RESEARCH ARTICLE

Hydrocarbon Potential of the Middle–Late Jurassic Series of Northwestern Iraq: A Case Study in the Shaikhan Oil Field

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ABSTRACT

The Middle–Late Jurassic Sargelu, Naokelekan, and Barsarin formations of northwestern Iraq have been investigated in the Shaikhan oilfield (well Shaikhan-8) to assess their potential for hydrocarbon generation.The results of total organic carbon analysis and rock-eval pyrolysis revealed a good-to-excellent hydrocarbon content and suggest that the depositional conditions were suitable for the production and preservation of organic matter. The thermal maturity proxy indicates that the studied formations were at the start of the hydrocarbon generation period. Most of the samples from the Sargelu and Barsarin formations belong to kerogen type II, whereas those of the Naokelekan Formation belong to kerogen type II/III.The Pr/Ph, Pr/n-C_{17}, and Ph/n-C_{18} ratios of the extracted bitumen indicated that the organic matter originated from marine sources under reducing conditions. The stable carbon isotope composition of the saturated and aromatic hydrocarbon fractions ranged from –28.3 to –27.7 ‰ and –28.0 to –27.7 ‰, respectively. The biomarker results show a high contribution of marine organic matter that was preserved under relatively anoxic conditions. The profiles of the burial and thermal maturity history show that the simulated generation zones, based on the calculated vitrinite reflectance, indicate immature (0.44%–0.6%)-to-early oil generating (0.6%–0.75%) source rock. The low thermal maturity of the studied formations relative to the depth may be attributed to the low geothermal gradient and heat flow.

Keywords: Middle-Late Jurassic, Rock-eval, Biomarker, Burial history, Shaikhan oilfield

1. INTRODUCTION

The majority of the discovered hydrocarbon reserves in northern Iraq are believed to be sourced from the Triassic and Jurassic rocks, and are trapped in the Jurassic, Cretaceous, and Tertiary reservoirs in the Zagros fold–thrust belt (Jassim and Goff, 2006; Aqrawi et al., 2010; Al-Ameri and Zumberge, 2012).

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The Middle–Late Jurassic succession includes the most important source rocks across northern Iraq because of their high total organic carbon (TOC) content (Jassim and Al-Gailani, 2006; Al-Ameri et al., 2014).

A pioneering study on the stratigraphy of the Sargelu Formation in the Surdash Anticline of the High Folded zone in the Sulaimani District of Iraqi Kurdistan, was presented by Wetzel (1948) (in Bellen et al., 1959). Wetzel and Morton (1950) (in Bellen et al., 1959) were the first to focus on the Late Jurassic stratigraphic units, namely the Naokelekan and Barsarin formations. They described the lithologies of these units at their type localities in the Naokelekan and Barsarin villages in northeastern Iraq.

The Bathonian–Bajocian, Callovian–Oxfordian, and Oxfordian–Kimmeridgian ages were suggested as the developmental time periods for the Sargelu, Naokelekan, and Barsarin formations, respectively (Al-Ameri and Zumberge, 2012; Al-Ameri and Al-Naqshbandi, 2015).

English et al. (2015) constructed a thermal maturity map of the Middle–Upper Jurassic areas of Iraqi Kurdistan Region. That map indicated a relatively low maturity across Mosul High where the source rock interval is overlain by a thin succession from the Cretaceous and Cenozoic periods. The maturity increases from the northwest to the southeast based on the thickness variations of the Cenozoic foredeep sediments within the Zagros foreland basin (Abdula, 2018).

2. GEOLOGICAL SETTING

Northern Iraq represents the northeastern boundary of the Arabian Plate (AP) and is a part of the Alpine Mountain belt. This belt has an E–W trend in the northern part and a NW–SE trend in the northeastern part (Jassim and Buday, 2006). The studied area (Fig. 1) is a part of the Zagros basin and represents the Zagros fold belt of northern Iraq. Based on folding intensity, the folded zone has been subdivided into 2 parts, namely the High Folded and the Foothill zones (Fig. 2) (Jassim and Goff, 2006).

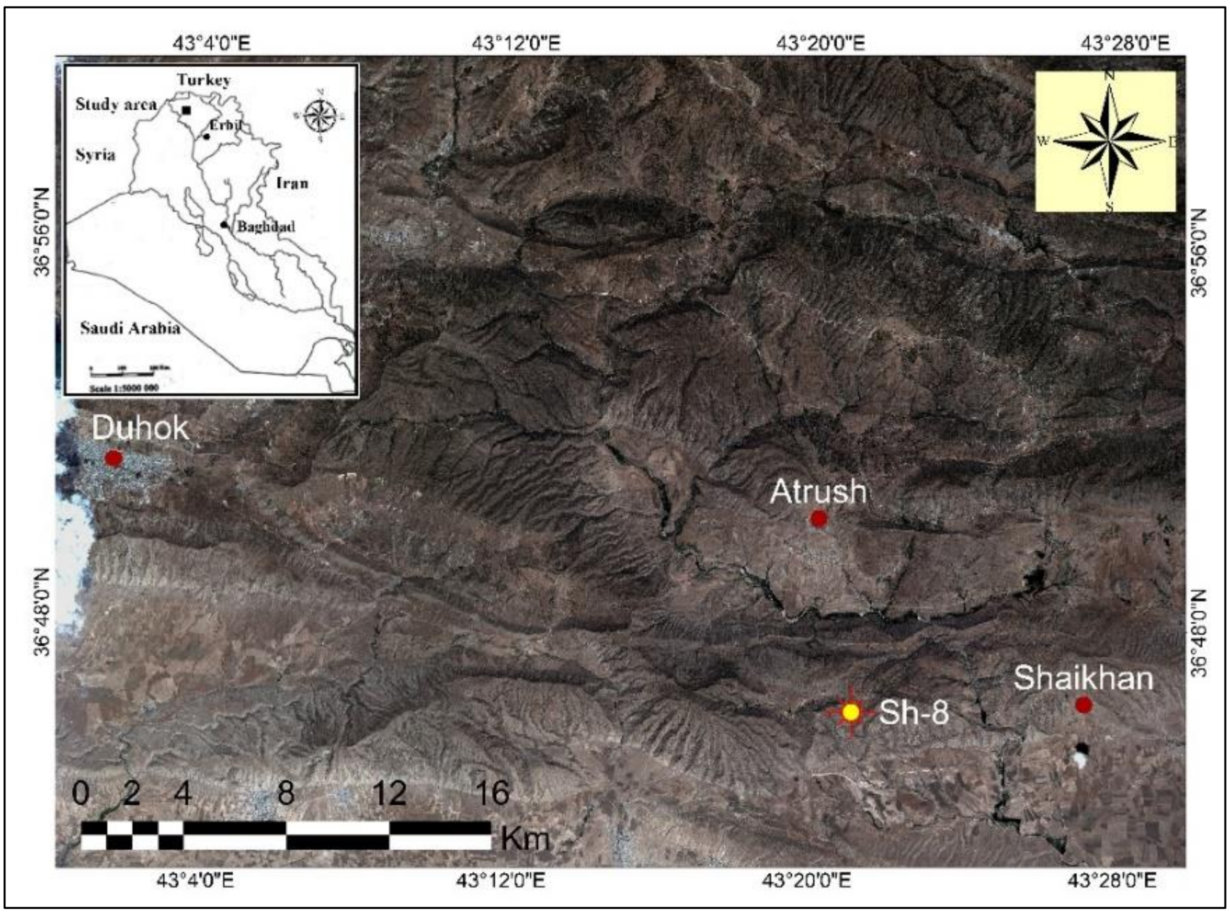


Figure 1. A Landsat image showing the location of Well Shaikhan-8 (Sh-8)

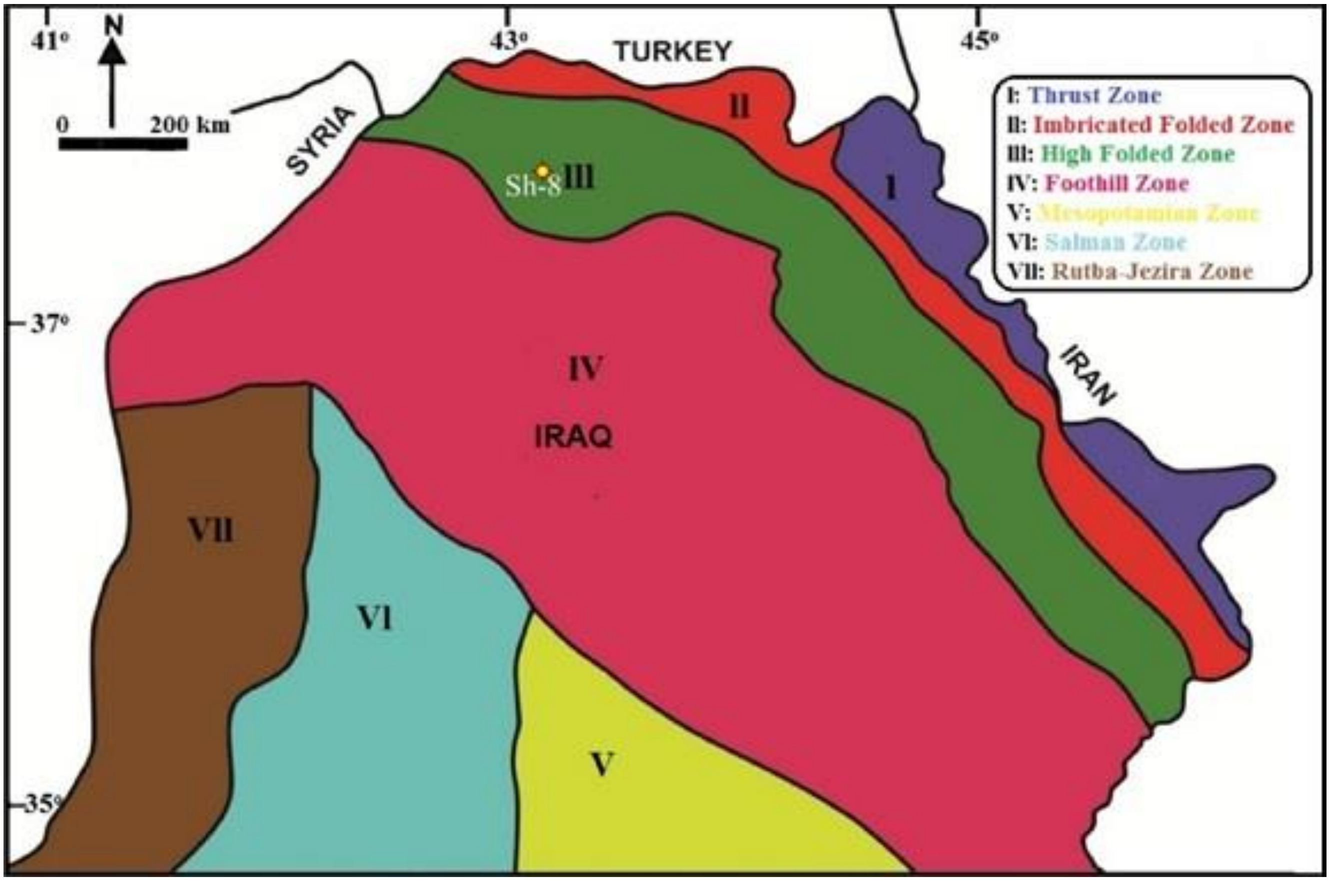


Figure 2. Tectonic map of middle and northern Iraq (redrawn based on Buday, 1980; Ameen, 1992)

The Shaikhan oilfield is located in the High Folded zone about 60 km north of Erbil city. This oilfield is a recent oil discovery in the Kurdistan Region of Iraq. The Shaikhan anticline is a WNW–ESE trending, doubly-plunging, asymmetrical anticline with a gentle southwestern limb and a steeper back limb. The attitude of the fold axis is 275°/5°. This fold is considered as an open structure because of its interlimb angle of 120° (Al-Azzawi and Hamdoon, 2008).

The stratigraphic succession, exposed within well Shaikhan-8 (Sh-8), includes the following (from the oldest to youngest): The Jurassic Alan, Sargelu, Naokelekan, and Barsarin formations. Younger Cretaceous units are composed of the Chia Gara, Garagu, Sarmord, Qamchuqa, Kometan, Wajna (informal name), and Aqra formations. These were further overlain by a Tertiary succession comprising the Kolosh, Gercus, and Pila Spi formations (Fig. 3).

The lithology of the Sargelu Formation in the studied well consists of the following (from bottom to top):
(1) limestone, which is light gray, gray, dark brown, occasionally pale, yellowish brown, firm to slightly hard, soft in part, commonly opaque, finely crystalline, and slightly argillaceous with poor porosity;
(2) shale, which is dark gray to gray, slightly firm, fissile, and slightly calcareous; and
(3) anhydrite, which is white, soft, pasty, occasionally firm to slightly hard, opaque, and interbedded with limestone (Fig. 4).

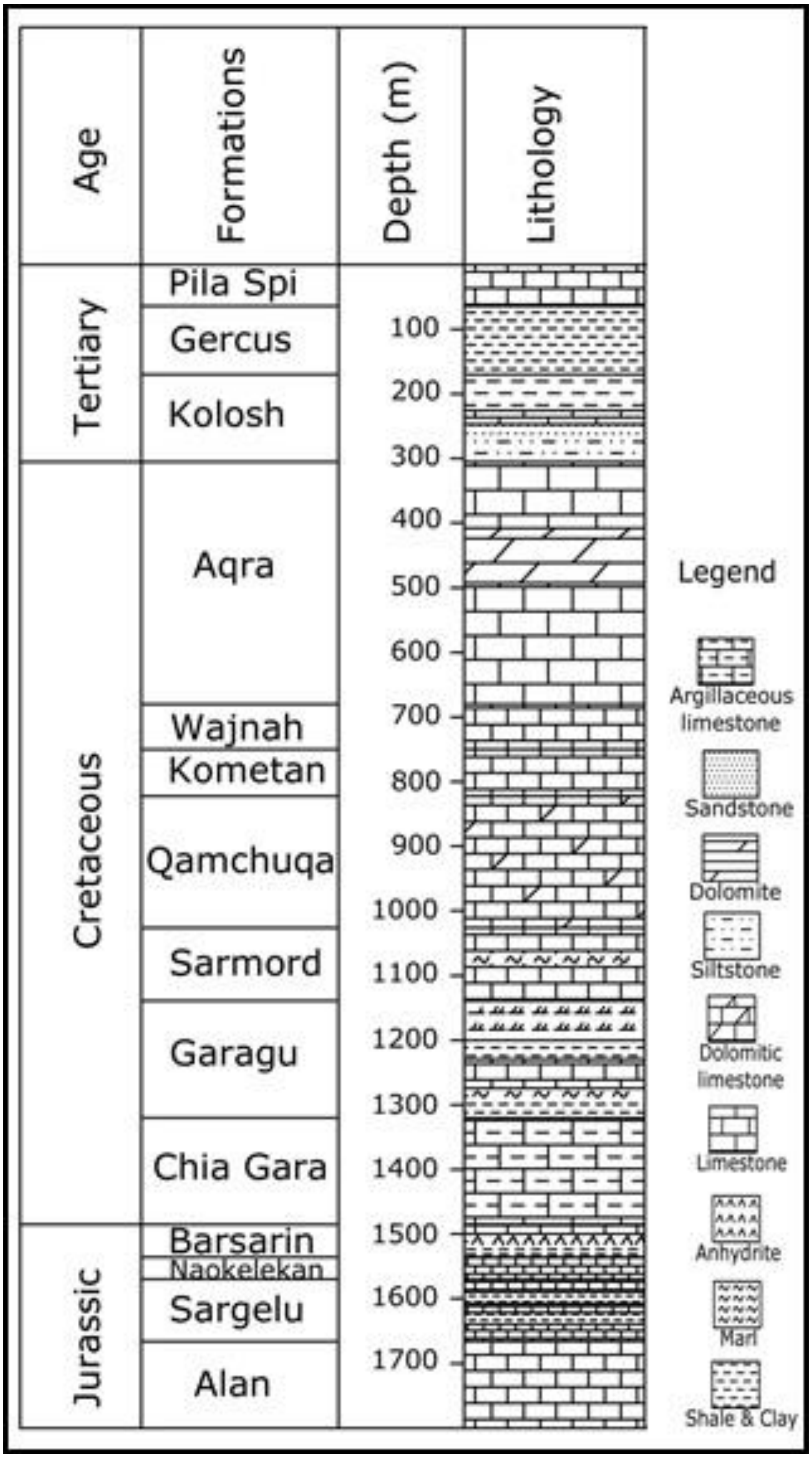


Figure 3. Stratigraphic column of well Sh-8 (Al-Atroshi et al., 2019)

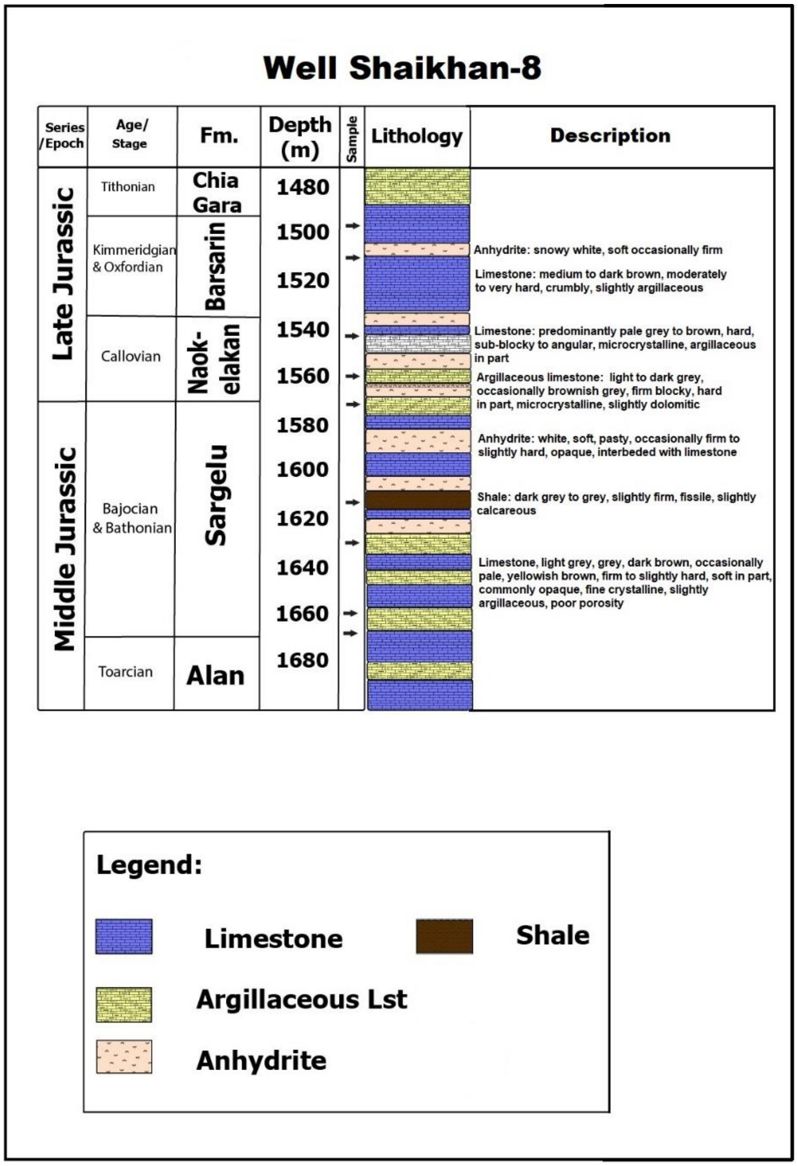


Figure 4. Lithologic description of the studied formations in well Sh-8

The Naokelekan Formation has conformable contacts with the overlying Barsarin and the underlying Sargelu formations.

The Naokelekan Formation's lithology consists of the following (from bottom to top):

(1) argillaceous limestone, which is light to dark gray, occasionally brownish gray, firmly blocky, hard in part, microcrystalline, and slightly dolomitic;

(2) limestone, which is predominantly pale gray to brown, hard, sub-blocky to angular, microcrystalline, argillaceous in part, and slightly dolomitic; and

(3) calcareous claystone, which is very dark gray to brownish gray, moderately hard, sub-blocky to angular, and carbonaceous.

The lithologic composition of the Barsarin Formation consists of the following (from bottom to top):

(1) anhydrite, which is snowy white, soft, and occasionally firm;
(2) limestone, which is medium to dark brown, moderately hard to very hard, crumbly, and slightly argillaceous;
(3) shale that is light gray to dark gray, brownish, moderately soft to moderately hard, and fissile; and
(4) dolomite that is medium to dark brown, hard, and brittle.

3. MATERIALS AND METHODS

A total of 9 well cutting samples were collected from the shaly limestone and limestone units within the Sargelu, Naokelekan, and Barsarin formations. All samples were analyzed by facilities available at the Geological Survey Repository in Erbil, Iraq.

The TOC (wt.%) was determined using a Buchner funnel and LECO C230 analyzer (Leco Corporation, St Joseph, MI, US). The studied rocks were analyzed by rock-eval pyrolysis, which estimates the genetic potential (GP) of rock samples, using a Rock-Eval 6 apparatus (Vinci Technologies, Nanterre, France) that operates according to a programmed temperature pattern. Results of pyrolysis are represented by the S_1 S_2, and S_3 peaks and T_{max}. The T_{max} can also be used to calculate the vitrinite reflectance (R_o) using the following mathematical formula introduced by Peters et al. (2005):

R_o (calculated) = $(0.018 \times T_{max}) - 7.16$

Other diagnostic ratios were calculated from the S_1, S_2, and S_3 peaks and TOC values, such as the production index (PI), hydrogen index (HI), and the oxygen index (OI). Pyrolysis data were recorded with the aim of characterizing the organic richness, kerogen type, petroleum generation potential, and the thermal maturity (Espitalie et al., 1977; Espitalie et al., 1980; Espitalie et al., 1985; Peters and Cassa, 1994).

Gas chromatography (GC) was introduced to measure the abundance of alkane peaks. Four rock extracts were fractionated and analyzed in a fashion similar to that for oil using a Hewlett Packard HP 6890 Series II GC system (Agilent Technologies, Wilmington, DE, US). The stable carbon isotopes of the saturated and aromatic hydrocarbon fractions were also determined.

The studied well was modelled using Schlumberger's PetroMod 1-dimensional (1-D) modelling software (IES, 2007). The 1-D burial history model, one of the common commercial modelling software tools, was used in this study for the reconstruction of the burial and temperature history of well Sh-8. Accordingly, source rock maturation and the timing of hydrocarbon generation and expulsion could be modelled (El Nady and Hakimi, 2016).

The samples of the Sargelu, Naokelekan, and Barsarin formations from the studied well were processed at StratoChem Services, Cairo, Egypt.

4. RESULTS AND DISCUSSION

4.1. Hydrocarbon Potential

The hydrocarbon potential of the Sargelu, Naokelekan, and Barsarin formations in well Sh-8 was determined from rock-eval data (Table 1). Several parameters were examined to determine the thermal maturity of the source rocks. The quality of the OM defines whether the kerogen is oil prone (type I and II) or gas prone (type III) (Peters and Cassa, 1994).

TOC, total organic carbon (wt%); S_1, free hydrocarbon (HC) content (mg HC/g rock); S_2, remaining hydrocarbon generative potential (mg HC/g rock); S_3, carbon dioxide yield (mg CO_2/g rock); T_{max}, temperature at maximum of S_2 peak; HI, hydrogen index = $S_2 \times 100$/TOC (mg HC/g TOC); OI, oxygen index =$S_3 \times 100$/TOC (mg CO_2/g TOC); PI, production index = $S_1/(S_1+S_2)$; GP, genetic potential = (S_1+S_2) (kg HC/ton rock); R_o,calculated vitrinite reflectance.

Table 1: Details of the cutting samples collected for pyrolysis from the studied formations from Well Sh-8

Formation	Depth (m)	TOC	S_1	S_2	S_3	T_{max} (^0C)	HI	OI	PI	GP	R_o %
Barsarin	1495	3.13	1.22	16.70	1.03	429	534	33	0.07	17.92	0.56
Barsarin	1509	2.36	1.33	12.99	0.70	434	550	30	0.09	14.32	0.65
Naokelekan	1542	0.90	0.25	2.08	1.04	427	232	116	0.11	2.33	0.53
Naokelekan	1557	1.18	0.24	3.33	0.91	429	282	77	0.07	3.57	0.56
Naokelekan	1569	1.24	0.36	3.89	1.25	428	314	101	0.08	4.25	0.54
	1611	1.16	0.49	4.97	0.82	422	428	71	0.09	5.46	0.44
Sargelu	1629	4.16	1.89	18.88	0.72	436	454	17	0.09	20.77	0.69
Sargelu	1659	11.60	2.52	63.75	0.90	440	550	8	0.04	66.27	0.76
Sargelu	1664	4.48	1.43	23.95	0.72	436	535	16	0.06	25.38	0.69

The plot of TOC vs. S_1 provides conclusive evidence about the source of the hydrocarbon present, namely if it is indigenous (autochthonous) or non-indigenous (allochthonous) (Hunt, 1996). All the analyzed samples from well Sh-8 lay below the inclined line (not migrated), and most of them have a high TOC content relative to the low S_1 values, which indicate their indigenous origin and contamination-free nature (Fig. 5).

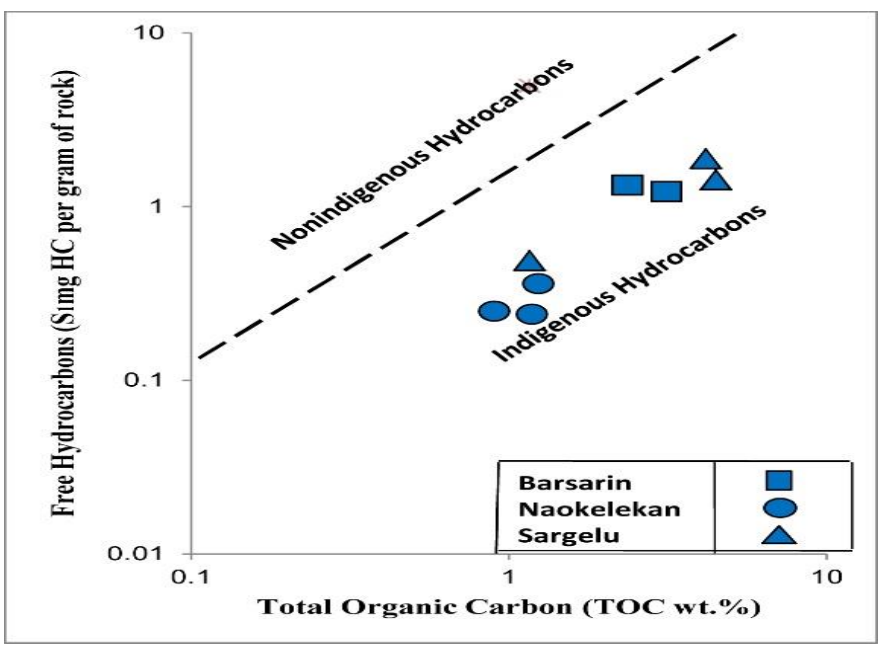


Figure 5. Plot of TOC versus S_1 for the identification of migrated hydrocarbons in the studied samples

The TOC content ranges from 1.16 to 11.6 wt%, 0.9 to 1.24 wt%, and 1.22 to 1.33 wt% for the Sargelu, Naokelekan, and Barsarin formations, respectively, indicating good-to-excellent organic richness (Table 1). The variations in the TOC content of these formations are

because of the changes in the environmental conditions, which caused the formation of different lithologies.
The measured Tmax values ranged between 427°C and 442°C, which indicate that all the samples were in the early maturation stage (Moldowan et al., 1985). Similarly, the OI values ranged from 6 to 166 mg CO2/g rock, being <200 mg CO2/g rock, which indicates an absence of intensive weathering or mineral decomposition (Jarvie and Tobey, 1999). The calculated Ro values ranged between 0.53% and 0.80%, corresponding to the onset of oil generation (Table 1).

The pyrolysis data (Tmax vs. HI) suggest that most of the analyzed samples from the Sargelu and Barsarin formations are limited to the mature and immature zones of kerogen type II, whereas most of samples from the Naokelekan Formation fall within the zone of mixed type II/III kerogen (Fig. 6). This also corresponds with their HI and Tmax values, which range from 245 to 550 mg HC/g TOC and 427°C to 442°C, respectively (Table 1). This suggests that the Sargelu and Barsarin formations have a limited capacity to generate liquid hydrocarbons, and the Naokelekan Formation is more likely to be gas prone.

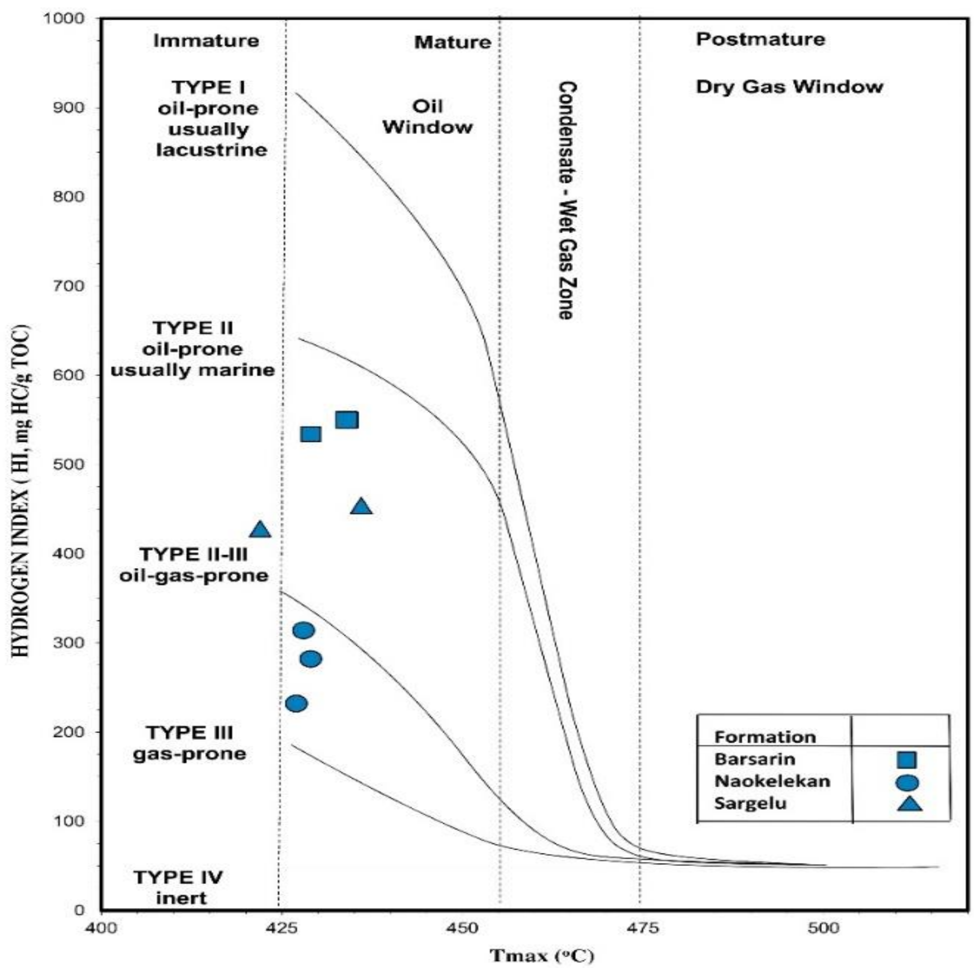


Figure 6. Plot of HI vs. T_{max} for the analysis of the samples from the studied formations

4.2. Gas Chromatographic Analysis

Four cutting samples from the studied formations were selected to determine the ratios of isoprenoid hydrocarbons, namely pristane (Pr) and phytane (Ph), which act as indicators of the depositional environments (Table 2). Carbonate source rocks that were deposited in an anoxic depositional environment have a Pr/Ph value of <2 (Peters et al., 2005). A higher Ph content and lower Pr/Ph ratio can be attributed to the presence of a reducing environment at the time of deposition of the source rock (Ten Haven et al., 1987).

Table 2: Results of the analysis of liquid and the carbon isotopes, and the gas chromatography results for the studied formations from Well Sh-8

Formation	Depth (m)	Lithology	Pr/Ph	Pr/n-C_{17}	Ph/n-C_{18}	CPI	$\delta^{13}C_{Sat}$ (‰)	$\delta^{13}C_{Aro}$ (‰)	CV	SAT wt%	ARO wt%	NSO wt%	ASPH wt%
Barsarin	1509	LST	0.44	0.33	0.56	1.04	-28.3	-28.0	2.21	11.70	12.90	33.06	42.34
Naokelekan	1569	LST	1.04	0.32	0.36	1.28	-27.7	-27.7	3.06	42.62	21.02	20.45	15.91
Sargelu	1629	Shaly LST	0.58	0.34	0.53	0.94							
Sargelu	1664	LST	0.62	0.32	0.46	0.93	-28.2	-28.1	2.68	16.40	6.67	12.31	64.62

The carbon preference index (CPI) is used as an indicator of maturity (Peters et al., 2005). Early researches concluded that immature source rocks frequently show high CPI values of >1.5, whereas the CPI values for mature rocks are always <1.2 (Jalees et al., 2010). Moldowan (1985) believes that mature source rocks have CPI values of between 0.8 and 1.2.

The Sargelu, Naokelekan, and Barsarin formations have low Pr/Ph values of between 0.58 and 0.62, 1.04, and 0.44, respectively, indicating an anoxic, reduced marine carbonate depositional environment (Tissot and Welte, 1984) (Fig. 7).

This conclusion was drawn by Mohialdeen et al. (2018) at the Miran oilfield, northeastern Iraq. Pr/Ph values of less than 0.8 with CPI values of less than 1.0 indicate saline to hypersaline conditions that are associated with carbonate and evaporate deposition. In contrast, Pr/Ph values greater than 3.0 indicate terrigenous plant input deposited under oxic to suboxic conditions (Peters et al., 2005; Hakimi et al., 2018).

The relatively low CPI values of less than 1.0 that were obtained in well Sh-8 suggest that the analyzed extract samples of the studied formations were generated from marine source rocks (Fig. 8).

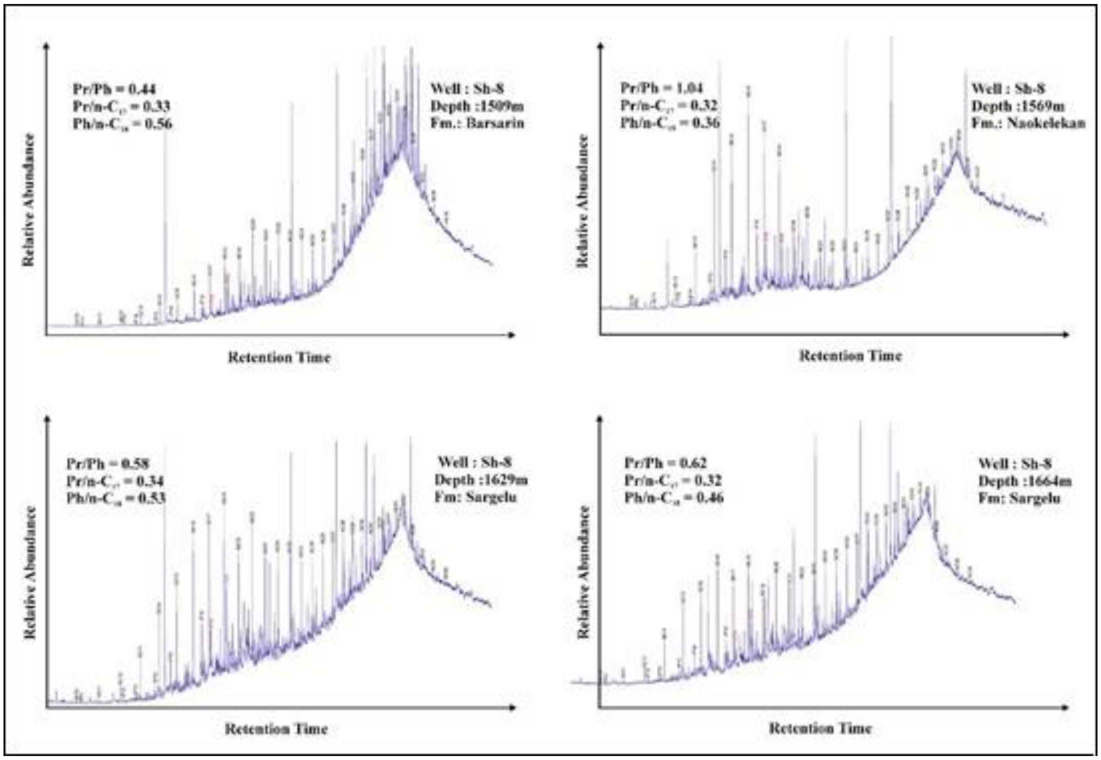


Figure 7. Gas chromatographs of the extracted rock samples from the studied formations in well Sh-8

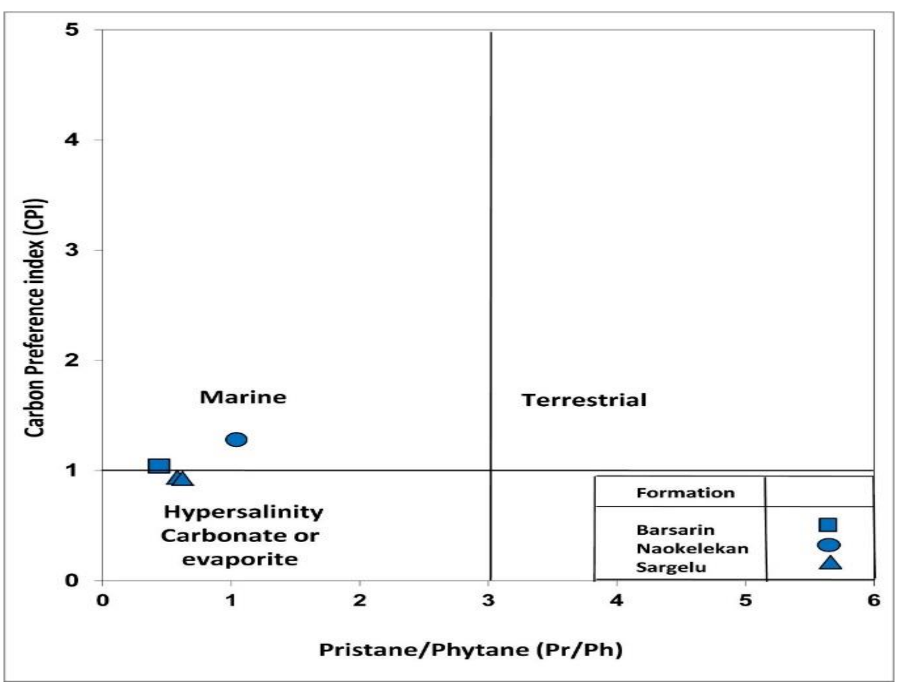


Figure 8. A plot of the CPI values vs. the Pr/Ph ratios (Hakimi et al., 2018)

The Pr/n-C17 ratio is helpful for discriminating between OM that formed in a marine environment (when the ratio is <0.5) and OM that formed in a swamp environment (when the ratio is >1.0) (Osuji and Antia, 2005). Lower values of Ph/n-C17 and Pr/n-C18 indicate a marine source rock bearing type II kerogen (Obermajer, 1999).

The Pr/n-C17 and Ph/n-C18 ratios of the 4 extract samples for the Sargelu (0.32–0.34; 0.46–0.53), Naokelekan (0.32 ; 0.36), and Barsarin (0.33; 0.56) formations (Table 2), indicate that the extracted bitumen was derived from a carbonate-rich source rock and deposited in a reduced marine environment with low to medium biodegradation (Fig. 9). The CPI values of the extracts of the studied formations are between 0.80 and 1.20, indicating a marine source at the maturation stage, with an exception in a sample from the Naokelekan Formation that scored a CPI of 1.28, indicating an immature stage (Table 2).

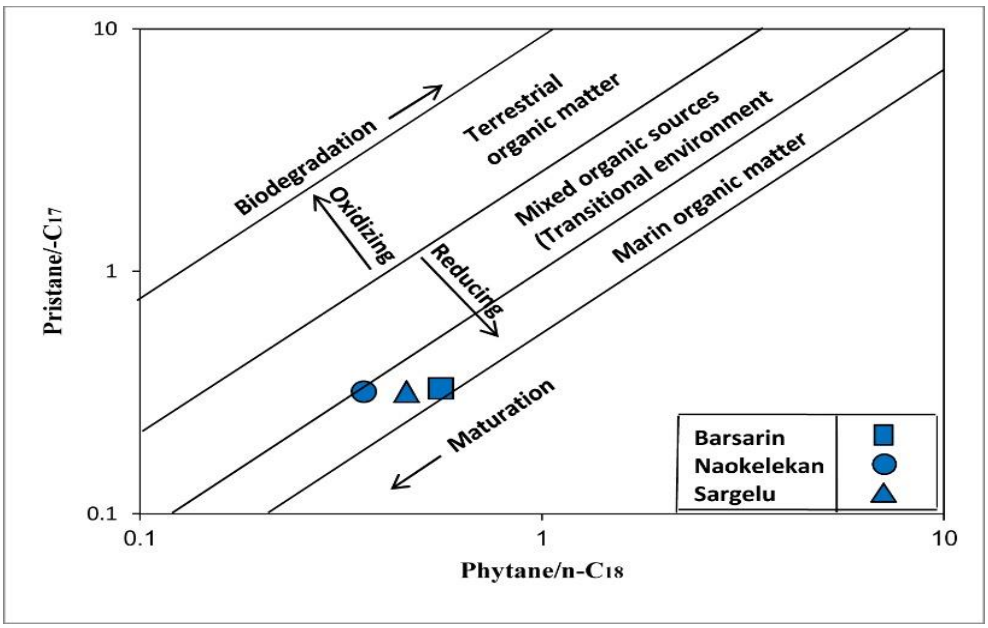


Figure 9. Ph/n-C_{17} vs. Pr/n-C_{18} for the bitumen extracts from the studied formations in well Sh-8 (Shanmugam, 1985)

4.3. Carbon Isotopes ($\delta^{13}C$ ‰)

The isotope composition of the extracted bitumen (saturates and aromatics) is employed to discriminate between marine and terrigenous depositional environments by applying a mathematical relation known as the canonical variable (CV) introduced by Sofer (1984). A CV value of <0.47 mostly indicates marine OM, whereas values of >0.47 indicate that the OM is mostly terrigenous (Sofer, 1984). The calculated CV values for the studied extracts range from –3.06 to –2.21 indicating a predominantly marine environment (Table 2).

The values for the carbon isotopes measured for the saturates (δ13CSat) and aromatics (δ13CAro) for 3 rock extract samples from the studied formations, ranged from –28.3‰ to –27.7‰ and –28.2‰ to –27.7‰, respectively (Table 2). These values point out a slight variation in the isotopic composition of the samples owing to the different maturation levels among them (Demaison and Huizinga, 1991), therefore indicating that the OM of the 3 studied formations was mainly derived from a marine source (Fig. 10).

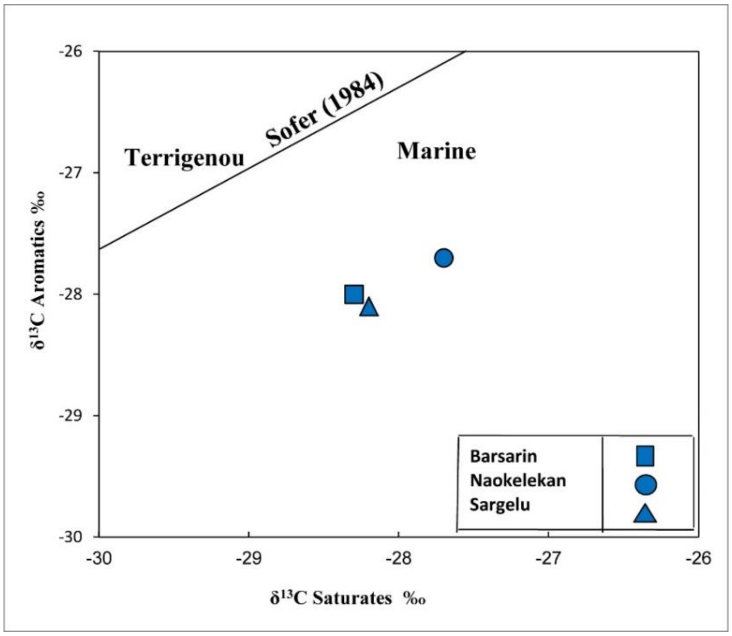


Figure 10. δ ^{13}C saturate vs. δ^{13}C aromatic cross plot for the analyzed extracts (according to Sofer, 1984)

4.4. Modeling Source Rock Maturation

The input data for the source rock maturation modeling include formation depths (in meters), related lithologies, ages (Ma), well temperatures (oC), erosional time (Ma), petroleum system element (as source, reservoir, or seal), TOC (wt.%), source rock kinetics, and HI (mg HC/g TOC). The erosional events and ages of deposition were used according to the geologic time scale of Sharland et al. (2001) (Table 3).

Table 3: Input data used to construct the burial history and thermal maturity hydrocarbon generation curves in Well Sh-8

Formation	Thickness (m)	Eroded (m)	Deposited from (Ma)	Deposited to (Ma)	Eroded from (Ma)	Eroded to (Ma)	Lithology
Pila Spi	64	1666	39.1	33	33	0.1	Limestone, dolomite
Gercus	106	64	54.9	40.4	40.4	39.1	Claystone, anhydrite, siltstone
Kolosh	135		62	54.9			Sandstone, siltstone
Aqra	375	220	80.5	75	75	62	Shale, chalky limestone
Wajna	70		83.5	80.5			Limestone, marl
Kometan	72		90.6	83.5			Limestone
Qamchuqa	204.5	241	116.2	99.6	99.6	90.6	Limestone, dolomite
Sarmord	112.5	199	133.9	128.7	128.7	116.2	Limestone, marl
Garagu	181		140.2	133.9			Limestone, Sandstone, marl
Chia Gara	165	160	148.1	142.8	142.8	140.2	Shale, limestone, marl
Barsarin	51		153.2	148.1			Limestone, anhydrite
Naokelekan	34		164.7	153.2			Argillaceous limestone, limestone, anhydrite
Sargelu	96		177.2	164.7			Limestone, argillaceous limestone, anhydrite, shale

The 1-D PetroMod program requires correction of the thermal regime (Fig. 11) based on the calculated thermal conductivities of the rock succession, heat flow parameters, burial history linked to the present-day surface, and bottom hole temperature (BHT) (Pitman et al., 2004).

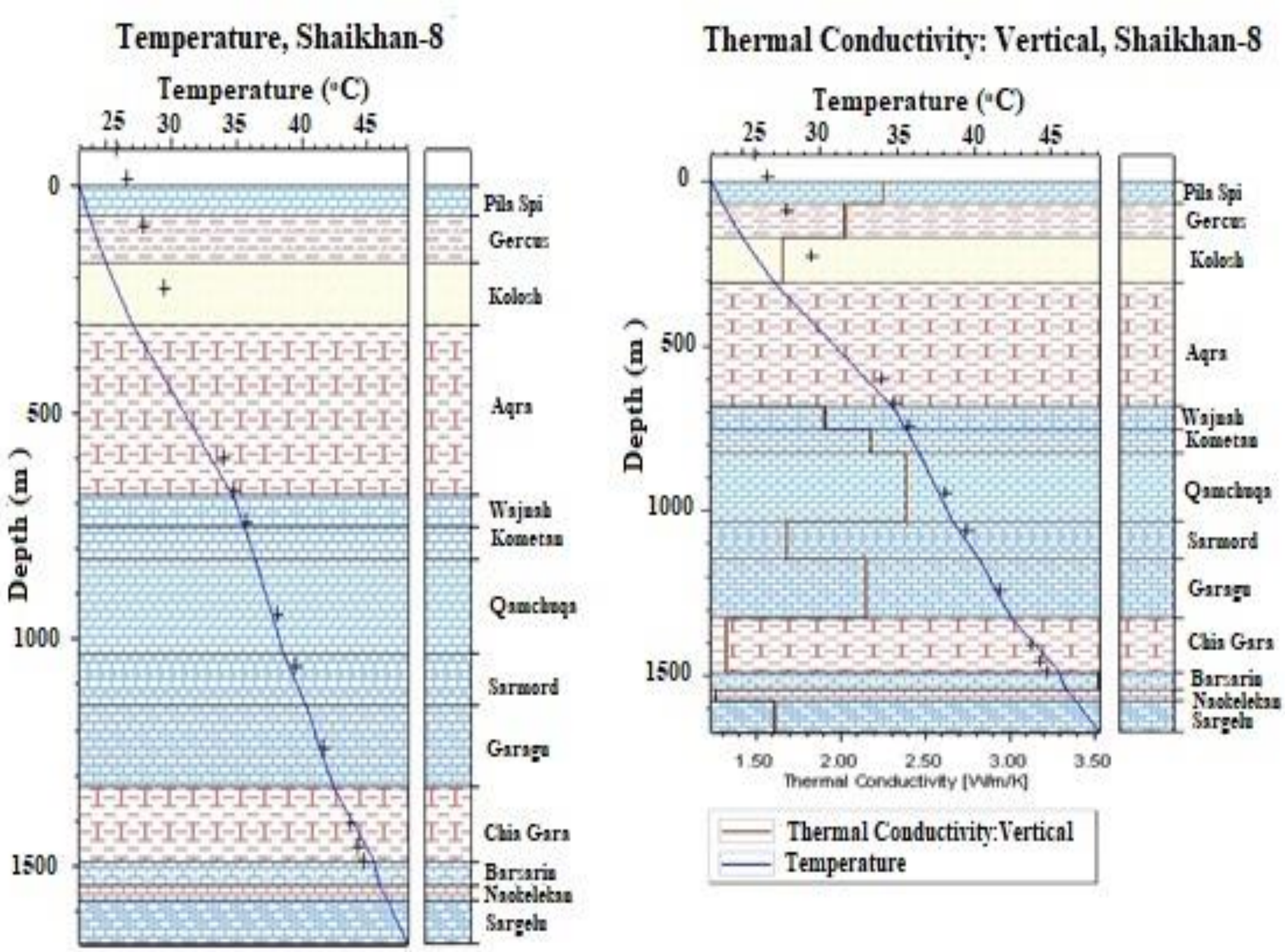


Figure 11. Modeled geotherm and thermal conductivity for the studied well

The present-day geothermal gradient for well Sh-8 was calculated using BHT and subsequently corrected for the drilling mud circulation. The kinetics for a type IIS kerogen were used for source rock maturation considering the high sulfur contents (nitrogen, sulfur and oxygen [NSO] = 12.31% to 33.06%) in the analyzed samples (Table 2).

Several erosion events have been recognized in the studied well (Table 3). The burial history of well Sh-8 (Fig. 12) shows that during the Middle–Late Jurassic period, the sedimentation was characterized by relatively low subsidence rates leading to the present thickness of about 346 m.

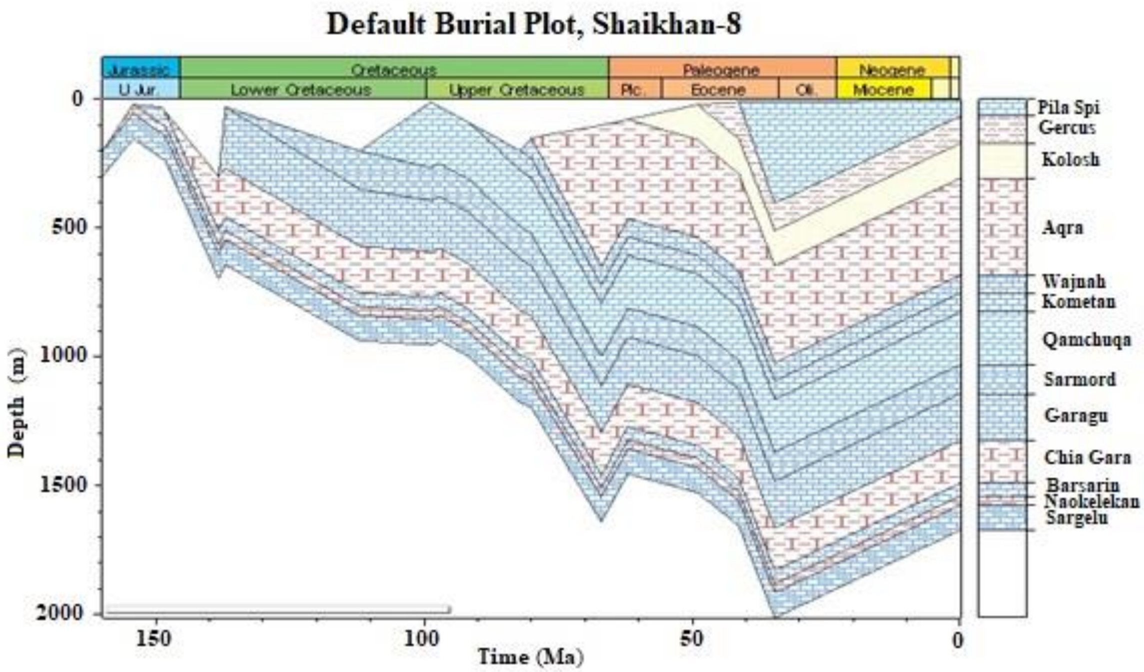


Figure 12. Burial history modelling for the studied well (Sh-8)

Subsidence and sedimentation continued in the Cretaceous period when the rate of the former increased, leading to the present thickness of about 1015 m. The overlying Tertiary units were characterized by a relatively low subsidence rate and a total thickness of 305 m of sediments accumulated during the Tertiary Period.

The burial and thermal maturity history profiles for the studied well (Fig. 13) show that the generation zones that were simulated based on the calculated Ro (Table 1) for the Sargelu, Naokelekan, and Barsarin formations are immature (0.25% – 0.55%) and in the early oil generation stage (0.55% – 0.70%).

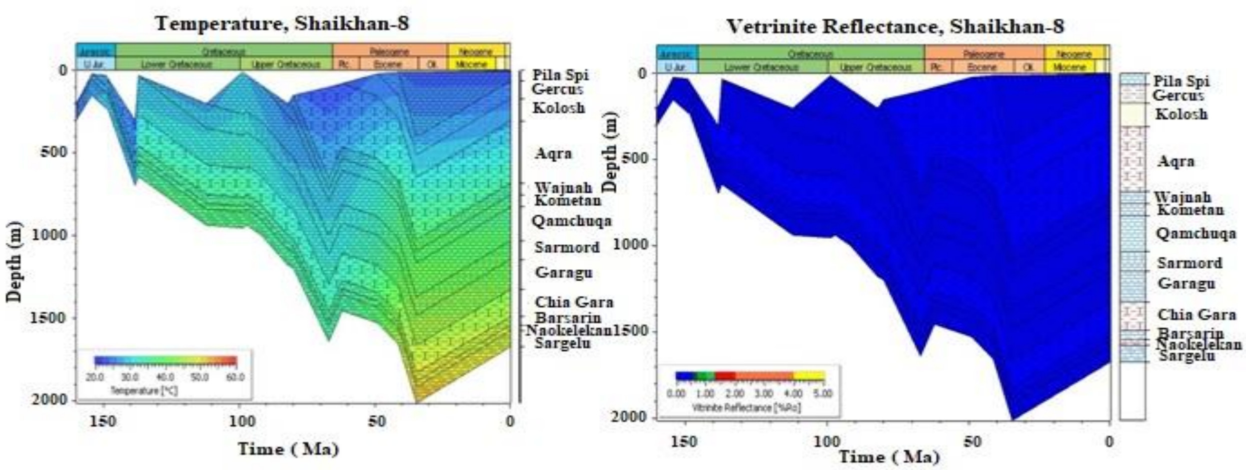
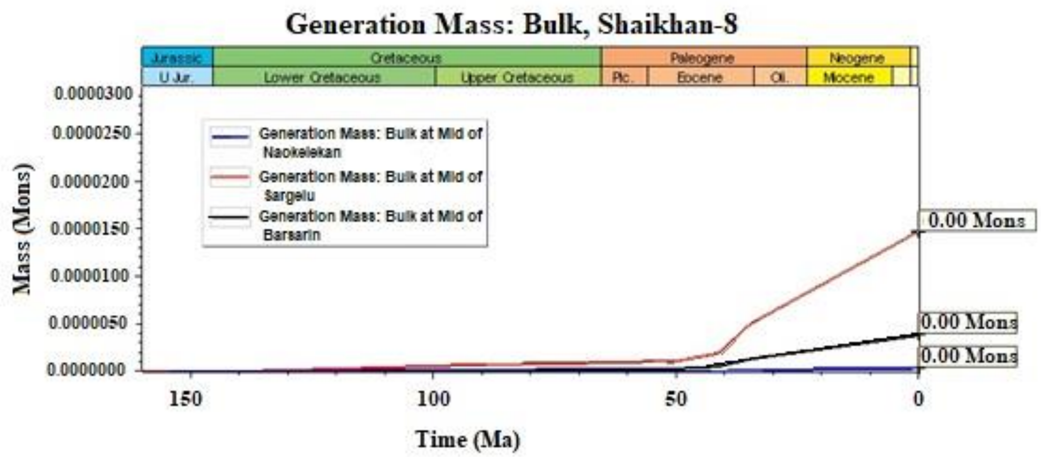


Figure 13. Burial and thermal maturity histories of the studied well (Sh-8)

The thermal maturation of the Jurassic source rocks in Mosul High is relatively low and less than that of the Kirkuk Embayment because of the thinning of the overlying Cretaceous section and a thinning or missing Cenozoic section (English et al., 2015). The presence of thick layers of high thermal conductivity carbonates in the

Cretaceous formations and the absence of the younger Tertiary formations caused a reduction in the geothermal gradient toward the northwest of the Kurdistan Region (Abdula, 2018). However, the low thermal maturity of the studied source rocks relative to the depth in well Sh-8 may be attributed to the lower geothermal gradient and heat flow.

The onset of oil generation can be expected with a transformation ratio (TR) of 0.1, whereas a TR greater than 0.5 offers an estimate of the peak oil generation stage (Hantschel and Kauerauf, 2009). The modelled generation mass of the Middle–Late Jurassic formations and their TRs associated with the geologic time of the studied well (Fig. 14) indicated that all studied formations did not reach the early phase of oil generation (TR <0.1). This is because of the shallower burial depths and low geothermal gradients of the studied well.



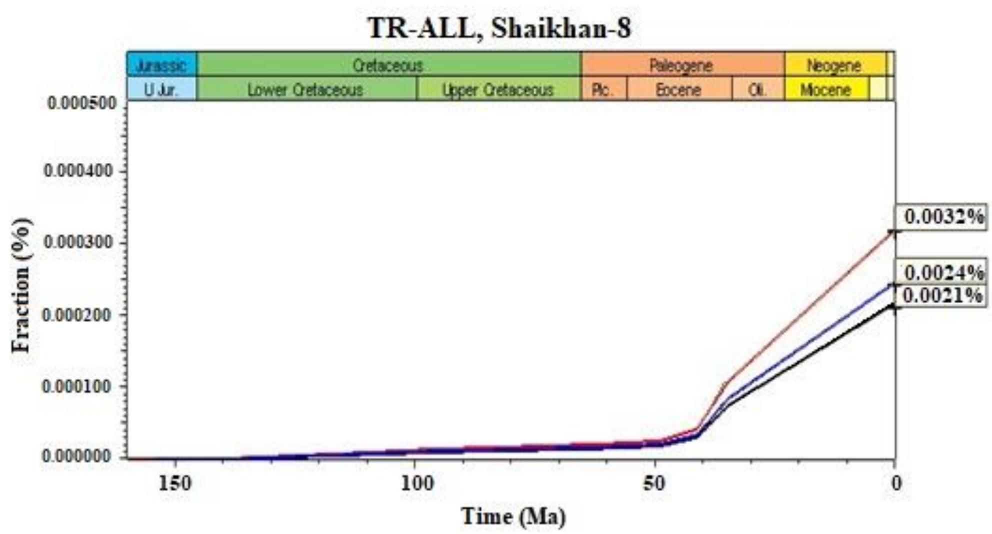


Figure 14. Generation mass and TR ratio vs. time for the Middle–Late Jurassic source rocks in the studied well (Sh-8)

5. CONCLUSIONS

The study of the organic geochemical parameters, biomarker analyses, and burial history of the Sargelu, Naokelekan, and Barsarin formations in the Sh-8 well in the northwestern Iraqi Kurdistan Region have led to the following conclusions:

The OM in the Naokelekan Formation is mainly of type II/III, whereas that of the Sargelu and Barsarin formations is predominantly type II.

The TOC contents ranged from 1.16 to 11.60 wt.% (with an average of 5.35 wt.%), 0.90 to 1.24 wt% (with an average of 1.11 wt%), and 2.36 to 3.13 wt% (with an average of 2.75 wt%) for the Sargelu, Naokelekan, and Barsarin formations, respectively; these figures indicate the good potential of the source rock.

The OM in the rocks of these formations were deposited in an anoxic environment, as revealed by the Pr/Ph, Pr/n-C17, and Ph/n-C18 ratios, and they also appear to be biodegraded to a medium to low extent.

The stable carbon isotype composition of the saturates and aromatics, and the CV values indicate that the OM of the Sargelu, Naokelekan, and Barsarin formations were mainly derived from marine sources.

The applied PetroMod 1-D models indicated that all the studied formations did not reach the early phase of oil generation owing to their shallow burial depths (1570 m, 1536 m, and 1465 m for the Sargelu, Naokelekan and Barsarin formations, respectively) and the low geothermal gradients of the Sh-8 well.

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