MedMax Publishers

ISSN: 2769-2310

International Journal of Environmental & Earth Sciences Research Article

Petrophysical Analysis using well Logs Data to Evaluate the Hydrocarbon Potentiality of the Sudanese Red Sea Coastal Plain

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Received: 24 February 2022; **Published**: 25 April 2022

Abstract
This study represents an evaluation of the petrophysical properties in two wells are located in Sudanese Red Sea Coastal Plain. The petrophysical evaluation is based on well logs data to delineate the reservoir characteristics. The environmental corrections and petrophysical parameters such as porosity, water saturation, and hydrocarbon saturation are computed and interpreted using Interactive Petrophysics (IP) program. The petrophysical interpretation yielded three hydrocarbon pay zones of interest in Well No-1 as follows: The first interval (A) in from 2780 to 2815m in Lower Zeit Formation has gross sand of 30m, net pay of 2m, Average porosity of 17% and Saturation Water (Sw) is 51%. The second interval (B) from 2865 to 3020m in Lower Zeit Formation has gross sand of 155m, net pay of 6m, Average porosity of 21% and SW is 51%. The third interval (C) from 3220 to 3255m in Lower Zeit Formation has gross sand of 33m, net pay of 9m, Average Porosity of 21% and SW is 49%. The petrophysical interpretation yielded three hydrocarbon pay zones of interest in Well No-1 as follows: The first interval (A) is in the Upper Zeit from 1750 to 1820m. The gross sand is 9.5m, net pay 4m, Average Porosity 16% and Sw 44%. The second interval (B) is in the Middle Zeit from 2370 to 2400m. The gross sand is 17m, net pay 8m, Average Porosity 14% and Sw 51%. The third interval (C) in the Middle Zeit from 2435 to 2466m has gross sand of 20m; net pay of 4.5m, the Average porosity is 14% and Sw 56%.The above results show that the study area potential in hydrocarbons spatially gas and condensates.

Keywords: Petrophysics, Zeit Formation, Shale Volume, Porosity, Saturation

Introduction

Petrophysics is the study of rock properties and their interactions with fluids (gases, liquid hydrocarbons, and aqueous solutions). The geologic material forming a reservoir for the accumulation of hydrocarbons in the subsurface must contain a three-dimensional network of interconnected pores in order to store the fluids and allow for their movement within the reservoir. Thus the porosity of the reservoir rocks and their permeability are the most fundamental physical properties with respect to the storage and transmission of fluids. Accurate knowledge of these two properties for any hydrocarbon reservoir, together with the fluid properties, is required for efficient development, management, and prediction of future performance of the oilfield [1]. The nature of reservoir rocks containing oil and gas dictates the quantities of fluids trapped within the void space of these rocks, the ability of these fluids to flow through the rocks, and other related physical properties. The measure of the void space is defined as the porosity of the rock, and the measure of the ability of the rock to transmit fluids is called the permeability. Knowledge of these two properties is essential before questions concerning types of fluids, amount of fluids, rates of fluid flow, and fluid recovery estimates can be answered. Methods for measuring porosity and permeability have comprised much of the technical literature of the oil industry. Other reservoir properties of importance include the texture, the resistivity of the rock and its contained fluids to electrical current, the water content as a function of capillary pressure, and the tortuous nature of the interstices or pore channels [2].

The Study Area

The study area lies in NE Sudan in the Red Sea State. It is bounded by longitudes 37o 30′ E & 38o 15′ E and latitudes 19o 00′ N & 22o 00′ N. (Fig 1.) .The main physiographic features in the study area are part of Red Sea Hills in the west and coastal plain in the east. The Sudanese coastal plain is 740 km long, generally 20 km wide but increasing to 40 km at Halaib area on its northern edge and to 50 km at Tokar Delta in the south [3]. The coastal plain generally has gentle topography. It lies between the Red Sea and the erosional scarp that bounds the Red Sea Hills from the east. The coastal plain is predominantly made of interdigitating marine and continental deposits of Pleistocene and recent age, including raised coralline limestone near the shoreline and thick, very coarse, angular terrace deposits near the foot of the Red Sea Hills. These sediments overlie unconformably the Tertiary deposits of the Red Sea littoral [4]. The main features of the coastal plain north of Port Sudan are the presence of several isolated outcrops of clastic and carbonate deposits; these include the Low Conical Hills, Eit outcrops, Jebel Saghum, Jebel Tobanam and Jebel Hmamit. These coastal hills are formed almost entirely of carbonate, gypsum and clastic deposits with a height of over 100 m and they extend north - south. The southern extension of the Low Conical Hills trend in a curve – shape nearly to the eastern escarpment of the Red Sea Hills. The width of the coastal plain in the study area is about 16 km. It is generally flat to gently sloping towards the Red Sea, interrupted by scattered sedimentary outcrops and ridges consisting of continental and marine sediments. The study area is covered mainly by recent deposits, characterized in the north-eastern portion of the area mainly by sand dunes, alluvial terraces and sabkha deposits near the Red Sea shoreline. The eastern and northern parts of the area are flat and covered by gravel terraces of basic and acidic origin, except in the main course of Khor Eit, where the sediments are smaller in size. The Red Sea is a long narrow marine basin, with a total length in Sudan of about 740 km. It extends from the Eritrean border in the south to the border with Egypt in the north. Its maximum width is 306 km. The Red Sea is the eastern boundary of the study area, with a width of about 148 km in the study area [5].

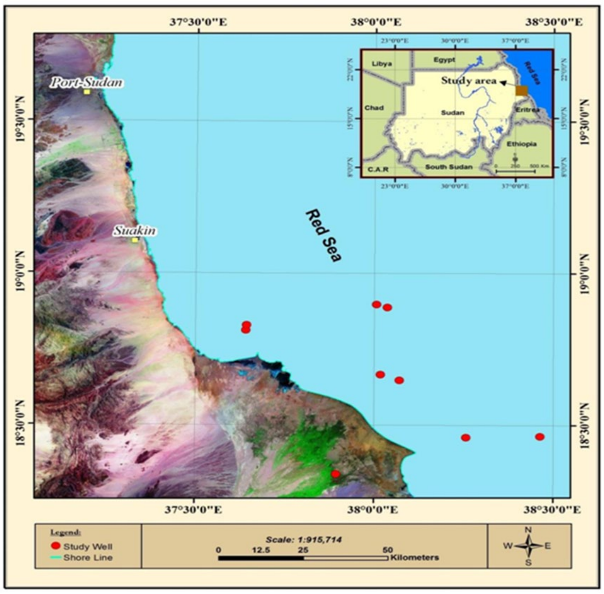

Figure 1: Location Map of the StudyArea, after [5].

Stratigraphy

The stratigraphic frame work of the Sudanese Red Sea Cenozoic strata have been established through a series of studies since [5-7]. The stratigraphy of the study area constituted by the following lithological units from bottom to top , (Figure 2) [5]:

(A) Basement Complex (Cambrian): The igneous rocks in Digna-1 well are mainly metamorphosed from intermediate to basic igneous rocks (lower metamorphic facies). The Basement has been also reached in Durwara-2 well.

(B) Kareem Formation (Oligocene): It is mainly defined in Durwara-2 well represented by sandstone and shale with a thickness of about 542m. The section unconformably overlies metamorphic Basement rocks.

(C) Belayim Formation (Late Oligocene): It is encountered only in two wells in the study area, Durwara-2 and Digna-1 wells with different facies. In the Durwara-2 well, the Belayim Formation is represented by sandstone and shale at the top and two main anhydrite beds at the bottom separated by shale interbeds. It has a thickness of 527m. The lithology changes to mainly carbonate facies intercalated with thin anhydrite and shale beds in well Digna-1 well with a thickness of 429m, dated as undifferentiated Belayim- Kareem.

(D) Dungunab Formation (Miocene): It is composed of a very thick sequence of evaporites (rock salt and anhydrite) with thin beds of shales. The thickness ranges from 300-900m. The Dungunab Formation is represented in the study area by massive salt section ranging in thickness from 300m in Digna-1 to about 870m in Durwara-2 well.

(E) Zeit Formation (Late Miocene): Top of the Zeit Formation is defined based on the first thick anhydrite bed. It is represented mainly by rapid intercalations between clastics (shale and sandstone) and evaporites (salt and anhydrite). The average thickness of Zeit Formation is about 1800-1900m. Based on the lithology of Suakin-1 well, the Zeit Formation could be subdivided into three main units mostly separated by unconformity surfaces. The Upper Zeit is characterized by dark grey shale with anhydrite, salt and sand intercalations. The basal part of the Upper Zeit is marked by a vari-colored course grained sandstone bed that might represent an unconformity surface. The Middle Zeit is represented by light to dark grey shale, siltstone and thin evaporate streaks. It is characterized by the dominance of red shale with a relatively thick red shale bed near its base. The Lower Zeit is topped by a relatively thick evaporite unit about 80m in two beds at depth 2683m in Suakin-1 well, which is correlated to a thinner unit (about 20m) at 2558.5m in Suakin-1 well.

(F) Wardan Formation (Late Pliocene): It is dominated by sandstones, shales with siltstone and thin carbonate interbeds, and evaporite streaks. The thickness of Wardan Formation ranges between 410-1140m.

(G) Shagara Formation (Pleistocene-Holocene): It is represented by mixed lithofacies consisting of marine sand/sandstone section intercalated with claystone, partially with thin streaks of dolomite, anhydrite and limestone. The thickness of Shagara Formation ranges between 217-1240m.

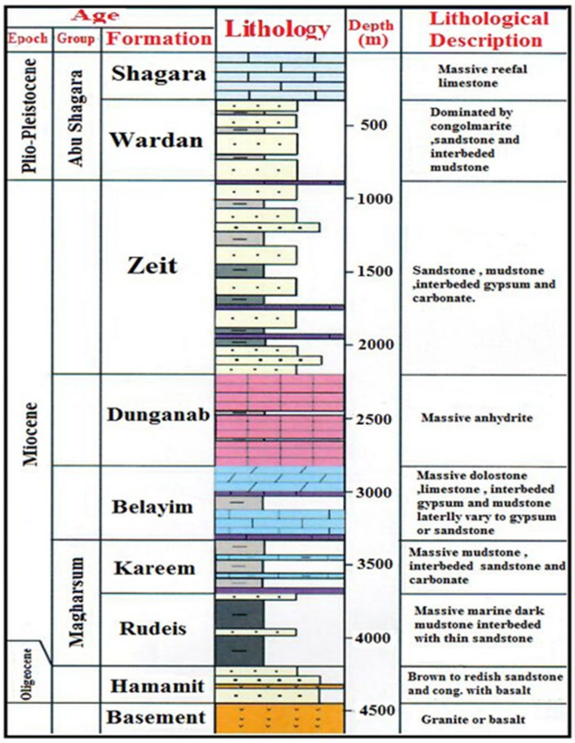

Figure 2: Lithostratigraphic column of the study area (modified after) 8].

Objectives

The main objective of the petrophysical interpretation in this study is to re-evaluate and define the hydrocarbon potentiality in Wells No.1 and Wells No.2 using open hole logs namely; Res., Den., Neut. & GR recorded in the wells using Interactive petrophysics IP Software. The petrophysical interpretation study started with data loading and importing the available data for Wells No.1and 2 checked the quality of the data and processed the logs using Industry Standard Methods. Part of the Lower Section of the Wells was not logged due to engineering problems.

Material and Methods

This paper involves the analysis of petrophysical properties using data from the available logs such as caliper, gamma ray, density, neutron, sonic, and resistivity logs, The available open hole logs data imported into the appropriate Interactive Petrophysics software (IP- Version 3.5) for analysis and interpretation. One reading per 0.5m depth is selected for recording the input data measurements. Log data are adversely influenced by the borehole environment such as borehole size, pressure, salinity, drilling mud, filter cake. The effects of these environment conditions on the log data may be eliminated through environment correction. After the well log curves were checked and calibrated to the depth by using gamma ray log as a reference curve, all environment corrections (gamma ray, density, neutron, and resistivity logs) have been done using Schlumberger chart (SLB, 2005), which is supplied to this software program as the environmental correction module; then shale volume (Vsh) calculations were made, and the lithology and mineralogy discriminations were interpreted through appropriate cross plots, and porosity (Φ) estimated from neutron and density logs. The resistivity logs were utilized in order to obtain water saturation (Sw).

Results and Discussion

Petrophysical properties form a set of essential parameters and still remain the basic tools to obtain reliable information by which reservoir rocks may be described quantitatively, in order to assist petroleum geologists in the evaluation of hydrocarbon reserves and for planning well completion and optimize production operations during the reservoir life. The petrophysics approach has been used to evaluate reservoir properties such as shale volume, porosity and water saturation, to estimate the hydrocarbon potentiality in the studied intervals.

Shale Volume (Vsh) and Gross Sand Estimation

In order to calculate the volume of shale, gamma ray log is the most common indicator. The maximum gamma ray response is taken as the shale point and minimum response as the clean point. The lower shale content usually reveals a better reservoir whereas increase in volume of shale decreases the effective reservoir capacity. The volume of shale must be correct, if it is not corrected, gives erroneous during calculation volume of hydrocarbon, porosity and water saturation. In the studied wells there are three pay intervals in the Well No-1 that might by hydrocarbon bearing from the petrophysical point of view. The first interval (A) from 2780 to 2815m in Lower Zeit Formation has gross sand of 30m, net pay of 2m (Fig.3). The second interval (B) from 2865 to 3020m in Lower Zeit Formation has gross sand of 155m, net pay of 6m (Fig.4). The third interval (C) from 3220 to 3255m in Lower Zeit Formation has gross sand of 33m, net pay of 9m (Fig.5), (Table 1, 2). In the Well No-2 the first interval (A) is in the Upper Zeit from 1750 to 1820m (Fig.6). The gross sand is 9.5m, net pay 4m. The second interval (B) is in the Middle Zeit from 2370 to 2400m. The gross sand is 17m, net pay of 8m (Figure 7). The third interval (C) in the Middle Zeit from 2435 to 2466m has gross sand of 20m, net pay of 4.5m (Figure 8), (Table 1& 3)

Porosity (Φ)

The porosity of a rock is the volume of the non-solid portion of the rock that is filled with fluids divided by the total volume of the rock [9]. In general porosities tend to be lower in deeper and older rocks due to cementation and overburden pressure stress on the rock [10]. Generally, porosity has two main types: total porosity and effective porosity. Total porosity is defined as the ratio of the entire pore space in a rock to its bulk volume, or the porosity derived directly from the logs without correction for the clay content. Effective porosity represents the pore space that contains hydrocarbon and bound water [11]. The resultant porosity in effective porosity can be determined after removal of the effect of clay. In an interval without shale, the total porosity equals the effective porosity. The porosity from logs can be estimated from a single porosity log (density, neutron, sonic) or a combination of porosity logs. In the studied well no-1 the first interval (A) from 2780 to 2815m in Lower Zeit Formation has Average porosity of 17% (Fig.3). The second interval (B) from 2865 to 3020m in Lower Zeit Formation has Average porosity of 21% (Fig.4). The third interval (C) from 3220 to 3255m in Lower Zeit Formation has Average porosity of 21 % (Fig.5), (Table 1, 2). In the Well No-2 the first interval (A) is in the Upper Zeit from 1750 to 1820m the Average Porosity is 16% (Fig.6). In the second interval (B) is in the Middle Zeit from 2370 to 2400m the Average Porosity is 14% (Fig.7). The third interval (C) in the Middle Zeit from 2435 to 2466m has the Average porosity is 14 %. (Figure 8), (Table 1& 3).

Water Saturation (Sw)

Water Saturation it is the amount of pore volume in a rock that is occupied by formation water. Water saturation is represented as decimal fraction or as percentage [12]. In the studied Well No-1the first interval (A) from 2780 to 2815m in Lower Zeit Formation has is 51% (Fig.3). The second interval (B) from 2865 to 3020m in Lower Zeit Formation has SW is 49% (Fig.4). The third interval (C) from 3220 to 3255m in Lower Zeit Formation, has SW is 49% (Fig.5), (Table 2). In the studied Well No-2 the first interval (A) is in the Upper Zeit from 1750 to 1820m has Sw 44% (Fig.6). The second interval (B) is in the Middle Zeit from 2370 to 2400m has Sw 51% (Fig.7). The third interval (C) in the Middle Zeit from 2435 to 2466m has Sw 56% (Fig.3), (Table 3). All the test results and hydrocarbon shows were presented in table 4.

Table 1: Summary of Petrophysical Analysis of Studied Wells

Well	Interval (m)	Formation	Net Pay (m)	Av. Porosity
	2780-2815		2	17
	2865-3020		6	21
Well No-1	3220-3255	Lower Zeit	9	21
Well No-2	1750-1820	Upper Zeit	4	16
	2370-2400	Middle Zeit	8	14
	2435-2466		4.5	14

Table 2: Petrophysical Summation of Well No.1, Intervals A, B & C, Petrophysical analysis for Well No.1
Reservoir summary Cutoff Phi ≥ 8% Sw ≤ 60% Vcl ≤ 40%

Zone Name	Top	Bottom	Thickness	Gross Sand	Net Pay	N/G	Av. Phi	Av. Sw	Av. Vcl
Interval A	2780	2815	35	30	2	0.06	0.17	0.51	0.24
Interval B	2865	3020	155	155	6	0.04	0.21	0.51	0.31
Interval C	3220	3255	35	33	9	0.26	0.21	0.49	0.23

Table 3: Petrophysical Summation of Well No.2, Interval A, B &C
Petrophysical analysis for Well No.2
Reservoir summary Cutoff Phi ≥ 8% Sw ≤ 60% Vcl ≤ 40%

Zone Name	Top	Bottom	Thickness	Gross Sand	Net Pay	N/G	Av. Phi	Av. Sw	Av. Vcl
Interval A	1750	1820	80	9.5	4	0.05	0.16	0.44	0.45
Interval B	2370	2400	30	17	8	0.26	0.14	0.51	0.14
Interval C	2435	2466	31	20	4.5	0.15	0.14	0.56	0.13

Table 4: Test Results and Hydrocarbon Shows

Well Name	Hydrocarbon Zone of Interest
Well No.1	Log analysis interprets three zones at 2780-2815m, 2865-3020m and 3220-3255m, net pay 2m, 6m and 9m respectively, not tested. Gas shows, C1-C5 indications from Mud log.
Well No.2	Log analysis interprets three zones at 1750-1820m, 2370-2400m and 2435-2466m, net pay 4m, 8m and 4.5m respectively, not tested C1-C5 indications from Mud log.

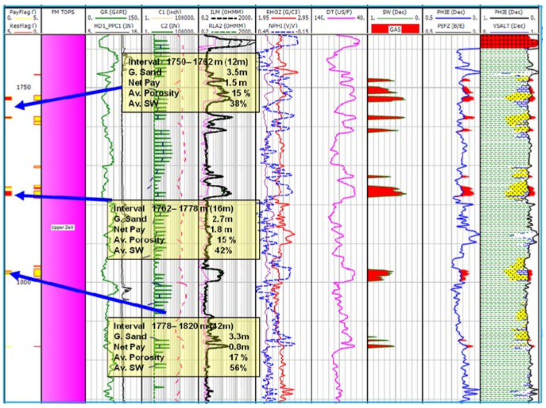

Figure 3: Petrophysical interpretation of Well No.1, Interval (A): 1750-1820m

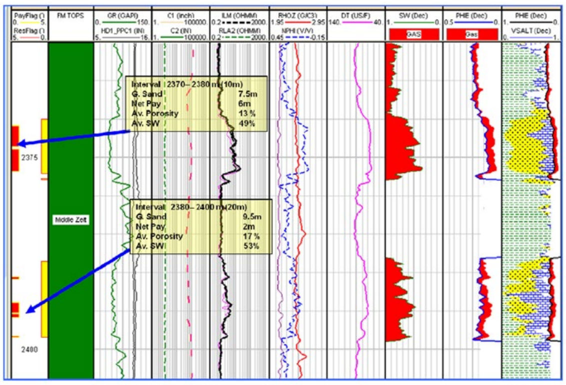

Figure 4: Petrophysical interpretation of Well No.1, Interval (B): 2370-2400m

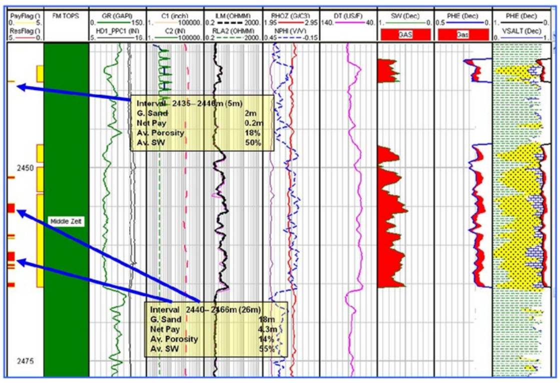

Figure 5: Petrophysical interpretation of Well No.1, Interval (C): 2435-2466m

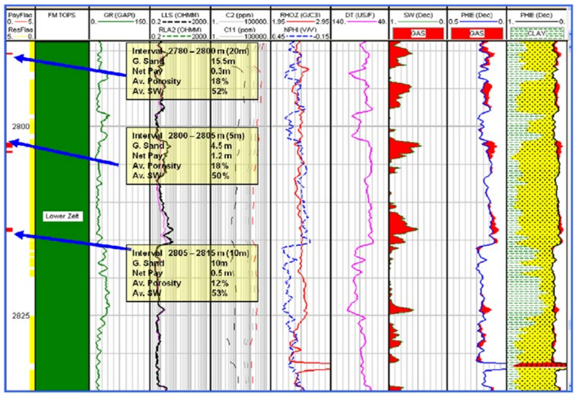

Figure 6: Petrophysical interpretation of Well No.2, Interval (A): 2780-2815m

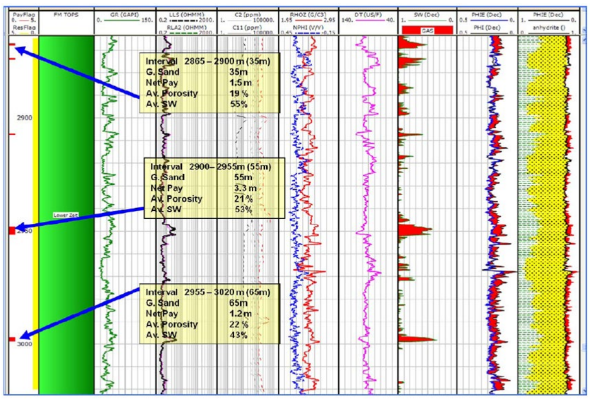

Figure 7: Petrophysical interpretation Well No.2, Interval (B): 2865-3020m

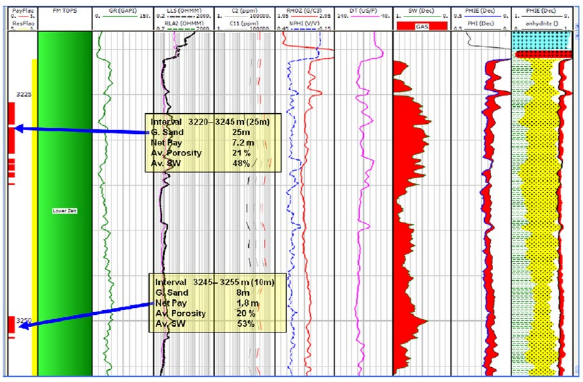

Figure 8: Petrophysical interpretation of Well No.1, Interval (C): 3220-3235m

Conclusion

Well logging is a technique used to obtain continuous detailed recording of physical parameters of a geological formation as a function of time or depth, by measuring various physical, chemical and lithological properties of the formations.

In the studied Well No-1 the intervals (A),(B),(C) from 2780 to 3255m in Lower Zeit Formation has fair gross sand ranging between 30-155m, average porosity its good ranging between 17%-21% and SW is ranging between 49%- 51%.

In the studied Well No-1 the intervals (A),(B),(C) from 1750 to 2466m in the Upper Zeit Formation has fair gross sand ranging between 9.5-20m, average porosity its good ranging between 14%-16% and SW is ranging between 44%- 56%.

Log analysis interprets three zones at 2780-2815m, 2865-3020m and 3220-3255m, net pay 2m, 6m and 9m respectively, not tested. Gas shows, C1-C5 indications from Mud log.
Log analysis interprets three zones at 1750-1820m, 2370-2400m and 2435-2466m, net pay 4m, 8m and 4.5m respectively, not tested C1-C5 indications from Mud log.

Based on these results, the Zeit Formation have good reservoir potential and contains many pay zones for hydrocarbon accumulation in gas window, which the Lower Zeit Formation is the main reservoir with high porosity, low shale contents and water saturation [13-28].

Acknowledgement

Author was indebted to Petroleum Labs, Researches and Studies (PLRS) most of core samples, data and direct support during field work in the study area; and also thanks to International University of Africa (IUA), Faculty of Minerals and Petroleum for their generous support which helped to improve the manuscript.

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Citation: Sadam H MA Eltayib. Petrophysical Analysis using well Logs Data to Evaluate the Hydrocarbon Potentiality of the Sudanese Red Sea Coastal Plain. Int J Envi & Eart Scie 2022, 3 (2): 1-6