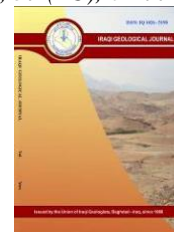




Iraqi Geological Journal

Journal homepage: <https://www.igi-iraq.org>



Reservoir Characterization of the Paleogene Khurmala Formation in Tawke and Shaqlawa Areas, Kurdistan Region of Iraq

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Abstract

Received:
10 October 2023

Accepted:
18 December 2023

Published:
31 March 2024

Well logs were utilized to investigate petrophysical properties of the Khurmala Formation's surface outcrops in Shaqlawa Subdistrict and Tawke Oilfield, e.g., lithology, shale volume, porosity, and fracture. The thickness of the formation is about 15 m in the Shaqlawa section and 42 m in the Tawke Oilfield. Porosity logs were used to estimate porosity; where the porosity values reached a maximum of 52% from the sonic log, 48% from the density log, and 35% from the neutron porosity log. The reservoir quality of the Khurmala Formation, as determined through the analysis of thin sections, which were obtained from outcrop samples, is deemed to be of low quality. The determined shale volume within the examined interval exhibits a moderate level of clay constituents, with the highest gamma-ray measurement indicating a shale content of 29% at some locations within the reservoir. This integrated method using various conventional well logs suggests a great probability of petrophysical properties in the Khurmala Formation to be considered as the reservoir.

Keywords: Khurmala Formation; Petrophysical properties; Porosity; Shale content; Tawke Oilfield

1. Introduction

Based on field evidence and petrographic analysis, the Khurmala Formation is deposited in a shallow marine environment (Karim et al., 2018; Asaad and Balaky, 2018; Asaad et al., 2022). The carbonate sediment contains four microfacies associated with shoal banks (Kh2), lagoons (Kh1), intertidal (Kh1, Kh3), and supratidal (Kh4), whereas the clastic sediment contains two lithofacies associated with estuaries depositional environment (Al-Banna, 2006). Based on a microfacies study of the Khurmala Formation in the Dukan Region, Sulaimaniyah Provenance, this stratigraphic unit was deposited in a shallow marine environment (Al-Ehmeedy et al., 2012). The Lower Eocene Khurmala Formation is well exposed in the Duhok area, e.g., Spindar (Gara), Birkyat (Khair), and Barbuhar (Bekhair). These sections were studied by Barzani (2020) to identify carbonate microfacies in order to construct their sedimentary facies type and interpret the formation's depositional environment.

Many diagenetic processes affecting limestone were identified and accordingly, four diagnostic horizons were recognized (Al-Lihaibi, 2012). Five diagenetic processes, including micritization, cementation, dissolution, dolomitization, and compaction have an impact on the Sinjar and Khurmala formations. Micritization, cementation, and compaction are less effective processes, whereas dolomitization and dissolution have a direct impact on the carbonate pore systems and are more effective (Omer et al., 2014; Tamar-Agha et al., 2015).

DOI: [10.46717/igi.57.1C.5ms-2024-3-17](https://doi.org/10.46717/igi.57.1C.5ms-2024-3-17)

The field observation and petrographic investigations helped to determine the type and origin of the dolomite and its impact on porosity. The porosity types of the Khurmala Formation are intercrystalline porosity, moldic porosity, intraskeletal porosity, fenestral porosity, and vuggy porosity (Barzani and Al-Qaym, 2019). In addition, Rashid et al. (2020) analyzed wireline logs to understand reservoir potentiality and fluid distribution. The production profile across the slotted liner interval of the W-1 Well in the Khurmala Oilfield was assessed. The study detected possible water entry points, verified the distribution and nature of fluids, and estimated fluid segregation after the shut-in period. This was accomplished by using PLTs and Emeraude software to interpret the data (Hamoudi et al., 2019).

The main tool for evaluating the formations in most reservoir characterization studies is log data. The chief aim of this research is to regulate the reservoir categorizations of the Khurmala Formation in the Tawke Oilfield and outcrop section in the Shaqlawa Area. The study includes reservoir petrophysical characteristic investigations, such as lithology, shale content, porosity (particularly secondary porosity), and fracture identification. Furthermore, the effect of these fractures on increasing porosity and permeability. The benefit of this work is to retrieve additional possible data on the Khurmala Formation. In order to achieve the aims, two sections were chosen (Fig. 1). The first section is located near Shaqlawa City (44°16'28"E, 36°26'13"N). The second section is in the Tawke Oilfield, which is located approximately 12 km north-east of Zakho.

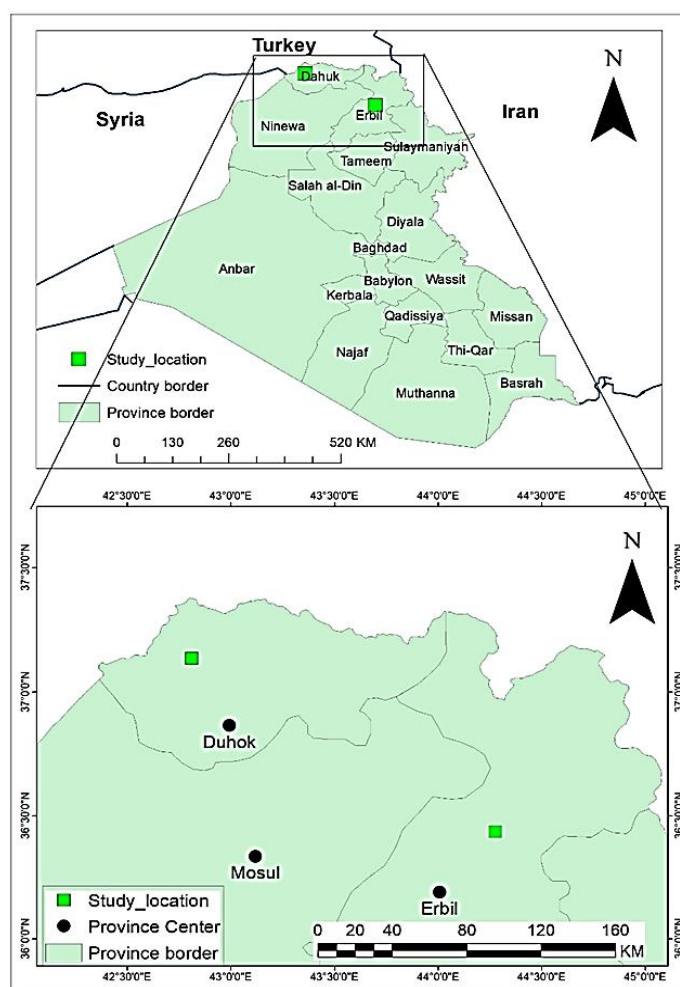


Fig. 1. Location map of the studied sections

2. Materials and Methods

According to the data recorded, there are two major categories for the methods used in this study.

2.1. Rock sampling

Across 15 m of the studied Shaqlawa section, we collected 10 rock samples; one sample per 1.5 m that is used to describe the lithology and porosity of the formation and its reservoir characteristics.

2.2. Well Log Data

The materials and methods of this study are also based on the estimation and determination of the reservoir properties of the subsurface section in the Tawke Oilfield by using various types of well log determination and interpretation. We used many software for various purposes, such as Getdata digitizer, Grapher 14, and ImageJ. We obtained our data by digitizing Gamma ray, Caliper, Density, Sonic, and Neutron. Curves were made by using Getdata digitizer software and we created lithological columns by Adobe Illustrator software. In addition to conventional software such as Excel, a Geographic Information System (GIS) was used in this study. For the subsurface investigation, the sonic log, density log, neutron log, caliper log, and gamma ray log were utilized.

3. Geological Setting

The thickness of the Khurmala Formation varies throughout the field, ranging from 100 m at the northeastern limb of Taq Taq anticline to 109 m at the southeast plunge. In other areas, it is, for instance, 50 m in Aqra, 15 m in Shaqlawa, 40 m in Bekhma, 80 m in Koisanjaq, and 42 m in Tawke (Jassim and Al-Gailani, 2006). Miliolids, small valvulinids, clavulinids, and very rare "ghosts" of indeterminable alveolinids are largely obliterated by recrystallization and dolomitization; algae fragments and small gastropods also occur, but their specificity or generality cannot be determined (Bellen, 1956). The formation's age is estimated to be Paleocene to Lower Eocene (Bellen et al., 1959). This age is largely determined by the stratigraphic position of the formation in the sequence.

The formation has a thickness of 15 meters at the studied outcrop location. Based on field observations, the rock succession is divided into three units. The bottom part is a thin yellow bed of marl, the following medium unit is a thin bed of marly limestone, and the upper unit is a massive limestone. The oil column in Tawke is currently estimated to be 180 meters in the Paleogene reservoir and 900 m in the Cretaceous reservoir (Eide & Brandvold, 2007).

4. Results and Discussion

4.1. Lithology Identification and Shale Content

4.1.1. Lithology determination from porosity logs

There are many methods developed by logging services in oil industry companies for determining the lithology of drilled rock sequences from log data. These methods can also be called indirect methods for the determination of lithology because in these methods rock samples are not used (Priisholm and Michelsen, 1979).

The formation's lithology must be determined to evaluate a reservoir. The lithology cannot be inferred from a single tool measurement. When both logs are used, the formation's lithology can be calculated collectively (Rider, 1996).

4.1.2. Neutron-density cross plot

Simply, a cross plot is a combination of multiple log measurements. This particular cross plot, known as an N-D cross plot, is made up of neutron and density logs. Three diagonal lines representing the lithology types such as dolomite, calcite (limestone), and quartz matrix with water-filled porosity are plotted in this cross plot.

Fig. 2 shows the lithology column that is found by N-D cross plot chart of the studied field. Both neutron and density logs are porosity logs and this cross plot is typically used for lithology identification; in other words, those points that fall on one of the diagonal lines i.e., calcite (limestone) line will become limestone and those points that fall between two different lines, i.e., limestone and dolomite will become a mixture of this two lithologies which is called dolomitic limestone (Bowler, 1981). The lithology of the Khurmala Formation consists mostly of dolomite and dolomitic limestone because many plotted points fall along the dolomite line and between dolomite and limestone, and there is also a minor amount of limestone and marl because a minor number of points fall along limestone and sandstone line.

In addition, there is another method that can be used to determine lithology such as cross plot of sonic *versus* density logs, but it is widely used for the interpretation of shaly sand formations, but our studied formation (Khurmala Formation) is composed mainly of carbonate. So, for carbonate formations, the ideal way is using density *versus* neutron cross-plots (Burke et al., 1969).

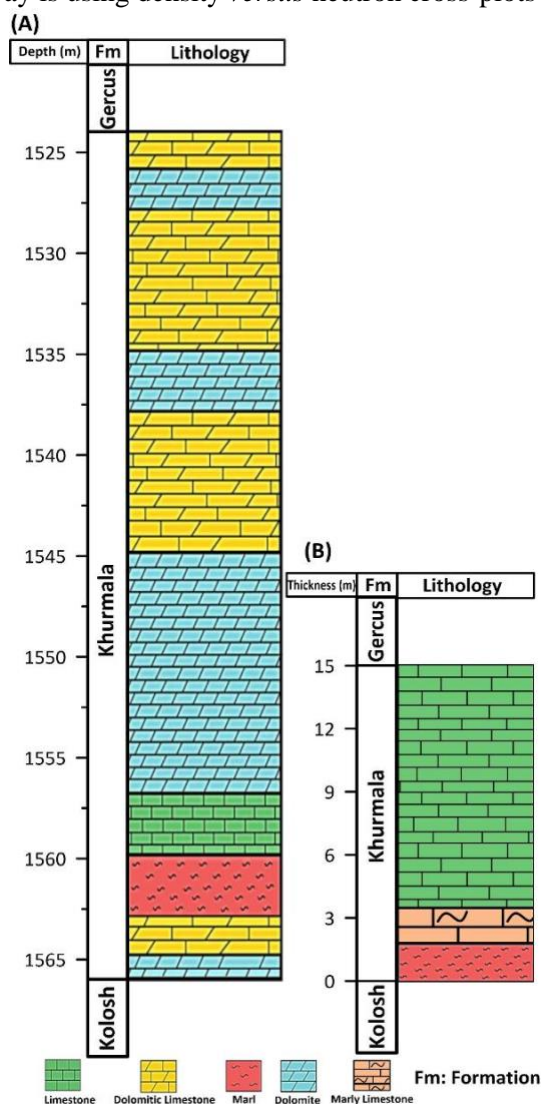


Fig. 2. Lithological column from log data (A) and outcrop section (B) of the studied formation

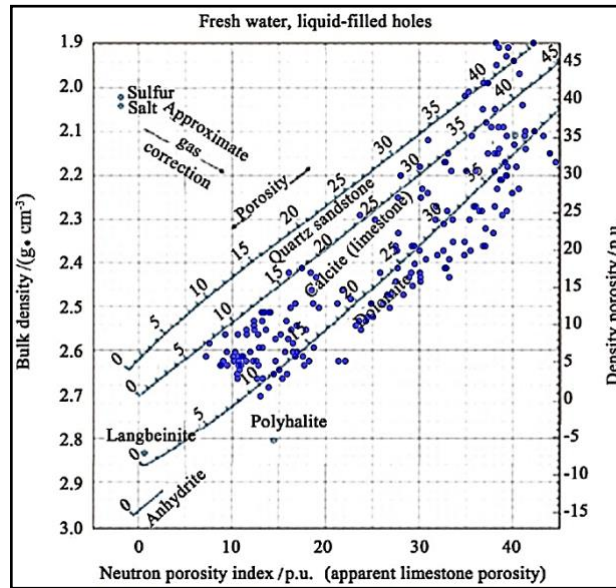


Fig. 3. Identified lithology of the studied formation from N-D cross plot (Asquith and Gibson, 1982)

In addition to the lithology determination from neutron-density combination, the neutron and density porosity were used to estimate shale content, shale distribution types, and effective porosity (Fig. 4). Fig. 4 shows that the studied formation is generally shale formation, representing a maximum content of about 29% (green lines on Fig. 4). The shale distribution types are structure and dispersed (Fig. 4, blue line). Fig. 4 also shows the effective porosity (pink line) which can estimate that the effective porosity ranges from (10 to 40) %. The plotted data indicated that the amount of effective porosity in the structure type of shale distribution type is higher than in the dispersed type. It indicated that the dispersed shale in the reservoir degrade the reservoir quality.

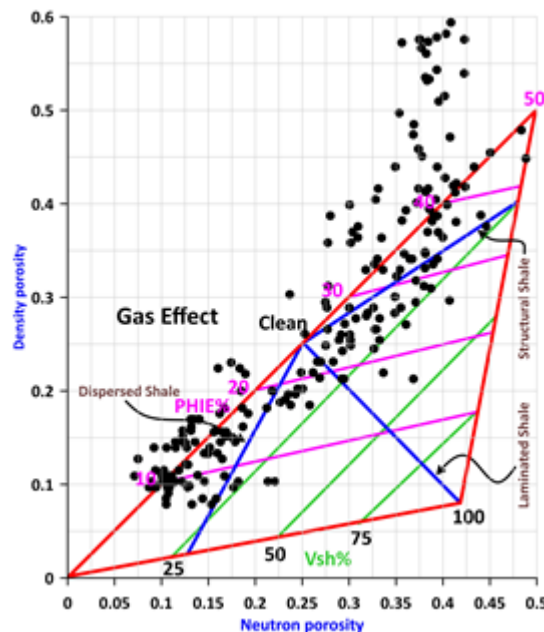


Fig. 4. Neutron-Density porosity cross-plot showing shale content estimation, shale distribution type, and effective porosity for the studied formation

4.1.3. Caliper log

In this study, the caliper log is used as a lithology indicator. The bit size used to drill the hole is 8.5 inches. In gauge occurs in the borehole at intervals of 1528–1543 m, there is no mudcake buildup, and there is a borehole enlargement in the log that is 15 inches, indicating that the borehole enlargement occurred in the marl beds as shown in Fig. 5.

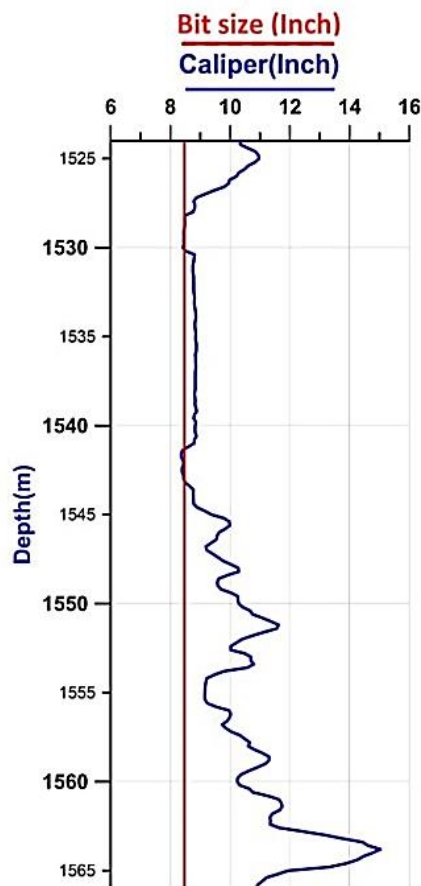


Fig. 5. Caliper log of the Khurmala Formation in Tawke oil well

4.1.4. Gamma ray log

Radiation from uranium, thorium, and potassium, as well as many related daughter products of radioactive decay, are combined to form the response of the normal gamma ray log (Asquith and Krygowski, 2004). We can learn more about the formation's lithology and composition by analyzing the sources of the natural gamma radiation (Paul, 2010).

Like other methods of well logging, the gamma ray log is conducted by lowering an instrument into the borehole and measuring the variations in gamma radiation with depth. Gamma radiation is frequently measured using American Petroleum Institute (API) units, a unit of measurement created by the petroleum industry (Petrogav, 2009).

This research used a gamma ray (GR) curve (Fig. 6) for identifying lithology and shale volume. Since radioactive materials are concentrated in shale; therefore, shale has high gamma ray readings (Assaad, 2009).

The conventional gamma ray log assumes that no other radioactive minerals besides shale exist during the process of quantitatively assessing the amount of shale present (Khan, 1989). The shale volume, as the name implies, is the portion of shale in the formation (Asquith and Krygowski, 2004).

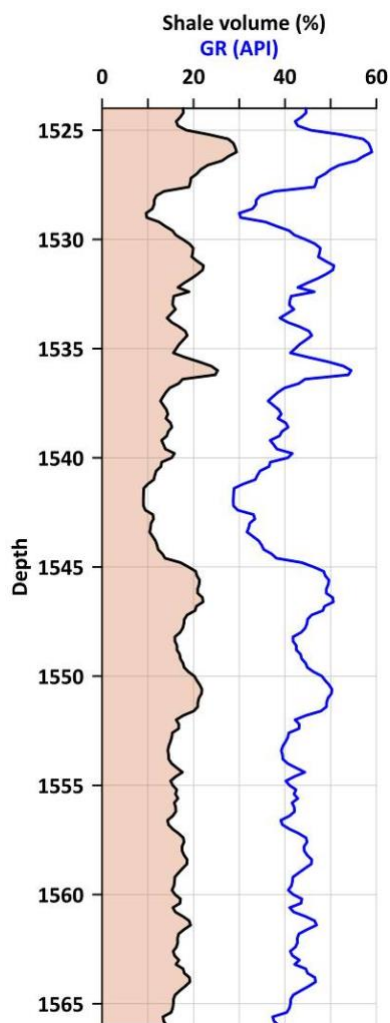


Fig. 6. Gamma ray log (blue curved line), Shale volume curve (black curved line) in the studied formation in Tawke oil well

The gamma ray log data was utilized to compute the shale volume of the rocks of the reservoir, this is significant because the shale volume threshold value is frequently used to distinguish between reservoir and non-reservoir rocks (Paul, 2010). Initially, the IGR is computed from the GRlog (Schlumberger, 1974) using this relationship (Eq. 1):

$$IGR = (GR_{log} - GR_{min}) / (GR_{max} - GR_{min}) \dots\dots\dots (1)$$

where:

- IGR = the gamma ray index
- GRlog = the gamma ray reading
- GRmin = the minimum gamma ray reading
- GRmax = the maximum gamma ray reading

Based on the age of the studied formation, Larionov’s (1969) equation for the Tertiary aged rocks is used to determine shale volume (Eq. 2).

$$V_{shale} = 0.083 (23.7 * IGR - 1) \dots\dots\dots (2)$$

Table 1 presents the data of shale zonation on the basis of the percentage of shale volume, which is a method of stratigraphic analysis used to identify and classify shale deposits. This method is based on the observation that shale deposits are usually composed of different types of shale, which can be identified by their physical and chemical properties. In our result, the maximum shale volume is 29%, the minimum value is 9%, and the average shale volume is 17%; as shown in Fig. 6. This result indicates

that the studied formation is generally a clean shaly formation, depending on its shale content as presented in Table 1.

Table 1. Shale zonation on the basis of percentage of shale volume (Ghorab et al., 2008)

| Vsh (%) | Zones |
|---------|------------|
| <10 | Clean zone |
| 10-35 | Shaly zone |
| >35 | Shale zone |

4.2. Porosity Estimation and Porosity Units

4.2.1. Sonic log

Sonic transit times are inversely related to sound speed, the elastic characteristics of the rock matrix. The relative speed of this sound depends on the density of the medium, and the density of the medium is dependent on rock and pore space volumes. If there are pores filled with hydrocarbon liquids or gases; in other words, if there is no solid medium then the speed of the sound will decrease and require more time to pass through one foot of formation. However, in case there are no pore spaces to be filled with hydrocarbon; in other words, if there is a solid medium the speed of sound will increase and require less time to pass the formation (Asquith and Gibson, 1982). Fig. 7 shows that graph A sonic log values and graph B shows sonic porosity. Table 2 shows matrix densities and velocities of lithologies that are used in the sonic porosity equation.

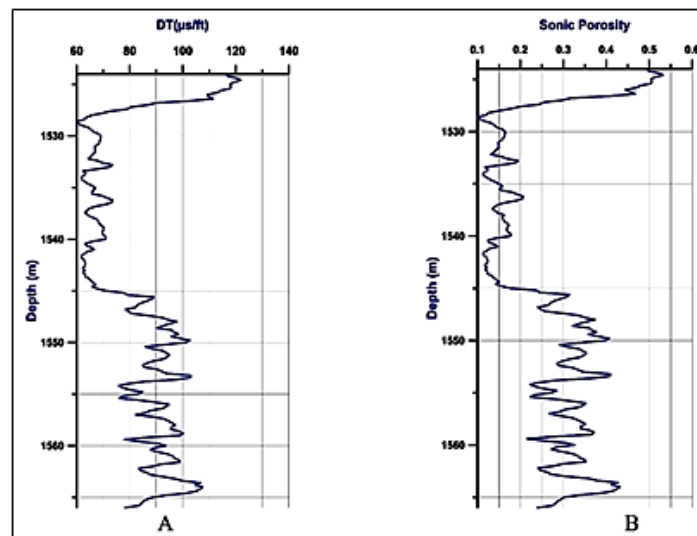


Fig. 7. (A) Sonic log data, (B) Sonic porosity in the studied formation

Table 2. Matrix densities and velocities of common lithologies and fluids (Schlumberger, 1972)

| Lithology/Fluid | $V_{ma}(ft/sec)$ | $\Delta t_{ma} \left(\frac{\mu s}{ft}\right)$ | $\Delta t_{ma}(\mu s/ft)$ (commonly used) |
|-----------------|------------------|---|--|
| Sandstone | 18,000-19,500 | 55.5-51.0 | 55.0 |
| Limestone | 21,000-23,000 | 47.6-43.5 | 47.5 |
| Dolomite | 23,000 | 43.5 | 43.5 |
| Anhydrite | 20,000 | 50.0 | 50.0 |
| Fresh Water | 5,280 | 189.0 | 189.0 |
| Salt Water | 5,980 | 185.0 | 185.0 |

In the current research, we already calculated the sonic porosity by the following equation (Eq. 3) (Asquith and Gibson, 1982):

$$\phi_{sonic} = \frac{\Delta t_{log} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}} \dots\dots\dots(3)$$

where:

ϕ_{sonic} = Porosity from sonic log

Δt_{log} = Acoustic transit time log reading (μsec/ft)

Δt_{ma} = Acoustic transit time of the rock matrix (μsec/ft)

Δt_f = Acoustic transit time of interstitial fluids (μsec/ft)

The determined porosity has an average of 0.20 (20%), which is very good and may be due to the composition of the Khurmala Formation, which is mostly dolomitic limestone and dolomite (Fig. 2 and 3). Fig. 7B illustrates the sonic porosity (Sonic) of the studied formation. The average of the total sonic porosity is 0.26, and the porosity is divided into four intervals; initially, at the depth interval of 1524–1527 m, the porosity average was 0.47, and then decreased from interval 1527–1529 m to 0.17, then increased at the interval of 1529–1545 m to 0.21, and finally increased further at the interval of 1545–1566 m to 0.32.

4.2.2. Density log

The density log contains a radioactive source and two detectors and can be used quantitatively to calculate porosity and to determine indirectly the hydrocarbon density. Qualitatively, it is suitable as a lithology indicator, minerals’ recognizer, organic source rock evaluation, and abnormal pressure and fracture porosity identifier (Horsfall et al., 2013). Fig. 8 shows that graph A is the density log values and graph B shows the density of the porosity. Table 3 shows the matrix densities of lithologies that are utilized in the density of the porosity equation.

The following equation (Eq. 4) is for calculating the density of the porosity (Asquith and Gibson, 1982):

$$\phi_{Density} = \frac{p_{ma} - p_b}{p_{ma} - p_{fl}} \dots\dots\dots(4)$$

where:

ϕ_D = Porosity from density log

p_{ma} = Matrix density (g/cc)

p_b = Formation bulk density (g/cc)

p_{fl} = Fluid density

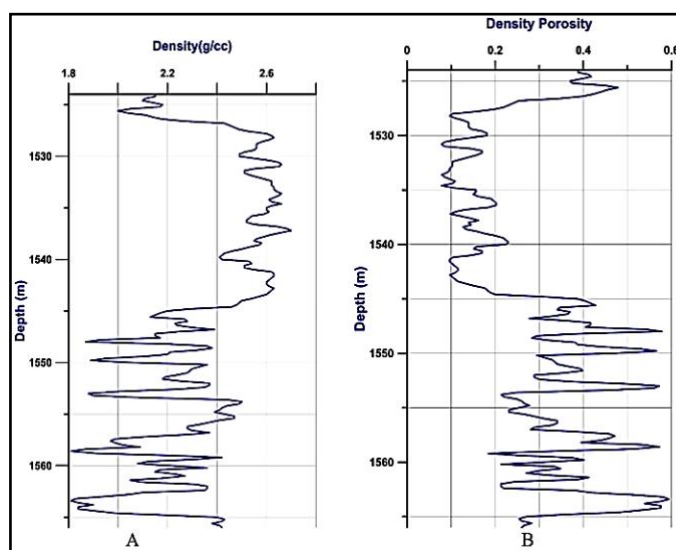


Fig. 8. (A) Density log data, (B) Density porosity of the studied formation

Fig. 8B illustrates the density porosity (Density) of the studied formation. The average of the total density porosity is 0.27, and the porosity is divided into three intervals, initially at the interval of 1524–1526 m, the porosity average was 0.41, then decreased at the interval of 1526–1545 m to 0.15, and then increased again at the interval of 1545–1566 m to 0.36.

Table 3. Matrix densities of common lithologies and fluids (Schlumberger, 1972)

| Lithology/ fluid | $\frac{p_{ma}}{p_{fl}}$ (g/cm^3) |
|------------------|--------------------------------------|
| Sandstone | 2.644 |
| Limestone | 2.710 |
| Dolomite | 2.877 |
| Anhydrite | 2.960 |
| Salt | 2.040 |
| Fresh water | 1.000 |
| Salt water | 1.140 |

4.3. Fracture Identification

Fractures are the most common features that can be seen in reservoir rocks, and it is likely that most reservoirs have some natural fractures. It is important to come up with some basic criteria for figuring out when fractures are important to the performance of a reservoir and for figuring out the nature and performance of a naturally fractured reservoir (Tiab and Donaldson, 2011).

There are many tools and techniques that can be used for this purpose including Micro Resistivity log, Sonic log, Nuclear log, Vertical Seismic profile, and Caliper log (Iverson, 1992).

4.3.1. Fracture quantification

A common analytical method is using logs to identify fractures, there is no special tool to respond to fractures only some tools sensitive to the presence of an open fracture. There are some log tools that

can be used to qualitatively interpret fractures such as Sonic, SP, Caliper, Neutron, and Density log combination relationship (Mian, 1992).

Equation 5, which was proposed by Asquith and Gibson (1982) is used to calculate fracture porosity.

$$\phi_f = \phi_D - \phi_S \dots \dots \dots (5)$$

where:

ϕ_f = Secondary porosity

ϕ_D = Density porosity

ϕ_S = Sonic porosity

Fig. 9 shows that fracture porosity values range from 0.000 to 0.220, and the average of the secondary porosity is 0.03; initially, at the interval of 1524–1544 m, the average of the secondary porosity was 0.005, then increased from the interval of 1544–1566 m to 0.057, whereas the maximum secondary porosity is at the depth of 1555 m, which is 0.220. However, the decision of the presence of fracture is only based on the secondary porosity curve, which has some uncertainties. So, by comparing the caliper (Fig. 5) and secondary porosity curve (Fig. 9), the decision of the presence of fracture will be more reliable and uncertainties will be lower. An increase and decrease of both curves are almost similar and this might imply the presence of fractures and support the result that we achieved from the secondary porosity curve.

4.3.2. Porosity units

To evaluate porosity, the qualitative description of North (1985) was applied (Table 4). Table 5 shows the average porosity of each porosity log, which includes density, sonic, and neutron porosity logs, with the log curve divided into three different porosity units. The results of Units-1 and 3 values showing the studied well are quantitatively excellent, Unit-2 values are fair.

The notable reservoir horizons within the Khurmala Formation have been referred to as three horizons which are shown in Fig. 10. In porosity horizon-1, the minimum and maximum recognized values for sonic porosity are 0.22 and 0.54; for density porosity, the range is 0.23 to 0.47; and for neutron porosity, the range is 0.24 to 0.48. The porosity values in Unit-1 have the same range. The porosity unit-2 also showed the same range of porosity values: for sonic porosity, the range is 0.10 to 0.21; for density porosity, the range is 0.078 to 0.300; and for neutron porosity, the range is 0.07 to 0.30. The porosity of Unit-3 range is 0.18 to 0.44 for sonic porosity, 0.018 to 0.590 for density porosity, and 0.25 to 0.48 for neutron porosity. The maximum porosity range from density porosity at unit-3 has a higher porosity range than that of Unit-1 and Unit-2.

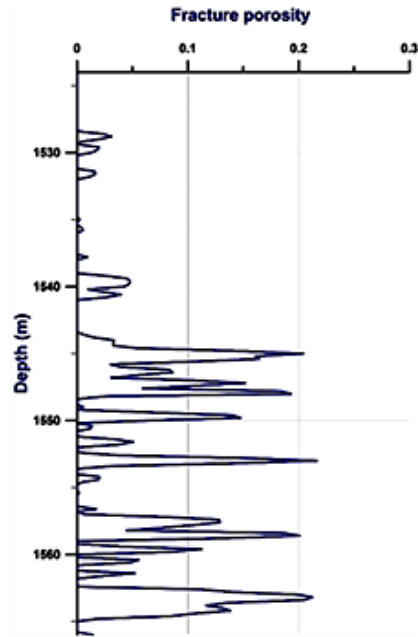


Fig. 9. Fracture Porosity of the studied formation.

Table 4. Qualitative description of porosity as proposed by North (1985)

| Percentage porosity (%) | Qualitative description |
|-------------------------|-------------------------|
| 0-5 | Negligible |
| 5-10 | Poor |
| 10-15 | Fair |
| 15-20 | Good |
| 20-30 | Very good |
| >30 | Excellent |

Table 5. Average and units of porosity in the studied formation

| Units | Average porosity | | |
|--------|------------------|-------|---------|
| | Density | Sonic | Neutron |
| Unit-1 | 0.41 | 0.41 | 0.35 |
| Unit-2 | 0.15 | 0.17 | 0.14 |
| Unit-3 | 0.36 | 0.21 | 0.34 |

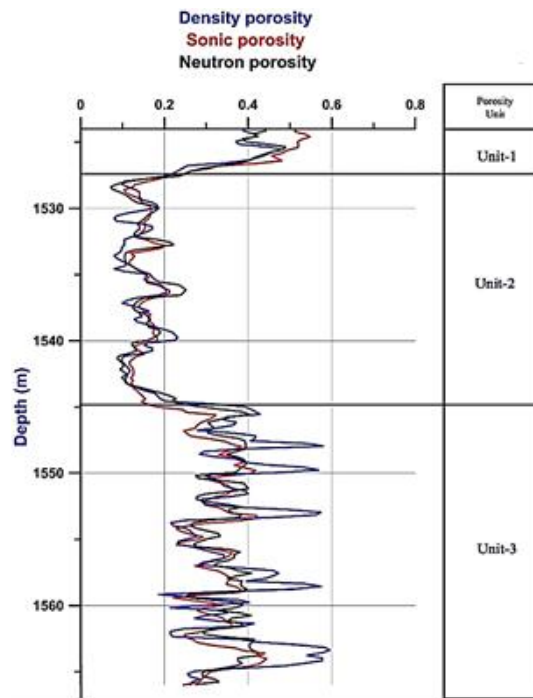


Fig. 10. Porosity units of the studied formation

4.3.3. Porosity from thin sections

Ten thin sections impregnated with blue resin were prepared from the outcrop section in the Khurmala Formation (Fig. 11A-J). These images present the pore structure of the studied formation under a petrographic microscope at x2.5 magnification; the blue resin technique was used in order to measure the porosity.

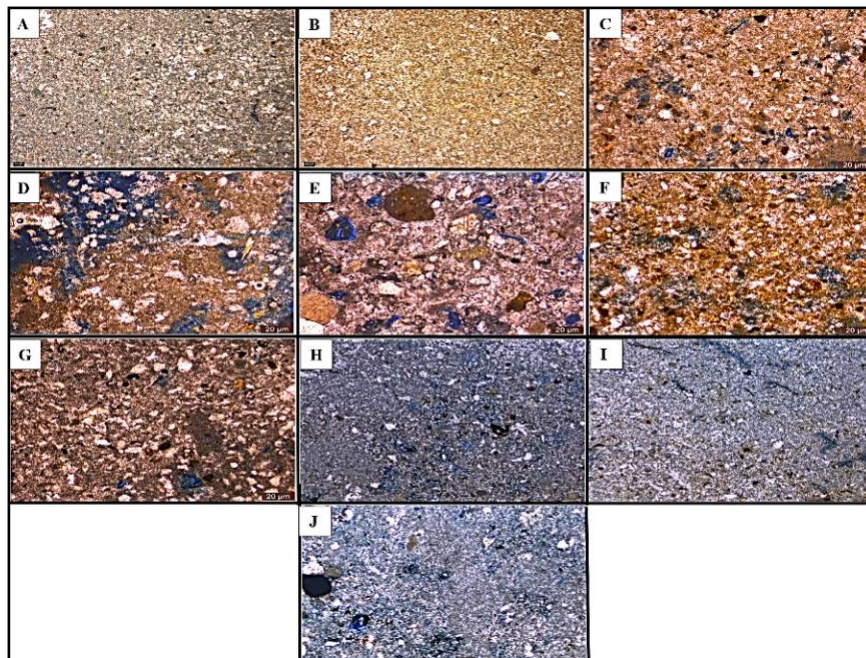


Fig. 11. Thin section with a blue resin of the studied formation. These images present the pore structure of the studied formation under a petrographic microscope at x2.5 magnification

Table 6 presents an illustration of the average porosity of the studied formation from outcrop thin sections. The table shows the average porosity for each sample which quantitatively varies from negligible to very good. The average porosity for all samples is 6.28%, which is poor quality. The standard qualitative description (Table 5) proposed by North (1985) was applied.

Table 6. The average porosity of porosity of the units in the studied formation from the outcrop thin section

| Sample No. | Average porosity (%) | Qualitative description |
|------------|----------------------|-------------------------|
| A | 1.8 | Negligible |
| B | 0.0 | Negligible |
| C | 6.4 | Poor |
| D | 24.4 | Very good |
| E | 6.8 | Poor |
| F | 7.8 | Poor |
| G | 2.1 | Negligible |
| H | 1.4 | Negligible |
| I | 9.7 | Fair |
| J | 2.1 | Negligible |

5. Conclusions

The following can be concluded from this study:

- The lithology of the Khurmala Formation is mostly limestone, dolomite, and dolomitic limestone;
- The calculated shale volume showed that the formation is generally clean of shaly formation;
- Determined porosity from well logs demonstrated that the Khurmala Formation has very good reservoir quality;
- The reservoir quality of the Khurmala Formation using thin sections from outcrop section is poor; among the available samples used in this study; and the secondary porosity values indicated that the Khurmala Formation has a low fracture value.

Acknowledgements

We thank the Ministry of Natural Resources in Erbil for providing the well logs.

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