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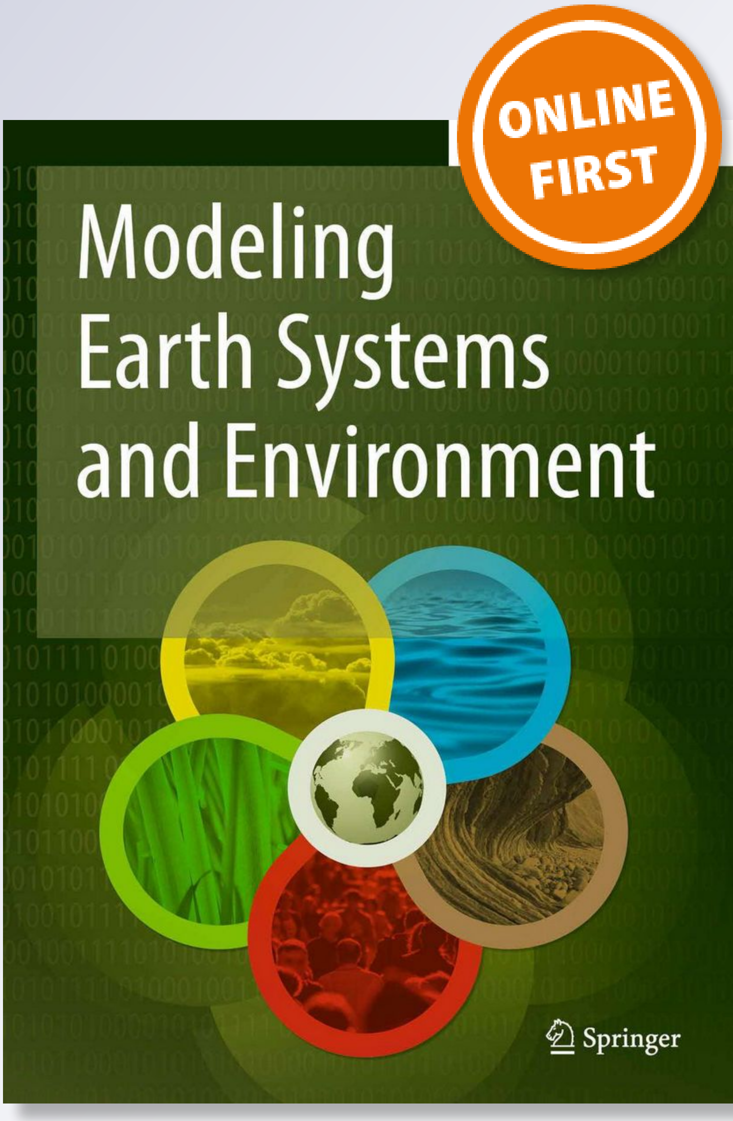
Modeling Earth Systems and Environment

ISSN 2363-6203

Model. Earth Syst. Environ.
DOI 10.1007/s40808-019-00673-0



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https://doi.org/10.1007/s40808-019-00673-0

ORIGINAL ARTICLE

Applications of biomarker and geochemical characterization of crude oil for Mesopotamian basin, Southern Iraq

Amna M. Handhal[1] · **Muwafaq F. Al‑Shahwan**[1] · **Hussein A. Chafeet**[2]

Received: 13 September 2019 / Accepted: 21 October 2019

Abstract
In this study, geochemistry analysis of oil and source rock extracts from different fields of Basra and Amara oil fields is implemented. Results indicate that the type of producing oil rocks are marine algae carbonate type II rocks and no contribute from terrestrial sources. These rocks are deposited under marine environment (> 150 m deep) and have normal saline and reduced conditions. No biodegradations are observed in the studied oil. The correlation of oil–oil exhibits that the oils have the same group and family and back to the same rock. On the other hand, the correlation between oil and source rock demonstrates that both of them have the same geochemical characteristics. The results of isotopic analysis of oil show so that source rocks of oil are marine mature rocks and have high sulfur content with API in range (15–48).

Keywords Biomarker · Geochemistry analysis · Crude oil · Mesopotamian basin · Southern Iraq

Introduction

Biological markers are complex molecular fossils derived from biochemical, particularly lipids, in once-living organisms. Biomarker can be used to correlate oil to extract oil; hence, they could be used to define the characteristics of petroleum of source rocks when only oil samples are available (Peters et al. 2005). They also provide information on the organic matter in the source rock, environmental during deposition and burial, the thermal maturity experienced by rock or oil, the degree of biodegradation, some aspects of source rock mineralogy, and age (Peters et al. 2005). The study area contains oil reservoirs in Cretaceous Formations, at different depths and in a variety of lithologies. There is having in the same area, several possible source rocks for such hydrocarbon. They are includes Five fields: Zubair, Nahr Umr, Majnoon, Halfaya and Amara as shown in (Fig. 1). They are located south eastern part of Iraq between (30°58′–32°08′ latitudes) and (46°52′–47°56′ longitudes). Cores and crude oil samples from (Sulaiy, Yamama, Zubair, Nahr Umr, Mishrif, and Hartha) Formations covering of study region have been utilized. According to Buday and Jassim (1987) the studied area is located at the southern part of Iraq within the Mesopotamian basin (Fore deep) of the unstable shelf. The stratigraphic column of Southern Iraq is shown in (Fig. 2). The objective of the current study was to identify different genetic types of crude oils in the basin using established geochemical parameters and to determine source-rock ages and depositional environments by correlating geochemical data.

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Source rock and depositional environment

In the following sections, number of the commonly used biomarker and discussion of their use in exploration studies are shown.

n-Alkanes

n-Alkanes with the respect to the study area, the Mishrif in Hf-2, Nahr–Umr in Hf-8, Nahr–Umr in Am-1, Mishrif in

Published online: 02 November 2019

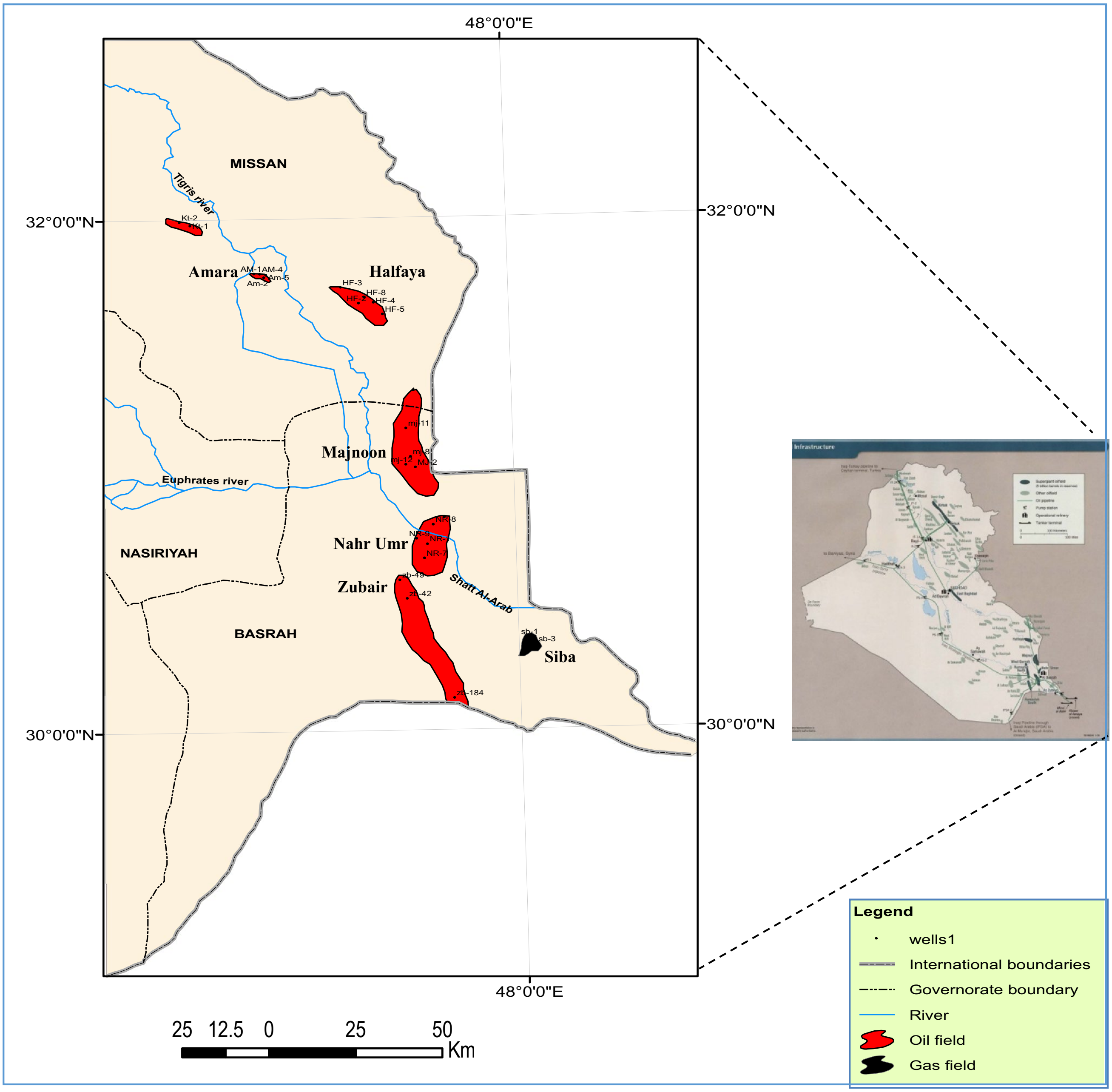

Fig. 1 Map of the study area

Am-4, Nahr Umr in Am-5, Nahr Umr in NR-1, Mishrif in Zb-89, Zubair in Zb-89, Mishrif in Mj-2, Hartha in Mj-2, Zubair in Mj-2, and Zubair in NR-7 have same source rocks of oils and they are carbonate rocks deposited in reducing environment. The predominance of C15–C23 and CPI value over one suggested that the origin is algae, (Fig. 3) and Table 1. The other parameters derived from *n*-alkanes which can be used to enhance results are as follows:

Terrigenous/aquatic ratio (TAR)

This ratio is estimated from the following equation (Peters et al. 2005):

$$\mathrm{TAR} = \frac{(n-\mathrm{C27}) + (n-\mathrm{C29}) + (n-\mathrm{C31})}{(n-\mathrm{C15}) + (n-\mathrm{C17}) + (n-\mathrm{C19})}. \tag{1}$$

The ratio was adopted in present study to estimate the source as shown in Table 1. The TAR values in all samples

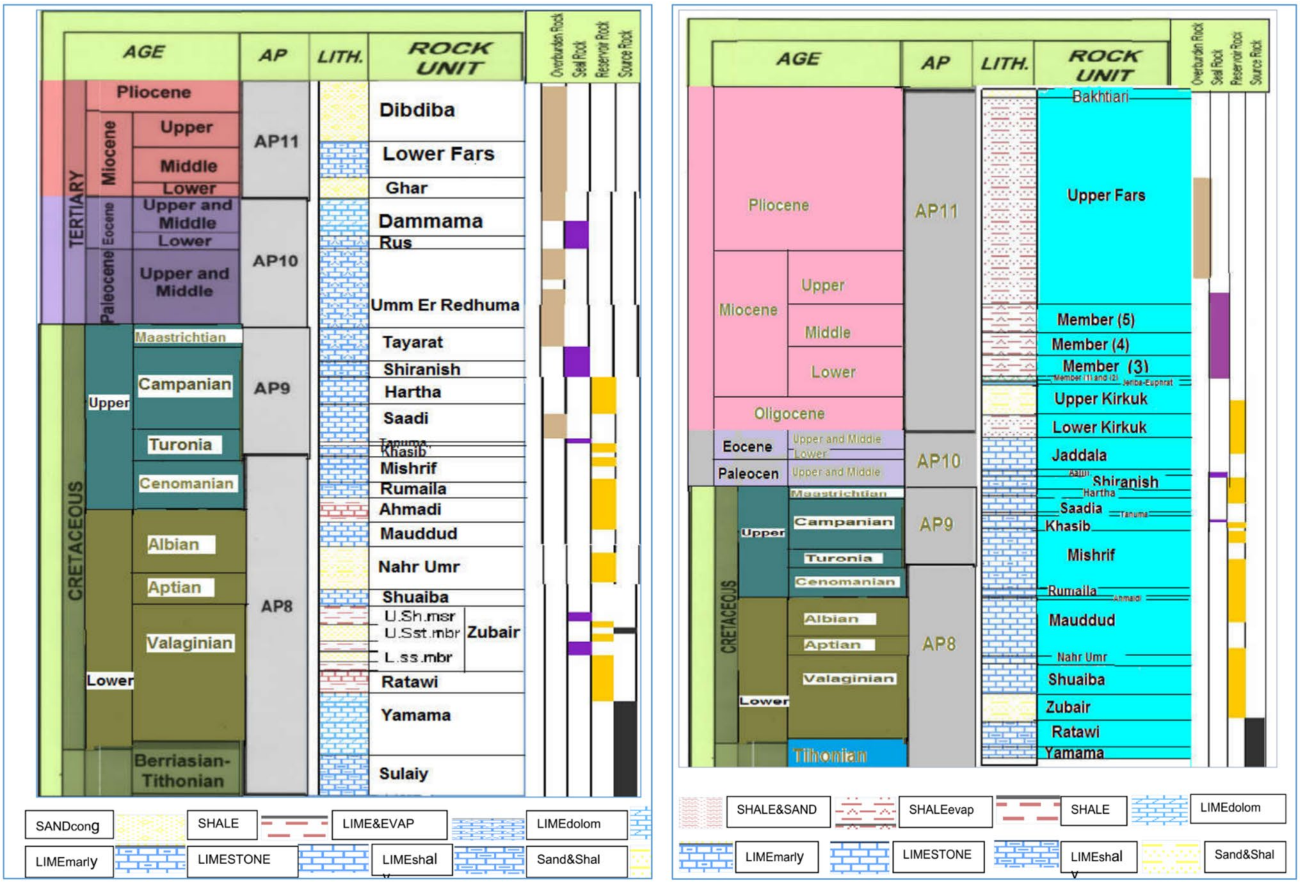

Fig. 2 Stratigraphic column in southern Iraq. **a** Nahr Umr field (NR-7). **b** Halfaya oil field(Hf-5)

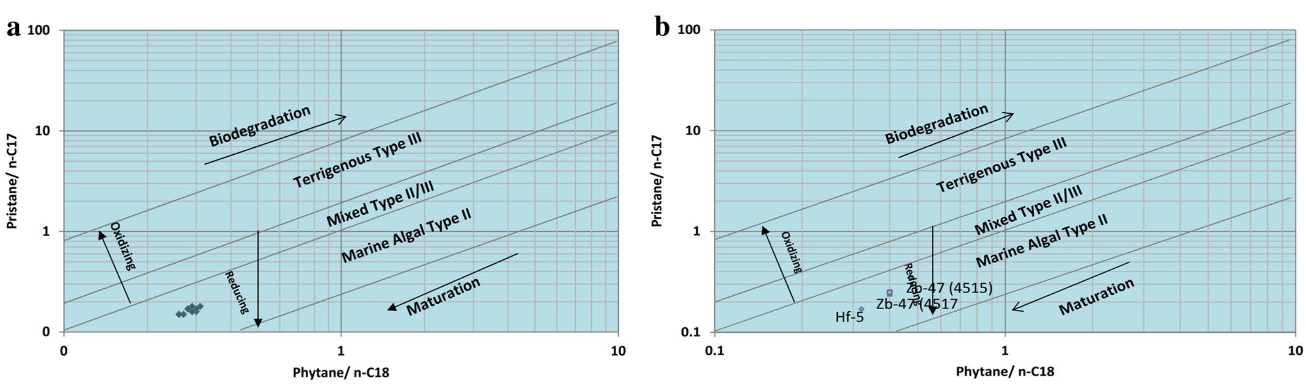

Fig. 3 Ph/*n*-C18 vs. Pr/*n*-C17 plots for: **a** crude oil, **b** Extracted oil of Sulaiy Formation from studied area

of crude oil are less than one indicating that origin of oil is marine algae rather than terrigenous source.

Carbon preference index (CPI) and odd-to-even predominance (OEP)

The Bray and Evans (1961) measurements of CPI and Scalan and Smith (1970) measurements odd-to-even (OEP) are:

$$CPI = \left[\frac{\frac{C25+C27+C29+C31+C33}{C26+C28+C30+C32+C34} + \frac{C25+C27+C29+C31+C33}{C26+C28+C30+C32+C34}}{2} \right] \quad (2)$$

$$CPI(2) = 2((C23 + C25 + C27 + C29 / [C22 + 2(C24 + C26 + C28) + C30])) \quad (3)$$

Table 1 The source rock and environmental parameters (crude oil)

Field	Well	Formation	TAR	OEP1	OEP2	S	CPI	CPI	nC27/nC17	nC17/nC31	C22/C21	C24/C23	C26/C25
Halfaya	Hf-2	Mishrif	0.142	1.041	0.997	3.838	1.080	1.212	0.18	6.464	1.11	0.26	0.74
Halfaya	Hf-8	Nahr Umr	0.135	0.980	1.025	3.632	0.942	1.043	0.20	9.69	0.98	0.29	0.73
Amarah	Am-1	Nahr Umr	0.130	1.024	0.985	4.145	1.022	1.171	0.17	6.741	1.12	0.26	0.74
Amarah	Am-4	Mishrif	0.118	1.008	1.040	4.538	1.008	1.142	0.17	8.448	1.08	0.26	0.75
Amarah	Am-5	Nahr Umr	0.112	0.978	0.945	3.985	0.999	1.029	0.17	11.84	0.94	0.32	0.74
Nahr Umr	NR-1	Nahr Umr	0.095	0.979	1.003	4.357	1.029	1.066	0.15	15.403	0.97	0.30	0.77
Zubair	Zb-89	Mishrif	0.113	0.924	0.962	3.955	1.067	1.048	0.16	12.367	0.96	0.31	0.72
Zubair	Zb-89	Zubair	0.129	1.023	0.998	3.985	0.979	1.116	0.18	8.727	1.11	0.26	0.71
Majnoon	Mj-2	Mishrif	0.140	1.001	1.010	3.782	1.059	1.156	0.19	7.703	1.09	0.27	0.70
Majnoon	Mj-2	Hartha	0.102	1.023	0.997	4.774	1.047	1.183	0.14	8.862	1.14	0.25	0.76
Majnoon	Mj-2	Zubair	0.127	0.994	0.975	3.609	1.001	1.036	0.19	10.60	1.07	0.29	0.70
Nahr Umr	NR-7	Zubair	0.013	1.002	0.928	12.99	0.931	1.028	0.03	139.9	0.83	0.32	0.72

Field	Well	Formation	22S/22R	ETR	C26/C25	C35S/C34S	C34S	C34R	C31R/H	C25S	C25R	C35S	C35R	C-35 INDEX	Pr/Ph	V/N
Halfaya	Hf-2	Mishrif	1.323	0.94	0.74	1.11	14	9	0.35	2	2	15	10	0.118	0.68	4.06
Halfaya	Hf-8	Nahr Umr	1.160	0.93	0.73	1.06	8	6	0.37	2	1	9	6	0.10	0.62	
Amarah	Am-1	Nahr Umr	1.20	0.94	0.74	1.07	17	11	0.35	3	2	18	12	0.11	0.65	3
Amarah	Am-4	Mishrif	1.24	0.94	0.75	1.10	13	8	0.35	2	2	14	9	0.12	0.67	3.24
Amarah	Am-5	Nahr Umr	1.14	0.927	0.74	1.02	7	5	0.36	1	1	8	5	0.10	0.64	1.55
Nahr Umr	NR-1	Nahr Umr	1.21	0.90	0.77	1.03	7	4	0.36	1	1	7	4	0.1	0.71	
Zubair	Zb-89	Mishrif	1.22	0.93	0.72	1.06	10	6	0.36	2	1	10	7	0.10	0.64	
Zubair	Zb-89	Zubair	1.29	0.94	0.71	1.12	17	11	0.36	3	2	19	12	0.12	0.63	4.39
Majnoon	Mj-2	Mishrif	1.26	0.94	0.70	1.13	18	12	0.34	3	2	20	13	0.12	0.67	3.33
Majnoon	Mj-2	Hartha	1.34	0.93	0.76	1.02	13	8	0.35	3	2	13	9	0.11	0.69	
Majnoon	Mj-2	Zubair	1.22	0.94	0.70	1.04	14	10	0.38	2	2	15	10	0.10	0.64	
Nahr Umr	NR-7	Zubair	1.1	0.85	0.72	0.86	1	1	0.32	1	1	1	1	0.07	0.85	

Field	Well	Formation	C28/H	C29/H	X/H	C31R/H	GA/31R	C35 INDEX R	C35 IN(S + R)	C29/H	10 Ga	GA IND	S1/S6	S/H	% C27	% C28
Halfaya	Hf-2	Mishrif	0.01	1.70	0.0	0.35	0.23	0.11	0.11	1.70	0.7	8.16	0.11	0.15	35.18	24.02
Halfaya	Hf-8	Nahr Umr	0.01	1.44	0.01	0.37	0.14	0.09	0.10	1.44	0.5	5.23	0.22	0.24	33.31	25.99
Amarah	Am-1	Nahr Umr	0.01	1.81	0.0	0.35	0.22	0.11	0.11	1.81	0.7	7.68	0.11	0.15	33.64	23.71
Amarah	Am-4	Mishrif	0.01	1.71	0.0	0.35	0.23	0.11	0.11	1.71	0.7	7.87	0.14	0.16	33.07	24.11
Amarah	Am-5	Nahr Umr	0.01	1.38	0.01	0.36	0.18	0.09	0.10	1.38	0.6	6.39	0.21	0.21	33.52	24.53
Nahr Umr	NR-1	Nahr Umr	0.01	1.51	0.01	0.36	0.20	0.09	0.09	1.51	0.6	7.03	0.28	0.21	35.13	23.76
Zubair	Zb-89	Mishrif	0.01	1.41	0.01	0.36	0.18	0.10	0.10	1.41	0.6	6.65	0.19	0.21	33.42	25.02
Zubair	Zb-89	Zubair	0.01	1.58	0.0	0.36	0.22	0.11	0.11	1.58	0.7	7.94	0.11	0.16	33.51	24.50
Majnoon	Mj-2	Mishrif	0.01	1.64	0.0	0.34	0.25	0.11	0.12	1.64	0.7	8.42	0.12	0.16	33.96	24.12
Majnoon	Mj-2	Hartha	0.01	1.90	0.0	0.35	0.24	0.11	0.11	1.90	0.7	8.48	0.07	0.14	33.25	23.30
Majnoon	Mj-2	Zubair	0.01	1.54	0.01	0.38	0.22	0.10	0.10	1.54	0.7	8.30	0.20	0.17	34.91	23.21
Nahr Umr	NR-7	Zubair	0.02	1.49	0.02	0.32	0.15	0.07	0.07	1.49	0.4	4.89	0.52	0.40	38.28	24.73

Table 1 (continued)

Field	Well	Formation	%C29	C28/C29	C27/C29	P/DBT	DBT/P	DBT/C4 N	Pr/nC17	Ph/nC18	OL/H	C24Tet/C21T
Halfaya	Hf-2	Mishrif	40.79	0.58	0.86	0.36	2.81	2.79	0.18	0.31	0.00	0.176
Halfaya	Hf-8	Nahr Umr	40.70	0.63	0.81	0.58	1.72	2.24	0.16	0.29	0.00	0.166
Amarah	Am-1	Nahr Umr	42.64	0.55	0.78	0.35	2.88	2.65	0.15	0.26	0.00	0.175
Amarah	Am-4	Mishrif	42.81	0.56	0.77	0.36	2.746	3.11	0.17	0.28	0.00	0.173
Amarah	Am-5	Nahr Umr	41.95	0.58	0.79	0.44	2.29398	2.74	0.15	0.27	0.00	0.158
Nahr Umr	NR-1	Nahr Umr	41.11	0.577	0.854	0.71	1.40	1.71	0.17	0.28	0.00	0.165
Zubair	Zb-89	Mishrif	41.56	0.602	0.804	0.50	1.983	1.86	0.16	0.29	0.00	0.161
Zubair	Zb-89	Zubair	41.99	0.583	0.79	0.36	2.74	2.30	0.16	0.30	0.00	0.177
Majnoon	Mj-2	Mishrif	41.92	0.57	0.81	0.36	2.76	2.59	0.17	0.30	0.00	0.178
Majnoon	Mj-2	Hartha	43.45	0.53	0.76	0.30	3.375	2.18	0.15	0.26	0.00	0.187
Majnoon	Mj-2	Zubair	41.89	0.55	0.83	0.53	1.90	2.39	0.16	0.29	0.00	0.137
Nahr Umr	NR-7	Zubair	37.00	0.66	1.034	0.92	1.09	1.31	0.18	0.29	0.00	0.355

$$\mathrm{OPE(1)} = (\mathrm{C21} + 6\mathrm{C23} + \mathrm{C25})/(4\mathrm{C22} + 4\mathrm{C24}) \quad (4)$$

$$\mathrm{OPE(2)} = (\mathrm{C25} + 6\mathrm{C27} + \mathrm{C29})/(4\mathrm{C26} + 4\mathrm{C28}). \quad (5)$$

The data presented in Table 1 indicate that the organic matter in these sediments was deposited in a reducing environment. The reducing state of the environment of deposition is indicated by low OEP value near unity and ratio of pristine–phytane (Pr/Ph) less than 1.

Marine versus terrigenous *n*-alkanes (*S*)

The ratio of marine of terrigenous *n*-alkanes as given by Philippi (1974)is written as follows:

$$S = (n - \mathrm{C21} + n - \mathrm{C22})/(n - \mathrm{C28} + n - \mathrm{C2}. \quad (6)$$

All samples of oil for the study area have values of *S* greater than (1) indicating the marine algae source rocks and indicate that light hydrocarbon is predominant. All collected samples have light hydrocarbon dominant.

(*n*-C17/*n*-C31) and (*n*-C27/*n*-C17)

From, Table 1, the ratio of (*n*-C17/*n*-C31) ranges from (6 to 139) and the ratio (*n*-C27*n*-C17) ranges from (0.03 to 2) which exhibits the marine algae source of organic matter.

Isoprenoids

All samples of crude oil and extracted oil in the study area have ratio of Pr/Ph less than 1 indicating a reducing type environment and normal saline environment, Table 1. It could be noticed that low values of OPE and Pr/Ph ratio mark that organic matter was deposited in reducing environment.

Isoprenoids/*n*-alkanes

The ratio of Pr/*n*-C17 versus Ph/*n*-C18 for the studies samples are shown in (Fig. 1) and Table 1. From, (Fig. 3), the source of oils is marine algal type II. Type II kerogen-originates from zoo plankton, phytoplankton and bacteria.

Terpanes

Tricyclic terpanes

In order to know the type of source rock there are many parameters as described below:

a. *Tricyclic terpanes ratio (C22/C21): C24/C23 and C26/C25)* With respect to oil of collected samples for this study, the values of C24/C23 and C22/C21 are shown in (Fig. 4a, b) in which all points are taking place in carbonate source rocks. The ratio of C24/C25 tricyclic terpane biomarker versus C31R/Hopane is shown in (Fig. 5). Form, (Fig. 5)shows that the source rocks of all samples are carbonate rocks.
b. *Tetracyclic terpane* The C24 tetracyclic terpane/hopane, C24 tetracyclic/C23 tricyclic terpane and C24 tetracyclic/C26 tricyclic terpane ratio are common source rock parameters. The values of these ratios for collected oil samples, (Figs. 4a, b) and Table 1, refer that the source rocks of crude oils are marine carbonate rocks.

Hopanes

The families of hopanes include groups of compounds:

1. *Regular hopanes* The values of ratio T_s/T_m in Table 1 indicates anoxic marine deposition environment. Peters et al. (2005) suggested that ratio of C35S/C34H is greater than

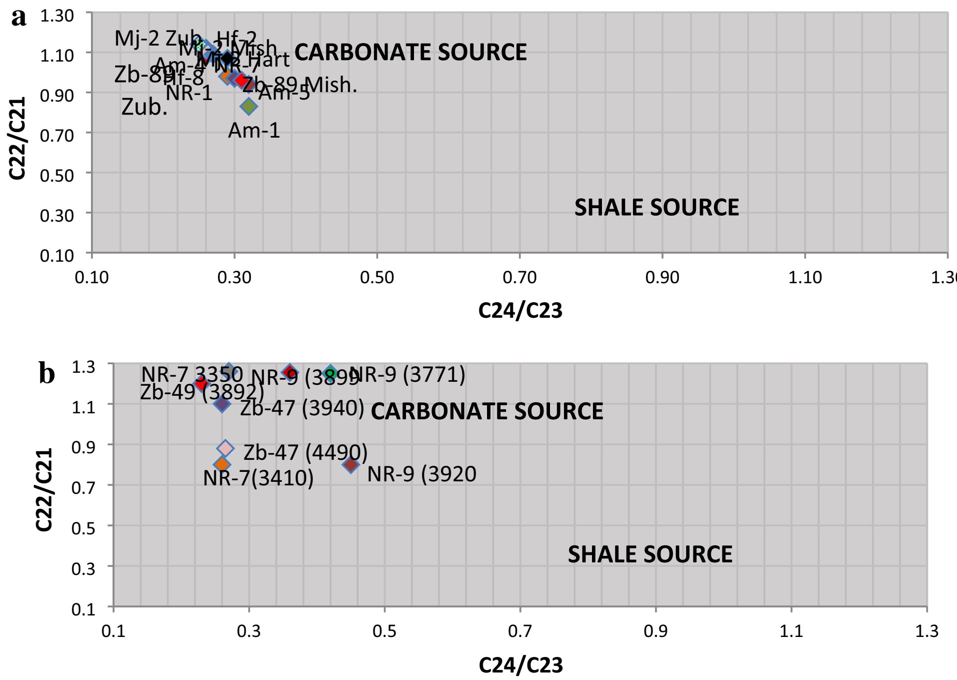

Fig. 4 **a** Ratio of C24/C23 vs. C22/C21 (crude oil). **b** Ratio of C24/C23 vs. C22/C21 (extract oil)

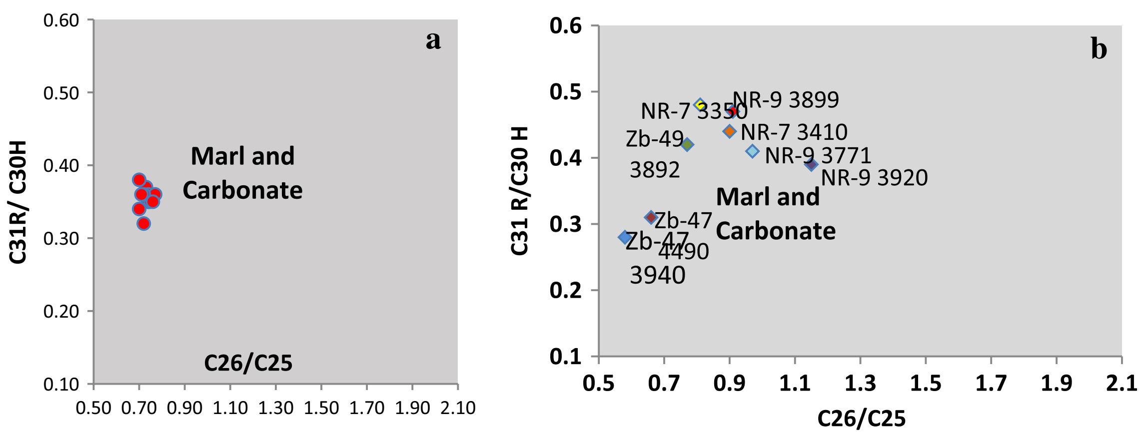

Fig. 5 Relationship between C26/C25 Tricyclic terpane and C31 R/C30 H Hopane. **a** Crude oil. **b** Rock extract

0.8 and ratio of (C24/C30H) > 0.6 that indicate marine carbonate source rocks, (Fig. 6a, b) and Table 1. Peters and Moldowan (1991) proposed that a high C35 homohopane index and low Pr/Ph value indicate reducing but not necessary hypersaline conditions. From, Table 1, the oil samples of study area have high C35 index and low Pr/Ph ratio indicating reducing environment. The other ratio is C31/C30 hopane which is a useful index to distinguish between marine versus lacustrine source rock deposition environments. This ratio is expressed as C31 22R/C30 hopane (C31R/H) (Peters et al. (2005). This ratio is useful to know the marine and lacustrine crude oil in combination with other parameters such as C26/C25 tricyclic terpane and the canonical variable (CV) from stable carbon isotope measurements, (Fig. 5); from this figure, all the samples of crude oil drop in carbonate and marl area.

2. *28-30-Bisnorhopane* Abundance of BNH and TNH in oil indicates deposition of the source rock under clay-poor, anoxic conditions (Katz and Elrod 1983). Values of this ratio for the collected samples of study area, Table 1, refer to anoxic conditions of deposition.
3. *30-Norhopanes* This series reflects microbial activity during original period of deposition and is widely distributed in oils from carbonate source rocks (Subroto et al. 1991). All samples of crude oil and rock extracts

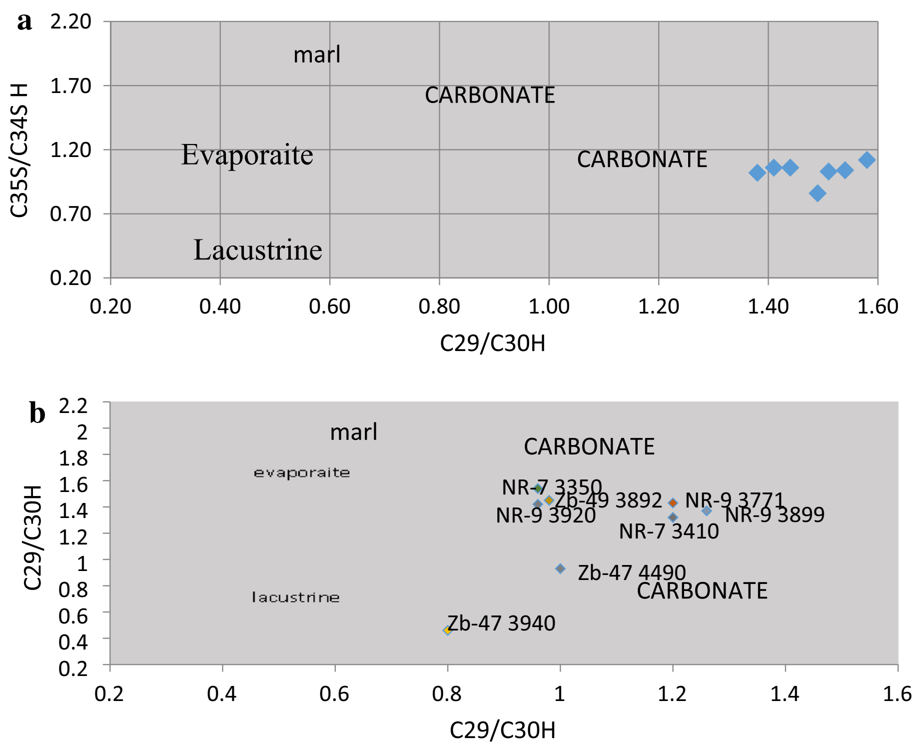

Fig. 6 **a** Relationship between C29/C30H and C35S/C34S H Hopane index (crude oil). **b** Relationship between C29/C30H and C35S/C34S H Hopane index (rock extract)

have value of C29/C30H greater than one indicate anoxic carbonate source rocks.

4. *Diahopanes* Several years ago the significant presence of a C30 terpane eluting between the C29 and C30 hopane in number of Australian crude oils led to its tentative identification as compound X (Philp and Gilbert 1986). The ratio of X/H for the samples of study area range between zero to very little amount indicating that the crude oil are not derived from terrigenous and no oxic–suboxic environment.

Non-hopanoid terpanes

1. *Oleananes (C30 triterpane marker of angiosperms)* Oleanane are formed in sediments through diagenetic and catagenetic alteration of various 3β functionalized angiosperm triterpenoids (Ten Haven and Rullkötter 1988). All samples of study area have values of OL/H equal to zero which indicate that this index does not contain contribution of terrigenous input in source rocks, Table 1.
2. *Gammacerane* A high content of gammacerane in source rock or oil is generally associated with hypersaline depositional environment (Moldowan et al. 1985). The principal characteristics of the biological marker of saline/hypersaline sediment extracts are a dominance of phytane and high content of gammacerane and abnormal distribution of homohopanes (Homohopane index ≫ 1) (Fu et al. 1990). For the crude oil of collected samples in the study area, Table 1 and (Fig. 7), the oils are deposited in normal salinity water in marine source depositional environment of late cretaceous rich in Type II-kerogen.

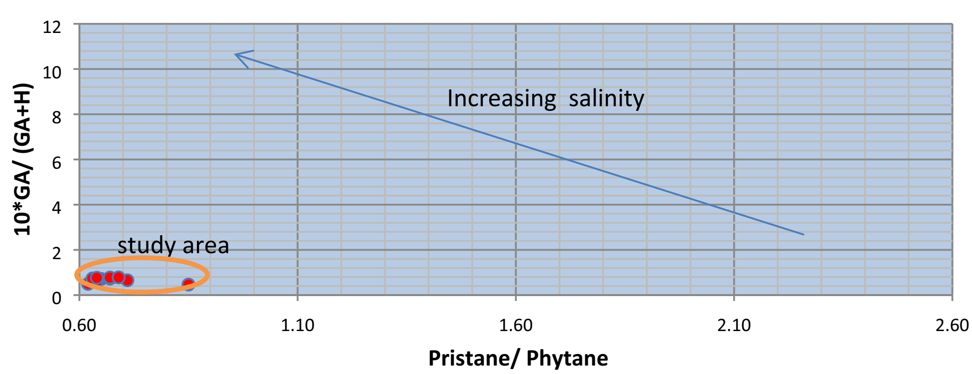

Fig. 7 Pr/Ph vs Gammacerane index for water column stratification

Steranes

Many parameters can be calculated from this isomers steranes such as source, depositional environmental and thermal maturity.

Regular steranes/17α-hopanes

In general, high concentrations of steranes and high steranes/hopanes (≥ 1) typically marine organic matter with major configuration from planktonic and/or benthic algae (Moldowan et al. 1985). As it can see from, Table 1, the high values of C29, C27 denote marine algae carbonate source rock. Average C27/C29 sterane and steranes/hopane ratio, (Fig. 8), is lower for all samples indicating source rock in Upper Jurassic.

Diasterane (rearranged steranes (S1))

The ratio of diasteranes/steranes (S1/S6) or (rearranged/regular steranes) are commonly used to distinguish petroleum from carbonate versus clastic source rocks (Mello et al. 1988). High disterane/steranes ratios are typical of petroleum derived from clay-rich source rocks. However, high of this ratio in some crude oil can result from high thermal maturity and/or heavy biodegradation (Seifert and Moldowan 1978). Based on values in Table 1, the low values of S1/S6 denote marine carbonate source rocks.

C27–C28–C29 steranes

When one put the values of %C27, %C28, and %C29 steranes for all samples of crude oils and rock extracts on the ternary diagram, they are found located on the area of marine algae and bacteria deposited in deep marine (> 150 m), (Fig. 9) and Table 1.

Porphyrins

Porphyrins are complex tetrapyrrolic organometallic compounds that contain a great deal of Ni and V in crude oils (Philp 2007). Low V/(V + Ni) porphyrin ratios in marine Toarcian rocks reflect oxic to suboxic conditions while high ratios reflect anoxic sedimentation (Moldowan et al. 1986). When plot the values of Ni versus V for crude oils of study area, they are located on high S-marine and low diasteranes, (Fig. 10) and Table 1.

Aromatic fraction

There are many compounds of aromatic, such as:

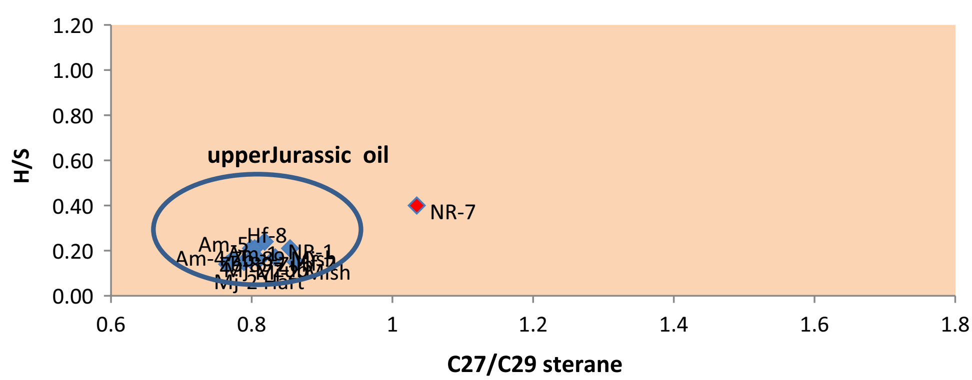

Fig. 8 Relationship between C27/C29 sterane vs. H/S (crude oil)

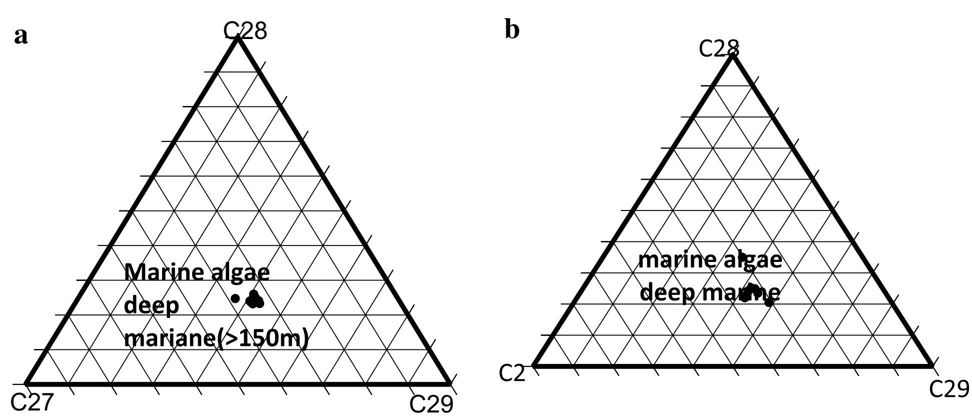

Fig. 9 Ternary diagram shows the relative abundances of C27, C28, and C29 regular steranes in the saturate fractions of (a) crude oil samples and (b) rock extracts from study area

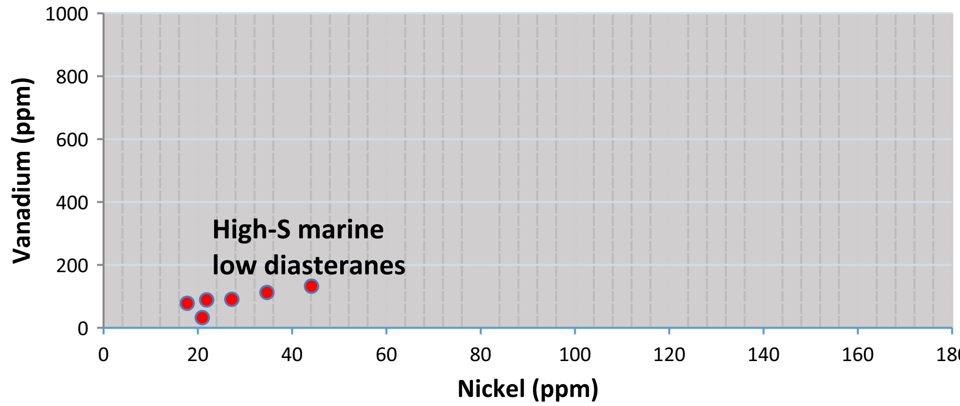

Fig. 10 Relationship between Nickel and Vanadium for crude oil

Organo-sulfur compounds

Most of these compounds will be discussed along with their significance and potential uses:

1. Methyldiben zothiopheres (MDBT) and dibenzothiophenes (DBT)

    Oil derived from carbonate source rocks were observed to have an abundance of substituted dibenzothioph where those from silic–clastic rocks had decreasing amounts of dimethyl and trimethyl–dibenzothiophenes (Philp 2007). The ratio of phenanthrenes/DBT (P/DBT) that in Table 1 is less than 1 indicating deposition in saline water environment and the carbonate rocks are deposited under anoxic conditions and high organo-sulphur content.

Phenanthrenes (P) and methylphenanthrene (MP) (MP three ring aromatic hydrocarbon (*M/Z* 191)

The relative proportion of phenanthurenes in the aromatic fractions of marine source rocks and crude oils were typically lower than observed for oils of terrigenous origin and source rocks (Fan et al. 1991). The phenanthurenes in all samples of crude oils is low referring to marine source rock, Table 1.

Naphthalenes (N)

The abundant in crude oils C0–C4 naphthalenes, lighter oils and enriched in the naphthalenes, whereas heavy, degraded or weathered oils are enriched in larger-ring compounds (Peters et al. 2005). Naphthalenes decrease faster than other PAHs due to greater evaporation and water solubility.

Fluorene (F)

The relative abundance fluorenes may serve as a good indicator for sedimentary environment of source rocks (Li et al. 2005). With respect to study area in Table 1, the values of fluorene are low indicating that the source rocks are marine carbonate.

Triaromatic steroids (TAS)

Difference in relative abundances of triaromatic steroids may reflect differences in organic matter source input or sedimentary environments (Riolo et al. 1986). Ratios of C26/(C26–C28), C27/(C26–C28) and C28/(C26–C28) triaromatic steroids are potentially effective source parameters, the triaromatic steroids ratios should be more sensitive to thermal maturation (Peters et al. 2005). The ratio of C26/C28 S and C27/C28 R triaromatic steroids can be used to distinguish oil families which refer that the oil represented as one petroleum system (Picha and Peters 1998). Triaromatic steroids aromatization ratio [TA (I)/TA (I + II)] where [TA (I) = C20 + C21 TAS; TA (II) = C26 + C27 + C28 TAS, 20S + 20R isomers] increase from 0 to 100% during thermal maturity (Peters et al. 2005). For the crude oil of the study area, the ratio of TAS refers to marine carbonate rocks and one family group, (Fig. 11).

Maturity

Thermal maturity heat-driven reaction converts sedimentary organic matter into petroleum. While not all of the maturity parameters will be discussed in details, it is useful to make short comment concerning most commonly used ones:

1. *Tricyclic/17αHopanes (C19–C25T)/(C29–C33H):* The increasing of tricyclics/17αH−ratio leads to increase oil thermal maturity (Seifert and Moldowan 1978). From, Table 2, it is obvious that this ratio for all samples of crude oil is high indicating that oils are mature.
2. *22S/(22S + 22R)* Homohopane isomerization typically uses the C31 or C32 homologs: the 22S/(22S + 22R) ratio rises from 0 to 0.6 (0.57–0.62 = equilibrium) (Seifert et al. 1980). During maturation the range of ratio (0.5–0.54) has barely entered oil generation, while ratios in the range 0.57–0.62indicate that the main phase of oils generation has been reached or surpassed (Peters et al. 2005). The values of 22S/

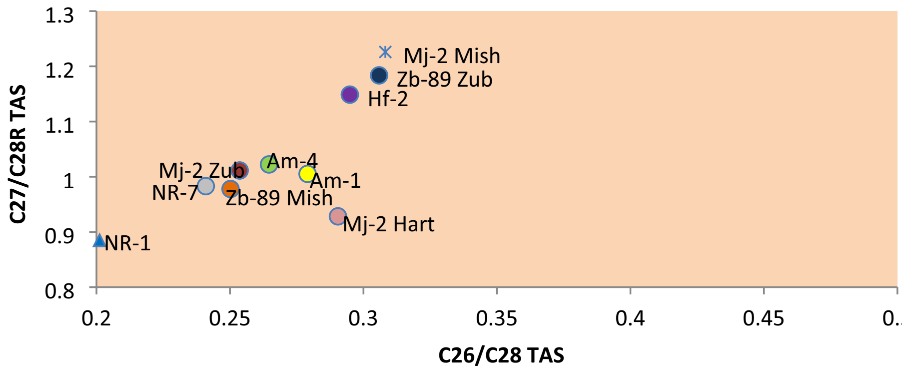

Fig. 11 Relationship between C26/C28 TAS and C27/C28R TAS (crude oil)

(22S + 22R) for C31 and C32 are given in Table 2, for all samples of crude oil and oil extracts indicate that oil of the study area is above early oil generation.

3. *$T_s/(T_s+T_m)$* As seen from, Table 2 and (Fig. 12), value of T_s/T_m of all samples of crude oils and oil extracts are moderate to high maturity.
4. *18β/(α + β)-oleananes and oleanane index (immature to early mature range):* There are no oleananes in all samples of study area.
5. *20S/(20S + 20R) isomerization:* The ratio of sterane isomerization ranges between 0.47 and 0.73 that is at or above peak oil generation in all samples of crude oils and medium to high maturity oils.
6. *T_s/Hopane* All samples of crude oils have T_s/H values ranging from 0.08 to 0.15 indicating early to peak oil generation except one 0.24 (Zubair Formation in NR-1) at above peak oil generation, Table 2. The rock extracts of the study area have value of T_s/H between peak oil generations to above peak oil.
7. *Moretanes/hopanes* The value of this ratio, Table 2, for crude oils and rock extracts is less than 0.1 revealing that oil of the study area is mature, (Fig. 12).
8. *C29 T_s/(C29 hopanes) + C29 T_s)* 18α-30 Norneohopanes (C29 Ts) abundance relative to the 17α-hopane is related to thermal maturity (Hughes et al. 1985). In Table 3, the values of these parameters show that all samples have values indicating moderate maturity except the Zubair Formation in NR-7 which has high maturity.
9. *(BNH + TNH)/hopanes (also express as C28/C30 hopanes)* The ratio decreases with thermal maturity, Table 3. All samples of crude oils and rock extracts have few values of this ratio indicating that all samples are mature.
10. *20S/(20S + 20R) steranes* C29 [20S/(20S + 20R)-C29ααα cholestane was found to range between 0.47 and 0.73 in crude oils and 0.13 and 0.87 for rock extracts of study area which reveals oils at or above peak oil generation of thermal maturity, Table 3.
11. *Diasteranes/Steranes* The ratio of diasteranes/steranes shown in Table 1 suggests that maturity at peak oil window (~ 1% R_o) for all samples of crude oil and rock extract.
12. *TA (I)/TA (I + II)* It is commonly used for maturity. This ratio increases with thermal maturity. The values of this ratio in Table 3 show high maturity in Zubair Formation at NR-7 and other samples have medium maturity at peak oil generation.
13. *C26 triaromatic 20S/(20S + 20R)* In Table 2, the ratio of C26 TAS shows values at or above peak oil generation.

(14) *Isoprnoid/n-alkane ratios* These ratios decrease with thermal maturity; the ratios of Pr/*n*-17 and Ph/*n*-C18 shown in Table 2 indicate that all samples of crude oil are mature.

(15) *Carbon preference index and odd to even predominance (CPI and OEP).* CPI and OEP values of the study area indicate medium maturity for all samples of crude oil and rock extract, Table 2.

(16) *Aromatic maturity indicators* There are many parameters for aromatic ratios:

1. This ratio is written as (Connan et al. 1986):

$$
\begin{aligned}
\mathrm{MPI}_1 &= \frac{(1.5\,(2-\mathrm{MP}+3-\mathrm{MP}))}{(\mathrm{P}+1-\mathrm{MP}+3\,\mathrm{MP})}\\
\text{and } \mathrm{MPI}_2 &= \frac{(3\,(2-\mathrm{MP}))}{(\mathrm{P}+1-\mathrm{MP}+9-\mathrm{MP})}\\
\text{and } \mathrm{MPI}_3 &= \frac{(2-\mathrm{MP}+3-\mathrm{MP}))}{(P+1-\mathrm{MP}+3\,\mathrm{MP})}\\
\text{and } \frac{\sum MP}{P} &= \frac{(1-\mathrm{MP}+2-\mathrm{MP}+3-\mathrm{MP}+9\,\mathrm{MP}))}{\mathrm{P}},
\end{aligned}
\tag{7}
$$

where MP is the methyl phenathrene, P is the phenanthrene, − MP is the number that indicates the position of methyl substitution, MPI is the thermal maturity parameter bases on the relative abundance of phenanthrene and methyl phenanthrene (three rings) aromatic hydrocarbons. MPI and MPI3 increase with maturity. According to above, the MPI of

Table 2 The source rock and environmental parameters (extract oil)

Well No.	Depth (m)	Formation	OEP1	CPI	C22/C21	C24/C23	C26/C25	C31R/H	ETR	C35S/C34S	C29 20S/R	C31R/H	F	Ph/nC18	Pr/nC17	Pr/Ph
NR-7	3350	Yamama			1.26	0.27	0.81	0.48	0.93	0.96	0.59	0.48	0.34			
NR-7	3410	Yamama			0.8	0.26	0.9	0.44	0.83	1.2	0.59	0.44	0.31			
NR-9	3771	Yamama			1.25	0.42	0.97	0.41	0.88	1.2	0.59	0.41	0.43			
NR-9	3899	Yamama			1.255	0.36	0.91	0.47	0.86	1.26	0.6	0.47	0.3			
NR-9	3920	Yamama			0.8	0.45	1.15	0.39	0.82	0.96	0.62	0.39	0.37			
Zb-47	3940	Yamama			1.1	0.26	0.58	0.28	0.6	0.8	0.6	0.28	0.37			
Zb-49	3892	Yamama			1.2	0.23	0.77	0.42	0.91	0.98	0.59	0.42	0.3			
Zb-47	4490	Sulaiy			0.88	0.265	0.66	0.31	0.88	1	0.57	0.31	0.53			
Zb-47	4515	Sulaiy	1.15	1.25										0.47	0.36	0.99
AM-3	4515	Sulaiy	0.99	1.02										0.4	0.25	0.52
HF-5	4414	Sulaiy	0.95	0.99										0.32	0.17	0.57
Zb-47	4517	Sulaiy	1.01	1.04										0.4	0.24	0.52

GA/31R	S1/S6	%C27	%C28	%C29	C28/C29	C27Ts/Tm	TS/H	P/DBT	DBT/N	TA(I)/TA(I+II)	M/H	OL/H	C28/H	C29/H	X/H
0.23	0.07	36	22	42	0.52	0.23	0.1	0.696	2.34	0.6	0.06	0	0.01	1.54	–
0.14	0.53	32.8	25.2	42	0.6	0.8	0.27	2.046	4.792	0.72	0.08	0.02	0.02	1.32	0.03
0.13	0.38	33.9	24.3	41.8	0.58	0.46	0.18	9.728	1.252	0.43	0.06	0.01	0.01	1.43	0.01
0.13	0.3	32	23.5	44.5	0.52	0.65	0.2	1.752	2.86	0.6	0.06	0.01	0.02	1.37	0.02
0.16	0.46	32	24.9	43.1	0.57	0.93	0.31	2.39	1.151	–	0.07	0.02	0.02	1.42	0.04
0.05	2.08	30.7	20.5	48.8	0.42	2.13	0.29	61.65	0.282	0.67	0.08	0.01	0.01	0.46	0.08
0.18	0.14	35.5	22.7	41.8	0.54	0.33	0.14	1.551	7.066	0.35	0.07	0	0.01	1.45	0.01
0.3	0.05	30.1	35	34.9	1.02	0.27	0.12	0.430	0.788	0.21	0.12	0.04	0.04	0.93	0.02

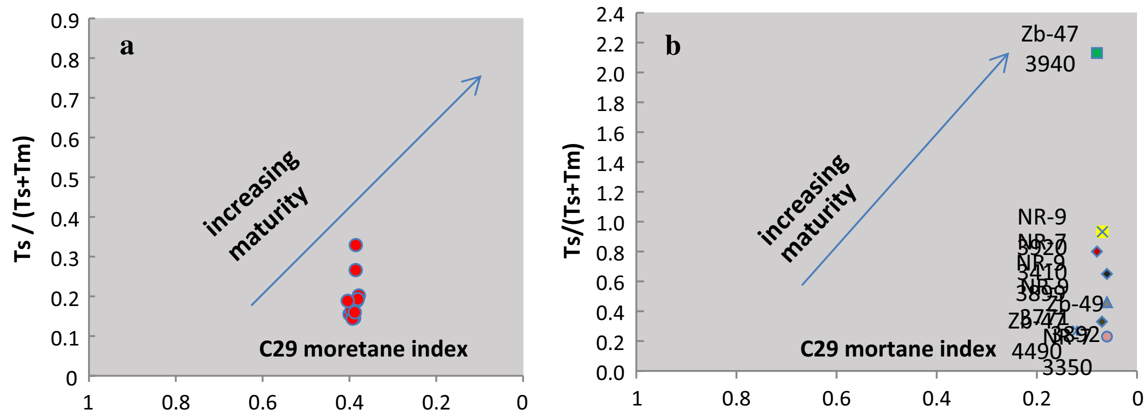

Fig. 12 Maturity index for: **a** crude oil, **b** extracted oil

crude oil and rock extract samples of the study area ranges between 0.649 and 0.940 with average value of 0.77 suggesting that the maturation stage of these samples range from moderate to early mature (i.e., 0.5–0.75% R_o).

2. *Methyl dibenzothiophene ratios* Maturity parameters including indices (MDBI1 and MDBI3) is defined by Moldowan et al. (1996) as follows:

$$\mathrm{MDBI}_1 = \frac{(1.5\,(4\mathrm{MDBT} + 2,3\mathrm{MDBT}))}{(\mathrm{DBT} + 2,3\mathrm{MDBT} + \mathrm{MDBT})}$$
$$\text{and } \mathrm{MDBI}_1 = \frac{4 - \mathrm{MDBT} + 2,3\,\mathrm{MDBT}}{2,3\,\mathrm{MDBT} + 1\mathrm{MDBT}}. \tag{8}$$

1-Methyldi benzothiophene decreases relative to the 4-methyl isomers; therefore, the 4-to 1-MDBT ratio MDB 4.1 or the methyl dibenzothiophene indices (MDBI and MDBI3 in Table 3 should increase with maturity (Moldowan et al. 1996). Connan et al. (1986) defined the methyl DBT ratios (MDR4 defined as (4-MDBT/1-MDBT). MDR1 defined as (1-MDBT/DBT) and MDR2, 3 defined (2–3-MDBT/DBT) as maturity parameters. Values of MPI, MDR 2,3 and MDR4 for the crude oil of the study area are (0.64–0.94, 1.57–2.36, 2.11–3.38) suggesting that oil are mature to above peak oil generation and marine saline water depositional environment, Table 3.

Biodegradation

The samples of all crude oil samples are non-biodegrade because the light hydrocarbons are greater than heavy hydrocarbons, the ratio of (*n*-C21 + *n*.C22)/(*n*-C28 + *n*.C29); the removal of isopenrode, *n*-alkane, hopane, steranes (C27, C28, C29), alkylphenanthrenes, dibenzo thiopenes, etc. does not happen; low concentration of fluorenes aromatic compound; and very low values of Pr/*n*-C17 and Ph/*n*-C18 for all samples.

Age dating of crude oils

Moldowan et al. (1996) used various norcholestane to detect age changes and various workers have noted the fact that the oleannanes which can be associated with the evolution of the flowering plants show a significant increase in concentration in oils of tertiary and late Cretaceous age. The following ratios are used to age identification:

Extended tricyclic terpanes ratio

Age-related parameter to distinguish Triassic from Jurassic oil samples (Peters et al. 2005). ETR = ((C28 + C21)/(C28 + C24 + TS)) (Holba et al. 2001). The ETR for all sample crude oils in study area have values less than 2 indicating that oils are generated from middle to late upper Jurassic source rocks, Table 1.

(C28/C29 steranes

Grantham and Wakefild (1988) observed that C28/C29 steranes is < 0.5 for Paleozoic and older oils, 0.4–0.7 for upper Paleozoic to lower Jurassic oils and greater than 0.7 for upper Jurassic to Miocene oils. The ratio of this index for crude oil of the study is between 0.4 and 0.7, Table 1.

Biomarkers indicate the biological sources of organic matter in the all samples of crude oils are marine algae and bacteria with depositon in anoxic conditions of deep water marine (depth > 150 m). This may indicate that the age of source rocks is upper Jurassic–lower Cretaceous (Sulaiy Formation and possibly Yamama Formation).

Table 3 Maturity parameters for crude oil

Field	Well	Formation	Tri/17αH	22S/22S + RC31	22S/22S + RC32	C27Ts/Tm	C29Ts/Tm	TS/H	M/H	C28/H
Halfaya	Hf-2	Mishrif	37.29	0.584	0.601	0.19	0.08	0.09	0.06	0.01
Halfaya	Hf-8	Nahr Umr	25.71	0.581	0.60	0.23	0.08	0.10	0.06	0.01
Amarah	Am-1	Nahr Umr	45.9	0.59	0.605	0.18	0.07	0.09	0.06	0.01
Amarah	Am-4	Mishrif	35.4	0.59	0.601	0.20	0.08	0.10	0.06	0.01
Amarah	Am-5	Nahr Umr	18.83	0.58	0.590	0.25	0.08	0.10	0.06	0.01
Nahr Umr	NR-1	Nahr Umr	22.08	0.59	0.597	0.36	0.09	0.15	0.06	0.01
Zubair	Zb-89	Mishrif	23.22	0.57	0.597	0.24	0.08	0.10	0.07	0.01
Zubair	Zb-89	Zubair	41.79	0.57	0.605	0.17	0.07	0.08	0.06	0.01
Majnoon	Mj-2	Mishrif	43.85	0.59	0.598	0.17	0.07	0.08	0.06	0.01
Majnoon	Mj-2	Hartha	38.35	0.597	0.598	0.23	0.08	0.12	0.06	0.01
Majnoon	Mj-2	Zubair	29.47	0.58	0.605	0.19	0.07	0.08	0.07	0.01
Nahr Umr	NR-7	Zubair	20.19	0.602	0.600	0.49	0.12	0.24	0.07	0.02

c29/c29H + c29Ts)	(BNH + TNH)/H	S1/S6	TA(1)/TA(1 + 11)	TAS1	TAS2	TAS3(CR)	TAS4	TAS5	Pr/nC17	Ph/nC18	C26TAS(20S/(20 + 20R)	OEP1	CPI
0.02	0.011	0.11	0.41	0.55	0.48	0.31	0.29	1.15	0.18	0.31	0.17	1.04	1.21
0.023	0.01	0.22	0.37	0.51	0.46	0.28	0.19	0.98	0.16	0.29	0.13	0.98	1.04
0.02	0.009	0.11	0.43	0.57	0.48	0.31	0.28	1.01	0.15	0.26	0.17	1.02	1.17
0.023	0.010	0.14	0.46	0.59	0.50	0.33	0.26	1.02	0.17	0.28	0.16	1.008	1.14
0.024	0.011	0.21	0.40	0.51	0.47	0.30	0.18	1.08	0.15	0.27	0.12	0.98	1.03
0.024	0.013	0.28	0.68	0.69	0.59	0.42	0.20	0.88	0.17	0.28	0.15	0.98	1.07
0.024	0.011	0.19	0.40	0.56	0.48	0.30	0.25	0.98	0.16	0.29	0.16	0.92	1.05
0.02	0.010	0.11	0.43	0.57	0.48	0.31	0.31	1.18	0.16	0.30	0.16	1.02	1.12
0.02	0.010	0.12	0.41	0.55	0.48	0.30	0.31	1.23	0.17	0.30	0.17	1.00	1.16
0.022	0.011	0.07	0.72	0.74	0.56	0.43	0.29	0.93	0.15	0.26	0.18	1.02	1.18
0.02	0.009	0.20	0.41	0.55	0.48	0.30	0.25	1.01	0.16	0.29	0.17	0.99	1.04
0.03	0.032	0.52	1.19	0.79	0.75	0.56	0.24	0.98	0.18	0.29	0.16	1.00	1.03

Field	Well	Formation	MDR	MPI 1	MPI 2	MPI	MDR1	MDR2,3	MDR4	MDR4,1	Sum (MDBT)/DBT	Sum (MP)/P	MDBI3
Halfaya	Hf-2	Mishrif	2.27	0.81	0.98	0.81	0.93	1.57	2.11	2.27	4.61	4.32	1.47
Halfaya	Hf-8	Nahr Umr	2.56	0.72	0.86	0.72	0.87	1.59	2.24	2.56	4.71	3.58	1.55
Amarah	Am-1	Nahr Umr	2.30	0.85	1.02	0.85	0.95	1.65	2.19	2.3	4.79	4.56	1.48
Amarah	Am-4	Mishrif	2.35	0.83	1.01	0.83	0.92	1.62	2.16	2.35	4.69	4.39	1.49
Amarah	Am-5	Nahr Umr	2.37	0.74	0.88	0.74	0.97	1.68	2.29	2.37	4.94	4.22	1.50
Nahr Umr	NR-1	Nahr Umr	2.36	0.65	0.73	0.65	0.96	1.6	2.27	2.36	4.83	3.73	1.51
Zubair	Zb-89	Mishrif	2.29	0.68	0.79	0.68	1.02	1.69	2.33	2.29	5.04	3.97	1.48
Zubair	Zb-89	Zubair	2.24	0.83	1.01	0.83	0.97	1.63	2.17	2.24	4.76	4.39	1.46
Majnoon	Mj-2	Mishrif	2.21	0.84	1.02	0.84	1.01	1.68	2.24	2.21	4.93	4.55	1.46
Majnoon	Mj-2	Hartha	2.65	0.94	1.13	0.94	0.86	1.77	2.29	2.65	4.92	4.79	1.54
Majnoon	Mj-2	Zubair	1.95	0.67	0.80	0.67	1.23	1.75	2.39	1.95	5.37	4.39	1.39
Nahr Umr	NR-7	Zubair	2.77	0.73	0.81	0.73	1.22	2.36	3.38	2.77	6.97	5.15	1.60

Correlation

Oil–oil correlation

All samples of crude oil for this study have similar parameters terpane and steranes distributions indicating the similarity in source materials. The distributions of the tricyclic and pentacyclic terpane for all samples have strong similarities in these distributions particularly in the typical carbonate. Type hopane distribution is characterized by the enhanced concentrations of the extended C35 hopane. Additional configuration of the correlation between oils can be found in the sterane distributions; the close similarity between the C27, C28 and C29 distributions indicates a definite correlation in source materials between these samples. The differences in the various isomers between the samples are due to different levels of maturity. The Pr/Ph ratios as a correlation parameter refer that all crude oil samples are significantly less than one; these values are accompanied by high porphyrin and sulfur content which indicates anoxic environment typical of carbonate source rocks, (Figs. 13 and 14).

Oil-source rocks correlation

Because they are inherited from the source rock, biomarkers in migrated crude oils and source rock extract can be compared like finger prints to infer genetic relationships (Picha and Peters 1998). From (Fig. 15), which explains the correlation between source rock and crude oil; one can conclude that the source of crude oil is Sulaiy and Yamama formations.

Petroleum geochemistry

Petroleum geochemistry has become an important tool for reservoir characterization studies and for providing information to reservoir and production engineers. However, for the geologist and engineers that have not exposure to this type of geochemistry, it will be necessary to review these topics:

Bulk characteristics

API gravities

API gravity is bulk physical property of oils that can be used as crude indicator of thermal maturity. From, Table 4, the API for samples of crude oil of the study area ranges from 17 to 45.54 which can be classified as heavy oil to light oil. The Zubair Formation in NR-7 indicates the higher maturation in Nahr Umr oil field because this field includes many variations due to tectonic role activities, (Fig. 16).

Sulfur content

From, Table 4, values of (%S) refer to oils of sulfur rich and the type of kerogen is kerogen II, (Fig. 16). Tissot and Welte (1984) suggested that oils with low sulfur contents less than 1 are classified as paraffinic, paraffinic naphthenic or naphthenic classes, while oils of high sulfur content (more than unity) belong to the aromatic intermediate class; in addition, the sulfur content decreases with increasing maturity.

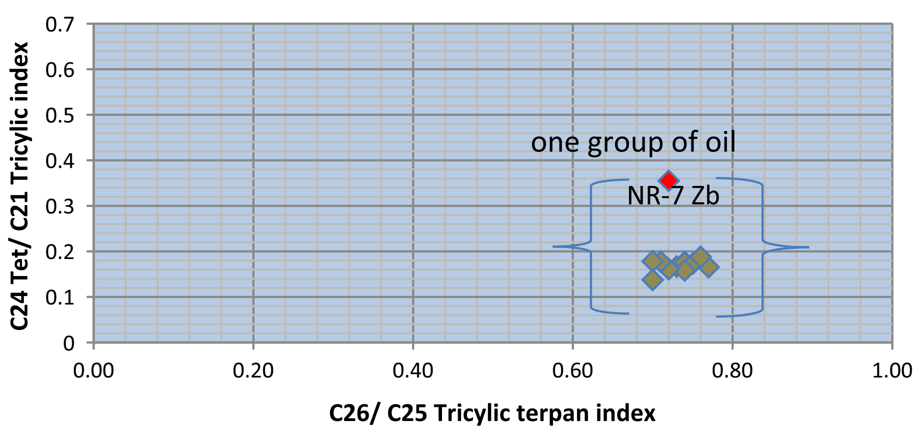

Fig. 13 Relationship between C26/C25 Tricylic terpan index and C24 Tet/C21 Tricylic index (crude oil)

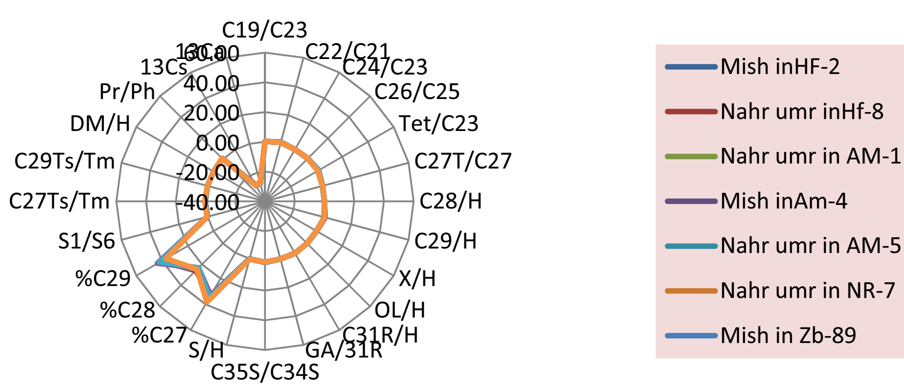

Fig. 14 Correlation of oil and oil for the study area

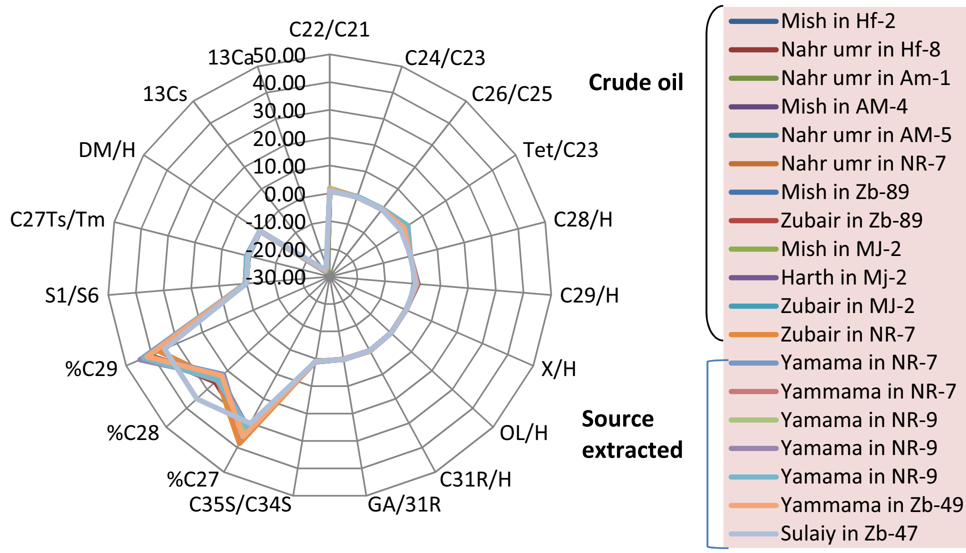

Fig. 15 Correlation between source rock and crude oil

Table 4 Thermal maturity parameters (rock extract)

Well no.	Depth (m)	Formation	22S/(22S + 22R)	Ts/Tm	M/H	Ts/H	C_{28}/H	9MP	1 MP	DBT	C2920S/R
NR-7	3350	Yamama	0.59	0.23	0.06	0.1	0.01	2109	927	1603	0.81
NR-7	3410	Yamama	0.59	0.8	0.08	0.27	0.02	3308	1771	671	0.82
NR-9	3771	Yamama	0.59	0.46	0.06	0.18	0.01	2084	803	516	0.87
NR-9	3899	Yamama	0.6	0.65	0.06	0.2	0.02	3707	2021	441	0.83
NR-9	3920	Yamama	0.62	0.93	0.07	0.31	0.02	495	285	274	0.85
Zb-47	3940	Yamama	0.6	2.13	0.08	0.29	0.01	2878	1730	41	2.32
Zb-49	3892	Yamama	0.59	0.33	0.07	0.14	0.01	4173	2056	1279	0.86
Zb-47	4490	Sulaiy	0.57	0.27	0.12	0.12	0.04	19026	10,648	46,906	0.13

Diast/Ster	TA(I)/TA(I + II)	MPI	C4 N	P	3MP	2MP	4 MDBT	MPI2	MPI3	MPI1
0.07	0.6	0.55	684	1116	615	916	3101	0.66	0.58	0.86
0.53	0.72	0.52	140	1373	962	1268	2939	0.59	0.54	0.81
0.38	0.43	0.41	412	5020	920	1228	707	0.47	0.32	0.48
0.3	0.6	0.56	154	773	983	1424	2561	0.66	0.64	0.96
0.46	–	0.47	238	655	192	257	659	0.54	0.39	0.59
2.08	0.67	0.56	145	2528	1059	1620	60	0.68	0.50	0.76
0.14	0.35	0.5	181	1984	1204	1523	3609	0.56	0.52	0.78
0.05	0.21	1.01	59,501	20,176	14,484	19,176	215,606	1.15	0.74	1.11

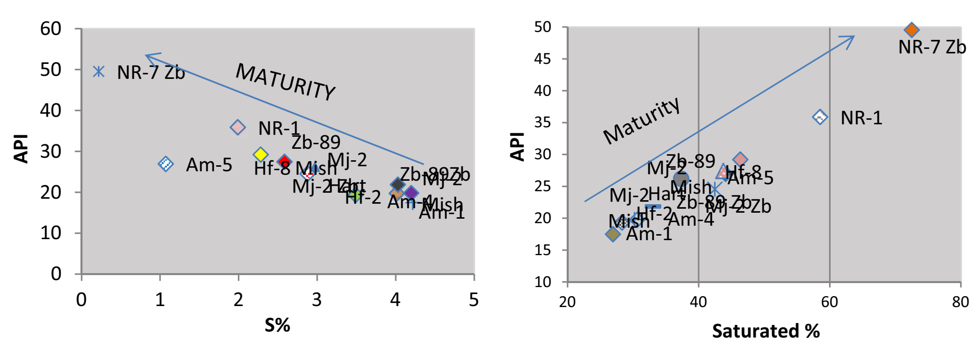

Fig. 16 Relationship between sulfur and API and saturated and API

Crude oil composition

Light hydrocarbons

(% < C15) When looking in Table 4, the value of this ratio ranges between 24.12 and 46.85 (except one which has the value 85.99) which indicates high maturity condensates. The collected oil samples are mid-oil window marine oils.

Saturated and aromatic hydrocarbons

With respect to study area, some crude oil and rock extract samples have ratio of aromatic compounds higher than saturated indicating that oils are aromatic crude oils. Value of %S > 1 refers to anoxic marine conditions.

High molecular weight NSO compounds (Resins and Asphaltenes)

High molecular weight constituents of crude oils usually contain N, S, and O compounds (Tissot and Welte 1984).

According to Tissot and Welte (1984) classification the crude oil of study area can be classified int the following (Fig. 17):

a. *Paraffinic–naphaenic oils* Class includes sample of Nahr Umr Formation in NR-1.
b. *Naphthenic class oils* Only one sample classifies in this class in Zubair Formation NR-7. But this sample is of high maturity.
c. *Aromatic-intermediate crude oil class* This class contains Nahr Umr Formation in Hf-8 and Nahr Umr Formation in Am-5.
d. *Aromatic-naphthenic class* The remainder samples of crude oil (Mishrif in Hf-2, Nahr Umr in Am-1, Mishrif in Am-4, Mishrif in Zb-89, Zubair in Zb-89, Mishrif in Mj-2, Hartha in Mj-2, Zubair in Mj-2) are in this class but these samples have high sulfur content above 1 and non-degraded oils.

Stable carbon isotope

Sofer (1984) recognized the isotopic composition of carbon including C15 + saturated and C15 + aromatic hydrocarbon fractions and connects relationships between them to estimate the source input by following equations (Sofer 1984):

$$^{13}\delta C_{aro} = 1.12\,^{13}\delta\, C_{sat} + 5.45 \text{ \{For oils of terrigenous organic source\}}$$

$$^{13}\delta C_{aro} = 1.10\,^{13}\delta\, C_{sat} + 3.75 \text{ \{For oils of marine organic source\}}.$$

The difference between the two equations was evaluated statistically and a statistical.

Parameter, C_V (the canonical variable) ($C_v = -2.53^{13}\delta\, C_{sat} + 2.22\,^{13}\delta\, C_{aro} - 11.65$). It was used to distinguish between marine and terrigenous oils (Sofer 1984). C_V values larger than 0.47 indicate predominantly a terrigenous organic source for the oil, whereas C_V values smaller than 0.47 indicate mostly marine organic source (non-waxy). As can be seen from Table 5, the values of C_V are less than 0.47 revealing marine non-waxy oils. The values of $\delta 13$ for the $\delta^{13}C_{sat}$ is − 27.41‰ and for $\delta^{13}C_{aromatic}$ is − 27.03‰ which indicate marine rocks, (Fig. 18).

Conclusions

1. The source of generated oil is marine algal carbonate rocks deposited in normal saline environment, water depth more than 150 m. The type of Kerogen is Type

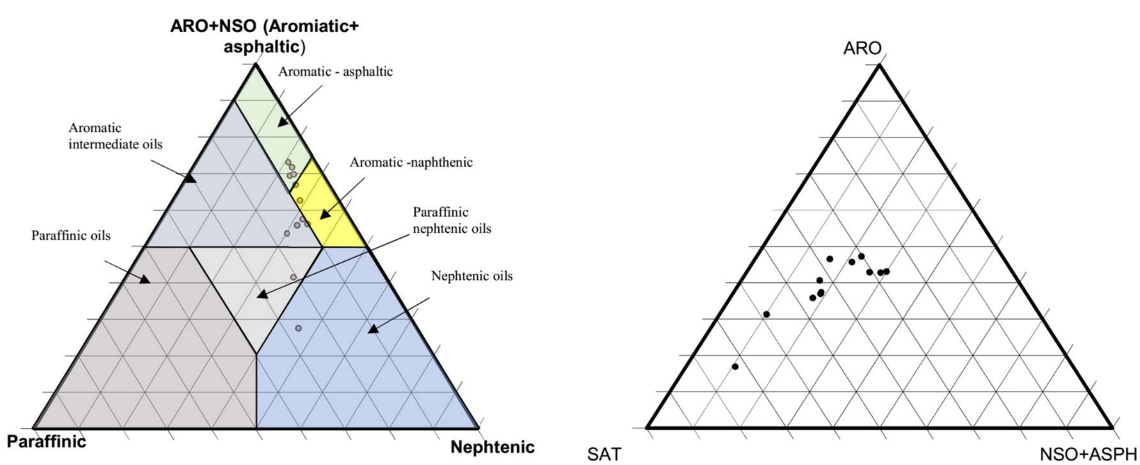

Fig. 17 Composition of crude oil Modified after Tissot and Welte (1984)

Table 5 Geochemical characteristics of crude oil

Field	Well	Formation	API	Type oil	<C15	% S	Ni (ppm)	V (ppm)
Halfaya	Hf-2	Mishrif	19.34	Heavy	26.23	3.49	21.86	88.79
Halfaya	Hf-8	Nahr Umr	29.20	Medium	33.96	2.28		
Amarah	Am-1	Nahr Umr	17.49	Heavy	24.12	4.22	44.11	132.34
Amarah	Am-4	Mishrif	19.76	Heavy	27.44	4.02	34.66	112.43
Amarah	Am-5	Nahr Umr	26.94	Medium	34.02	1.07	20.94	32.43
Nahr Umr	NR-1	Nahr Umr	35.90	Light	46.85	1.99		
Zubair	Zb-89	Mishrif	27.43	Medium	31.45	2.58	0.00	
Zubair	Zb-89	Zubair	21.85	Heavy	25.67	4.03	17.74	78.01
Majnoon	Mj-2	Mishrif	19.80	Heavy	24.58	4.20	27.20	90.60
Majnoon	Mj-2	Hartha	26.18	Medium	31.87	2.97		
Majnoon	Mj-2	Zubair	24.55	Medium	28.14	2.88		
Nahr Umr	NR-7	Zubair	49.54	Light	85.99	0.22		

% NSO	% Asph	Sat/Aro	P/N	13Cs	13Ca	CV	% Sat	% Aro.
10.09	18.81	0.66	0.26	– 27.34	−27.51	−3.55	28.33	42.78
9.77	8.03	1.29	0.53	– 27.72	−27.40	−2.35	46.35	35.85
10.29	19.68	0.62	0.29	– 27.24	−27.54	−3.87	26.92	43.10
10.09	16.36	0.71	0.33	– 27.36	−27.50	−3.48	30.63	42.92
7.71	11.23	1.19	0.40	– 27.70	−27.48	−2.57	44.11	36.94
9.64	0.51	1.87	0.55	– 27.44	−27.10	−2.39	58.54	31.30
11.14	7.69	1.17	0.30	– 27.89	−27.69	−2.56	43.77	37.40
12.59	8.66	0.72	0.29	– 27.27	−27.61	−3.95	33.03	45.73
11.14	11.37	0.64	0.27	– 27.32	−27.77	−4.18	30.21	47.27
11.98	4.16	0.80	0.30	– 26.99	−27.52	−4.46	37.33	46.53
9.30	7.59	1.05	0.33	– 27.70	−27.58	−2.80	42.47	40.64
10.62	0.00	4.30	0.58	– 27.66	−27.25	−2.17	72.50	16.88

Well no.	Depth (M)	Formation	Sat/Aro.	*P*/*N*	13Cs	13Ca	CV
NR-7	3350	Yamama	0.78	0.71	– 27.85	– 26.6	– 2.77
NR-7	3410	Yamama	0.57	0.07	– 27.36	– 26.7	– 1.7
NR-9	3771	Yamama	2.06	0.7	– 27.5	– 26.71	– 1.37
NR-9	3899	Yamama	1.22	0.5	– 27.3	– 26.48	– 1.37
NR-9	3920	Yamama	3.32	0.41	– 27.31	– 26.54	– 1.93
Zb-47	3940	Yamama	2.6	1			– 0.76
Zb-49	3892	Yamama	0.71	0.12	– 27.21	– 26.33	– 1.26
Zb-47	4490	Sulaiy	2.15	1.07	– 26.52	– 25.98	– 2.23

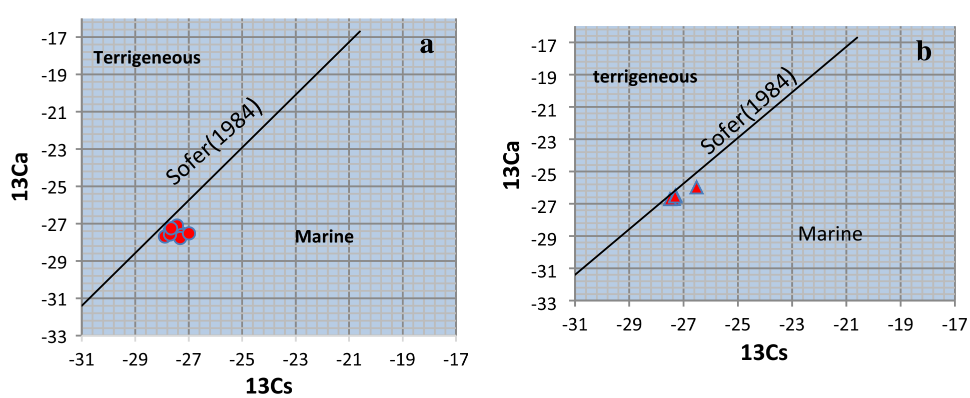

Fig. 18 Relationship between 13Cs and 13Ca. **a** crude oil, **b** rock extract

II and no contribution of terrigenous input in source rocks is found.
2. The age of source rocks is Upper Jurassic–Lower Cretaceous.
3. Moderate to high maturity levels are observed.
4. Correlations between oil–oil show that all oil have same characteristics and are from the same family. The correlations between oil-source rocks exhibit that the source rocks of all oil are the same (from Sulaiy and Yamama formations).
5. The ratio of *X*/*H* for the samples of study area ranges between zero and very little amount indicating that the crude oil is not derived from terrigenous and no oxic–suboxic environment.
6. In general, oil undergoes no biodegradation processes.
7. Oil has high sulfur content in addition to considerable quantities of Ni and Vi (both crude oil and extracted oil).
8. The ratio of phenanthrenes/DBT (P/DBT) is less than 1 indicating deposition in saline water environment and the carbonate rocks are deposited under anoxic conditions and high organo-sulfur content.
9. All samples of study area have values of OL/H equal to zero, indicating that this index does not contribute to terrigenous input during deposition of source rocks.
10. Oil samples of the study are can be classified into four classes: paraffinic-naphaenic (Nahr Umr Formation in NR-1), Naphthenic (Zubair Formation NR-7.), aromatic-intermediate (Nahr Umr Formation in Hf-8 and Nahr Umr Formation in Am-5), and aromatic-natphthenic class for the Mishrif in Hf-2, Nahr Umr in Am-1, Mishrif in Am-4, Mishrif in Zb-89, Zubair in Zb-89, Mishrif inMj-2, Hartha in Mj-2, and Zubair in Mj-2.
11. The values of C_V are less than 0.47 revealing marine non-waxy oils. The values of δ^{13} (excluding biodegraded oils) for the $\delta^{13}C_{sat}$ is (− 27.41‰) and for $\delta^{13}C_{aromatic}$ are (− 27.03‰) which indicate marine rocks.

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