



# Garau Formation as an unconventional hydrocarbon resource in southwestern Iran: a geochemical investigation

Ehsan Hosseiny<sup>1</sup> · Ahmadreza Mohseni<sup>2</sup>

Received: 2 January 2023 / Accepted: 11 April 2023 / Published online: 25 April 2023  
© The Author(s) 2023

## Abstract

Due to the growing need for hydrocarbons and the limited conventional resources, paying attention to unconventional oil and gas resources is essential. The upper Jurassic-Lower Cretaceous in western and southwestern Iran contains the most crucial source rocks of the Zagros sedimentary basin. One of the richest source rocks is the shaly Garau Formation. Owing to geochemical and geological characteristics, the Garau Formation, with Neocomian to Coniacian age and periodicity of radiolar black limestones with black pyrite bituminous shales, ammonite, and chertite shale, is the suitable potential sweet spot as oil shale and gas shale. In this study, a comprehensive regional study was conducted on the entire Garau Formation basin using Rock–Eval parameters and organic matter maturity data. In addition to investigating the hydrocarbon generation potential of the Garau Formation as a source rock, the prospect of this Formation as oil and gas shales in the entire Garau basin was investigated. For this purpose, 31 fields in 5 important sub-basins of Zagros, including East Lorestan, West Lorestan, Izeh zone, Dezful Embayment, and Abadan plain were investigated. The study showed that total organic carbon varies between 0.17 and 24.6, and more than 75% of total organic carbon had values greater than 1. By examining the quantity, quality, and maturity parameters and considering the necessary thresholds, it was found that East Lorestan and West Lorestan have the conditions for oil and gas shales. The highest quantity and best quality of organic matter are related to Eastern Lorestan. By moving west and south of Garau Basin, the quantity and quality of organic matter decrease, and the hydrogen index proves the results. Vitrinite reflection studies indicated that the lowest and highest levels of organic matter maturity belong to East Lorestan and West Lorestan, respectively. Therefore, the northeast of Garau Basin (Eastern Lorestan) has the potential for oil shale, and the northwest of the Basin (Western Lorestan) has the potential for gas shale.

**Keywords** Garau Formation · Oil shale · Gas shale · Hydrocarbon generation potential · Source rock

## Abbreviations

HI	Hydrogen Index
MI	Migration Index
OI	Oxygen Index
OM	Organic Matter
PI	Production Index
PI	Production Index
PP	Petroleum Potential
TOC	Total Organic Carbon

## Introduction

The Zagros Sedimentary Basin is one of the most petroliferous zones in the world (Bordenave et al., 2010). The dominant part is in Iran and extended to Iraq, Turkey, and Syria. In Iran, the Zagros basin is divided into several sub-basins and hosts most of the oil and gas fields (Bordenave 2002). A petroleum system comprises different elements, of which the source rock is the most critical element and must be adequately characterized and evaluated (Wang et al. 2007). Various petroleum systems have been identified in the Zagros Sedimentary Basin. One such active petroleum system was developed during the Lower Cretaceous, where organic-rich shales of the Garau Formation served as the source rock. Because of its lithology, thickness, and extension over the Zagros Basin, the Garau Formation is of paramount importance.

✉ Ehsan Hosseiny  
Ehosseiny@yazd.ac.ir

<sup>1</sup> Department of Mining and Metallurgical Engineering, Yazd University, Yazd, Iran

<sup>2</sup> Department of Petroleum Engineering, AmirKabir University of Technology, Tehran, Iran

Oil shale and gas shale resources in the USA and 137 shale resources in 41 other countries are estimated to account for 10% of the world's crude oil and 32% of the world's recoverable natural gas resources (U.S. Energy Information Administration, 2013). Shale oil is a synthetic crude oil produced by pyrolysis of kerogen from oil shale. Crude oil produced from oil shale can vary in properties and composition (Lee 1990).

According to the study of oil shales in the western USA, the two most important characteristics of oil shale are the high hydrogen content due primarily to the high concentration of paraffin and the high nitrogen content resulting from the high content of pyridines and pyrroles (Speight 2012a). In an oil shale, the organic carbon content and the hydrogen-to-oxygen ratio is often high (TOC > 3.5% and HI > 250) (Jarvie et al. 2007), and the oil shales are rocks with a vitrinite reflectance in the range of 0.41–0.6 (Hinrichs et al. 2010).

Shale gas is a natural gas and defines as one of the multiple forms of unconventional hydrocarbon resources. The shale gas is usually trapped inside shaly formations where the sediments are fine-grained or low-permeable (Linley 2011; Mokhtab et al. 2006). The gas shales are sedimentary strata with particular geochemical and geological properties and contain present total organic carbon (TOC) at higher than 2%, Ro values in the range of 1.1 – 3.0 (Curtis 2002; Zou et al. 2013), and usually have a minimum thickness of 20 m.

Investigating the transport properties of shales is facing challenges. The transport properties of gas deviate from the nominal values, reported without custody when confined inside a nano-size conduit (Alessa et al. 2021). The potential of shale formations has been realized, but their fundamental transport properties are not fully understood (Tran and Sakhaee-Pour 2018). Also, determining the effective transport properties of the shale at the core scale is more complex than for simple geometries investigated in nanofluidics.

Critical temperature ( $T_c$ ) and pressure ( $P_c$ ) change transport properties when the fluid is in nanosized confinement (Alessa et al. 2021). The critical temperature and gas pressure inside the nano-size conduit differ from the nominal values reported at identical pressures and temperatures (Tran and Sakhaee-Pour 2018). Transport properties depend on pore size, pore geometry, and fluid–wall interaction (Peterson et al. 1988; Tuller et al. 1999; Deinert and Parlange 2009; Singh and Singh 2011; Lee et al. 2020). Discriminating and appraising the two sizes are essential because the void space in the matrix is a nanofluidic system. Transport properties depend on the size of the nanofluidic system, which is not reported for wider conduits in porous and permeable media (Alessa et al. 2021). Researchers have also studied the fundamental challenges to understanding shale gas permeability (Sakhaee-Pour and Bryant 2012; Civan 2019; Taghavinejad et al. 2020). Shale permeability has not

yet been fully understood because of the complexities of modeling flow through nanoscale throats. Accurate measurement of shale permeability is challenging because it is so tiny, about  $10^{-21}$  m<sup>2</sup> (Sakhaee-Pour and Bryant 2012). Another reason for this difficulty is that the shale matrix has a network of interconnected conduits of different shapes and sizes.

Sakhaee-Pour and Bryant (2012) showed that the acyclic pore model reasonably estimates shale permeability based on the mercury injection capillary pressure measurements. Knowing the gas composition can also help to determine the deviations more accurately (Alessa et al. 2021). In order to measure two sizes, mercury injection capillary pressure and nitrogen absorption isotherms are used. The first set characterizes the pore-throat size distribution, and the second specifies the pore-body size distribution (Alessa et al. 2021).

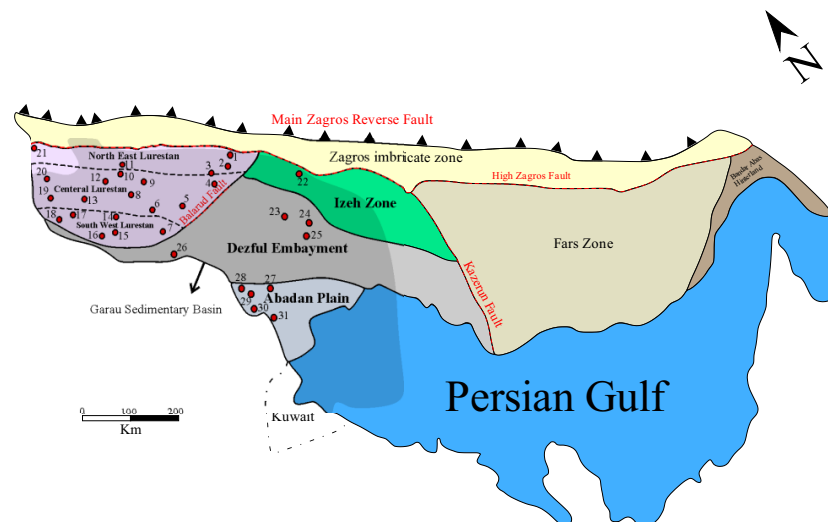
The present study investigates the hydrocarbon generation potential of the Garau Formation at a regional scale on the entire Garau basin in Iran with 31 wells in 5 important sub-basins, while the previous ones were conducted on a small area and a limited number of wells. We focused on five sub-basins of the Zagros Sedimentary Basin, including East Lorestan, West Lorestan, Dezful Embayment, IZeh Zone, and Abadan Plain, which can be seen in Fig. 1. Moreover, this research is an attempt to do a feasibility study on Garau Formation as an unconventional hydrocarbon resource in Iran from a geochemical point of view. To this end, Rock-Eval and vitrinite reflectance parameters were used. By examining the distribution of these geochemical parameters in the form of contour lines, the best prospect in terms of oil shale and gas shale is shown step by step. This has yet to be done in any of the reports so far.

## Oil shales

By definition, oil shales refer to source rocks that are so rich in organic matter (OM) but have never been at the required burial depth for becoming mature, leaving those immature (Ghavidel Seyooki 2013). Various definitions have been proposed for oil shale, some of which are mentioned in the following.

Oil shale is an important raw material for producing synthetic crude. By heating and dry-distillation the oil shale, one can produce shale-derived oil, dry gas, and semi-coke shale (Zou 2017). Rocks with high shares of OM are classified under oil shales (Brendow 2003). The oil shale is a stratified hard sedimentary rock with an ash fraction beyond 33% that can produce oil upon distillation (Gavin 1924). Welte and Tissot (1984) believed that no accurate definition of oil shales encompasses all geological and chemical aspects. However, any stratified rock with a shallow burial depth that can generate oil upon heating

**Fig. 1** Depositional environment of the Garau Formation and the studied fields (modified after Motiee, 1993)



1. Ghalikoh	2. Gashun	3. Chamsangar	4. Giroveh	5. Tange-Haft
6. Vizenhar	7. Samand	8. Gawar I	9. Dareh Baneh	10. Huleyan
11. Naft 1	12. North Shahabad	13. Bankul	14. Tang-a-Garau	15. Kabirkoh
16. Anjir	17. Baba Ghir	18. Vizenan	19. Pataq	20. Direh
21. Ab-e Zimkan	22. Ghale tak	23. Masjed soleiman	24. Asmari	25. Haftkel
26. Dehloran	27. Jufeyr	28. Kushk	29. Azadegan	30. Yadavaran
31. Darquian				

to a particular commercial standard can be recognized as oil shale. The oil shale is a combustible OM with high ash content. This rock type differs from coal in that it contains ash at fractions beyond 40% while being different from carbonated shale in that it has oil at fractions higher than 5% (Zhao et al. 1990).

Shale oil is an unconventional oil that can be produced through pyrolysis, hydrogenation, or thermal dissolution. This process artificially converts the OM content of the oil shale (i.e., kerogen) into oil and gas (Hinrichs et al. 2010). The oil shales can produce much less than the conventional sources, although they generate some oil upon heating up to 500 C. The TOC and the hydrogen-to-carbon ratio are often high in oil shale. Since oil shales have failed to reach the catagenesis stage and are still in the burial stage, the heat-produced oil contains not only the olefin components but also significant amounts of sulfur and nitrogen, which are typically absent in the crude oil (Hinrichs et al. 2010).

Focusing on maturity, the oil shales are rocks with a vitrinite reflectance ( $R_o$ ) in the 0.41–0.6 (Hinrichs et al. 2010). Economically efficient and proven oil and gas shale deposits in the USA and Canada exhibit high TOC. In general, the immature TOC level is, on average higher than 2 wt.% and, in some cases, reaches 4–6 wt% (Aqrabi and Badics 2015). For oil shales, the hydrocarbon-generating immature

kerogen (usually producing oil) is often Type II (Jarvie et al. 2007).

## Gas shales

Shale gas is a natural gas and defines as one of the multiple forms of unconventional hydrocarbon sources. The shale gas is usually trapped inside shaly formations where the sediments are fine-grained or low permeable. In such a case, the shaly rock simultaneously serves as the source rock and reservoir rock (Linley 2011; Rahmani et al. 2022). The natural gas is stored between thick layers of shale and cannot escape due to the low permeability of the surrounding rocks.

Numerous methods have been developed to exploit the gas shale. Two common and popular methods for such a purpose include hydraulic fracturing and horizontal drilling (Speight 2012b). Secondary cracking processes usually produce the gas in the gas shale on the oil (Aqrabi and Badics 2015). Geologically speaking, these shales usually have a minimum thickness of 20 m, high contents of quartz and carbonates, and a low clay content. These are the required conditions for artificial fracturing (Jarvie et al. 2007).

According to the definitions, the gas shales are sedimentary strata with particular geochemical and geological

properties and contain present TOC higher than 2% (Curtis 2002; Zou et al. 2013). In the meantime, some relevant studies have reported 1 wt.% as the minimum TOC for gas shales (Jarvie 2012). Focusing on the thermal maturity in vitrinite reflectance, a gas shale shall exhibit Ro values of 1.1–3.0 (Curtis 2002; Zou et al. 2013). Overlying the evaporites of Gotnia and Hith, the Garau Formation is highly rich in OM and contains light crude and wet gas (Aqrabi and Badics 2015).

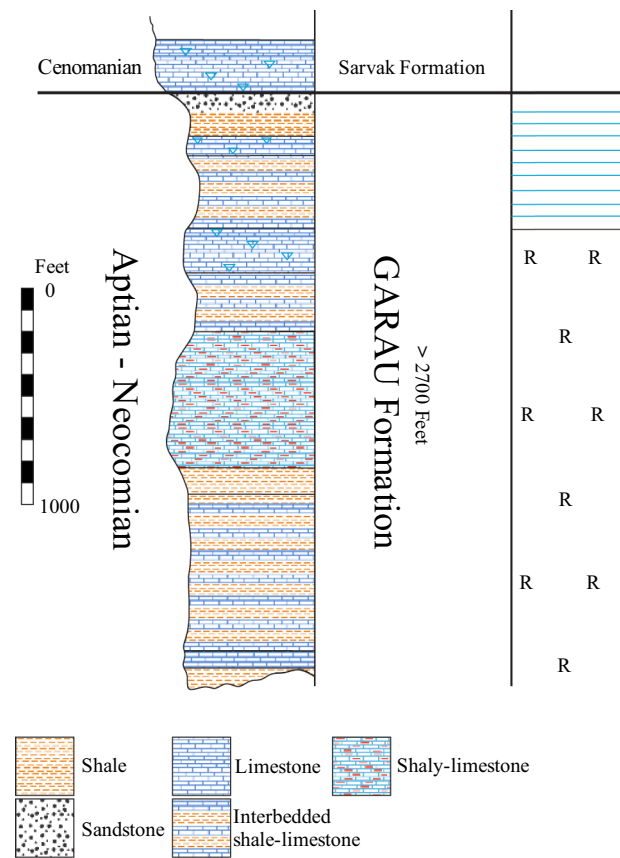
## Geological setting

Garau Formation extends from the Lorestan down to the Dezful Embayment, Abadan Plain, and northwest of the Persian Gulf, covering a significant portion of the Zagros Sedimentary Basin (Fig. 1). Moreover, regarding the progradation and retrogradation events in the basin, it is a source rock for different reservoir rocks (Motiee, 1993). This highlights the importance of evaluating the hydrocarbon generation potential and the type and maturity of the organic matter content of this formation. On the other hand, given the conditions of the Garau depositional environment, it is particularly worth investigating the potential of this formation as an unconventional hydrocarbon resource (Browning 1935; Lafferty 1935).

The Middle Jurassic-Lower Cretaceous formations in the north, center, and east of Iraq and the west and southwest of Iran in the Zagros Basin host some of the wealthiest source rocks in the world. These formations have developed in Iran's Zagros fold and thrust belt, the Mesopotamian Fore-deep Basin, Kuwait, and Lorestan and Khuzestan provinces (Motiee, 1993).

These source rocks include Sargelu, Naokelekan, Najmah, and Chia-Gara (Sulayir or Garau) formations (Aqrabi and Badics 2015). The Chia-Gara, Balambo, and Sulayir formations in Iraq are equivalent to the Garau Formation in western Iran (Aqrabi and Badics 2015; Bordenave and Hegre 2010). The shales of Garau have been named after the Garau Valley (i.e., Tang-a-Garau) in the Kabir-Koh region, Lorestan, Iran, with a type section located 10 km north-east of the Ghale-Dareh village (Motiee, 1993). At the type section, the Garau Formation exhibits a thickness of 896 m (Fig. 2).

Lithologically speaking, the lower 387 m of the formation is made up of alternations of radiolaria-bearing dark clayey limestones with black bituminous pyritic shales. This segment is overlaid by 140 m of dark gray to dark red highly clayey limestones with no shale, 113 m of brown pyritic and silicic shales and highly clayey chert-containing strata, 58 m of fine-grained limestone with chert nodules, 122 m of brown to black bituminous shales and highly clayey, bituminous, silicic, radiolaria-containing limestones, 74 m of dark



**Fig. 2** Type section of Garau Formation in Kabir-Koh, Lorestan (Wynd 1965)

gray glauconitic limestones containing pelagic foraminifera, large foraminifera, and echinoderms, and an upper 3 m layer of glauconitic and sandy limestones (Motiee, 1993).

The Garau Formation alternates radiolaria-containing highly clayey black limestones with pyritic and chert-containing bituminous black shales containing ammonite and belemnite. In Lorestan, the Garau Formation is dominantly shaly while it is limier in the Dezful Embayment (Motiee, 1993). The Garau Formation overlies the evaporites of the Gotnia Formation (dated back to the Upper Jurassic) or equivalent breccia-containing limestones in the Lorestan Basin and Dezful Embayment. Regarding the top of the Garau Formation, however, the situation is highly variable across the study area.

At the type section of this formation, the presence of glauconites and the sandy nature of the top of this formation indicate an erosional unconformity with the Bangestan limestones. Indeed, the sandy and glauconite-containing base of the Bangestan marks an erosional discontinuity separating the Garau and Sarvak formations (Alavi 2007; Falcon 1961). Different formations, including Ilam and Fahliyan formations, can overlay this formation.

In the central part of the Lorestan Basin, the Garau Formation is formed beneath the Surgah Formation (dated back to the Coniacian) (Alavi 2007). The presence of planktons and radiolaria in this formation characterizes a low-energy anoxic depositional environment. According to paleontological studies and given the presence of microfossils, ammonites, and radiolaria, the Garau Formation has been dated back to the Neocomian to the Coniacian (Fig. 3) (Motiee, 1993). Knowing that the Garau Formation is sealed both on the top and bottom, primary migration has been impossible in the vertical direction. Rather, it occurred laterally, charging the Sarvak, Dariyan, and

Fahliyan reservoirs (Ghavidel Seyooki 2013). As a result of this wide extension, the Garau Formation exhibits enormous potential for producing gas shales.

### Methodology

Going into more details about basins, we considered Ghali-Koh, Gashun, Girveh, Chamsangar, and Tange-Haft fields in the East Lorestan, Anjir, Babaghir, Kabir-Koh, North Shahabad, Pataq, Samand, Tang-a-Garau, Vizenan, Vizenhar, Ab-e-Zimkan, Bakul, Huleyan, Naft, Gawar,

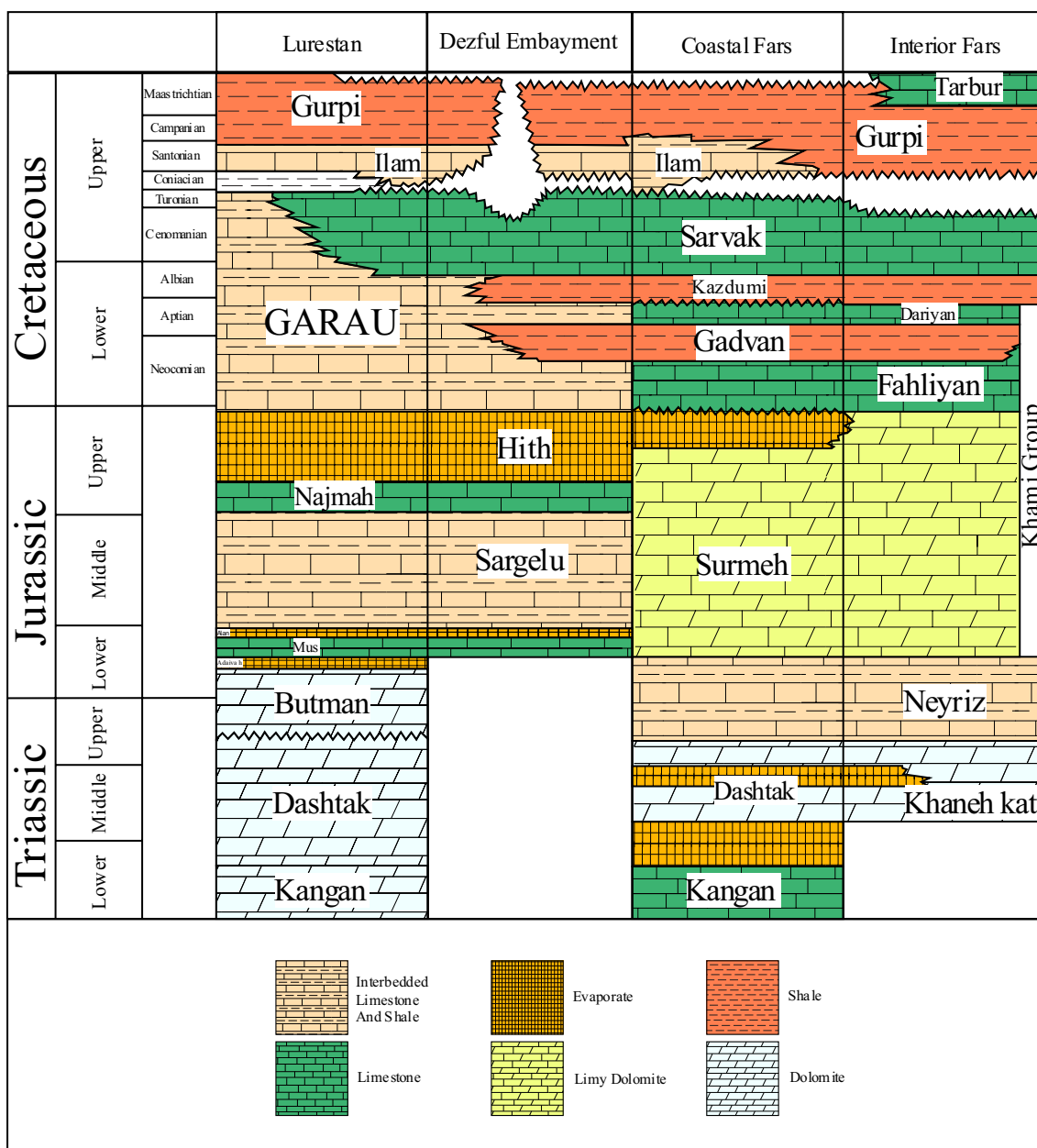


Fig. 3 Stratigraphic column of Zagros Basin in Iran (adapted from (Mahbobipour et al. 2016))

Direh, and Dareh-Baneh fields in the West Lorestan, Asmari, Dehloran, Masjed-Soleiman, and Haftkel fields in the Dezful Embayment, Ghale-Tak Field in the Izeh Zone, and Azadegan, Darquian, Jufeyr, Kushk, and Yada-varan fields in the Abadan Plain. Figure 1 shows the location of the studied area.

In the present research, results of Rock–Eval pyrolysis and vitrinite reflectance measurements were used to evaluate the hydrocarbon generation potential of the Garau Formation and identify the potential areas for unconventional hydrocarbon reserves. For this purpose, we used the values of S1, S2, S3, Tmax, total organic carbon (TOC), hydrogen index (HI), oxygen index (OI), migration index (MI), and vitrinite reflectance (Ro).

The parameters S1, S2, and S3 represent free hydrocarbon, future potential, and CO<sub>2</sub> content of the source rock, respectively. Accordingly, HI and OI are equal to  $S2/TOC \times 100$  and  $S3/TOC \times 100$ , respectively. The parameter Tmax denotes the temperature at which the parameter S2 is maximal (Peters and Cassa, 1994; Dembicki 2022).

Vitrinite is a type of kerogen or maceral particle composed of humic gels thought to be derived from the lignin-cellulosic cell walls of higher plants (Teichmüller 1989). For the first time, the increase in reflectance of vitrinite particles with increasing time and temperature was discovered in coals and used to determine the thermal maturity of coals. After vitrinite is recognized as part of the kerogen and source rock, the increase in vitrinite reflectance is related to the history of hydrocarbon production of the sediments. It is adopted as a maturity indicator to evaluate the source rock (Dembicki 2022).

The MI is equal to  $S1/TOC$ ; this index is used to verify the data and ensure the cleanness of samples. Indeed, the samples for which the MI was more significant than 1.5 and the production index (PI) greater than 0.5 were identified as contaminated and hence eliminated from the analysis (Espitalie et al., 1977; Peters and Cassa, 1994; Hosseiny and Barati, 2020). In this research, data on a total of 485 geochemical samples from 31 hydrocarbon fields in the five Iranian sub-basins of the Zagros Sedimentary Basin were used. Table 1 reports the average values of the geochemical parameters for the studied samples from the Garau Formation.

## Results and discussion

The first step of any geochemical study on the petroleum systems of a particular region is to identify the OM's quantity, quality, and maturity in the source rock (Espitalie et al., 1977).

### Quantity of organic matter

A potential source rock contains competent quantities of organic matter to produce oil but becomes an influential source rock when it reaches a suitable thermal maturity level for oil production. TOC describes the quantity or amount of organic matter. This parameter equals 0–0.5, 0.5–1, 1–2, 2–4, and more than 4 for poor, fair, good, very good, and excellent source rock, respectively (Peters and Cassa, 1994).

The level of TOC in the studied samples ranged from 0.17 to 26.4 wt.%, with the lowest and highest values corresponding to the Anjir and Ghali-Koh fields, respectively. Some 75% of the samples exhibited TOC values higher than 1 wt.%, indicating the good potential of the Garau shales in terms of the quantity of OM (Fig. 4). The TOC distribution map indicates that the Gashun and Ghali-Koh in the East Lorestan are the wealthiest fields in TOC, with the level of TOC decreasing as one moves toward the west and southwest of the Garau basin (Fig. 5).

Figure 4 demonstrates the hydrocarbon generation potential of the Garau Formation in different sub-basins of the Zagros Sedimentary Basin in the form of a plot of petroleum potential versus TOC (Hosseiny et al. 2016). Accordingly, the samples from East Lorestan were generally excellent in TOC. The average value of TOC over East Lorestan was 8.89 wt.%. Focusing on different fields in this sub-basin, the highest TOC values corresponded to Gashun and Ghali-Koh fields (averaged at 19.15 and 16.03 wt.%, respectively), while the lowest TOC values were those of Girveh and Chamsangar fields (averaged at 2.11 and 1.19 wt.%, respectively). In the West Lorestan, a decrease in the overall value of TOC was evident (averaged at 1.57 wt.%), characterizing the petroleum potential as poor to moderate.

Focusing on different fields within this sub-basin, the highest and lowest TOC values were those of Samand and Anjir fields (averaged at 3.43 and 0.17 wt.%, respectively). Some samples exhibited moderate to good petroleum potentials in the Izeh Zone and the Dezful Embayment. In contrast, most of the samples from the Abadan Plain showed poor to moderate petroleum potentials. Considering the sub-basins in general, the West Lorestan, Izeh zone, Dezful Embayment, and Abadan Plain exhibited poor to moderate petroleum potential. At the same time, East Lorestan showed excellent levels of petroleum potential.

### Quality of organic matter

The type and quantity of the hydrocarbon produced in a particular basin are directly associated with the type of contained kerogen (Hunt 1995). Considering the standards, oil-prone source rock with kerogen type I, HI is above 600, kerogen type II, HI is 300–600, mixed oil and gas prone with kerogen type II/III, HI is 200–300, and gas-prone source

**Table 1** Average values of the considered geochemical parameters for the Garau sedimentary basin

Location	TOC	S1	S2	S3	HI	OI	$T_{max}$	PP	PI	Ro	References
Ab-e Zimkan	0.193	0.0625	0.18	0.2025	174.7	159.1	418	0.2425	0.26	0.7	(Khani 2018)
Anjir	1.694	0.27	0.37	0.235	61.318	33.7	445	0.643	0.43	0.85	(Mahbobipour et al. 2015)
Asmari	5.227	0.44	3.15	0.42	117.91	25.24	457	3.585	0.12	1.06	(Sadouni & Rabbani, 2018)
Azadegan	0.6	0.31	0.62	1.96	104.93	337.15	424.2	0.925	0.34	-	(Kobraei et al. 2017)
Babaghir	1.137	0.46	0.67	0.296	74.65	39.20	454.1	1.133	0.43	0.89	(Lotfiyar et al. 2018; Mahbobipour et al. 2016)
Bankul-1	1.973	0.798	0.923	0.368	53.123	28.561	415	1.721	0.46	0.8	(Khani 2018)
Chamsangar	1.191	0.331	1.313	0.394	120.461	34.188	454	1.643	0.21	1.01	(Kassae 2005)
Dareh-Baneh	0.9	1.03	1.155	0.49	130.582	63.127	443	2.185	0.47	0.81	(Khani 2018)
Darqain	3.11	1.242	3.492	0.682	186.589	45.987	443	4.735	0.26	0.887	(Kobraei et al. 2019; Zeinalzadeh et al. 2018)
Dehloran	0.623	0.653	1.775	0.23	282.36	37.48	438.5	2.4275	0.28	0.73	(Kobraei et al. 2017)
Direh-1	1.409	0.776	0.684	0.434	94.35	43.46	416	1.461	0.498	1.03	(Khani 2018)
Gashun	19.156	2.09	101.72	2.61	537.05	13.41	429.4	103.805	0.02	0.57	(Sadouni & Rabbani, 2018)
Gawar-1	1.452	1.82	2.75	2.263	192.18	167.295	435.6	4.565	0.40	0.68	(Khani 2018)
Ghale-Tak	0.971	0.223	3.558	0.579	348.28	65.064	430.3	3.781	0.069	0.58	(Kassae 2005)
Ghali-Koh	16.029	1.75	88.83	1.48	553.44	10.74	431.4	90.585	0.020	0.605	(Shekarifard et al. 2019)
Girveh	2.114	0.18	0.522	0.218	23.59	14.01	503.8	0.703	0.28	1.8	(Yousefi & Nazari 2015)
Haftkel	1.54	0.88	1.54	0.79	109.9	52.59	444.2	2.422	0.37	0.84	(Kobraei et al. 2019)
Huleyan-1	2.524	1.292	0.963	0.431	46.25	21.02	431.4	2.255	0.49	1.3	(Khani 2018)
Jufeyr	2.47	1.27	6.21	1.238	252.87	50.81	438.8	7.478	0.19	0.74	(Kobraei et al. 2019)
Kabir-Koh	1.42	0.34	0.98	0.88	69.01	61.97	448	1.32	0.26	0.9	(Mahbobipour et al. 2016)
Kushk	5.078	3.138	5.09	0.668	10.24	15.831	441.8	8.227	0.33	0.8	(Kobraei et al. 2017)
Masjed-Soleiman	1.535	1.132	2.017	2.36	133.38	172.84	437.7	3.148	0.32	0.72	(Rezaee et al. 2009)
North Shahabad	1.29	0.748	0.996	0.292	80.468	23.217	414.4	1.744	0.43	0.8	(Mahbobipour et al. 2016)
Naft-1	2.089	0.642	0.77	0.681	38.289	38.714	505.5	1.412	0.46	0.6	(Khani 2018)
Pataq	2.65	0.08	0.64	1.3	24.15	49.056	459	0.72	0.11	1.1	(Mahbobipour et al. 2016)
Samand	1.624	0.476	0.622	0.28	58.59	20.52	451.2	1.098	0.43	0.96	(Mahbobipour et al. 2016)
Tang-a-Garau	0.829	0.112	0.25	0.211	45.77	38.563	436	0.362	0.31	1.24	(Mahbobipour et al. 2015)
Tange-Haft	2.1	0.195	0.68	1.24	29.85	69.15	495.9	0.872	0.22	1.3	(Khani 2018)
Veyzenhar	0.73	0.6	0.99	0.595	143.795	79.84	439.5	1.59	0.38	0.75	(Mahbobipour et al. 2016)
Viznan	2.49	1.85	2.16	0.3	86.75	12.05	460	4.01	0.46	1.1	(Mahbobipour et al. 2016)
Yadavaran	5.08	3.138	5.08	0.668	101.24	15.83	441.8	8.227	0.33	0.79	(Kobraei et al. 2019)

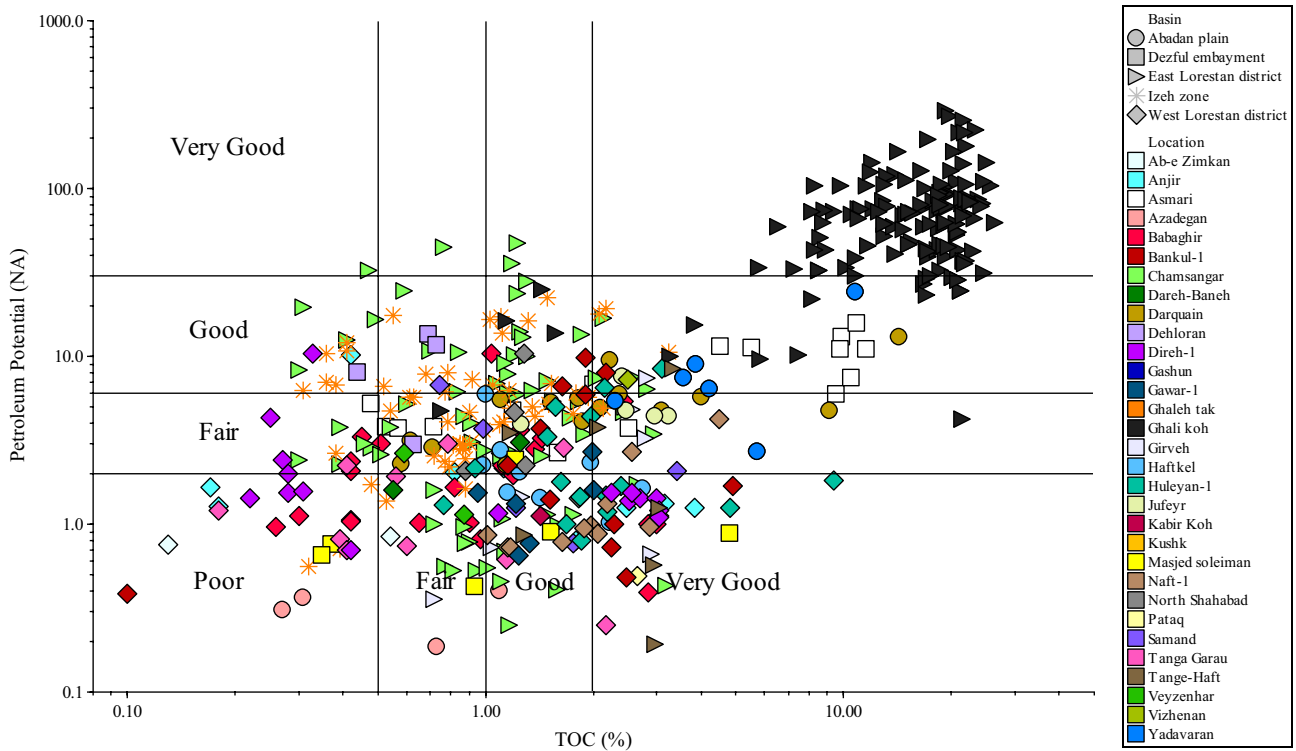


Fig. 4 Plot of petroleum potential versus TOC across the Garau sedimentary basin

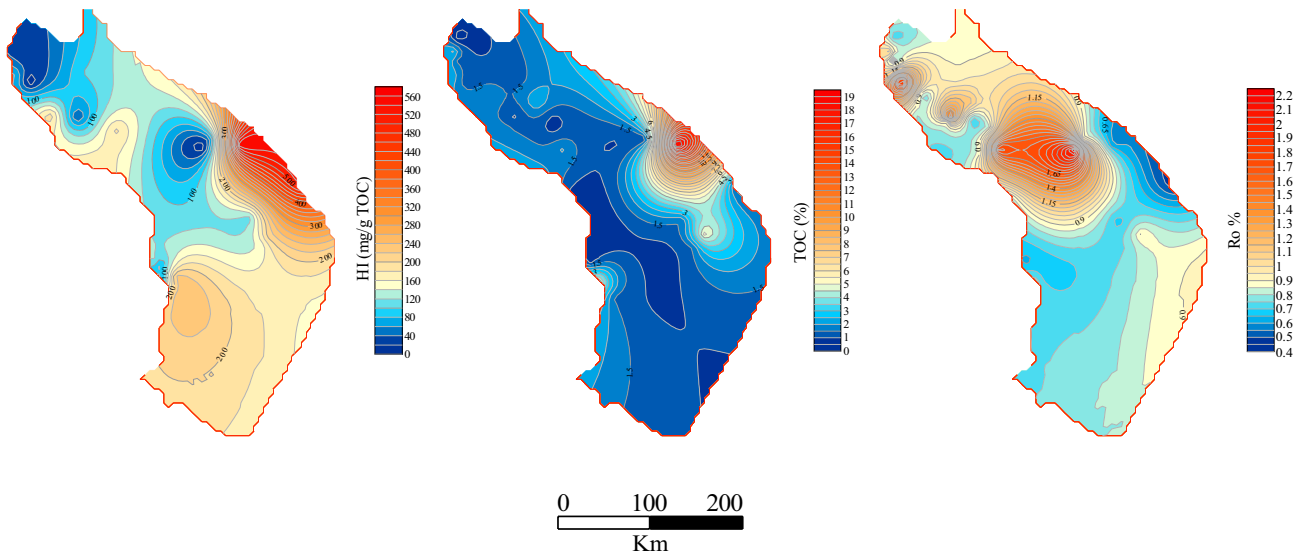


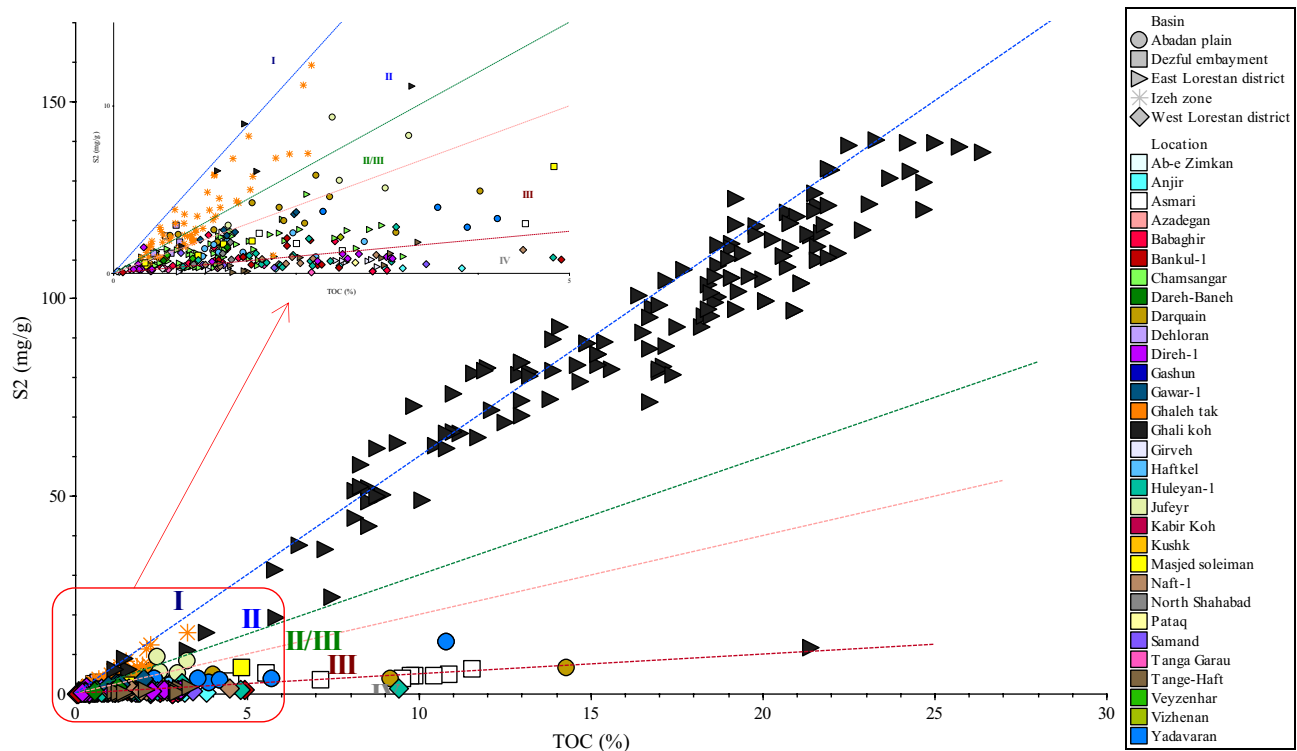
Fig. 5 Distribution of TOC, HI, and Ro across the Garau sedimentary basin

rock with kerogen type III, HI is 50–200 (Peters and Cassa, 1994).

A conventional approach to characterizing the kerogen is to use the plot of S2 versus TOC (Fig. 6) (Langford and Blanc-Valleron 1990). The slope of the separating borders on this plot indicates the range of HI for the corresponding kerogen. In East Lorestan, the highest

HI values correspond to Ghali-Koh and Gashun fields. The HI's maximum, minimum, and average values in the Ghali-Koh were 749.92, 54.77, and 553.44, respectively, while the same parameters in the Gashun were 645, 493, and 537.05, respectively. In the same sub-basin, the Chamsangar and Girveh fields show significantly lower HI values, following similar trends to the maturity ones.





**Fig. 6** Plot of S2 versus TOC for identifying the kerogen type in different fields across the Garau sedimentary basin

The maximum, minimum, and average values of the HI in the Chamsangar were 316.128, 26.113, and 120.46, respectively, while the same parameters in the Girveh were 30.73, 13.148, and 23.59, respectively.

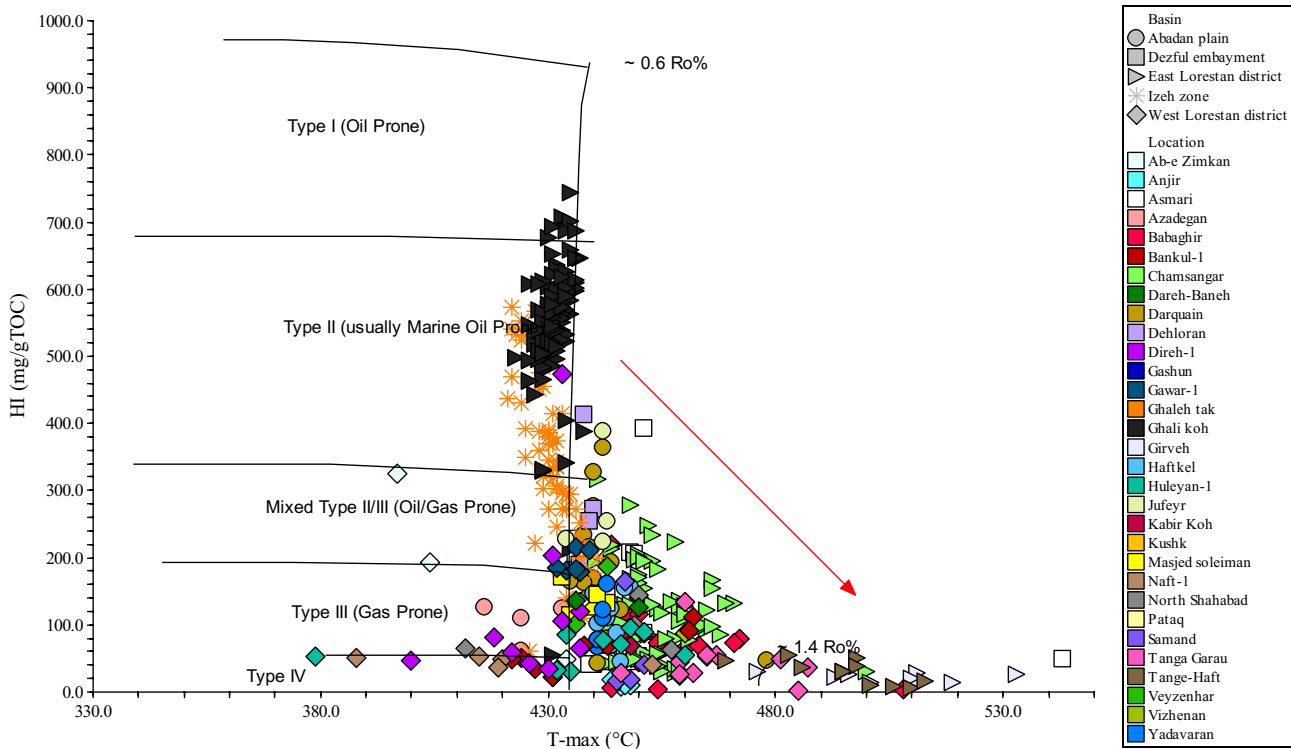
Variations of this parameter can be seen as distribution maps in Fig. 5. As one moves toward the West Lorestan, the HI decreases significantly. In the Dezful Embayment, the maximum, minimum, and average HI records were 413.04, 40.588, and 136.75, respectively, while Izeh Zone showed maximum, minimum, and average HI values of 573.27, 60, 348.28, respectively, and the Abadan Plain reflected a maximum, minimum, and average HI values of 388.75, 42.139, and 159.644, respectively.

Trying to detect the type of kerogen from the plot of S2 versus TOC, the Ghali-Koh and Gashun in the East Lorestan and the Ghale-Tak in the Izeh Zone were found to contain Type-II kerogen dominantly. The Chamsangar and Girveh fields in the East Lorestan were identified as containing Type-III kerogen for the most part, where the maturity data confirmed the alteration of the kerogen. The samples taken from the Dezful Embayment exhibited shreds of evidence of the mixed Type-II/III kerogen. At the same time, the Abadan Plain was dominated by Type-III kerogen except for the Jufeyr field, where the share of mixed Type-II/III kerogen was dominant.

### Maturity of organic matter

An output of a Rock–Eval pyrolysis is the Tmax, which is usually used to evaluate the maturity of the OM (Baudin et al. 2015). The plot of HI versus Tmax can be used to identify the type and maturity of the hydrocarbon-generating kerogen (Espitalie, 1985). On this plot (Fig. 7), with increasing OM maturity, the position of the corresponding samples shifts toward the right and bottom of the plot, and the level of HI decreases. As the OM maturity increases, the identified kerogen type changes from Type-I to Type-II, Type-III, and then Type-IV; this trend of change in the kerogen type with increasing maturity is evident in the samples from the Garau basin. Another critical parameter for investigating the maturity of the samples is the vitrinite reflectance (Ro%) (Dow 1977). Vitrinite reflectance refers to the percent reflection of light from a polished surface of vitrinite. According to Dow 1977, this parameter ranges from 0.6–1, 1–1.35, and 1.35–3 for oil, wet gas, and dry gas production, respectively.

The Ro of the samples from Gashun and Ghali-Koh were averaged at about 0.57 and ranged from 0.5 to 0.68, respectively, indicating the position of these fields in the early oil window. In the West Lorestan, Chamsangar, and Girveh fields exhibited a significant increase in the maturity coupled with decreased quality and quantity of the OM, which



**Fig. 7** Plot of HI versus Tmax for evaluating the maturity and quality of the OM

placed the corresponding samples in the gas-generating zone. Indeed, the Chamsangar and Girveh showed average Tmax values of 454 and 503.8, respectively, which indicates the increased maturity in these two fields and their gas-generating nature. The decreasing trends of OM quality and quantity coupled with an increasing trend of maturity in the samples from the West Lorestan are evident (Fig. 5) when looking at the values of TOC, HI, and Ro.

The values of vitrinite reflectance in the West Lorestan averaged at 1.12. Considering the levels of maturity in the Dezful Embayment (average Ro% = 1.01) and the Abadan Plain (average Ro% = 0.94), this finding shows that the mentioned sub-basins have once had Type-II kerogen but are present in the gas-generating stage, characterizing their Type-II kerogen content. The Izeh Zone was found to be in early oil production window (i.e., early maturity stage). However, Ghali-Koh and Ghale-Tak showed very similar maturity levels, with the only difference being the higher S2 value for the Ghali-Koh compared to the Ghale-Tak. All the mentioned interpretations are demonstrated on the distribution map in Fig. 5.

### Depositional environment

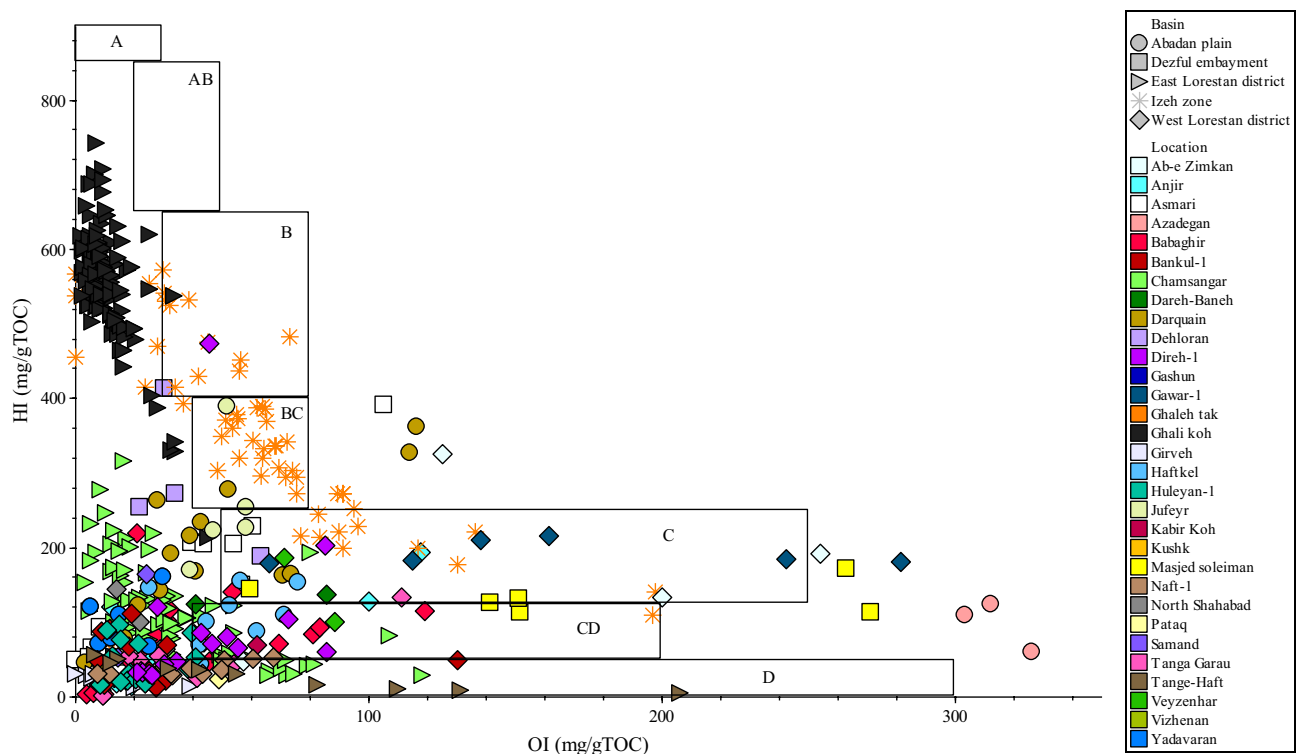
According to Jones' organic facies diagram (Jones 1987) (Fig. 8), the Zones A, AB, B, BC, C, CD, and D refer to the highly reductive lacustrine environment, reductive

prograding marine environment, relatively reductive marine-lacustrine environment, OM-bearing marine-terrestrial environment with a high sedimentation rate in a relatively oxidized environment, an environment with a moderate sedimentation rate under reductive environment, deep marine environment adjacent to orogenic hot spots, and highly oxidized terrestrial environment, respectively.

Table 2 provides detailed information on OM facies studied in this work. According to Fig. 8, the immature or early mature samples from East Lorestan fall in the AB and B zones, indicating that they had been deposited in an anoxic restricted environment. Given their adequate quality and high HI, the OM content of this sub-basin tends to generate oil. The samples from the Izeh Zone fall in the BC zone. According to reverse trends between maturity and quantity-quality of organic matter, Garau Formation was also deposited in a restricted environment with an anoxic condition in these zones.

### Identifying optimal areas as oil shale

According to the definitions proposed for the oil shale (TOC > 3.5%,  $0.41 < Ro\% < 0.6$ ), the samples from the Ghali-Koh and Gashun fields in the East Lorestan could be characterized as oil shales, making them sweet spot for the future. On average, TOC, HI, and Ro% for East Lorestan were equal to 8.89, 413.6, and 0.79, respectively. These



**Fig. 8** Jones' diagram (Jones 1987) for determining the facies of the OM of the samples from the Garau Formation

**Table 2** Association of kerogen-related parameters with organic facies (adapted from (Jones 1987))

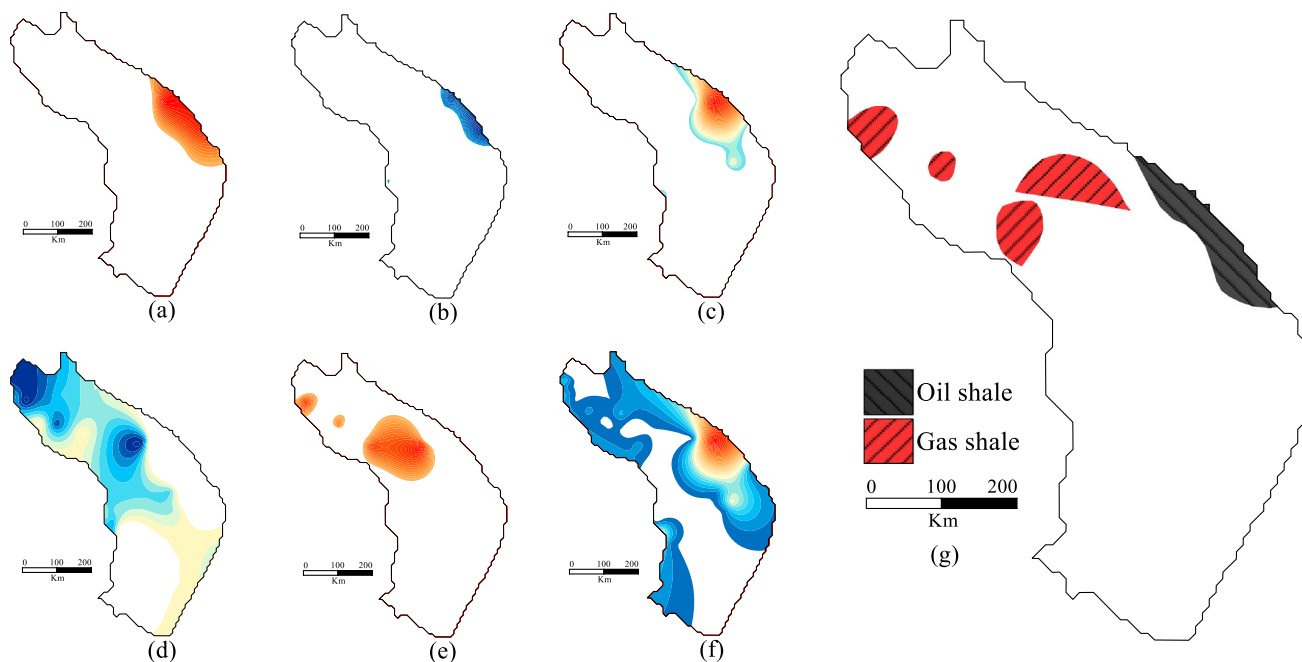
Organic facies	A	AB	B	BC	C	CD	D
% AOM of kerogen	Dominant			Mod	Usually low/absent		
AOM matrix fluorescence	Highest		Mod-weak		Weak	Usually absent	
% Prasinophytes of plankton	Highest	Mod	Rare		Usually very rare		
% Phytoclasts of kerogen	Low (Dilution)			Mod	Usually dominant		
Opaque: translucent phytoclast	Often high			Usually low		Increases	
Geochemical characteristics (for immature sediment)							
Hydrogen index	≥ 850	≥ 650	≥ 400	≥ 250	≥ 125	50–125	≤ 50
Kerogen type	I	I/II	II	II/III	III	III/IV	IV
TOC (wt%)	5–20+	3–10+		3–3+	≤ 3	< 0.5	
Environmental factors							
Proximal–distal trend	Distal			Proximal			Distal
Oxygen regime	Anoxic	Anoxic-dysoxic				Oxic	V. Oxic
Sediment accumulation rate	Low	Varies		High		Mod	Low
Organic facies	A	AB	B	BC	C	CD	D

values are equal to 16.03, 553.44, 0.6 and 19.15, 537.05, and 0.57 for Ghali-Koh and Gashun, respectively, and these areas have the appropriate values. The areas of immense potential in terms of the oil shale are marked in Fig. 9. Figure 9 (a, b, & c) shows the step-by-step selection of the suitable range as oil shale by considering the threshold limit for quantity, quality, and maturity parameters. Figure 9g shows the selected suitable area. The critical point is that an even

larger region can be considered to host the oil shales by lowering the TOC threshold.

### Identifying optimal areas as gas shale

Based on the mentioned definitions and previous studies on the Garau Formation sediments, one can identify unconventional hydrocarbon sources in the Lorestan Basin. In West



**Fig. 9** Step-by-step selection of sweet spot for oil shale and gas shale using threshold limit of quantity, quality, and maturity of organic matter in Garau basin. a, b, and c for oil shale and d, e, and f for

gas shale. **a** HI > 250, **b** Ro: 0.41–0.6, **c** TOC > 3.5, **d** HI: 50–250, **e** Ro > 1.1, **f** TOC > 1.5, and **g** proposed areas for the sweet spot of oil and shale gas

Lorestan, the fields can be recognized as unconventional sources of gas shale thanks to their TOC values (> 1.5 wt.%) and thermal maturity ( $Ro > 1.1$ ). In West Lorestan, the average TOC, HI, and Ro% values are 1.8, 68.11, and 1.1, respectively. These values are suitable for gas shale.

Brittleness is another crucial factor in the hydraulic fracturing of shale oil and gas reservoirs (Boonyasatphan 2017). Mineralogy is an important parameter that is vital in controlling shale properties. The presence of non-clay minerals such as quartz effectively estimates the brittleness index of rock. Brittleness measures a rock's ability to fracture, a function of lithology, mineral composition, toc, thermal maturity, and porosity (Wang and Gale 2009). Evaluating the mechanical properties of shale gas are a crucial parameter for creating fractures in the shale formation and determining the gas sweet spot. Young's modulus and Poisson's ratio are two controlling mechanical properties that determine the brittleness of shale gas layers (Rezaee 2015).

According to the study of Lotfiyar et al. (2018), to investigate the brittleness of the Garau Formation in the Lorestan basin, using mineralogy, the brittleness in this basin varies between 19–26%. The percentage of clay minerals is small enough to carry out Stimulation operations. Lotfiyar et al. (2018) also showed that the Garau Formation in Lorestan has a quartz content of > 20%, carbonate content of > 70%, and clay mineral content of > 4%. Figure 9 (d, e, & f) shows the step-by-step selection of the suitable range as shale gas

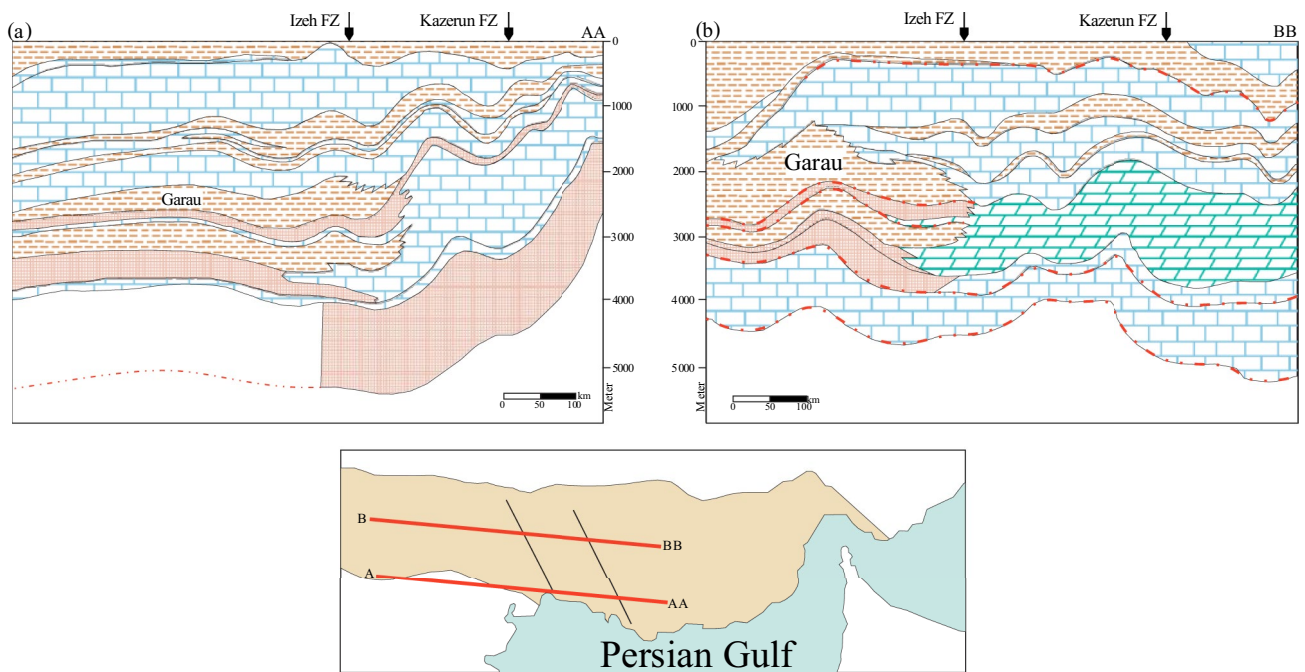
by considering the threshold limit for quantity, quality, and maturity parameters. Figure 9g shows the selected suitable area. An even larger region can be considered to host the gas shales by lowering the TOC and Ro thresholds.

One critical parameter in choosing the sweet spot of shale oil and gas is the thickness of the layer. About the Garau Formation, there is no information related to the underground contour map. Using different sections in the Zagros basin, Setudehnia (1978) investigated the facies changes of the layers and their thickness. Corresponding to Fig. 10, the Garau Formation is suitable for oil and gas shale in terms of layer thickness.

## Summary and conclusions

This study used the parameters of total organic carbon, hydrogen index, oxygen index, vitrinite reflectance, and  $T_{max}$  to identify sweet spot areas as oil shale and gas shale. By studying the East Lorestan, West Lorestan, Izeh Zone, Dezful Embayment, and Abadan plain regions, our study showed:

- The best areas for considering oil shale and gas shale are East Lorestan and West Lorestan, respectively, and these two regions are among the conditions they need for oil and gas shale. According to the definitions of oil



**Fig. 10** Regional sedimentary cross-sections along the Zagros belt show significant changes in the facies and the thickness of the formations in the Zagros basin. (modified from Setudehnia 1978)

- shale and gas shale, considering the ranges of 0.41–0.6 as maturity and quantity more significant than 3.5% for oil shale and maturity greater than 1.1 and organic matter quantity greater than 1.5% for gas shale, East Lorestan is the best place for oil shales. West Lorestan is the best place for gas shales.
- The highest total organic carbon and hydrogen index (average total organic carbon 8.89 and hydrogen index above 553) correspond to East Lorestan, and the lowest amount of total organic carbon and hydrogen index (average total organic carbon 1.57 and hydrogen index less than 120) is for West Lorestan.
  - Considering the necessary conditions for the maturation of organic matter in oil and gas shale, the East Lorestan region has a vitrinite reflectance of 0.5–0.68, and the average of this value for West Lorestan is higher than 1.1, which means that East Lorestan and West Lorestan are suitable Oil shale and gas shale regions, respectively.
  - Izeh zone has the necessary conditions to be considered as oil shale if the total organic carbon threshold value is reduced.
  - Dezful Embayment and Abadan plain do not have the condition of total organic carbon as oil and gas shale. Northwest of Dezful Embayment has layer thickness, hydrogen index (kerogen type), and vitrinite reflectance, but total organic carbon is deficient. Therefore, it cannot be considered shale gas.

- Our research has shown that the Garau Formation in East Lorestan is an excellent source rock; in West Lorestan is poor to fair, and in the sub-basins of Dezful Embayment, Abadan plain, and Izeh zone is considered an adequate to good source.
- Quantity, quality, and maturity parameters in East Lorestan showed the highest quantity, best quality, and type-II kerogen with low maturity. In West Lorestan, the quantity decreases, and the maturity of organic matter increases, and kerogens are the constituents of type III and some IV. To the south of the Garau basin, quantity and quality decrease, maturity rises, and the constituent kerogen is converted to type III.

**Author contribution** EH was contributed to conceptualization, methodology, investigation, reviewing, and editing, visualization. AM was contributed to methodology, interpretation, and writing.

**Funding** The authors did not receive support from any organization for the submitted work.

## Declarations

**Conflict of interest** The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

**Open Access** This article is licensed under a Creative Commons Attribution 4.0 International License, which permits use, sharing, adaptation, distribution and reproduction in any medium or format, as long as you give appropriate credit to the original author(s) and the source, provide a link to the Creative Commons licence, and indicate if changes were made. The images or other third party material in this article are included in the article's Creative Commons licence, unless indicated otherwise in a credit line to the material. If material is not included in the article's Creative Commons licence and your intended use is not permitted by statutory regulation or exceeds the permitted use, you will need to obtain permission directly from the copyright holder. To view a copy of this licence, visit <http://creativecommons.org/licenses/by/4.0/>.

## References

- Alavi M (2007) Structures of the Zagros fold-thrust belt in Iran. *Am J Sci* 307(9):1064–1095
- Alessa S, Sakhaee-Pour A, Sadooni FN, Al-Kuwari HA (2021) Comprehensive pore size characterization of Midra shale. *J Petrol Sci Eng* 203:108576
- Aqrabi AA, Badics B (2015) Geochemical characterisation, volumetric assessment and shale-oil/gas potential of the Middle Jurassic-Lower Cretaceous source rocks of NE Arabian Plate. *GeoArabia* 20(3):99–140
- Baudin F, Disnar JR, Aboussou A, Savignac F (2015) Guidelines for Rock-Eval analysis of recent marine sediments. *Org Geochem* 86:71–80
- Boonyasatphan P (2017) Reservoir characterization for unconventional resource potential, Pitsanulok basin, onshore Thailand. Colorado School of Mines
- Bordenave ML (2002, March) The Middle Cretaceous to Early Miocene petroleum system in the Zagros domain of Iran, and its prospect evaluation. In *AAPG annual meeting* (Vol 6, pp 1–9). Houston: Am. Assoc. Petrol. Geol..
- Bordenave ML, Hegre JA (2010) Current distribution of oil and gas fields in the Zagros Fold Belt of Iran and contiguous offshore as the result of the petroleum systems. *Geol Soc, London, Spec Publ* 330(1):291–353
- Brendow K (2003) Global oil shale issues and perspectives (Synthesis of the Symposium on Oil Shale held in Tallinn (Estonia) on 18 and 19 November 2002). *Oil Shale* 20(1):81–92
- Browning IB (1935) Relation of structure to shale gas accumulation. In *Devonian shales—a symposium by the Appalachian Geological Society: Charleston*, vol 1, pp 16–20, Appalachian Geological Society, West Virginia
- Civan F (2019) Can gas permeability of fractured shale be determined accurately by testing core plugs, drill cuttings, and crushed samples? *SPE J* 24(02):720–732
- Curtis JB (2002) Fractured shale-gas systems. *AAPG Bull* 86(11):1921–1938
- Deinert MR, Parlange JY (2009) Effect of pore structure on capillary condensation in a porous medium. *Phys Rev E* 79(2):021202
- Dembicki H (2022) Practical petroleum geochemistry for exploration and production. Elsevier
- Dow WG (1977) Kerogen studies and geological interpretations. *J Geochem Explor* 7:79–99
- Espitalié J, Laporte JL, Madec M, Marquis F, Leplat P, Paulet J, Boutefeu A (1977) Rapid method for source rocks characterisation and for determination of petroleum potential and degree of evolution. *Oil and Gas Sci Technol* 31:23–42
- Espitalie J, Deroo G, Marquis F (1985) Rock-eval Pyrolysis and its Application 2. *Revue De L Institut Francais Du Petrole* 40(6):755–784
- Falcon NL (1961) Major earth-flexuring in the Zagros Mountains of south-west Iran. *Q J Geol Soc* 117(1–4):367–376
- Gavin MJ (1924) *Oil-shale: An historical, technical, and economic study* (No. 210). Bradford-Robinson printing Company.
- Ghavidel Seyooki M (2013) *Petroleum Geology and its application in the exploration of hydrocarbon reservoirs* (In persian).
- Hinrichs KU, Michaelis W, Rullkötter J (2010) Advances in Organic Geochemistry 2009-Proceedings of the 24th International Meeting on Organic Geochemistry, Bremen, Germany, 6–11 September 2009. *Org Geochem* 41(9):857–1074
- Hosseiny E, Barati Boldaji S (2020) Evaluation of hydrocarbon generation potential of Sargelu source rock in the southwestern Iran and northwestern Persian Gulf. *Journal of Analytical and Numerical Methods in Mining Engineering* (In Persian), Vol 10, Issue 23.
- Hosseiny E, Rabbani AR, Moallemi SA (2016) Source rock characterization of the Cretaceous Sarvak Formation in the eastern part of the Iranian sector of Persian Gulf. *Org Geochem* 99:53–66
- Hunt JM (1995) Petroleum geochemistry and geology (textbook). *Petroleum Geochemistry and Geology (Textbook)*. (2nd Ed.), WH Freeman Company.
- Jarvie DM (2012) Shale resource systems for oil and gas: part I—shale gas resource systems. Part II—shale oil resource systems. Shale reservoirs-giant resources for the 21st century. *AAPG Mem* 97:69–87
- Jarvie DM, Hill RJ, Ruble TE, Pollastro RM (2007) Unconventional shale-gas systems: The Mississippian Barnett Shale of north-central Texas as one model for thermogenic shale-gas assessment. *AAPG Bull* 91(4):475–499
- Jones RW (1987) Organic facies: advanced in Petroleum Geochemistry (Brooks, J., and Welte, D. Eds.).
- Kassaie M (2005) Hydrocarbon source rock evaluation by using the rock-eval: evaluation of the Garu and Gadvan formations in the High Zagros Area in the North of Dezful embayment. *J Petrol Res* 15(51):26–37
- Khani B (2018) *Geochemical assessment and modeling of hydrocarbon system in Middle Jurassic and Lower Cretaceous sediments of Lorestan region from the perspective of unconventional hydrocarbon reserves* (In persian).
- Kobraei M, Rabbani AR, Taati F (2017) Source rock characteristics of the Early Cretaceous Garau and Gadvan formations in the western Zagros Basin—southwest Iran. *J Pet Explor Prod Technol* 7:1051–1070
- Kobraei M, Rabbani A, Taati F (2019) Upper Jurassic-lower cretaceous source-rock evaluation and oil—source rock correlation in the Abadan plain, Southwest Iran. *Geochem Int* 57:790–804
- Lafferty RC (1935) Occurrence of gas in the Devonian shale. In *Devonian shales: A symposium by Appalachian Geological Society: Charleston, West Virginia, Appalachian Geological Society* (Vol. 1, pp 14).
- Langford FF, Blanc-Valleron MM (1990) Interpreting Rock-Eval pyrolysis data using graphs of pyrolyzable hydrocarbons vs. total organic carbon. *AAPG Bull* 74(6):799–804
- Lee S (1990) Oil shale technology. CRC Press
- Lee H, Shakib FA, Liu K, Liu B, Bubach B, Varma RS, Ostadhasan M (2020) Adsorption based realistic molecular model of amorphous kerogen. *RSC Adv* 10(39):23312–23320
- Linley D (2011) Fracking Under Pressure. *The Environmental and Social Impacts and Risks of Shale Gas Development*.
- Lotfiyar A, Chehrizi A, Swennen R, GhasemiSiani M (2018) Geochemical, geological, and petrophysical evaluation of Garau Formation in Lurestan basin (west of Iran) as a shale gas prospect. *Arab J Geosci* 11:1–21

- Mahbobipour H, Kamali MR, Salagi A (2015) Geochemical evaluation of Garau Formation in Anjir and Kabirkouh anticlines in the southwest of Lorestan region (in Persian). *Oil Research*
- Mahbobipour H, Kamali MR, Solgi A (2016) Organic geochemistry and petroleum potential of Early Cretaceous Garau Formation in central part of Lurestan zone, northwest of Zagros. *Iran Marine and Petroleum Geology* 77:991–1009
- Mokhatab S, Poe WA, Mak JY (2006) Natural gas compression. *Handbook of Natural Gas Transmission and Processing*; Gulf Professional Pub, Burlington, MA, USA, pp 295–322
- Motiei H (1993) *Geology of Iran*. Geological Society of Iran Publications, Zagros Stratigraphy
- Peter KE, Cassa MR (1994) Applied source rock geochemistry. *AAPG Mem* 60:93–120
- Peterson BK, Gubbins KE, Heffelfinger GS, Marconi MB, U., & van Swol, F. (1988) Lennard-Jones fluids in cylindrical pores: Nonlocal theory and computer simulation. *J Chem Phys* 88(10):6487–6500
- Rahmani A, Naderi M, Hosseiny E (2022) Shale gas potential of the lower Silurian hot shales in southern Iran and the Arabian Plate: characterization of organic geochemistry. *Petroleum*. <https://doi.org/10.1016/j.petlm.2022.03.004>
- Rezaee R (ed) (2015) *Fundamentals of gas shale reservoirs*. Wiley
- Rezaee Z, Karampour A, Alizadeh B (2009) Genetic potential evaluation of source rocks in Masjed Soleiman oil field. *Geotech Geol* 5(2):121–125
- Sadouni J, Ahmadreza R (2018) Characteristics of the first occurrence of Jurassic petroleum in the Zagros Basin. *Iran Acta Geologica Sinica-English Edition* 92(6):2280–2296
- Sakhaee-Pour A, Bryant SL (2012) Gas permeability of shale. *SPE Reservoir Eval Eng* 15(04):401–409
- Setudehnia A (1978) The mesozoic sequence in south-west Iran and adjacent areas. *J Pet Geol* 1(1):3–42
- Shekarifard A, Daryabandeh M, Rashidi M, Hajian M, Röth J (2019) Petroleum geochemical properties of the oil shales from the Early Cretaceous Garau Formation, Qalikh locality, Zagros Mountains. *Iran Int J Coal Geol* 206:1–18
- Singh SK, Singh JK (2011) Effect of pore morphology on vapor–liquid phase transition and crossover behavior of critical properties from 3D to 2D. *Fluid Phase Equilib* 300(1–2):182–187
- Speight JG (2012a) Refining shale oil. *Shale Oil Production Processes*, pp 139–163.
- Speight JG (2012b) *Shale oil production processes*. Gulf Professional Publishing.
- Taghavinejad A, Sharifi M, Heidaryan E, Liu K, Ostadhassan M (2020) Flow modeling in shale gas reservoirs: A comprehensive review. *J Nat Gas Sci Eng* 83:103535
- Teichmuller M (1989) The genesis of coal from the viewpoint of coal petrology. *Int J Coal Geol* 12(1–4):1–87
- Tran H, Sakhaee-Pour A (2018) Critical properties (Tc, Pc) of shale gas at the core scale. *Int J Heat Mass Transf* 127:579–588
- Tuller M, Or D, Dudley LM (1999) Adsorption and capillary condensation in porous media: liquid retention and interfacial configurations in angular pores. *Water Resour Res* 35(7):1949–1964
- U.S. Energy Information Administration (2013) Technically recoverable shale oil and shale gas resources: an assessment of 137 shale formations in 41 countries outside the United States. U.S. Energy Information Administration, Washington, DC
- Wang FP, & Gale JF (2009) Screening criteria for shale-gas systems.
- Wang Y, Wang Z, Zhao C, Wang H, Liu J, Lu J, Liu D (2007) Kinetics of hydrocarbon gas generation from marine kerogen and oil: implications for the origin of natural gases in the Hetianhe Gasfield, Tarim Basin, NW China. *J Pet Geol* 30(4):339–356
- Welte DH, & Tissot P (1984) *Petroleum formation and occurrence*. Springer-verlag.
- Wynd JG (1965) Biofacies of the Iranian oil consortium agreement area. IOOC Report, 1082
- Yousefi M, & Nazari BA (2015) Characterizations of organic matter in the Garau Formation (Early Cretaceous), in the South of Lorestan. *Applied Sedimentology of Iran*.
- Zeinalzadeh A, Moussavi-Harami R, Mahboubi A, Sajjadian VA (2018) Source rock potential of the early cretaceous intervals in the Darquain field, Abadan Plain, Zagros Basin, SW Iran. *Geosci J* 22:569–580
- Zhao LY, Chen JN, Wang TS (1990) *Chinese Oil Shale Composition and Industrial Genetic Types*. China University of Geosciences Press, Hubei Wuhan
- Zou C (2017) *Unconventional petroleum geology*. Elsevier
- Zou CN, Yang Z, Tao SZ, Yuan XJ, Zhu RK, Hou LH, Pang ZL (2013) Continuous hydrocarbon accumulation over a large area as a distinguishing characteristic of unconventional petroleum: The Ordos Basin, North-Central China. *Earth-Sci Rev* 126:358–369

**Publisher's Note** Springer Nature remains neutral with regard to jurisdictional claims in published maps and institutional affiliations.