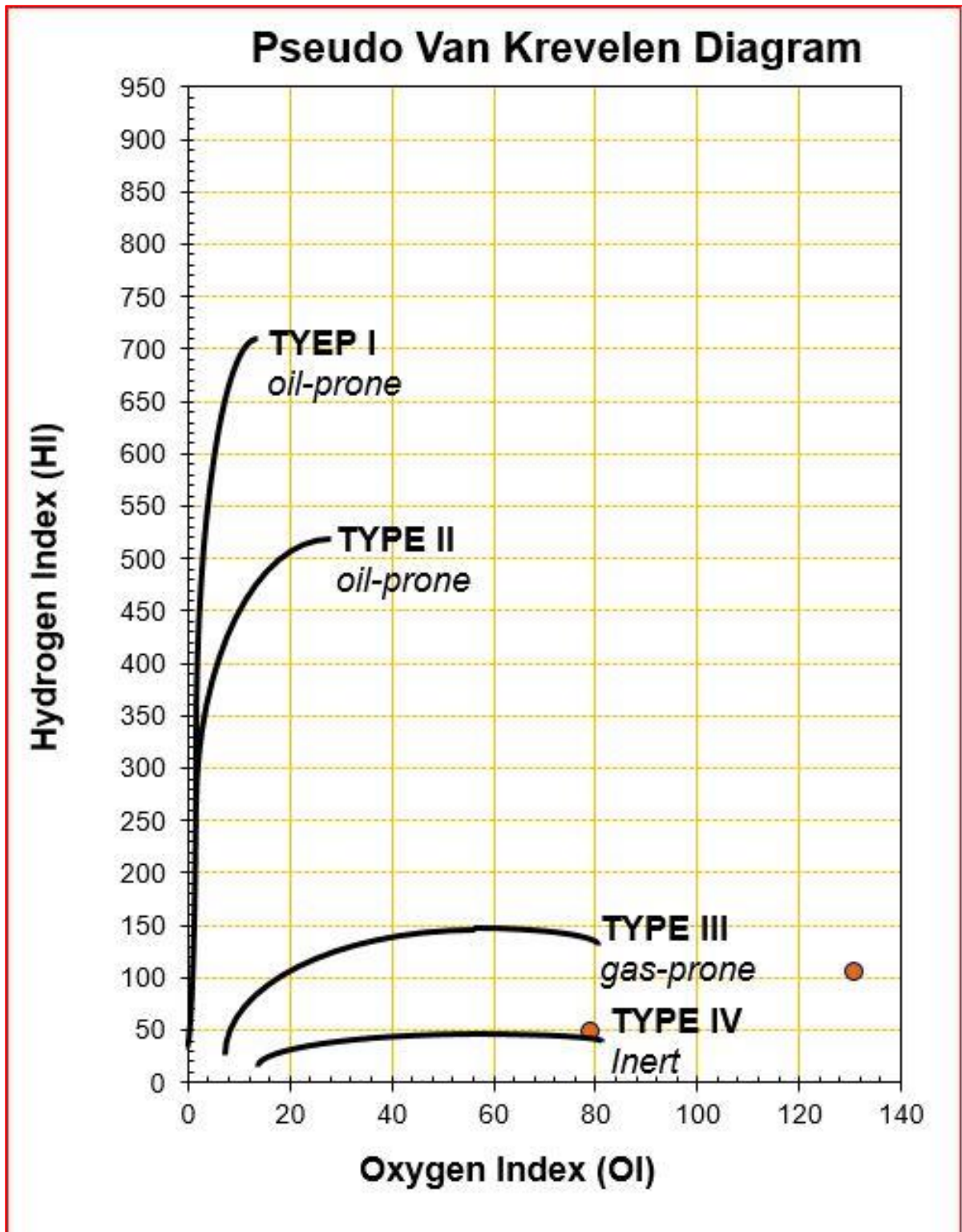
Figure 22: Chalbi-3 Pseudo Van Krevelen Diagram

Van Krevelen diagram (Figure 22 above) depicted the cross plot of the HI against OI which gave information about the kerogen type and maturity. Type III kerogen possess HI values between 50 –200mg HC/g TOC along with OI values at intervals 5 – 100 mg CO2/g TOC; and type IV kerogen commonly has HI indices beneath 50 mg HC/g TOC (Peters and Cassa,

1994; Tissot B, 1984). The HI values illustrated a disparity of hydrocarbon potentiality whereby one sample was slightly below the gas (C-08 whose HI value was 49) bracket but another lies the detectable gas component ratios of 50 – 200 (McCarthy, 2011). Therefore, using the relationship of HI vs OI, the two (C-02 and C-08) samples fall in the category of kerogen types III and IV respectively.

The TOC *vs* S2 (Figure 23) illustrate the relationship of the generic potential realized from thermally extracted OM (bitumen) in the selected drill/ core samples. These help in the characterization of the source-richness, as a case of their volume assessment and producible HC.
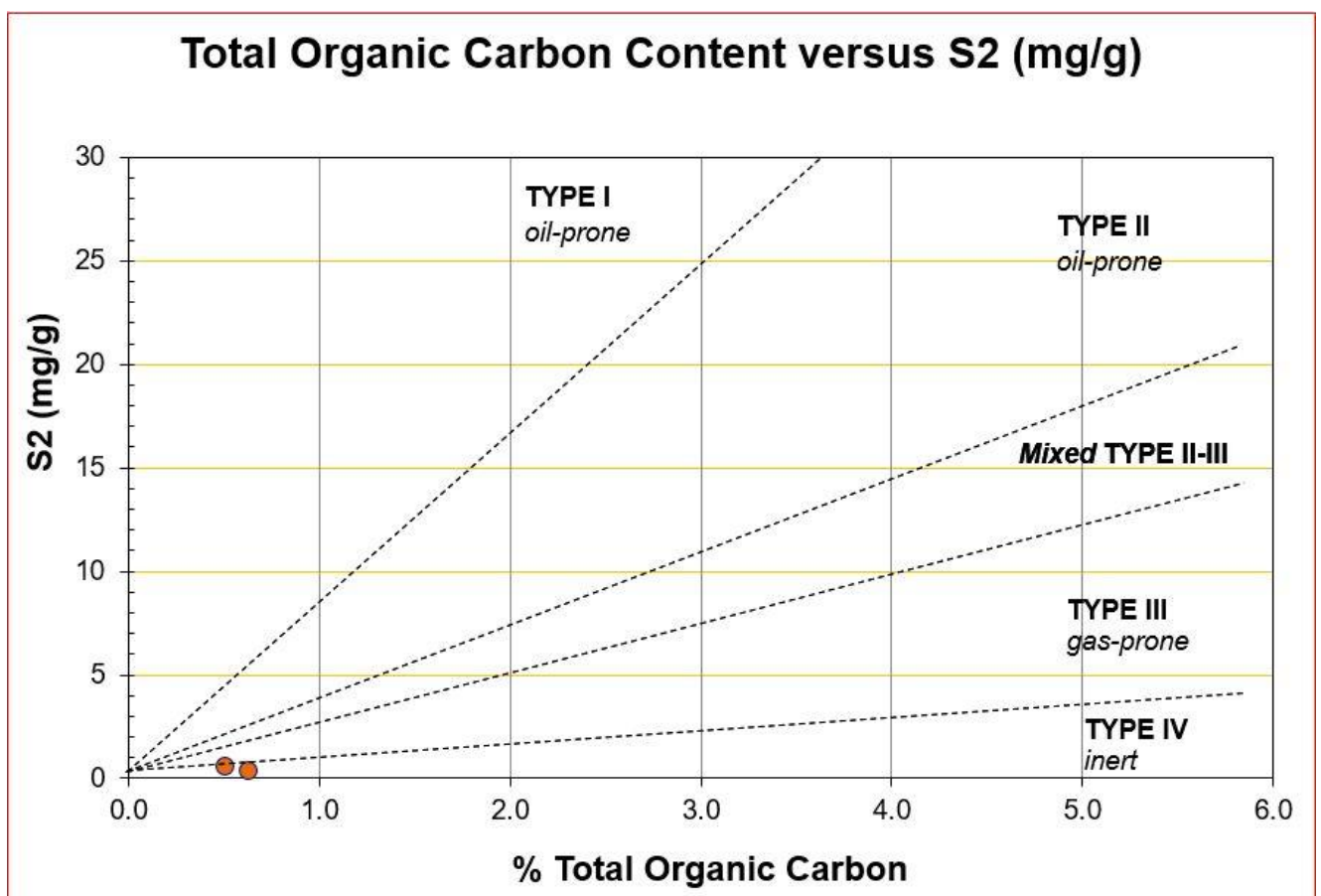
Figure 23: Chalbi-3 TOC vs S2

Chalbi-3 sample depths (1713m and 2680m) have relatively high percentages (good) of TOC with mature source rocks but has minimal ratios of extractable gas of kerogen type III. The drawing of the relationship between S2 *vs* TOC% (Figure 23 above) illustrated the cross plot of thermally extractable source rocks against their organic ratios (wt. %) of organic matter. The samples (C-02 and C-08) resulted in S2 of less than 2, therefore, it was ranked poor and non-producible (McCarthy, 2011).

4.2.2 Sirius-1 well

The bulk geochemical characterization for the source rock samples from TOC and pyrolysis assessment are listed in Table 4-6 below.

Table 4-6: Bulk geochemical data for analyzed sampled from Sirius-1 Well. Nd – not determined.

Well	Sample Ref.	Depth (m)	Wt.% TOC	S1 (mg/g)	S2 (mg/g)	S3 (mg/g)	HI	OI	PI	Tmax (°C)	S1 / TOC
Sirius -1	S-01	1027	0.47	nd	nd	nd	nd	nd	nd	nd	nd
	S-02	1106	1.91	0.16	2.96	0.49	155	26	0.05	444	8.38
	S-03	1109	1.77	nd	nd	nd	nd	nd	nd	nd	nd
	S-04	1335	2.50	0.28	6.88	0.34	275	14	0.04	444	11.20
	S-06	1360	0.36	nd	nd	nd	nd	nd	nd	nd	nd
	S-07	1495	5.94	0.86	60.01	0.79	1010	13	0.01	444	14.48
	S-08	1500	4.34	0.98	39.89	0.89	919	21	0.02	442	22.58
	S-09	1520	3.20	0.57	24.48	0.45	765	14	0.02	440	17.81
	S-10	1625	3.50	0.23	15.9	0.45	454	13	0.01	441	6.57
	S-11	1673	nd	nd	nd	nd	nd	nd	nd	nd	nd
	S-12	1725	1.92	0.16	4.32	0.49	225	26	0.04	444	8.33
	S-13	1930	0.42	nd	nd	nd	nd	nd	nd	nd	nd
	S-14	2018	0.31	nd	nd	nd	nd	nd	nd	nd	nd

The high TOC% in the range of 1.77-5.945 displayed by the samples in the depth range of 3630-5660ft (Table 4-6) indicate depth section with very good source rocks (Peters, 1986a; Peters and Moldowan, 2017). The observed variations in TOC content demonstrated different depositional sequences and OM burial history occurring in the drill/ core sampled sections. Therefore, sections with high TOC were characterized by high bio-productivity (OM) preservation throughout sediment deposition and early diagenesis processes.

Pyrolysis data (Table 4-4) portray that free HCs (S1) are in the order of 0.16 and 0.98 mg HC/g while thermally extractable HCs (S2) span from 2.96-60.01 mg HC/g. The S2 values are consistent with good oil generative potential (Peters, 1986a). The samples show Tmax peak values in the range of 441 ⁰C - 444 ⁰C depicting that source rocks (OM) are thermally mature for oil generation (J. Espitalie et al., 1985b). The high thermal maturity symbolize good burial and preservation history as well as geothermal conditions favourable for HC expulsion in the depth sections.

The hydrogen index (HI) for the analysed source rocks range between 155 and 1010 mg HC/g TOC (Table 4-6) reflect oil bearing zone enriched with OM (Peters, 1986a; Tissot et al., 1974). HI extend from 765-1010 mg HC/g TOC in the depth section from 4910-4990 are in particular suggestive of organic rich oil prone type 1 organic matter (Tissot et al., 1974) while the rest of the samples are of oil prone Type II organic matter. Indeed, the cross plots of HI *vs* Tmax (Figure 24) and of HI *vs* OI (Figure 25) illustrated that the source rocks are predominantly were oil prone of kerogen type 1 and II organic matter.

The production index (PI) for the drill/ core samples vary from 0.01-0.05 notwithstanding the evidence that Tmax suggested that they are mature source rocks. The low PI indices in drill/ core samples were consequently interpreted to point out that (thermally) extractable OM (S1) were from inherent source rocks and have not migrated from other places (Affouri et al., 2013).
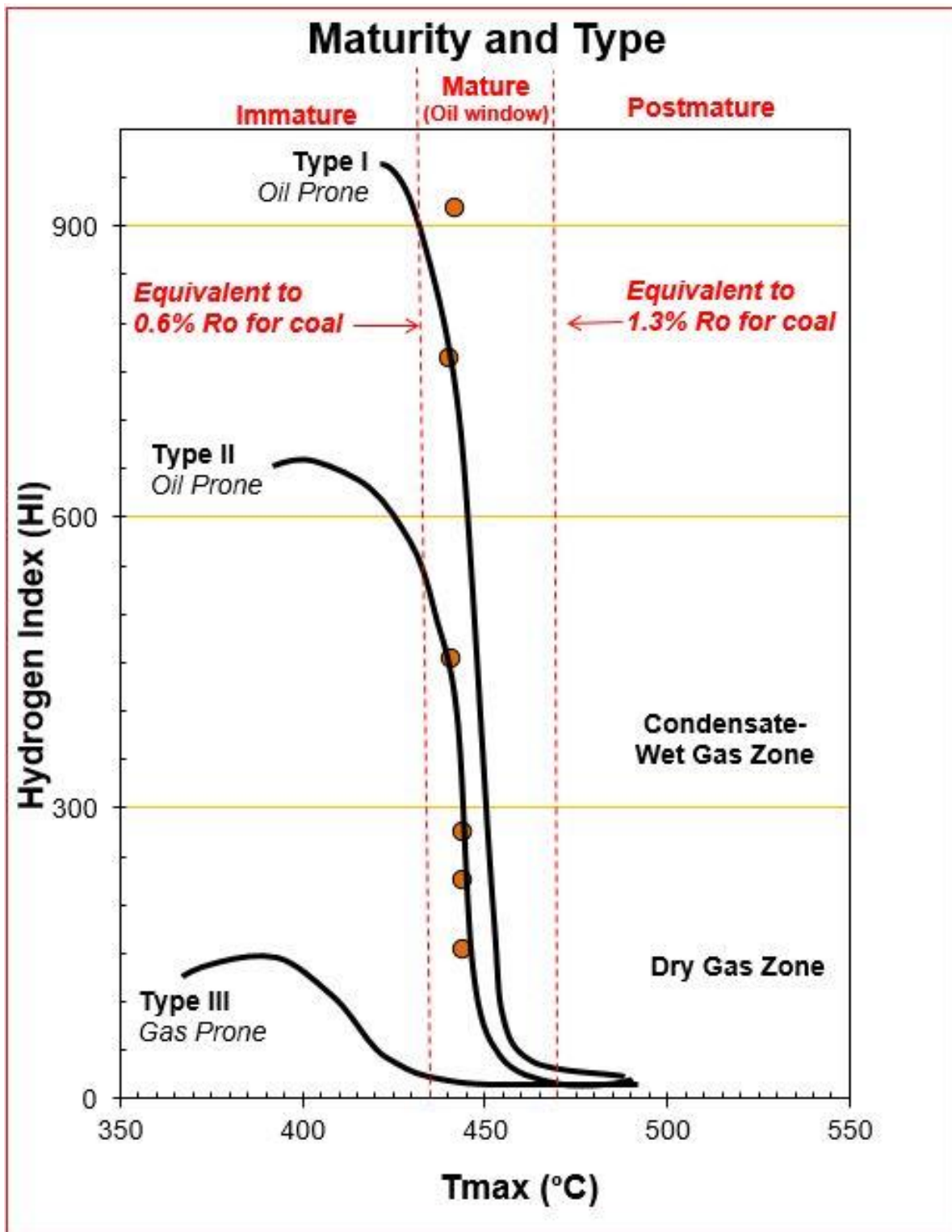
Figure 24: A cross plot of Tmax *vs* HI in Sirius-1 samples. Trend lines illustrate their respective kerogen types and maturity levels as mapped out by vertical lines. The round, brown dots represent the drill/cut samples.

Siruis-1 well samples were evaluate for their level of maturity using T-max values and related with the HI parameters for kerogen type classification. All the samples except S-09 (1520m depth) had mature (Hunt, 1996) Cretaceous shale deposits. Accordingly, their hydrogen ratio indices shown that Kerogen type I (S-07 - S-10, oil), II (S-04 and S-12, oil), type II-III (oil-gas

condensate) and III (S-02, early gas) occurred. The section of the well has good source rocks that can be thermally extracted for hydrocarbon.
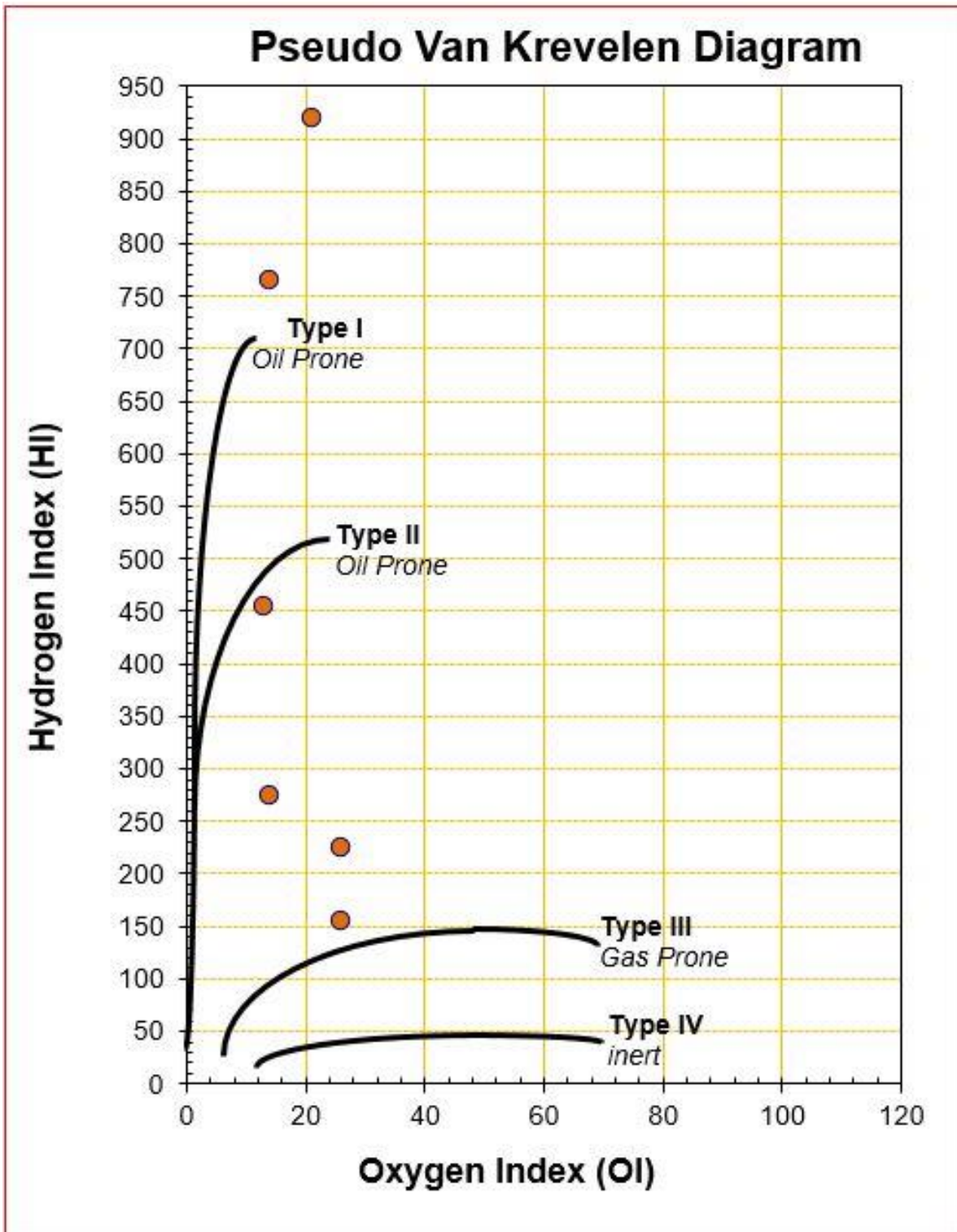
Figure 25: A cross plot of HI *vs* OI for the drill cut/core samples (after Tissot et al., 1974).

 A cross plot of the HI vs OI (Figure 25 above) which gave information about the kerogen type and maturity. S-02 Type III kerogen possess HI values between 50 –200mg HC/g TOC

and OI values ranging from 5 – 100 mg CO2/g TOC (Peters and Cassa, 1994; Tissot B, 1984).
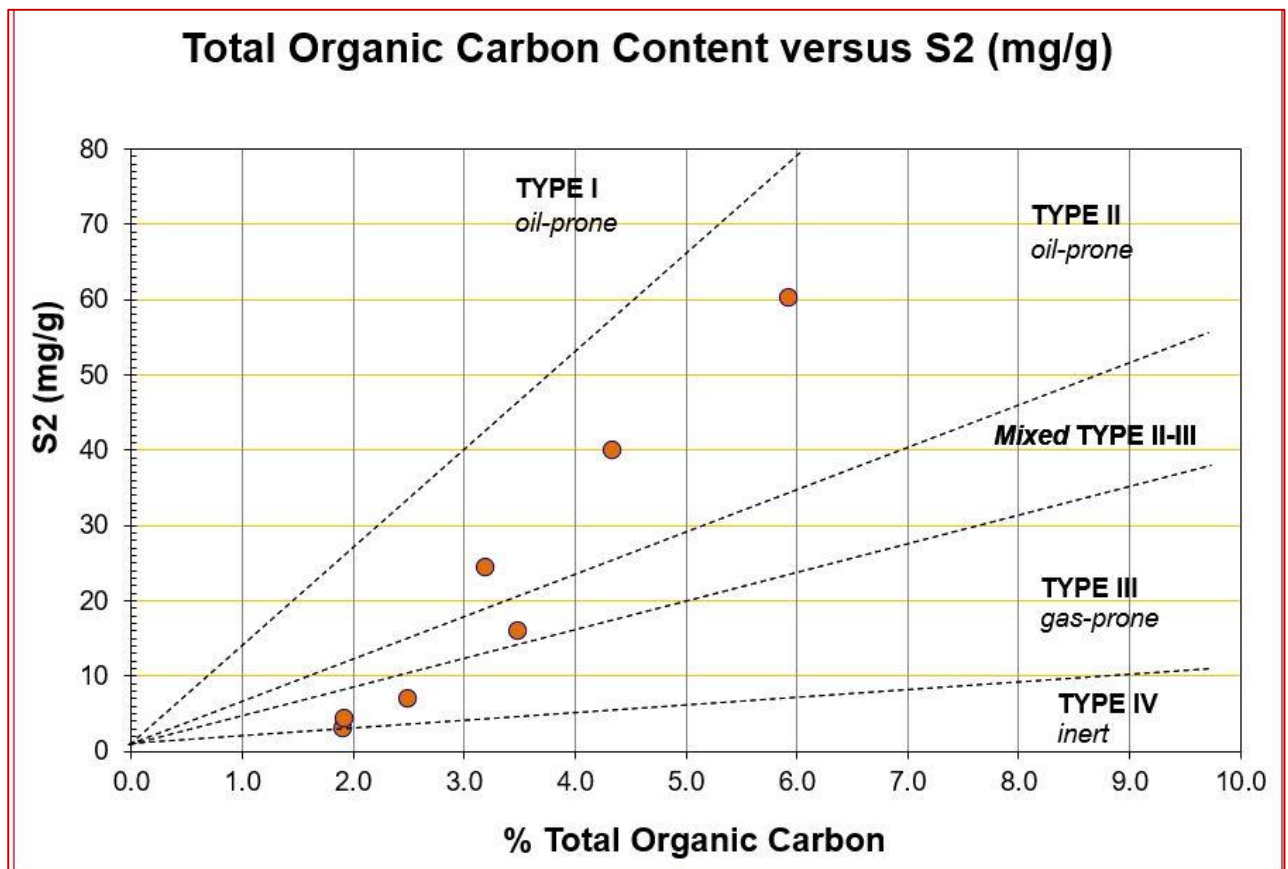
Figure 26: A schematic illustration of S2 *vs* TOC for Sirius-1 well.

A drawing of cross-section between S2 *vs* TOC (Figure 26) illustrated various kerogen types from type I-III of the source rocks. However, their ratio of organic matter against extractable hydrocarbon is directly influenced by the maturity of the source rocks. Therefore, the relationship of S2 vs T-max gave a predictive understanding of the source rock potentiality.

4.2.2.1 Matrix Correlation of TOC and Pyrolysis of Source Rock Evaluation

Source rock capability to produce hydrocarbon was evaluated using key parameters that included organic richness (TOC), thermal maturity (T-max and HI *vs* T-max graph) and identify the kerogen types (Figure 27). Anza graben has with deep sedimentary structures with varied shale composition at several depths. Well section between 1495 – 1625m, the TOC range from 3.2 to 5.94 wt.% shown excellent source rocks that was further evaluated for

pyrolysable hydrocarbon. T-max values above 440°C shown that the source rocks were mature and capable to generate gas-oil condensate to oil based on their relationship with HI.

Figure 27: Geochemical log displaying variation of different source rock parameters with depth.

Sirius-1 well evidently is potential for hydrocarbon based on the analyzed sampled depth sections. The Cretaceous source rocks were mature and extractable for oil and gas. Further depths (for which samples were not available) shown on petrographical study, using gamma log for shale content, that the depth from 2540m – 2597m.

CHAPTER FIVE GAS CHROMATOGRAPHY –MASS SPECTROMETRY

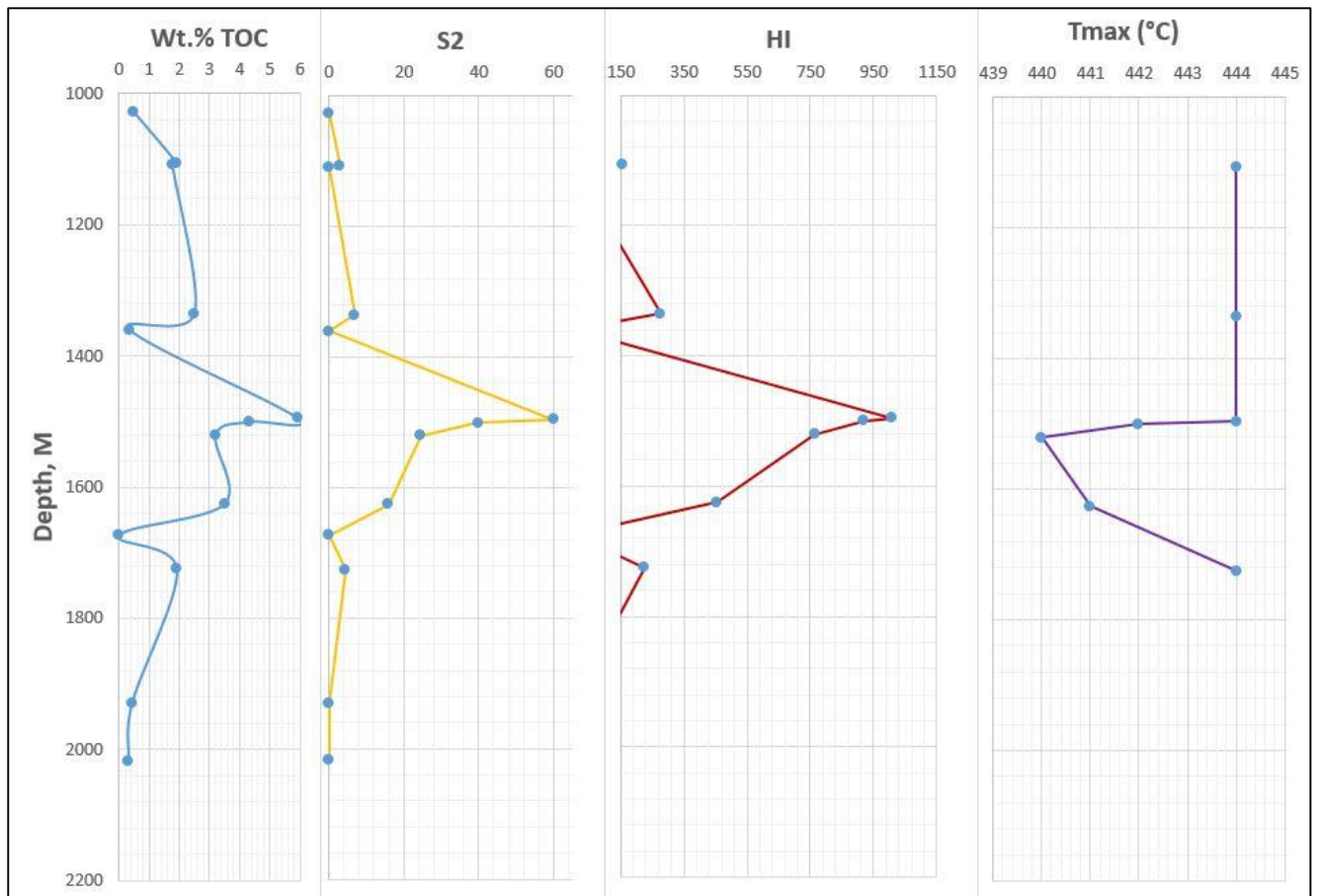The Gas Chromatography – Mass Spectrometry (GC-MS) was undertake for four samples that were selected based on their high indication for oil containment. The mass fragmentograms of the Sirius-1 drill cut/ core samples were presented in Figures 28-31 later in this chapter. The saturated fractions of the rock extract (through soxhlet extraction) were evaluated for n-alkanes, steranes, diasteranes and hopane distributions.

GC-MS mass spectra for the drill core/ cut samples and their mass to charge (m/z) ratios for various compounds were utilized to investigate existence (or not) of various biomarker and non-biomarker characterization. Their results were presented in form of tables and cross plots.

5.1   Saturated Hydrocarbons

Normal Alkanes

The total ion current (TIC) chromatogram of saturated hydrocarbons for the four studied rock extracts were generally of poor quality (Figure 28). They are characterized by huge hump of unresolved complex mixtures (UCM) and loss of almost all lower molecular weight saturate hydrocarbons up to nC_{20}. This could be attributed to exposure of the samples to higher temperature during preparation and/or due to biodegradation. However, bearing in mind that the depth from which the samples were collected, loss due to biodegradation is less likely.

The chromatograms generally display unimodal distributions in the range $n\text{-}C_{27}–n\text{-}C_{30}$ suggesting derivation from terrestrial organic matter (Brooks et al., 1969) due to the abundance of heavy carbon numbers. This may however not be reliable bearing in mind the possibility of having lost the lower chain hydrocarbons during sample preparation/degradation.

In the samples, isoprenoids; pristine and phytane are present in low concentrations but higher than the respective nC_{17} and nC_{18}. In addition, pristine is in higher abundance than phytane suggesting deposition in suboxic – anoxic environments. The higher abundance of isoprenoids relative to nC_{17} and nC_{18} would be suggestive of low maturity (Baker, 2009) however because of the excessive loss of the lower chain n-alkanes probably due to heating, such interpretation would be misleading. It would be better therefore base the interpretation other parameters such Tmax and hopane/sterane isomerization ratios.
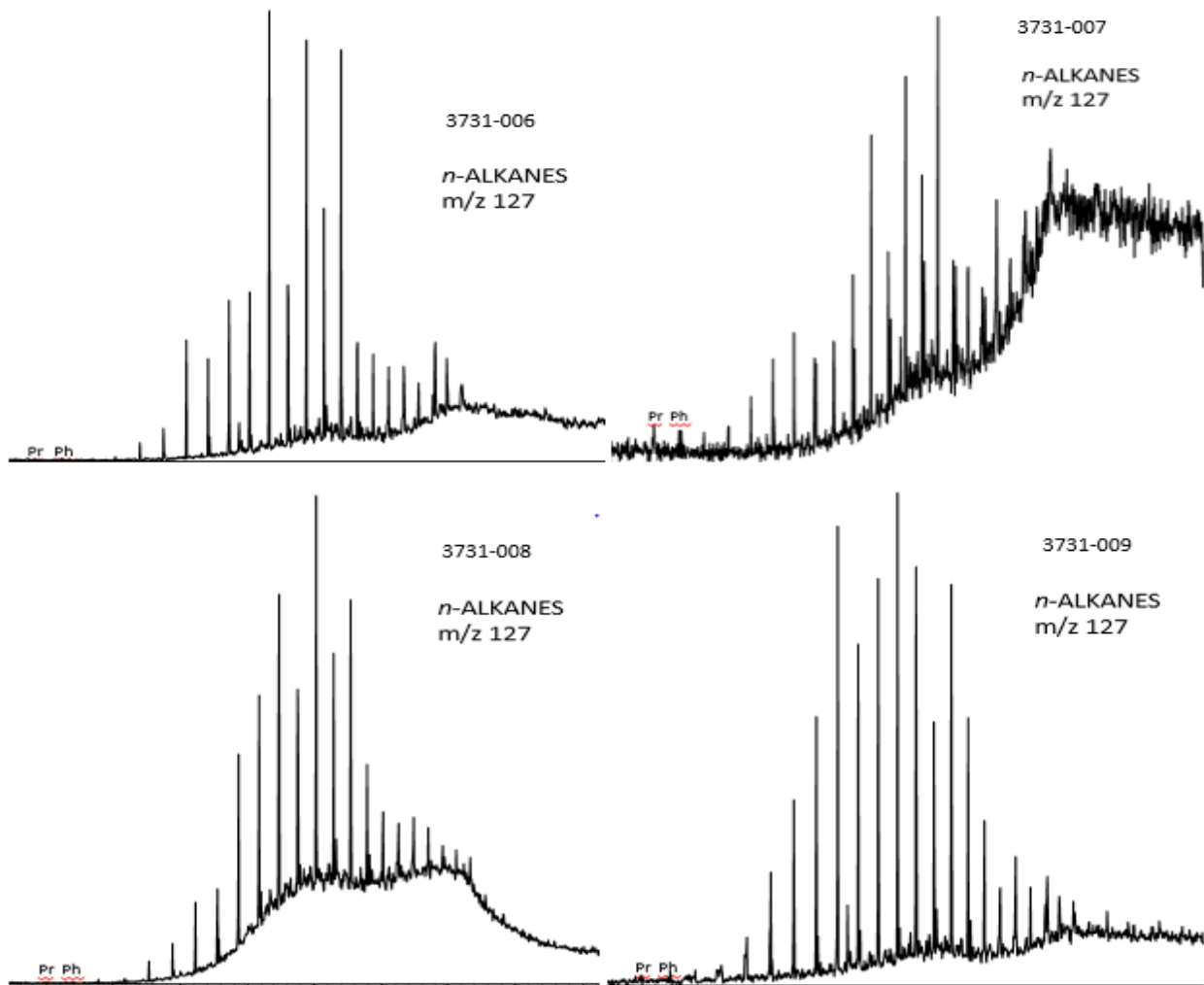
Figure 28: GC-MS m/z 127 mass fragmentograms showing n-alkanes Sirius-1 rock extracts.

5.2 Terpanes and Steranes distributions

The analysable samples were tested for the following that included tricyclic and tetracyclic terpanes (*m/z* 191), both regular and reorganized hopanes (*m/z* 191), steranes (*m/z* 217, 218, 259) as well as other compounds such as gammacerane (*m/z* 191). Their dispersion alongside volumetric assessment expressed a near-similar assemblages (Figures 29 & 30).

5.2.1 Terpanes

The classification and elemental count of the regular and reorganized hopanes (pentacyclic terpanes) obtained from the *m/z* 191 fragmentogram are shown in Figures 29 and 30. The resulted charts were presented in Tables 5-1 and 5-2.

The drill cut/ core samples illustrated the presence of very low volume indices of tricyclic terpanes compared to the hopanes that symbolized thermal maturity (Peters et al., 1990; Peters and Moldowan, 1993). Hopanes extend to C_{35} hopanes and are dominated by C_{30} αβ hopanes and C_{29} norhopane, 17α (H)-trisnorhopane (Tm), with the former being the most dominant (Figure 29 and 30). The high abundance of C_{30} αβ hopanes relative to C_{29} norhopane, 17α (H)-trisnorhopane (Tm) suggests derivation from clastic source rocks (Peters et al., 2005).

Table 5-1: Saturated Biomarkers Parameter Distributions in Rock Samples.

Source and Thermal Maturity Parameters of the Saturated Biomarkers Distributions in Rock Samples				
Sample Ref. No.	S-07	S-07	S-07	S-07
Depths (m)	1495	1500	1520	1625
Terpanes (m/z 191)				
TT1 = Ts/Tm	0.33	0.3	0.94	0.34
TT2 = Ts/Ts+Tm	0.25	0.23	0.48	0.26
TT3 = C30ab / C30ab + ba hopane	0.91	0.92	0.86	0.89
TT4 = C29ab norhopane / C30ab hopane	0.22	0.24	0.6	0.27
TT5 = C31 22S / C31 22S + 22R homohopanes	0.51	0.39	0.56	0.50
TT6 = C28 bisnorhopane/bisnorhopane + norhopane (bisnorhopane index)	0.07	0.05	0.2	0.05
TT7 = gammacerane / C30 17a hopane (gammacerane index)	0.17	0.61	0.15	0.11
TT8 = oleanane / oleanane + 17a hopane (oleanane index)	0.01	0.01	0.13	0.02
TT9 = C35/C31-C35 homohopanes (%)	6.02	6.08	14.39	9.4
TT10 = C19-C29 tricyclic terpanes / C30 17a hopane (tricyclic index)	0.03	0.05	0.5	0.05
TT11 = C24 tetracyclic terpane / C30 17a hopane	0	0	0.02	0
TT12 = C29Ts/C29 hopanes	0.22	0.16	0.15	0.17
TT13 = C22/C21 tricyclics	0.48	0.96	1.07	0.79
TT14 = C24/C23 tricyclics	0.78	0.87	0.69	0.75
TT15 = C26/C25 tricyclics	1.54	1.55	1.31	2.27
TT16 = C3122R/C30 hopane	0.07	0.09	0.19	0.11

Homohopanes decline linearly from the C_{31} to C_{35} $\alpha\beta$ hopane suggesting clastic freshwater environments (Waples and Machihara, 1990). The data sets collectively confirmed the presence for non-stratified fresh water environment characterized by the low gammacerane in the drill cut/ core samples (Figure 29 and 30) with low gammacerane index (gammacerane/C_{30} hopane ratio). Gammacerane abundances are often high in stratified, anoxic water columns (Collister et al., 1992).
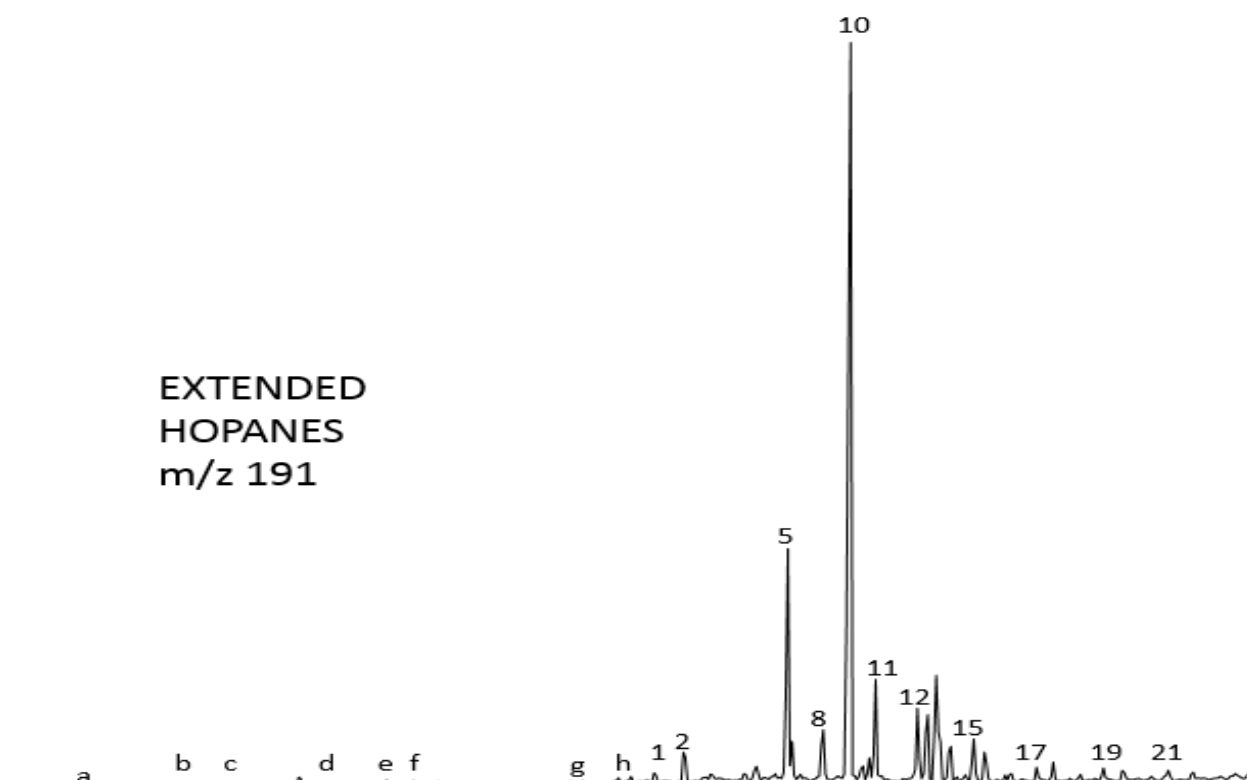
Figure 29: m/z 191 mass fragmentograms of Sirius-1 well extracts displaying extended pentacyclic terpanes. Compound identifications are provided in Appendix 1.

Isomerisation ratios of the C_{31} and C_{32} $\alpha\beta$-hopanes were predominantly span from 0.50-0.56 (Table 5-1) confirming that the assessed source rocks were mature within the stage of oil generation (Peters et al., 2005). This was confirmed by T-max data and other maturity biomarkers such as the low C_{30} moretane/ hopane ratios (Table 5-1; (Mackenzie et al., 1980)). This was perfectly in concurrence with the bulk geochemical data from Rock-Eval pyrolysis for the drill cut/ core samples.
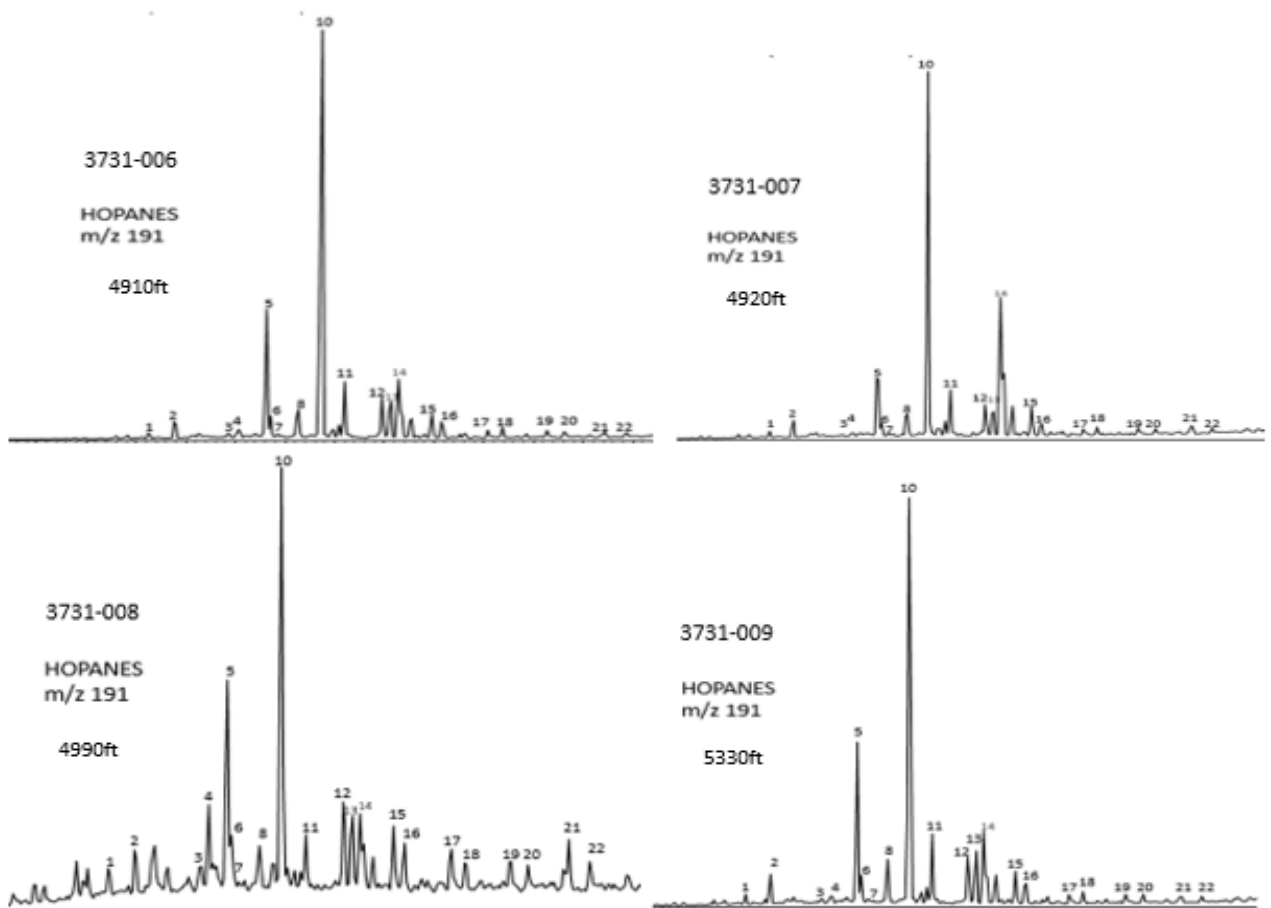
Figure 30: m/z 191 mass fragmentograms of Sirius well extracts displaying distribution of the hopane part of pentacyclic terpanes. Note the linear decline in the C30 to C35 homohopanes. Compound characterizations are provided in Appendix 1.

5.2.2 Sterane distributions

The regular sterane (m/z 217), αββ sterane (m/z 218), and the rearranged steranes (diasterane; m/z 259) biomarker evidence as displayed in Figure 32 and their respective data are given in Table 5-2.

Table 5-2: Saturated Biomarkers Parameter Distributions in Rock Samples.

Source and Thermal Maturity Parameters of the Saturated Biomarkers Distributions in Drill Cut/ Core Samples				
Sample Ref. No.	**S-07**	**S-07**	**S-07**	**S-07**
Depths (Inches)	**1495**	**1500**	**1520**	**1625**
Steranes (m/z 217, 218)				
ST1 = aa20S/aa20S+aa20R C29	0.52	0.43	0.37	0.20
ST2 = bb/aa+bb C29	0.63	0.58	0.56	0.29
ST3 = C2713b,17a 20R +20S/C27aa 20S+20R (diasterane index)	0.07	0.29	0.35	0.25
ST4 = C2913b,17a 20R +20S/C29aa 20S+20R (diasterane index)	0.59	0.33	0.95	0.14
ST5(1) = %C27bb steranes	17.70	20.44	31.07	25.50
ST5(2) = %C28bb steranes	37.78	22.72	36.95	41.38
ST5(3) = %C29bb steranes	44.52	56.84	31.98	33.13
ST6 (1) = %C27aa steranes	49.8	38.95	36.13	25.24
ST6 (2) = %C28aa steranes	37.05	32.66	23.14	20.04
ST6 (3) = %C29aa steranes	13.16	28.39	40.73	54.73
ST7 = C27-C29 steranes / C27-C35 hopanes (sterane/hopane index)	0.06	0.07	0.35	0.10
ST8 = C28/C29 sterane ratio (bb)	0.85	0.40	1.16	1.25

All samples contain C_{21} to C_{29} steranes (Figure 32; Table 5-2). The steranes are largely in very elemental numbers relative to pentacylic terpanes in all four samples as shown by the low sterane/hopane ratio (Table 5-2) suggesting contributions from prokaryotic organisms (bacteria) to the organic matter (Peters et al., 2005).
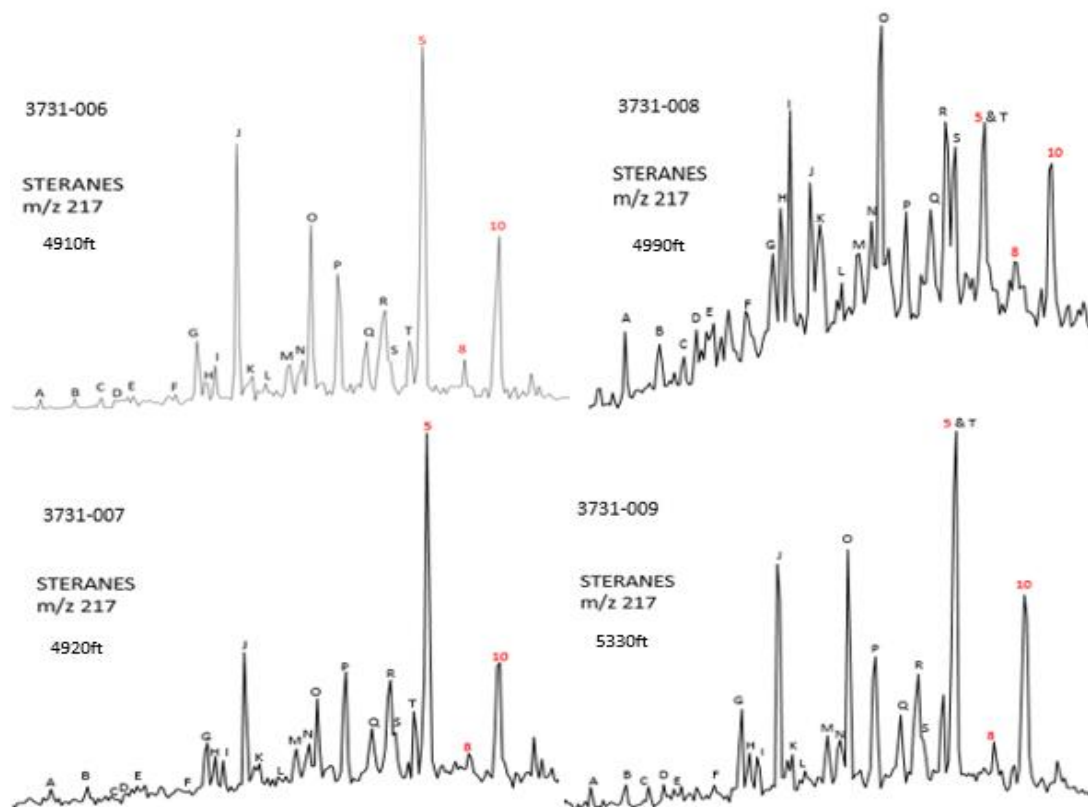
Figure 31: m/z 217 fragmentogram for Sirius -1 extract showing sterane biomarker distribution. Compound identifications are provided in Appendix 2.

The samples display significant levels of C_{28} steranes relative to C_{29} Steranes as shown by the high C_{28}/C_{29} sterane ratio in the range 0.4-1.25 indicating moderate heterogeneity of phytoplankton assemblages such as diatoms in the OM of the source rocks (Moldowan et al., 1985). The extracts generally show dominance of C_{28} and C_{27} relative to C_{29} steranes implying algal OM type (Peters and Moldowan, 1993). This was in agreement with results from Rock-Eval pyrolysis that showed type I/II organic matter.

Apart from the sample from 5330m, the 20S/(20S+20R) 14α(H),17α(H) C_{29} regular sterane ratios in the rest of the drill cut/ core samples range between 0.0.56 – 0.63 (Table 5-2) indicating that their maturation level lay within the oil expulsion stage (Mackenzie et al., 1980; Seifert and Moldowan, 1986). This is in total agreement with results from Tmax and hopane isomerisation ratios.

CHAPTER SIX: DISCUSSION, CONCLUSION AND RECOMMENDATION

6.1 Discussion

Kaisut-1 well was primary a shallow well with total depth at 1450m. It encountered silicic sandstones with minimal shale content. The depth level targeted did not result any identifiable potentiality for hydrocarbon but the intersections possible for good source rocks lies beneath at the Cretaceous rocks. Ndovu-1 well samples were from the Paleocene-Cretaceous age with sandstone–mudstone bearing shale deposited sediments. However, geochemical evaluation provided minimal ratios of TOC percentages. Geothermal gradient and rifting systems of the Yamicha sub-basin affected the deposition and accumulation of preserved organic matter.

For probable depths, well sections for up to Mesozoic should be analyzed. Chalbi-3 had confirmable volume of kerogen type III and mature source rocks but with very low hydrogen indices compared to oxygen indices. That meant, both samples were gas prone but further characterizations proved that the source rocks had little extractable ratios of hydrocarbon. The deeper depth sections of this category are confidential and therefore, could not be used for this research.

Bulk geochemical data and biomarker data for Sirius-1 well show that the analyzed source rocks are of oil prone organic matter Type I/II within the oil window (mature). Sirius-1 well has deep well intervals with good shale volume, high TOC percentages, and producible mature oil content. This illustrated that it require further development and exploratory study for future confirmation of oil volumes and generic sources of the hydrocarbon. Due to poor storage and handling of samples, the lighter hydrocarbons could not be analyzed using GC-MS. However, biomarker characterization was achieved for C_{17}- C_{35}.

6.1.1 Correlation of Petrographical and geochemical data for Sirius-1 well

Sirius-1 well was the most productive as per both the petrographical characterization that included visual analysis of the samples and geochemical evaluation of the Cretaceous shaly rocks. Therefore, the correlation map as shown in Figure 33 below portray a good source rock deposition and enrichment of mature extractable hydrocarbon content that is commercially viable. The mapped zone corresponds to the well section observed on the petrographical model was the case study section of the well.
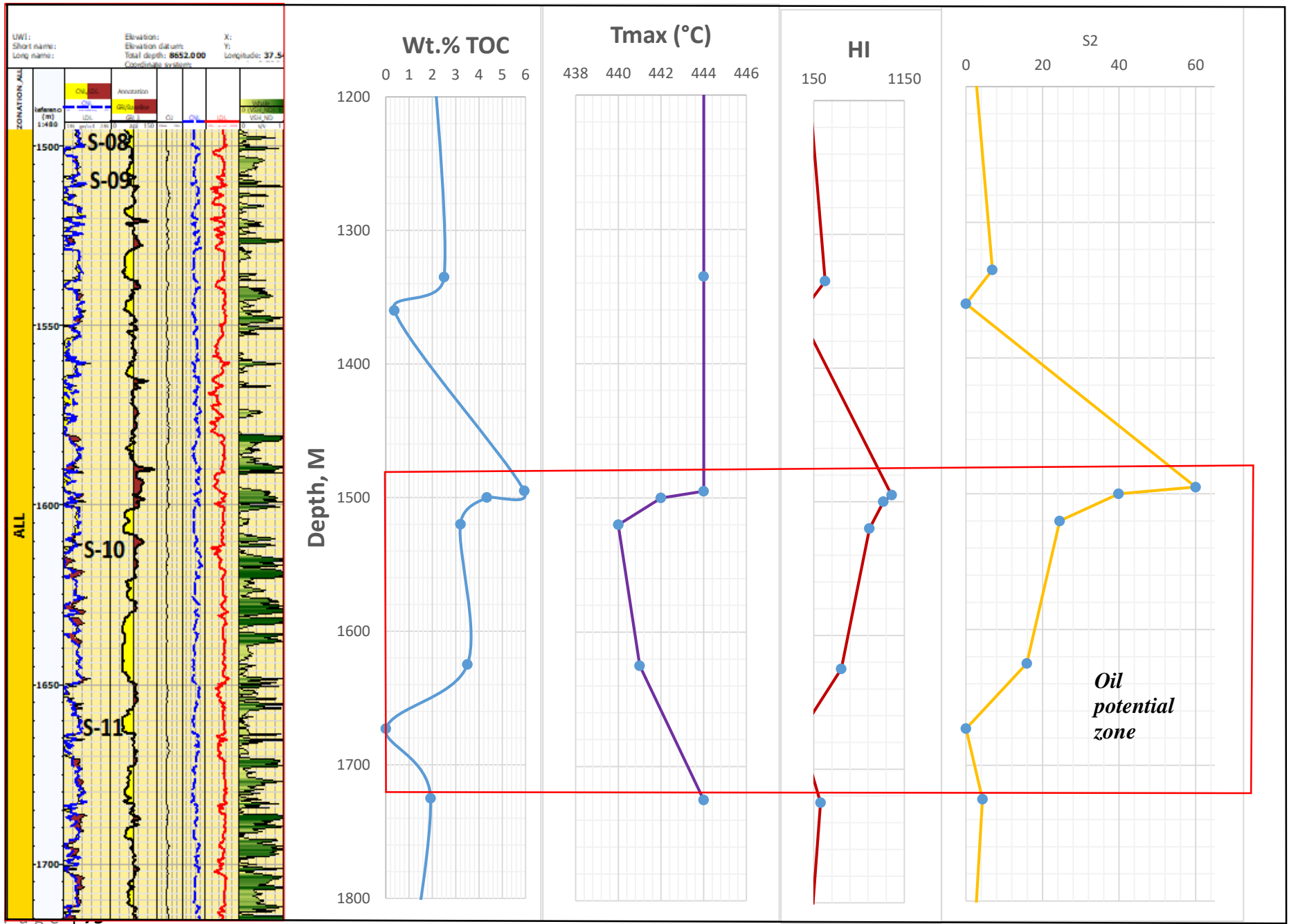
Figure 32: Correlation model of Sirius-1 well

6.2 Conclusion

The principal objective of the research was to undertake the geochemical evaluation of the drill cut samples from four wells in Anza basin namely: Kaisut-1, Ndovu-1, Chalbi-3 and Sirius-1. The evaluation of these wells was used to prognostically study of the source rock content that could have generated hydrocarbons in the Anza graben study area. The results from the interpretations of the lithological arrangement and composition of every well in the vast area revealed the presence of deep sediments ranging from 2000m to 11000m. These sediments are predominantly of siliciclastic fluvial to marine origin, deposited in a reduction environments; especially at shallower depths between 1400 - 2350m below the surface thus affected the preservation of organic matter. Therefore, this sedimentation has minimal composition of organic content for hydrocarbon generation.

However, although Sirius-1 well had only visible indications of oil and gas in the stratigraphic sections between 1100-2300m depths the geochemical samples evaluated for their level of maturity using T-max values and the related HI parameters for kerogen type classification confirmed that the samples except S-09 (1520m depth) had matured (Hunt, 1996) in the Cretaceous shale deposits. Accordingly, their hydrogen ratio indices indicated that Kerogen type I (S-07 - S-10, oil), II (S-04 and S-12 type II-III oil-gas condensate) and III (S-02, early gas) occurred. The proposed primary HC product is waxy crude oil or wet gas (North, 1985 and Barker, 1999). The section of the well has good source rocks that can be thermally extracted for hydrocarbon. Lithographic assessment indicated presence of reservoir rocks with good porosity (30%) were reported in the Sirius-1 (Rop, 2013); and that due to absence of tie vertical separation between source and reservoir rocks, it suggest that oil and gas there is a possibility that the oil and gas have not migrated much in this well section. He further suggested that the source rocks which apparently extended to the deeper eastern part of the well would probably have better oil and gas potential (Rop, 2013).

The observed variations in TOC content suggested presence of different sediment facies inherent in the localities from which the drill cut samples were collected. Thus, localities with high TOC indicate good sediment provenance history (surface bio-productivity) that subsequently underwent OM preservation during sedimentation processes and early diagenesis. Rock-Eval data in Sirius-1

well revealed that free hydrocarbons (S1) in the range of 0.16 and 0.98 mg HC/g while potential hydrocarbons (S2) are in the range 2.96-60.01 mg HC/g. The S2 values are consistent with good oil generative potential (Peters, 1986a). The samples show Tmax values in the range of 441 °C - 444 °C that suggest the presence of thermally mature source rocks intrinsic within oil generation peak (J. Espitalie et al., 1985b). The high thermal maturity is indicate the imperative OM burial and conducive sub-surface temperature for HC formation. The hydrogen index (HI) for the analysed source rocks spanned from 155 to 1010 mg HC/g TOC were compatible with oil prone OM type (Peters, 1986a; Tissot et al., 1974)

Kaisut sub-basin lies in the South Anza basin has predominantly sandstone interbedded with siltstone and claystone. Ndovu-1 had little intervals of shale. Chalbi sag basin has deeper sections of buried source rocks beyond 1600 m and with identifiable richness of organic content above 0.4% TOC. Sirius-1 and Chalbi-3 wells bear a Cretaceous source rocks whose shale content has HC apparently increase with deeper stratigraphic depth intervals. There is a feasibility of encountering HC potential source rocks in the Lower Cretaceous segment in the deeper part of the Chalbi Basin where Chalbi-3 well was drilled (Rop, 2013). Sirius-1 well has commercially extractable oil of up to depth intervals ranging from 2540–2597m.

The research concluded that the parametric controls for generation of extractable hydrocarbon, that was strictly based on source rock material (kerogen types), quality and their maturity, was comprehensively studied and demonstrated; therefore, the objectives of the research was satisfactorily achieved despite the inherent challenges that included sample storage and preparation as well as financial constraints.

6.3 Recommendation

This research was able to identify the sections with good percentages of source rocks with considerable depth levels. With relatively good reservoir rocks reported in the Sirius-1 well, the region should further be explored for HC potentiality. However, the storage and handling of the drill or core cuttings requires tight enclosure with minimal climatic interferences of samples.

During sampling, a big ratio of sampled drill cut samples were drilling mud, which may have affected the amount of source rocks after washing and extraction. Petrographic study of the cores should be considered to counter the loss of integrity of samples.

In addition, deeper sections of the well should be studied and preferably drilled deeper to underlying older Mesozoic rocks (Lower Cretaceous to Upper Cretaceous sedimentary sequences). This is because, based on the results of the studied sections, deeper wells sections have hydrocarbon potential with a proven characterization with increase in depth.

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APPENDICES:

Appendix 1: Peak identification for Pentacyclic terpanes (m/z 191) compounds.

Ion	Peak Label	Compound Name	Ret. Time	Area
191		C20 tricyclic terpane	26.1	947
191		C21 tricyclic terpane	27.7	1672
191	a	C22 tricyclic terpane	29.2	794.45
191	b	C23 tricyclic terpane	30.8	4276
191	c	C24 tricyclic terpane	31.7	3337
191	d	C25 tricyclic terpane	33.5	7349
191	e	C24 tetracyclic terpane	34.6	11719
191	f	C26 tricyclic terpane	34.8	11291
191	g	C28 tricyclic terpane	37.8	19964
191	h	C29 tricyclic terpane	38.6	33376
191	1	Ts 18α(H)-trisnorhopane	39.2	34181
191	2	Tm 17α(H)-trisnorhopane	39.8	105109
191	3	C28 17α18α21β(H)-bisnorhopane	40.9	53252
191	4	17αα21β(H)-30 norhopane	41.1	116272
191	5	C29 nor-30-hopane	41.6	717840
191	6	C29 Ts 18α(H)-norneohopane	41.7	156040
191	7	C30 17α(H)-diahopane	41.9	22150
191	8	C29 normoretane	42.3	265127
191	9	oleanane	42.5	20126
191	10	C30 17α(H)-hopane	42.7	3318241
191	11	C30 moretane	43.2	337067
191	12	C31 22S 17α(H) hopane	44.0	253719
191	13	C31 22R 17α(H) hopane	44.1	247943
191	14	gammacerane	44.3	573236
191	15	C32 22S 17α(H) hopane	45.0	173551
191	16	C32 22R 17α(H) hopane	45.1	86298
191	17	C33 22S 17α(H) hopane	46.1	38883
191	18	C33 22R 17α(H) hopane	46.4	44710
191	19	C34 22S 17α(H) hopane	47.3	57481
191	20	C34 22R 17α(H) hopane	47.6	43040
191	21	C35 22S 17α(H) hopane	48.4	50151
191	22	C35 22R 17α(H) hopane	48.9	30822

Ion	Peak Label	Compound Name	Ret. Time	Area
177	I	17a(H),21b(H)-25,28,30-trisnorhopane	39.6	
177	II	17a(H),21b(H)-25,30-bisnorhopane	40.2	
177	III	17a(H),21b(H)-25-norhopane	41.1	22530
177	IV	17a(H),21b(H)-22(R)-25-norhomohopane	42.5	
177	V	17a(H),21b(H)-30-norbishomohopane	42.7	

Appendix 2: Peak identification of sterane (m/z 217) compounds.

| Ion	Peak Label	Compound Name	Ret. Time	Area
217	a	C21 sterane	29.5	1228
217	a1	C22 sterane	29.7	196
217	b	C22 sterane	31.2	909
217	A	C27 ⲁⲁ 20S diasterane	36.3	2818
217	B	C27 ⲁⲁ 20R diasterane	36.8	3007
217	C	C27 ⲁⲁ 20S diasterane	37.1	3525
217	D	C27 ⲁⲁ 20R diasterane	37.4	3899
217	E	C28 ⲁⲁ 20S diasterane	37.5	6210
217	F	C28 ⲁⲁ 20R diasterane	38.2	3280
217	G	C28 ⲁⲁ 20S diasterane & C27 ⲁⲁ 20S sterane	38.5	22304
217	H	C27 ⲁⲁ 20R & C29 ⲁⲁ 20S diasterane	38.6	8849
217	I	C27 ⲁⲁ 20S sterane & C28 ⲁⲁ 20R sterane	38.8	8818
217	J	C27 ⲁⲁ 20R sterane	39.1	77822
217	K	C29 ⲁⲁ 20R diasterane	39.3	16297
217	L	C29 ⲁⲁ 20R diasterane	39.5	9170
217	M	C28 ⲁⲁ 20S sterane	39.8	13476
217	N	C28 ⲁⲁ 20R sterane & C29 ⲁⲁ 20R diasterane	40.0	12674
217	O	C28 ⲁⲁ 20S sterane	40.1	57061
217	P	C28 ⲁⲁ 20R sterane	40.5	57902
217	Q	C29 ⲁⲁ 20S sterane	40.9	22364
217	R	C29 ⲁⲁ 20R sterane	41.1	55270
217	S	C29 ⲁⲁ 20S sterane	41.2	18772
217	T	C29 ⲁⲁ 20R sterane	41.5	20560
218	C27ⲁⲁR	C27 ⲁⲁ 20R sterane	38.6	6252
218	C27ⲁⲁS	C27 ⲁⲁ 20S sterane	38.8	9734
218	C28ⲁⲁR	C28 ⲁⲁ 20R sterane	40.0	11712
218	C28ⲁⲁS	C28 ⲁⲁ 20S sterane	40.1	22403
218	C29ⲁⲁR	C29 ⲁⲁ 20R sterane	41.1	29125
218	C29ⲁⲁS	C29 ⲁⲁ 20S sterane	41.2	11079

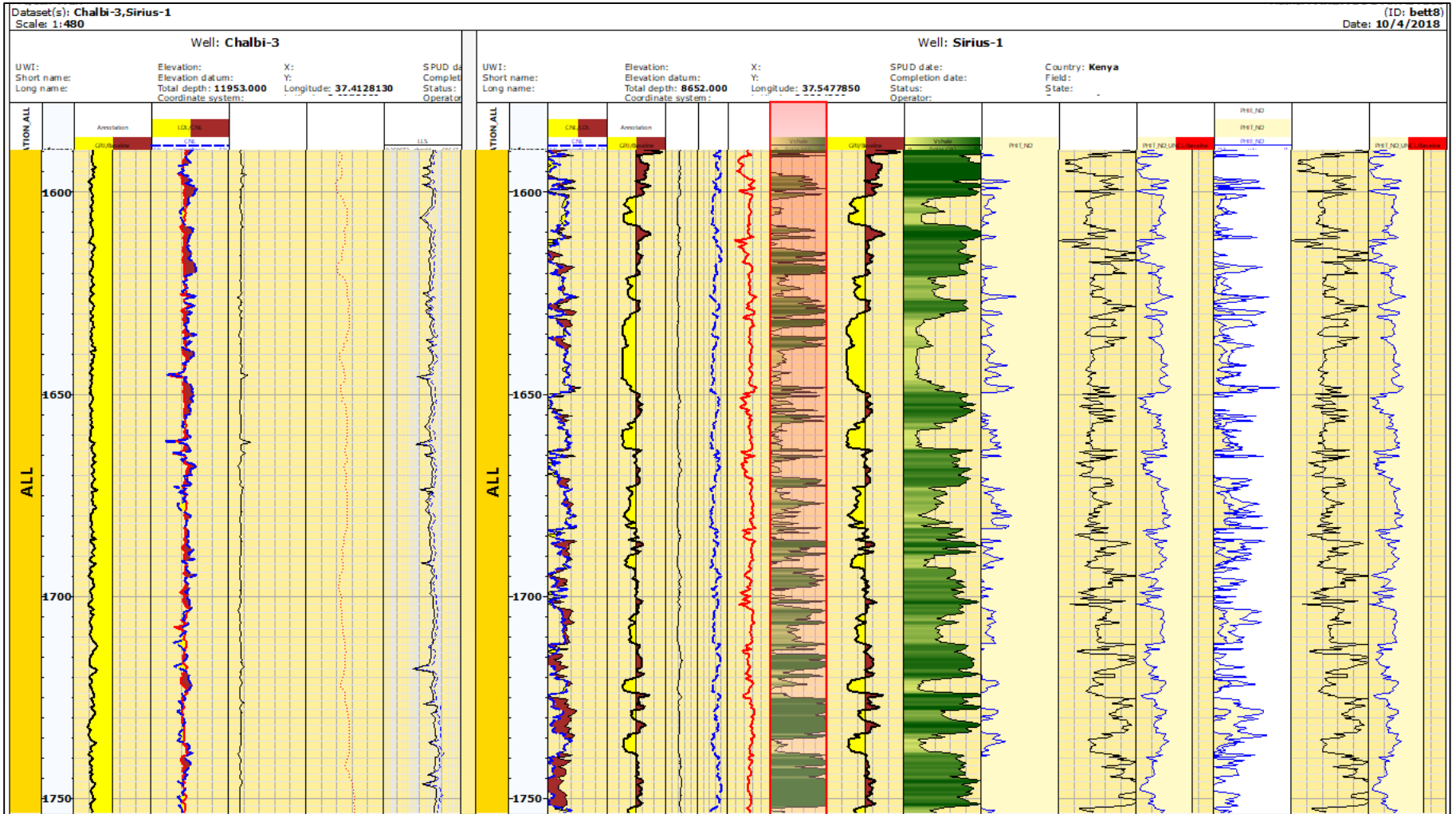Appendix 3: International Chronostratigraphic chart, 2018.
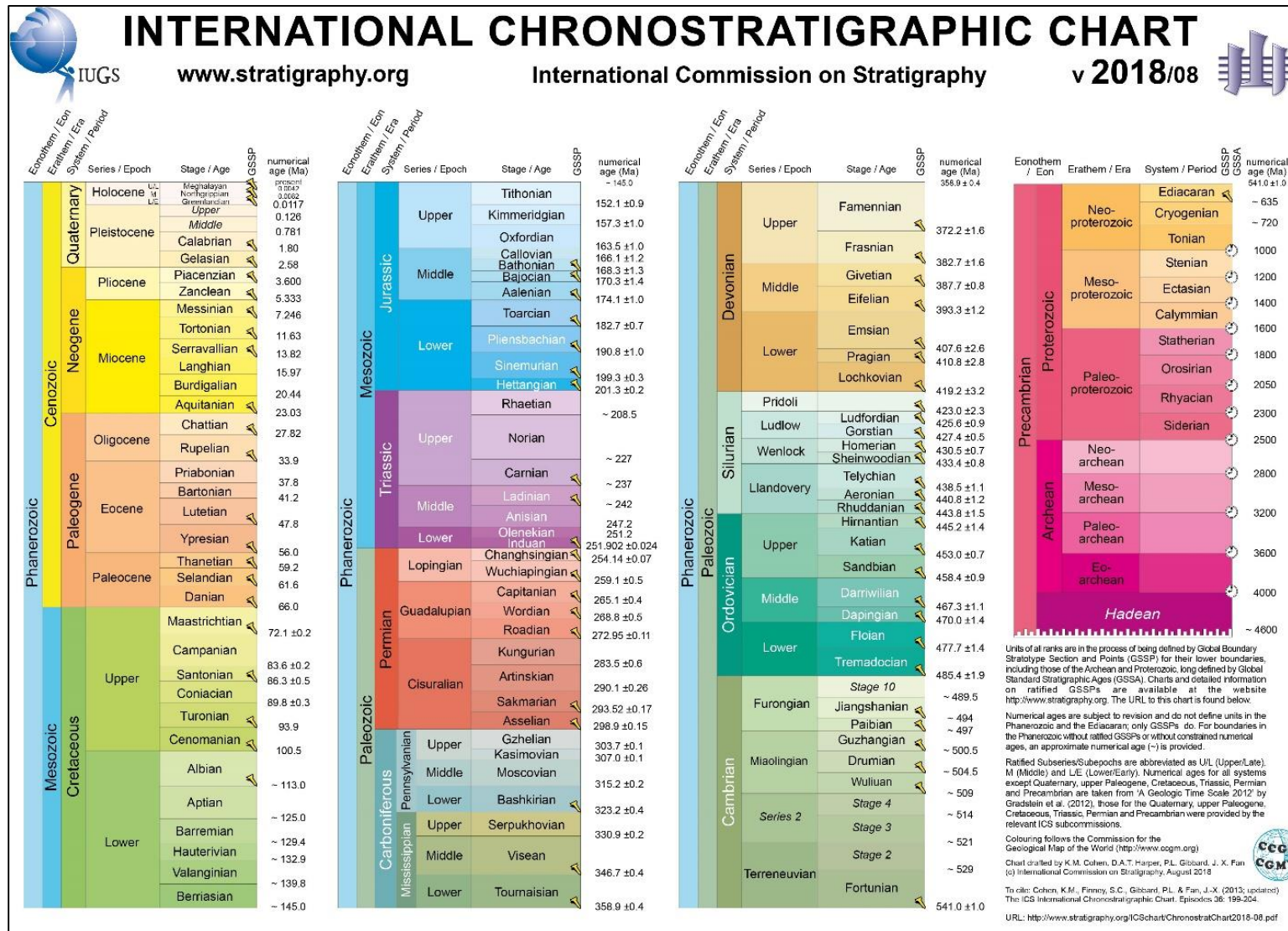
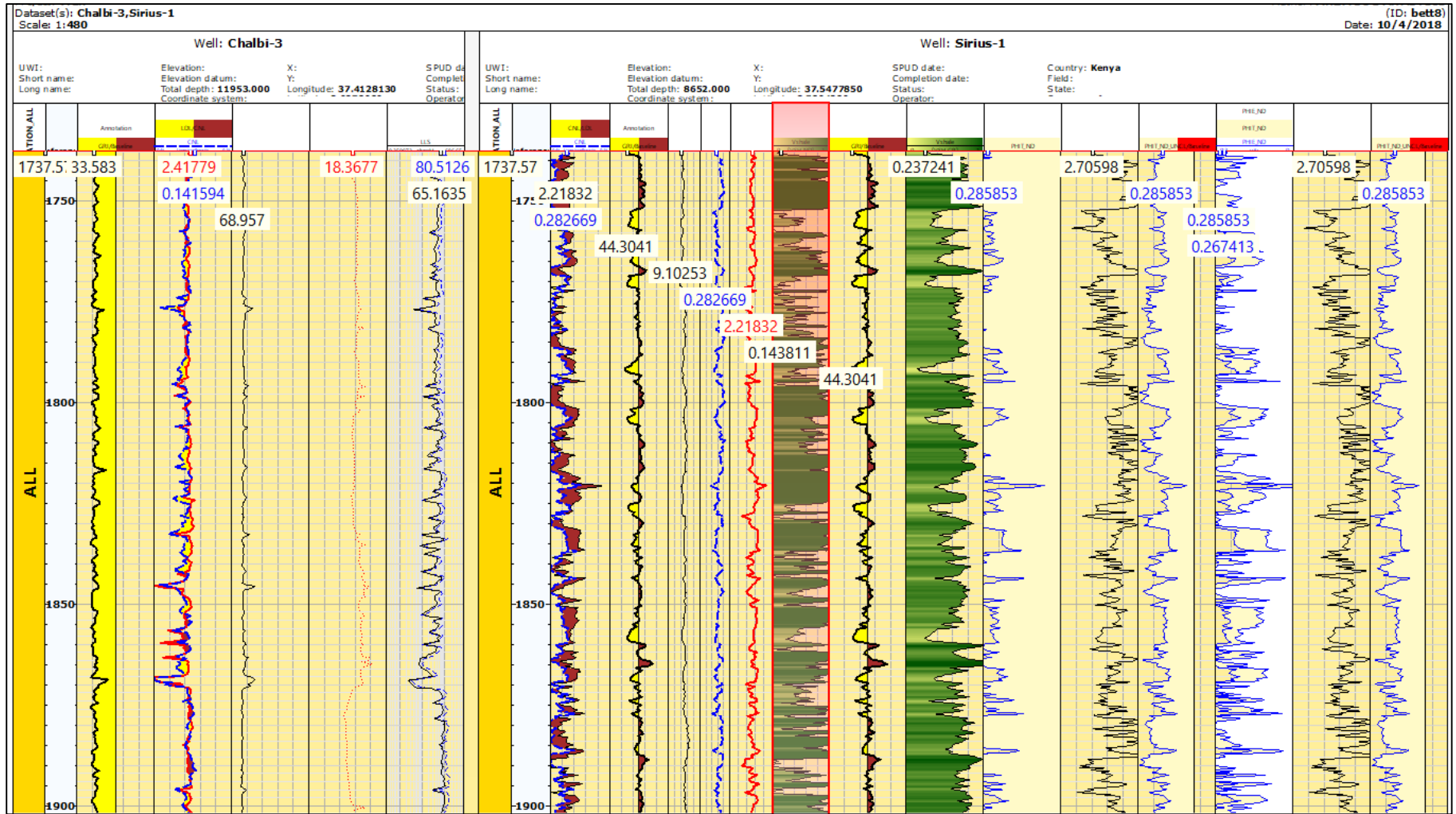Appendix 4: Chalbi-3 and Sirius-1 Vshale at deeper depths 1300-1450m.
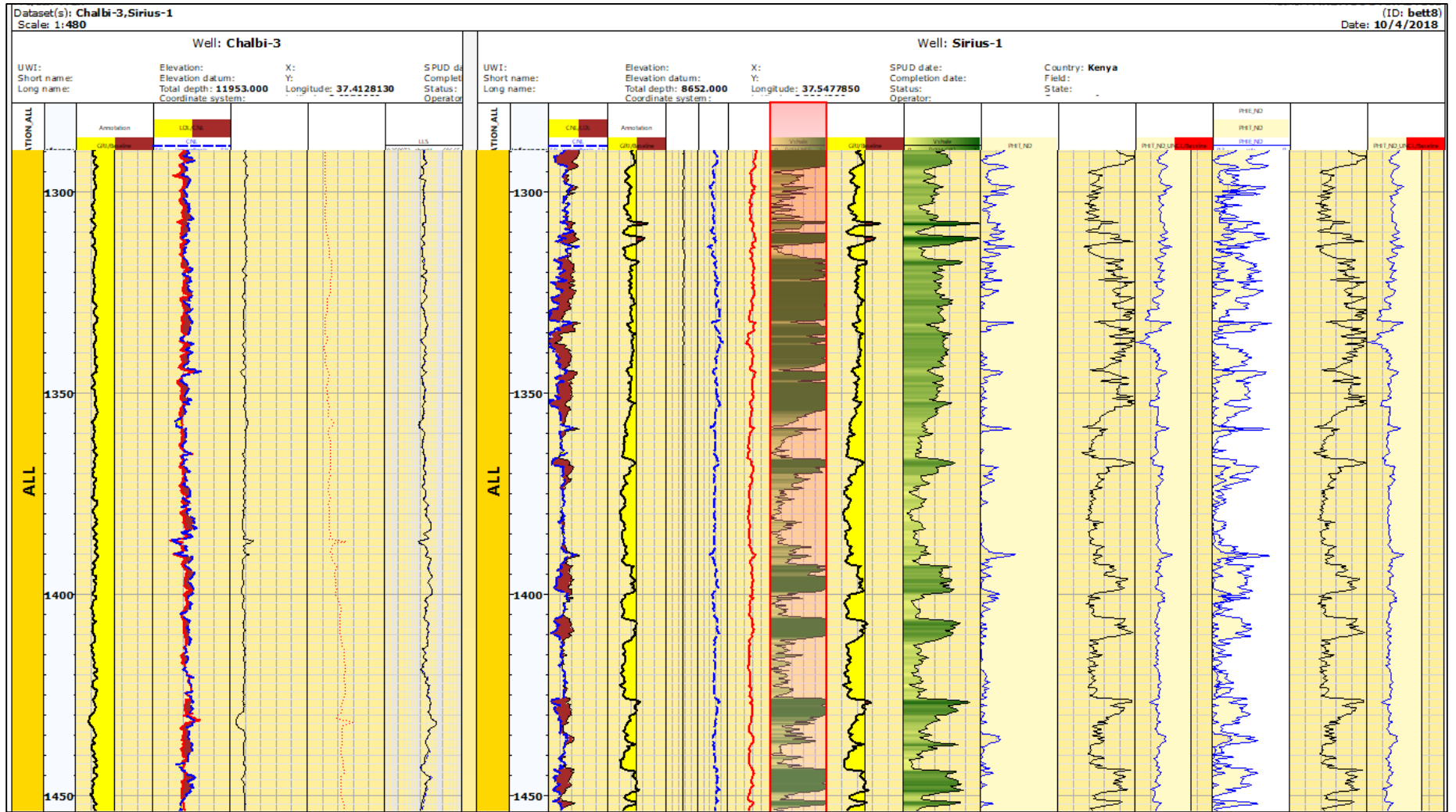
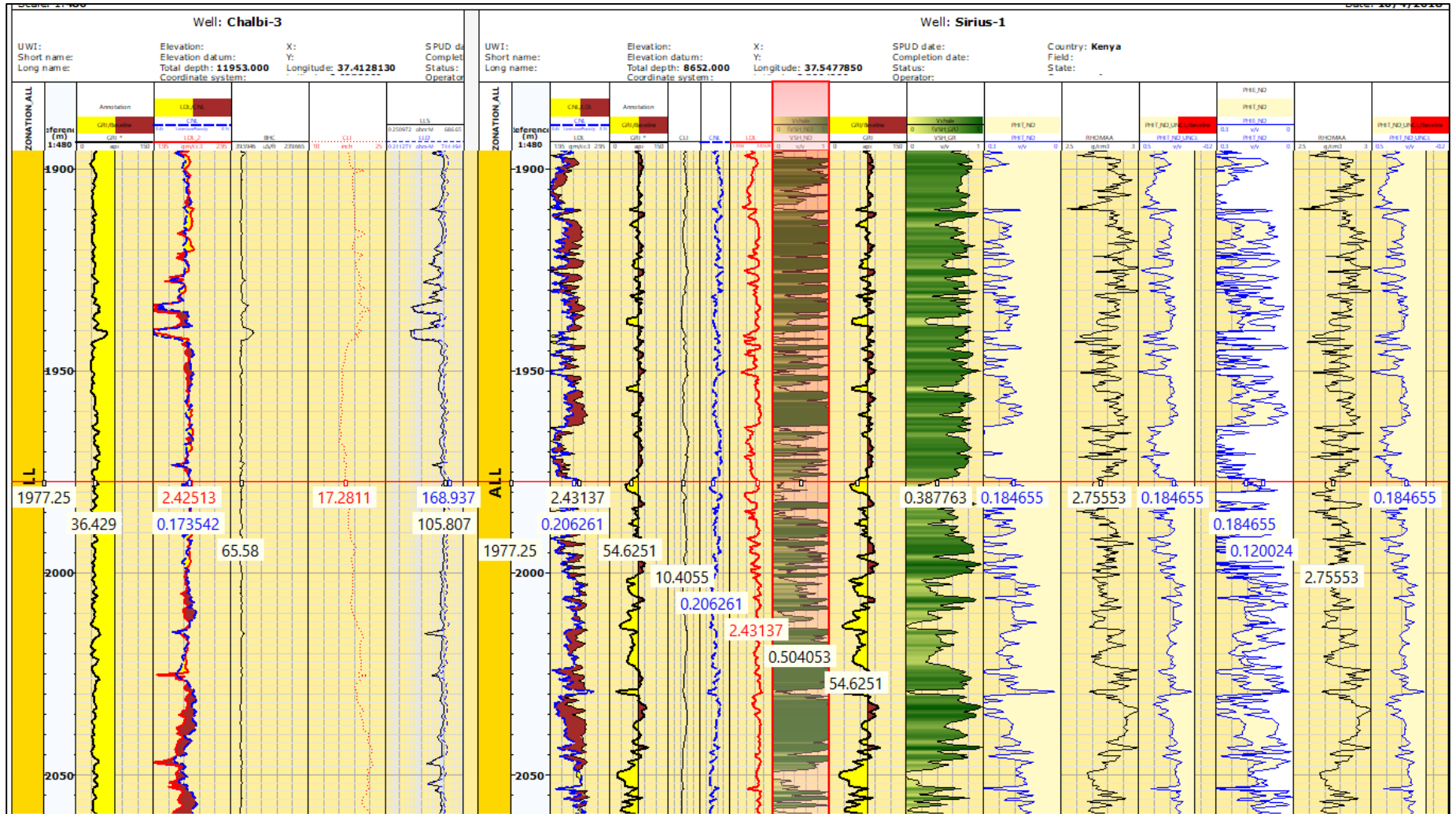Appendix 5: Chalbi-3 and Sirius-1 Vshale at deeper depths 1450 -1600m.
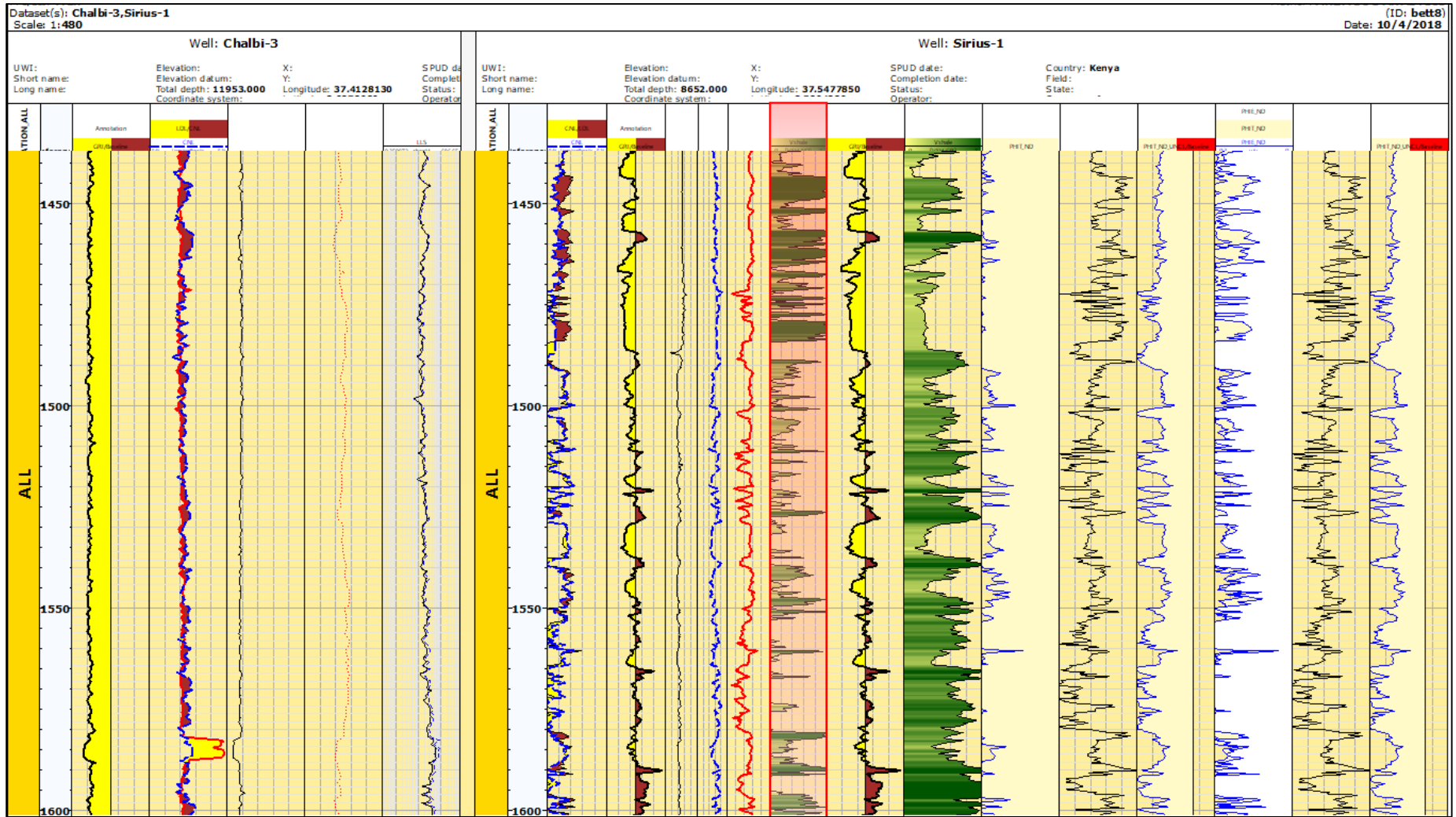
Appendix 6: Chalbi-3 and Sirius-1 Vshale at deeper depths 1600-1750m.

Appendix 7: Chalbi-3 and Sirius-1 Vshale at deeper depths 1750-1900m.

Appendix 8: Chalbi-3 and Sirius-1 Vshale at deeper depths 1900-2050m.

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GEOCHEMICAL EVALUATION OF THE HYDROCARBON POTENTIAL OF SOURCE ROCKS IN THE ANZA BASIN

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