

Implementation of an Integrated Geochemical Approach Using Polar and Nonpolar Components of Crude Oil for Reservoir-Continuity Assessment: Verification with Reservoir-Engineering Evidences

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Summary

The ability of geochemistry techniques in reservoir-continuity studies has already been proved. Most of the traditional methods mainly involve analyzing nonpolar components of crude oil and overlooking polar components. Despite valuable information obtained from nonpolar components, these compounds are sometimes affected by various alterations or likely provide only a piece of the reservoir-compartmentalization puzzle. In this paper, an integrated geochemical approach that uses nonpolar (i.e., saturates and aromatics) and polar (i.e., asphaltenes) components of crude oil was performed to evaluate reservoir continuity efficiently. The Shadegan Oil Field in the Dezful Embayment in southwest Iran was investigated for reservoir-continuity studies to show the efficiency of this proposed technique. The selected interparaffin peak ratios and light hydrocarbons [the C_7 oil correlation star diagram (C_7 -CSD)] from whole-oil gas chromatography (GC) (WOGC) chromatograms were used to obtain oil fingerprints from the nonpolar fraction of crude oils. The Fourier-transform infrared (FTIR) spectroscopy of asphaltenes was applied to obtain oil fingerprints from the polar fraction of crude oils. The pairwise comparison of studied wells by each technique was summarized in a similarity matrix with green, yellow, and red colors to show connectivity, limited connectivity, and disconnectivity according to oil fingerprints. Finally, a compartmentalization model was prepared from the integrated results of different techniques considering the worst-case scenarios regarding the occurrence or absence of reservoir continuity when relying on individual methods for the studied field. Results show that the Shadegan Oil Field comprises three zones in the Asmari Reservoir and two zones in the Bangestan Reservoir. Reservoir-engineering data, including pressure data and pressure/volume/temperature (PVT), completely corroborated the obtained results from the geochemical approach. The consistency of results suggested FTIR oil fingerprinting of asphaltene as a novel and straightforward technique, which is a complementary or even alternative method with respect to previous geochemical methods.

Introduction

Most reservoir-engineering issues are currently efficiently addressed by the geochemistry branch named “reservoir geochemistry.” The study of compositional changes of reservoir fluids (i.e., hydrocarbons and water) in the spatial and temporal scale comprises the basic principles of this discipline (Larter and Aplin 1994; Kaufman et al. 1997; Larter et al. 1997; England 2007; Asemani and Rabbani 2020a). Reservoir-engineering tools (e.g., openhole and casedhole logs, continuous reservoir-pressure monitoring, pressure-transient testing, and production-well-testing techniques) are likely very costly and time consuming to answer questions in the oil industry (Beeunas et al. 1999). But reservoir geochemistry provides a cost-effective, precise, and efficient way to achieve these answers. Because of its inherent advantages, this science has developed into a successful tool in different areas of reservoir engineering, and reservoir geochemistry has become an indispensable part of most reservoir-engineering projects.

One of the fascinating applications of reservoir geochemistry is evaluating reservoir continuity. The assessment of oil-fingerprint heterogeneities in different wells across a studied field is a primary tool in geochemistry to reveal compartmentalized regions in the studied field (England et al. 1987; Asemani et al. 2020; Asemani and Rabbani 2020a). Because of its necessity and importance in the development plan of a field, a considerable number of papers in the literature were dedicated to this theme (Slentz 1981; Hwang et al. 1994; Smalley et al. 1994; Kaufman et al. 1997; Beeunas et al. 1999; Milkov et al. 2007; Rein and Schulz 2007; Ventura et al. 2010; Pavlov and Vasiliev 2017; Mahmoudi et al. 2017; Ekpo et al. 2018). Geochemists traditionally explore nonpolar components of crude oil (i.e., saturates and aromatics) using techniques including 2D GC, multidimensional GC, GC-mass spectrometry, and GC fingerprinting (WOGC) as routine methods in reservoir-geochemistry projects to determine reservoir continuity (Ball et al. 1960; Baruya and Maddams 1978; Machel and Mountjoy 1986; Li et al. 1999, 2013; Trejo et al. 2004; Dembicki 2016; Márquez et al. 2016). Reservoir engineers mostly investigate the gradients of bulk-fluid properties, such as gas/oil ratio, density, asphaltenes content, and pressure gradient, to evaluate reservoir connectivity (Zuo et al. 2012a). The optical density measurement by downhole fluid analysis, which is linearly related to asphaltene concentration, permits the establishment of an asphaltenes gradient in the oil column. Currently, asphaltene-gradient estimation by downhole-fluid-analysis measurement—and comparing that with the obtained gradient from the Flory-Huggins-Zuo equation of state—is a popular technique to delineate reservoir discontinuities (Mullins et al. 2007a, 2007b; Betancourt et al. 2009; Freed et al. 2010; Zuo et al. 2012a, 2012b; Chen et al. 2015).

On the one hand, infilling processes (e.g., various source rocks, different source-rock facies, and gradual maturity of source rock) or post-filling processes (e.g., biodegradation, water washing, evaporative fractionation, charge history, and gravity segregation) cause variation in the oil fingerprints and results of traditional geochemical measurements (Larter and Aplin 1995; Westrich et al. 1999; Rein and Schulz 2007; Li et al. 2008; Zhang et al. 2014; Chen et al. 2017). This is because these techniques mainly rely on the nonpolar

components of oil (i.e., saturate and aromatic hydrocarbons). Hwang et al. (1994) showed that despite lateral continuity of a reservoir in the Unity Field, the oil fingerprint shows variations. They concluded that the organic facies variation and thermal maturity of source rock have significant effects on the alteration of the oil fingerprint. The migration fractionation, rock/fluid interaction, and in-reservoir maturation have negligible effects on the fingerprint variation in this field. Also, there are several literature cases in which GC fingerprinting could not reveal differences in the oil fingerprint of samples. Permayer et al. (2007) showed that although the GC fingerprint cannot differentiate two oils from the El Furrial Field in Venezuela, the FTIR spectroscopy of the oil samples revealed their differences. Márquez et al. (2016) illustrated that in the study of the Misoa B4, the GC fingerprint failed to distinguish differences between samples in Blocks I and III from this reservoir. They unravel the presence of permeability baffles and barriers using the FTIR spectroscopy of crude oils.

On the other hand, although the coupling of downhole fluid analysis and the Flory-Huggins-Zuo equation of state provides the most valuable information regarding fluid gradient in a reservoir, it has some difficulties. The downhole-fluid-analysis module is run with fluid-sampling tools on a wireline platform. This tool can only run in openhole environments, and the production from the well or drilling should be shut down. Because of the higher cost, this operation is routinely performed in selected wells. Therefore, new techniques are necessary to provide useful information for reservoir continuity. Oil fingerprinting from the structural characteristics of crude-oil polar compounds, especially asphaltenes, in the conjugation of nonpolar compounds can be this alternative solution and can strengthen the ability of geochemical approaches in revealing flow barriers.

The acceptable definition of asphaltenes is related to their solubility. These compounds are soluble in aromatic solvents (e.g., toluene and benzene) and insoluble in light normal alkane solvents (e.g., *n*-pentane, *n*-hexane, and *n*-heptane) (Hemmati-Sarapardeh et al. 2018). Furthermore, geochemistry science provides another definition for these compounds. It establishes that asphaltenes are the most similar fraction of reservoir crude oil to its precursor (i.e., kerogen) (Rubinstein et al. 1979; Behar et al. 1984; Behar and Pelet 1984, 1985; Pelet et al. 1986; Lehne et al. 2009). This characteristic has opened wide opportunities in geochemical studies. It is demonstrated that the FTIR technique provides valuable information from different fractions of crude oils, especially asphaltenes. This technique has successfully been used in various disciplines of geochemistry studies, such as reservoir continuity and geochemical correlations (Permayer et al. 2002; Asemani et al. 2020; Asemani and Rabbani 2021).

Permayer et al. (2002, 2005, 2007) suggested structural characteristics of crude oils obtained from the FTIR technique and synchronous ultraviolet fluorescence technique as a new tool for reservoir-compartmentalization studies. These authors showed that the results of this technique are corroborated by the routinely used technique of GC fingerprinting. Riley et al. (2016) used the attenuated total reflectance-FTIR spectra of asphaltenes in oil fingerprinting and detecting the source of an oil spill. Asemani and Rabbani (2016) considered the structural characterization of asphaltenes by FTIR spectroscopy as a correlation parameter and performed an oil/oil correlation. Asemani et al. (2020) proposed a modified moving-window correlation coefficient technique to obtain oil fingerprints from asphaltenes. Asemani and Rabbani (2020a) showed that structural characteristics of asphaltene subfractions are a useful technique for investigating oil-fingerprint similarity or dissimilarity. Asemani and Rabbani (2021) proposed a novel technique for the genetic classification of crude oil using the FTIR spectra of asphaltenes.

The main aim of this paper is to obtain oil fingerprints by an integrated geochemical approach using polar and nonpolar compounds. Then, the fingerprint heterogeneities and homogeneities are used to assess reservoir compartmentalization. As an example, to show the efficiency of the methodology, reservoir continuity in the Shadegan Oil Field was investigated. The interparaffin peak ratios and light hydrocarbons were used to assess the heterogeneity or homogeneity of fingerprints in different wells. Also, oil fingerprints in different wells were obtained by FTIR-technique results for asphaltenes. The similarity or dissimilarity in oil fingerprints was used to determine reservoir continuity or compartmentalization. Finally, a compartmentalization model for the studied field was suggested using the integration results of different techniques. Reservoir-engineering data were also used to corroborate and investigate the obtained results from the geochemical approach.

Geological Setting

The Zagros Orogen extends from southwest Turkey to east Iraq and to west/southwest Iran. From northeast to southwest, the Zagros Orogen consists of three structural units named the Urumieh-Dokhtar Magmatic Assemblage, the Zagros Imbricate Zone (Sanandaj-Sirjan Zone), and the Zagros Fold-Thrust Belt, according to sediment history and structural style (Alavi 1994, 2004). The Zagros Fold-Thrust Belt and its Foreland Basin are the most important parts of the Zagros Orogen because of the favorable conditions available for hydrocarbon generation, migration, and accumulation. The Zagros Fold-Thrust Belt is divided into Lurestan, Khuzestan (including Dezful Embayment and Izeh Zone), and Fars from northwest to southeast by the High Zagros, Balarud, and Kazerun faults, respectively (Fig. 1a) (Sepehr and Cosgrove 2004). The Dezful Embayment is one of the most known petroliferous regions globally, covering a surface area of 60 000 km² and containing approximately 8% of the world's reserves (Bordenave and Burwood 1995). The large anticlines within the northwest/southeast trend are characteristics of folds in this region (Hatzfeld et al. 2010).

The Shadegan Oil Field is located in the central region of the Dezful Embayment (Fig. 1a). The structure of this field is a symmetrical anticline. Asmari and Bangestan are the main reservoirs in which the Asmari Formation has two productive sections—namely, Upper Asmari and Lower Asmari—in this field. Three main faults have been diagnosed with seismic data in this field (Fig. 1b). These faults have been detected only in the Asmari Reservoir and have not occurred in the Bangestan Reservoir. The Asmari Formation (Oligocene to Early Miocene) is 250 to 300 m of high-energy limestone, in which induced fractures caused by tectonics have enhanced reservoir quality. Ahvaz Sandstone Member is a basal part of the Asmari Formation in southwest Khuzestan. The Bangestan group comprises Sarvak and Ilam limestone reservoirs and Kazhdumi source rock. The Sarvak Formation (Cenomanian to Turonian) is thicker (300 to 1000 m) than the Ilam Formation (50 to 200 m thick, Santonian). These formations appear as a single reservoir (i.e., Bangestan Reservoir) in most parts of the Dezful Embayment. The evaporite Gachsaran Formation as an efficient caprock has sealed the Asmari Reservoir (Fig. 2). It is believed that the Pabdeh (Middle Eocene to Oligocene) and Kazhdumi (Albian) formations are primary source rocks that have charged these reservoirs in the Dezful Embayment (Bordenave and Hegre 2005). The Kazhdumi source rock is likely the main source rock in the Shadegan Field (Asemani et al. 2021).

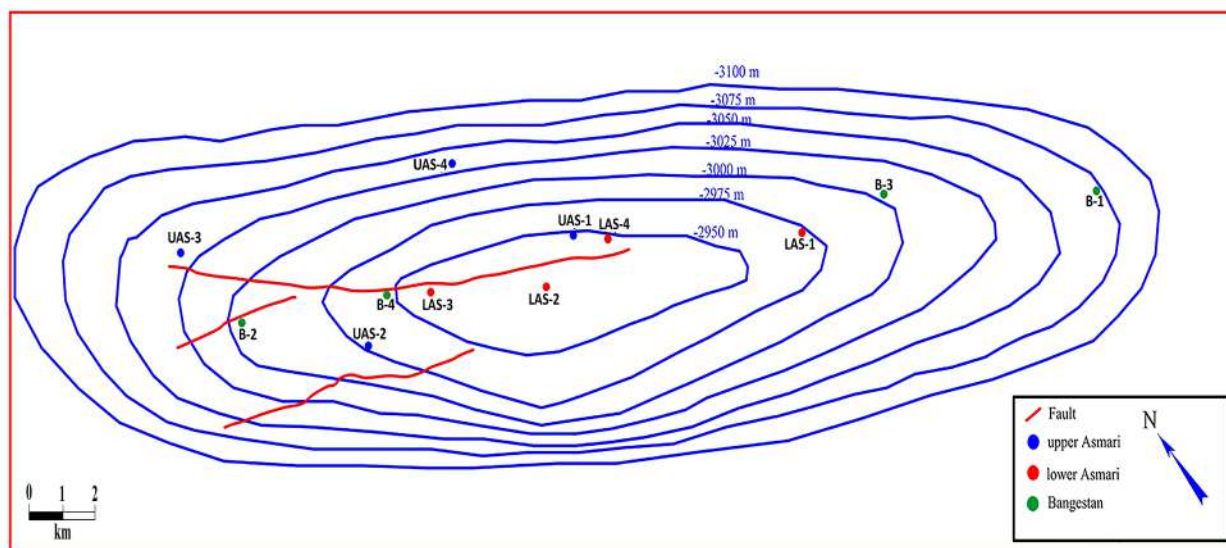
Materials and Methods

Samples. Twelve oil wells were sampled from three reservoir units (i.e., Upper Asmari, Lower Asmari, and Bangestan reservoirs) in the Shadegan Field. The studied samples were collected from the wellhead of producing wells at atmospheric conditions. The studied samples are reported in Table 1, and their locations are represented in Fig. 1b.

Analysis. °API. The Anton Paar DMA 4100 instrument was used to measure the density of studied samples at atmospheric conditions, and then °API values were calculated.



(a)



(b)

Fig. 1—(a) The Zagros Fold-Thrust Belt and its different structural regions (Farahzadi et al. 2019). (b) Contour map of the Shadegan Field base on top of the Asmari Reservoir.

Saturates/Aromatics/Resins/Asphaltenes Analysis. Samples were topped by a rotary evaporator with 89°C and a vacuum pressure of 10 mm Hg (13 mbar) to remove low-molecular-weight volatile components (Weiss et al. 2006). This process has two critical merits: The yield of asphaltenes increases and a lower amount of precipitating solvent is needed, and the weighing of the sample is precise. Because of the vaporization of low-molecular-weight components, the weight of samples is not constant. Because vaporization losses differ in various samples, weighing might be bearing some inaccuracy and errors.

Asphaltenes were extracted by *n*-hexane and using ASTM D6560-17 (2017). A mixture of crude oils and *n*-hexane at the ratio of (1:30, g/cm³) was refluxed for 1 hour. After overnight, the samples were filtrated by a filter paper with 2.5-μm pore sizes. The remaining filtrate cake on the paper was first washed under reflux by *n*-hexane to remove impurities coprecipitated by asphaltenes. Then all pure asphaltenes were washed with toluene. Asphaltenes were obtained after removing toluene by evaporation and heating of the sample in the oven at 100°C for 30 minutes. The fractionation of maltenes was performed by column chromatography, which was packed by activated silica gel. The elution of saturates, aromatics, and resins was performed by *n*-hexane, benzene, and toluene/methanol (90:10), respectively.

WOGC Analysis. WOGC analysis was performed by injection of 1 μL of crude oil directly to an HP 5890 Series II gas chromatograph equipped with a DB-1 capillary column (by Agilent) [60 m × 0.1 mm (inner diameter) and 0.25-mm film]. The flame ionization detector at 350°C was used as a detector, and the carrier gas (i.e., helium) had a constant flow of 1.6 cm³/min. The column temperature was programmed from 30°C (held for 5.0 minutes) to 320°C at a rate of 3°C/min and was finally held for 20 minutes. The repeatability of analysis was checked by replicate analysis of one sample. The standard deviation of the peak ratio measurements was better than 5% and mainly within 1 and 3%. Hence, a 5% cutoff was considered for revealing fingerprint heterogeneities or homogeneities. The pairwise comparison of fingerprints for different samples using interparaffin peak ratios or C₇ hydrocarbons is illustrated in a similarity matrix to display the fingerprint heterogeneities between each pair of studied wells in the studied field. Fingerprint similarity or dissimilarity between wells is shown by colors similar to traffic lights, in which green and red colors imply connectivity and disconnectivity between studied wells, respectively.

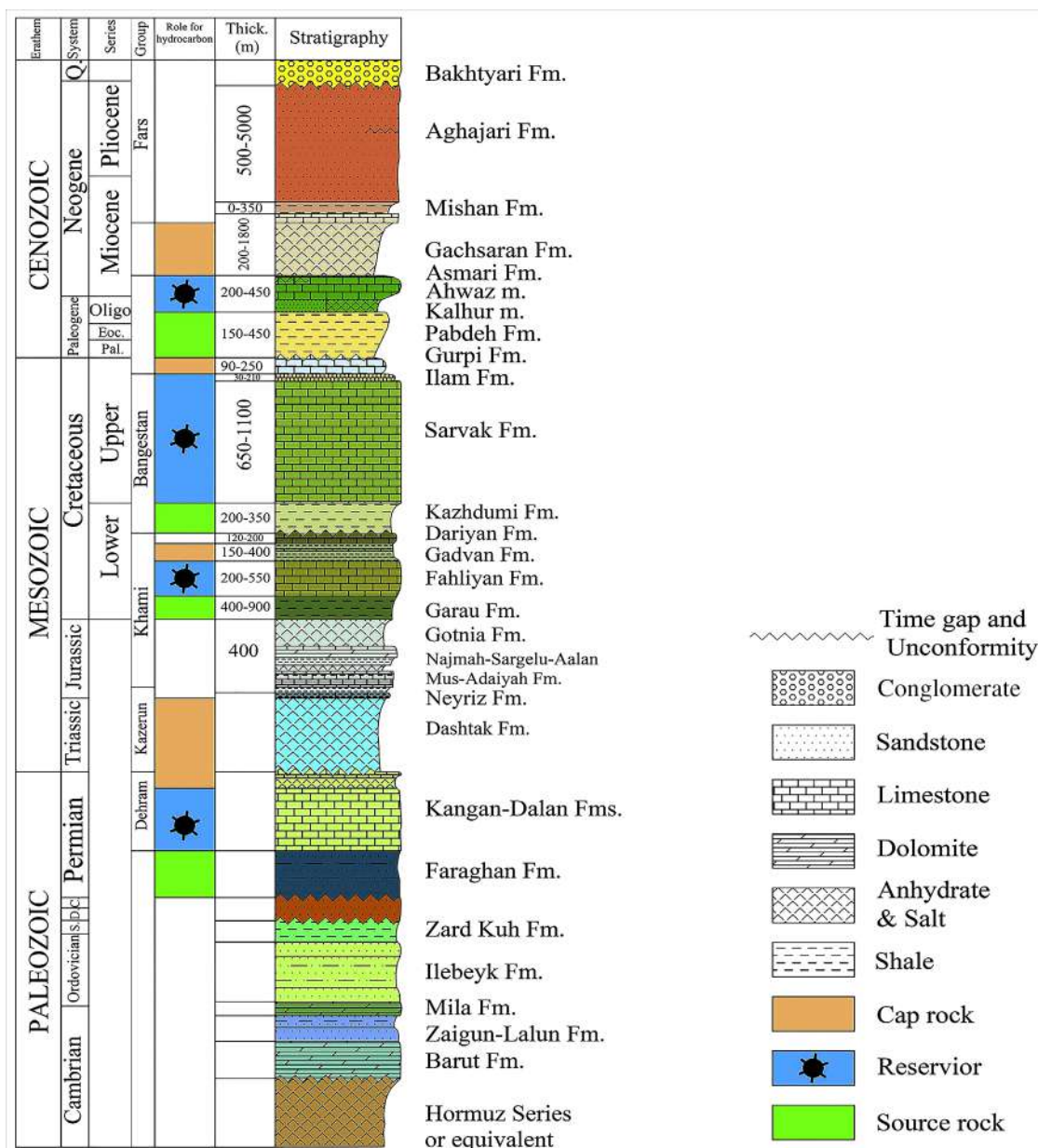


Fig. 2—The general stratigraphic column in the Dezful Embayment in southwest Iran (after Derikvand et al. 2018).

No.	Sample (Well) Name	Reservoir Unit	°API	Saturates (wt%)	Aromatics (wt%)	Resins (wt%)	Asphaltenes (wt%)
1	UAS-1	Upper Asmari	29.39	46.06	41.46	10.94	1.54
2	UAS-2	Upper Asmari	26.69	42.64	38.91	12.26	6.2
3	UAS-3	Upper Asmari	22.15	34.67	42.83	14.78	7.72
4	UAS-4	Upper Asmari	22.3	35.64	41.82	15.21	7.34
5	LAS-1	Lower Asmari	30.38	48.25	40.78	9.77	1.2
6	LAS-2	Lower Asmari	30.53	45.78	40.43	12.49	1.3
7	LAS-3	Lower Asmari	28.99	44.93	38.9	9.86	6.3
8	LAS-4	Lower Asmari	30.9	47.69	40.43	10.89	1
9	B-1	Bangestan	26.05	39.82	41.97	8.61	9.6
10	B-2	Bangestan	22.59	32.28	41.32	15.93	10.46
11	B-3	Bangestan	21.16	37.96	47.61	12.23	2.2
12	B-4	Bangestan	22.22	35.49	42.28	12.53	9.7

Table 1—Bulk characteristics of studied samples in the Shadegan Oil Field.

FTIR Spectroscopy. FTIR spectra were obtained from asphaltenes on the potassium bromide (KBr) pellet, prepared from mixing of grounded asphaltenes and KBr (1:100 wt/wt), by Thermo Nicolet-Nexus 670. The measurement was performed in the range of 4000 to 400 cm^{-1} with resolution of 4 cm^{-1} with coadding of 40 scans. Asphaltene extraction and FTIR analysis on one sample from each reservoir unit (namely UAS-1, LAS-3, and B-3) in the Shadegan Field were performed six times for threshold calculation in the fingerprint methodology. All spectra were normalized to maximum peak, with asymmetrical stretching of the C-H bond in methylene groups at approximately 2923 cm^{-1} , to remove the effect of different asphaltene amounts in the KBr-pellet preparation.

Oil Fingerprinting by FTIR Technique. For the visualization of differences between samples, 13 peak ratios were defined for comparison. These ratios are defined according to the bands in the three main important regions in the FTIR spectra of asphaltenes. These regions are 3100 to 2750 cm^{-1} , 1800 to 1000 cm^{-1} , and 1000 to 700 cm^{-1} . In each region, one band is considered a base peak, and the heights of other bands are calculated relative to this band. The base peaks are 2852, 1377, and 744 cm^{-1} for Regions I, II, and III, respectively. The region 4000 to 3100 cm^{-1} is excluded from investigations to avoid errors resulting from environmental conditions and moisture absorption of asphaltenes in the KBr pellet. Defined peak ratios are shown schematically in Fig. 3.

A star diagram helps visualize the differences, but decision making regarding the amount of homogeneity or heterogeneities is not applicable. Hence, a quantitative base technique similar to that in Riley et al. (2016) is used to assess heterogeneities between asphaltenes. These authors propose a method to obtain oil fingerprints from asphaltenes. They used this method for forensic studies regarding oil-spill-source determination. Herein, this method, with some modifications, was performed. In this method, the relative difference for the pairwise comparison between studied samples is calculated from Eq. 1.

$$\text{Relative difference} = (x_i - y_i) / \text{average}(x_i, y_i) \times 100, \quad i = 1 \text{ to } 13, \quad \dots \quad (1)$$

where x_i and y_i are the i th peak ratio for the x and y samples, respectively.

In this paper, the 13 defined peak ratios were used for comparison. The relative difference between the two studied samples in each ratio is compared with a defined threshold to decide regarding the similarity or differences of two samples. If the relative difference in all 13 ratios was lower than the threshold, two samples are similar, and vice versa. The similarity of samples shows the connectivity and flow communication between the two studied wells. The relative disconnectedness of two wells can be assessed by the number of peak ratios higher than the threshold. The higher number of differences indicates a higher disconnectedness between the two specific wells. Whatever the number of difference increases, the disconnectedness between the two wells reinforces. In this paper, wells with only one ratio higher than the threshold are considered as limited connectivity. In this situation, we proposed checking the connectivity with other methods further. The repeatability of defined ratios is the basis of defining an acceptable level of threshold (CEN/TR 15522-2 2006; Riley et al. 2016). One of the samples should be analyzed several times, and then the repeatability limit is calculated from Eq. 2 (ISO 5725-2 2019). The calculated relative standard deviation (RSD) for each peak ratio is multiplied by 2.8 to determine the repeatability limit to ensure that the two studied samples have more than 95% similarity.

$$r_{95\%} = 2.8 \times \text{RSD}, \quad \dots \quad (2)$$

where $r_{95\%}$ is the repeatability limit.

The acceptable level of threshold is equal to the maximum of the calculated values (Riley et al. 2016). We recommend measuring the threshold for each sample batch separately. The pairwise comparison of different wells in the studied oil field is illustrated in a similarity matrix. Colors similar to traffic lights are used to better visualize the results in the similarity matrix. A green color means that two specific wells have a similar oil fingerprint and are connected. A red color specifies the opposite meaning, and discontinuity. If two studied wells have only one peak ratio higher than the threshold, the yellow color is shown. It clarifies small differences between studied wells, and their condition should be checked further by other techniques. The number of peak ratios higher than the threshold between the studied samples indicates the relative intensity of discontinuity.

Results and Discussion

Oil Bulk Properties. Table 1 lists the saturates/aromatics/resins/asphaltenes analysis and $^{\circ}\text{API}$ results for studied samples. Saturate content varies from 32.28 to 48.25%. Aromatic and resin fractions range from 38.9 to 47.61% and 8.61 to 15.93%, respectively. Except for the Bangestan (i.e., B-1, B-2, B-3, and B-4), UAS-4, and UAS-3 samples, in which the aromatic fraction has the highest value, in the other samples, the saturate fraction is the highest component. Among the samples, the minimum and maximum of asphaltene content correspond to LAS-4 (1%) and B-2 (10.46%), respectively. The average of asphaltene content in the Upper Asmari, Lower Asmari, and Bangestan is 4.80, 3.20, and 6.86%, respectively. $^{\circ}\text{API}$ values range from 21.16 (B-3) to 30.90 (LAS-4). The average value of $^{\circ}\text{API}$ is 25.13, 30.2, and 23.01 for the Upper Asmari, Lower Asmari, and Bangestan reservoirs, respectively.

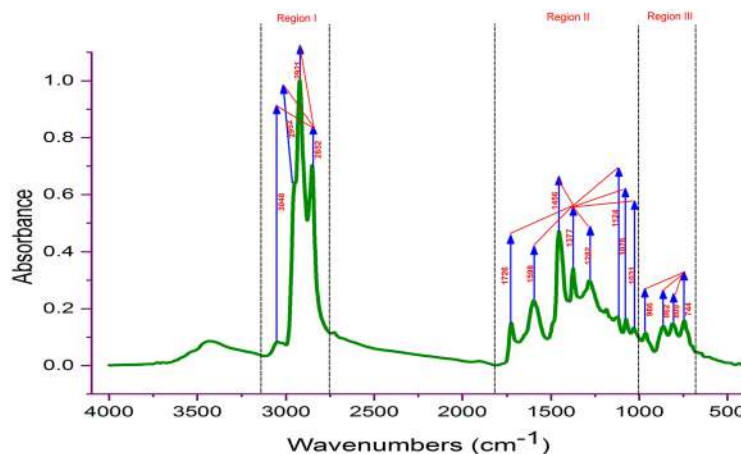


Fig. 3—Schematic of different FTIR ratios used to obtain the oil fingerprint from the asphaltenes.

Assignment of FTIR Spectra Bands. FTIR spectra for all studied samples from three reservoir units are shown in **Fig. 4**. The appearance of spectra for different samples is approximately similar, and they share similarities in most of the bands. FTIR spectra were divided into three regions according to their essential functional groups. These regions are 3100 to 2750 cm^{-1} , 1800 to 1000 cm^{-1} , and 1000 to 700 cm^{-1} . The 4000 to 3100 cm^{-1} region was not included in the regions. Moisture absorption by prepared KBr pellet causes the appearance of the O-H band in this region because of the high moisture absorption of KBr. This band is attributed to O-H stretching, and differentiation of this band to moisture absorption or contributed functional groups in the sample is not easy.

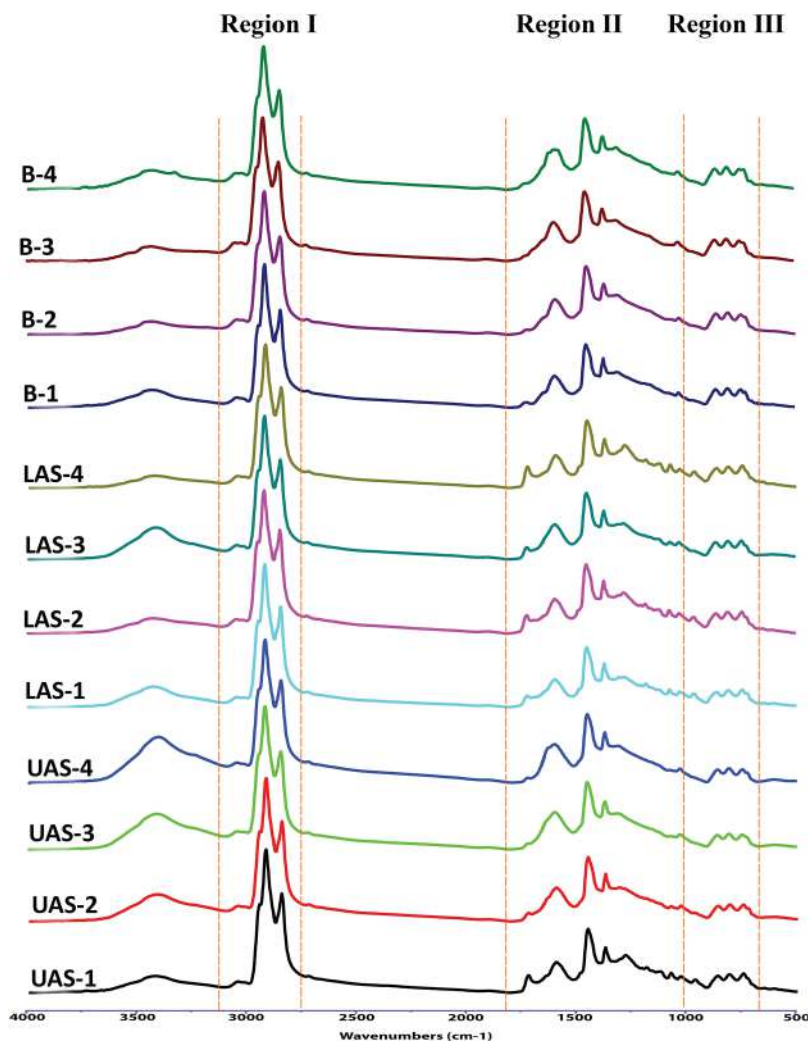


Fig. 4—FTIR spectra of studied asphaltene samples from the Upper Asmari, Lower Asmari, and Bangestan reservoirs.

Region I includes aromatic and aliphatic compounds. A small band near 3050 cm^{-1} is related to C-H stretching in the polynuclear aromatic compounds. A region between 3000 and 2750 cm^{-1} is known as an aliphatic region. The C-H stretching of methyl, methylene, and methine groups as an asymmetric or symmetric vibration generally gives rise to peaks in the 3000 to 2750 cm^{-1} region (Smith 1998; Asemani and Rabbani 2020b, 2021). Region II involves different critical functional groups. This region is known as the fingerprint region (Smith 1998). A band near 1730 cm^{-1} is caused by C=O stretching in the carboxylic acid and ester groups. The C=C aromatic stretching band, which is so-called ring mode, commonly gives rise to a band near 1605 cm^{-1} , and shifting toward lower wavenumbers is caused by increasing condensation in the aromatic compounds (Sharma et al. 2007; Asemani and Rabbani 2020b). In the studied samples, this band appears at approximately 1600 cm^{-1} . A band at 1460 cm^{-1} is attributed to CH_3 asymmetric bending, CH_2 scissoring, or both (Smith et al. 1993). These vibrations commonly occur at the same wavenumber. The umbrella mode vibration of methyl (symmetric bending) and the S=O stretching of sulfoxide groups occurred at approximately 1376 and 1030 cm^{-1} , respectively (Lin-Vien et al. 1991). Region III is known as a C-H bending region of the aromatic rings. The substitutions in the aromatic rings are determined by the frequency and number of bands in this region (Yen et al. 1984; Asemani and Rabbani 2020b). The 724 cm^{-1} band is related to the rocking vibration by methylene in the straight-chain alkanes, with more than four carbons (Pavia et al. 2008). The occurrence of this band in the studied samples shows asphaltenes have straight-chain alkanes with more than four carbons.

Reservoir-Continuity Assessment. The connectivity of a reservoir is a prerequisite of fluid-composition equilibrium in that reservoir. Strictly speaking, the homogeneity in reservoir-fluid composition and properties results from reservoir connectivity (Zuo et al. 2012a; Mullins et al. 2013; Pomerantz et al. 2013; Wu et al. 2014; Asemani and Rabbani 2020a). Therefore, the investigation of fluid composition is a critical procedure to obtain information regarding the architecture of the reservoir. It is noteworthy that the filling history and time required to mix oils in the reservoir are also important and should be considered.

Interparaffin Peak Ratios from WOGC Analysis. Fig. 5 shows the WOGC chromatogram for two representative samples from three reservoir units in Shadegan Field. The visual appearance of the chromatograms is similar. The pattern of normal alkanes is not helpful for the reservoir-compartmentalization issue. However, interparaffin peaks in the WOGC chromatogram are routinely used to obtain oil fingerprints for detailed comparison (Hwang et al. 1994; Kaufman et al. 1997; Nicolle et al. 1997). Different peak ratios were calculated in the $n\text{-C}_9$ to $n\text{-C}_{13}$ and $n\text{-C}_{18}$ to $n\text{-C}_{22}$ regions, and finally, peak ratios with higher differences were chosen for the construction of star diagrams and subsequent studies. We selected 14 peak ratios in the $n\text{-C}_9$ to $n\text{-C}_{13}$ region (Fig. 6) and 12 peak ratios in the $n\text{-C}_{18}$ to $n\text{-C}_{22}$ region (Fig. 7) to depict differences or similarities between samples.

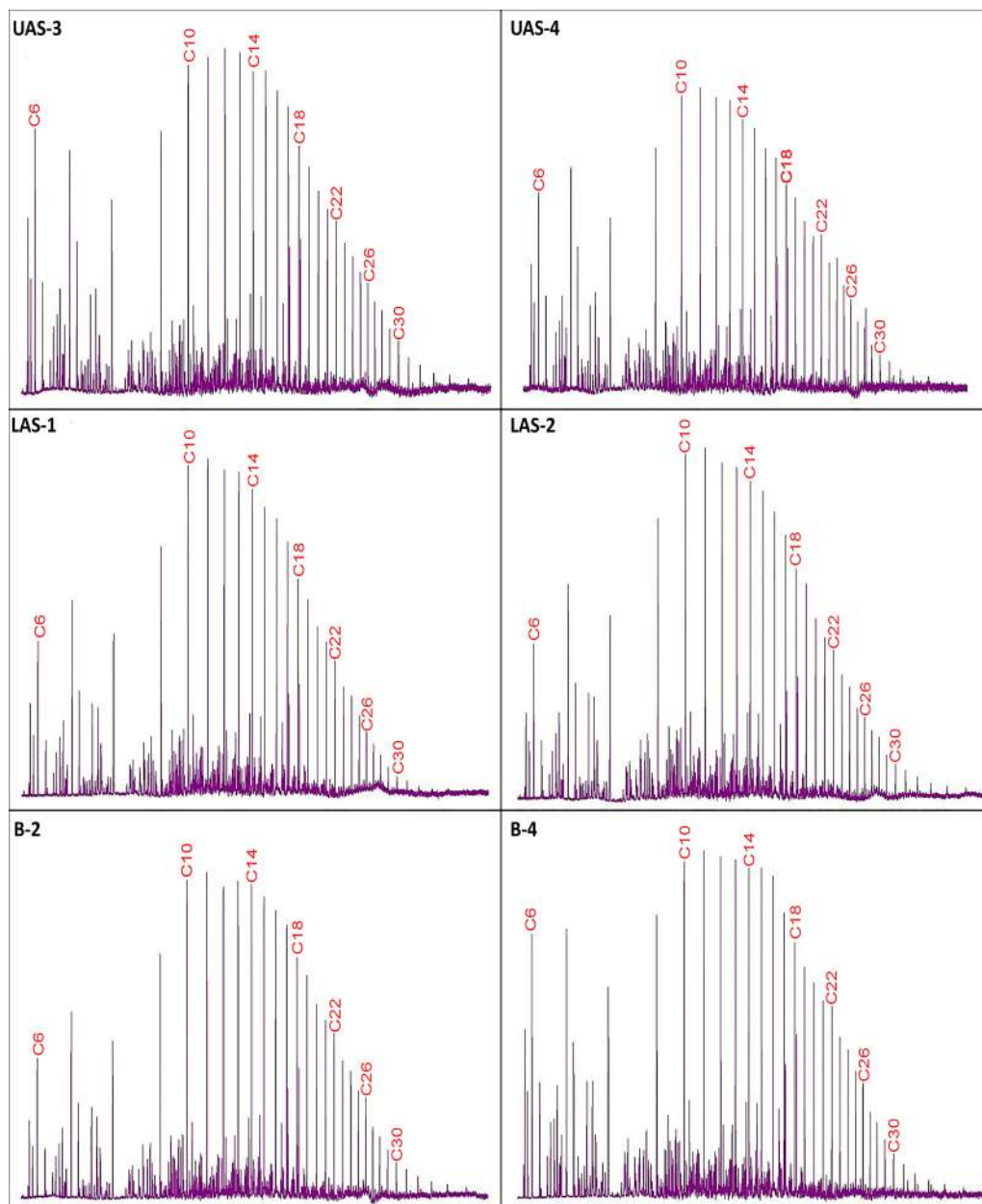


Fig. 5—WOGC chromatograms for two representative samples from three reservoir units.

Three different trends in defined peak ratios in the $n\text{-C}_9$ to $n\text{-C}_{13}$ region are evident in the Upper Asmari samples (Fig. 8a). Two general trends are apparent in defined peak ratios for the Lower Asmari samples (Fig. 8b), in which the LAS-1 sample has a pattern similar to that of the LAS-2 and LAS-4 samples and has a difference in only one peak ratio. The difference in the trend of the B-1 sample from that of the other samples in the Bangestan Reservoir is perceptible (Fig. 8c).

The interparaffin peaks in the $n\text{-C}_{18}$ to $n\text{-C}_{22}$ region were also considered to complete the obtained results from WOGC in the $n\text{-C}_9$ to $n\text{-C}_{13}$ region. Similar to previous findings, the UAS-3 and UAS-4 samples show a completely similar fingerprint (Fig. 9a). These similarities are not fortuitous because the selected peaks are the peaks with the highest relative difference between various samples. These samples have different fingerprints from the UAS-1 and UAS-2 samples in the Upper Asmari (Fig. 9a). The LAS-2 and LAS-4 samples have the same trend and are entirely different from the other samples in the Lower Asmari (Fig. 9b). In this plot, the LAS-1 sample has a completely different fingerprint from the LAS-2 and LAS-4 samples (Fig. 9b). Fig. 9c corroborates previous results regarding the Bangestan samples.

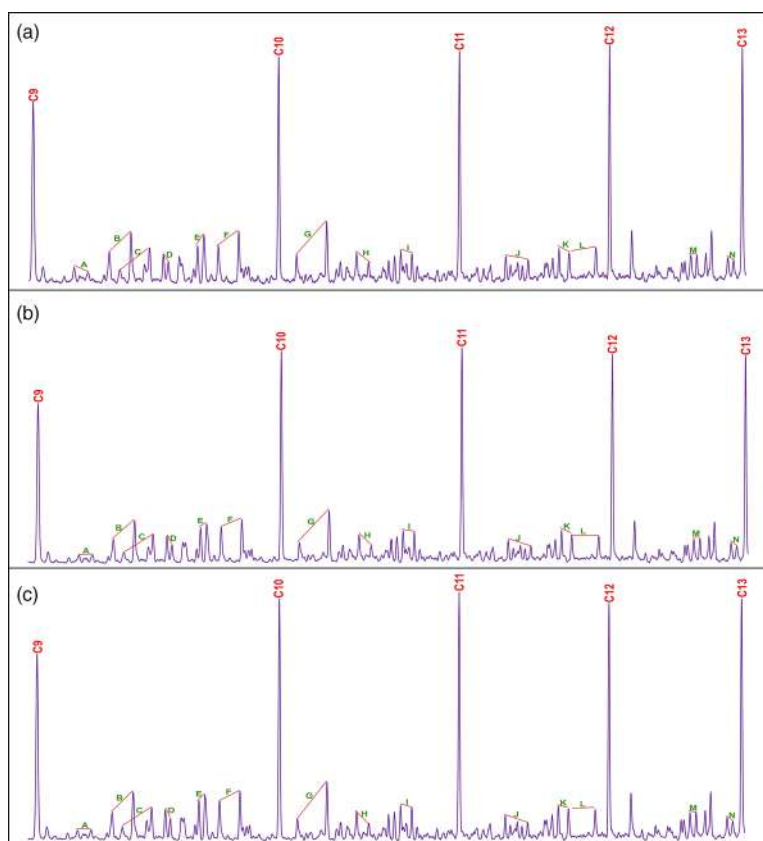


Fig. 6—Representation as chromatograms of different peak ratios used to obtain the oil fingerprint in the $n\text{-C}_9$ to $n\text{-C}_{13}$ region: (a) UAS-1 sample, (b) LAS-1 sample, and (c) B-1 sample.

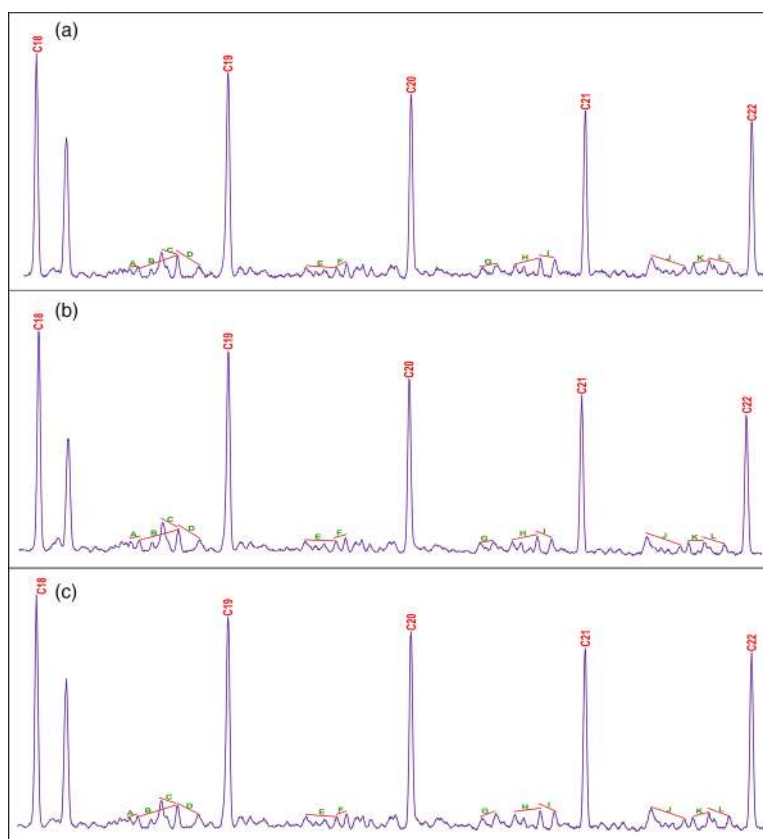


Fig. 7—Representation as chromatograms of different peak ratios used to obtain the oil fingerprint in the $n\text{-C}_{18}$ to $n\text{-C}_{22}$ region: (a) UAS-1 sample, (b) LAS-1 sample, and (c) B-1 sample.

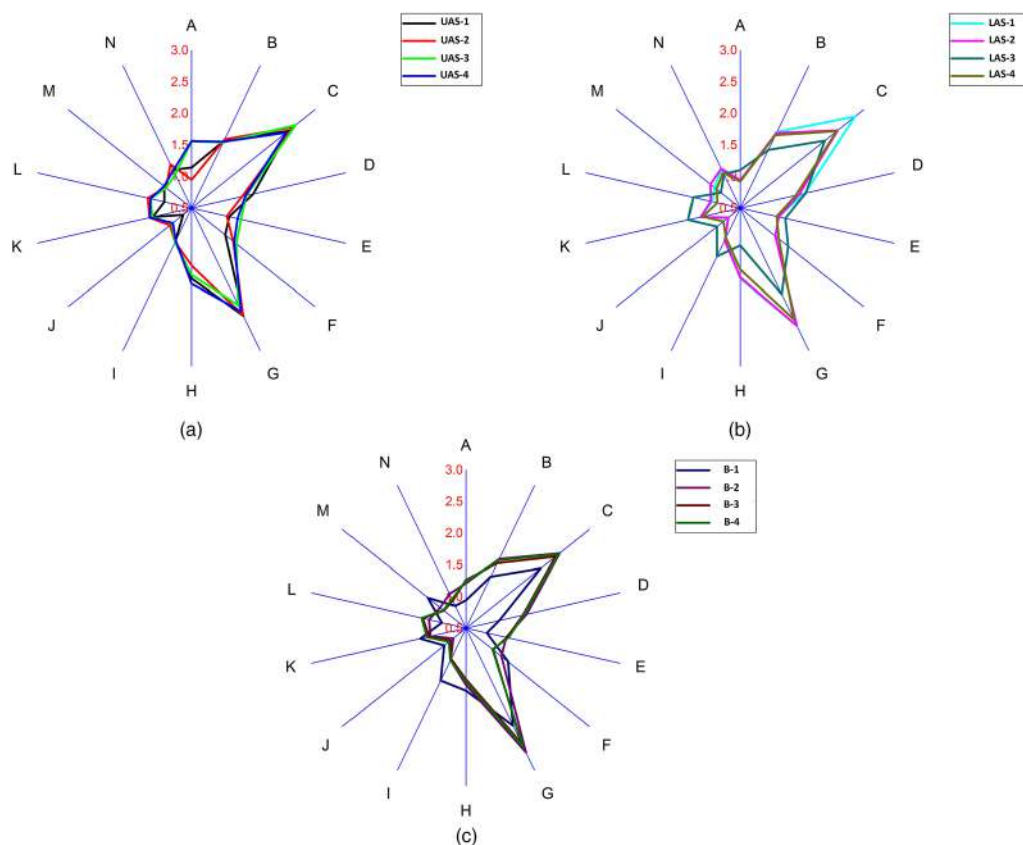


Fig. 8—Star diagram using the defined ratios from WOGC chromatograms in the $n\text{-C}_9$ to $n\text{-C}_{13}$ region: (a) Upper Asmari Reservoir, (b) Lower Asmari Reservoir, and (c) Bangestan Reservoir.

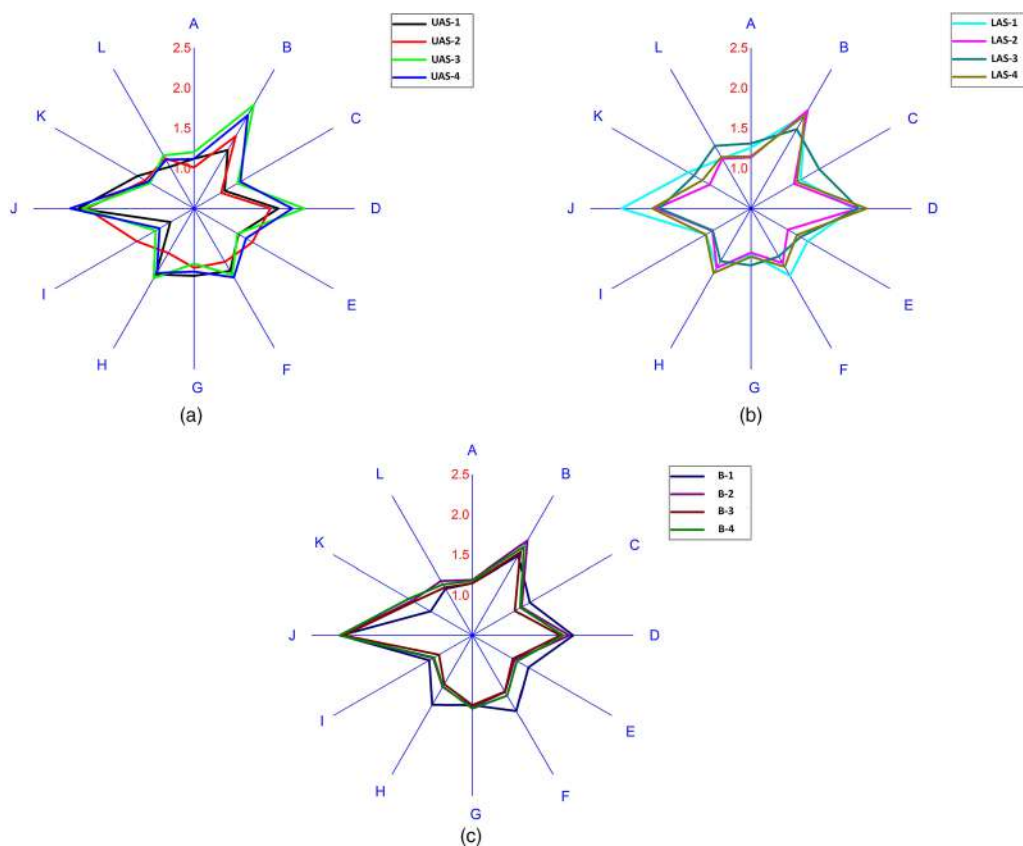


Fig. 9—Star diagram using the defined ratios from WOGC chromatograms in the $n\text{-C}_{18}$ to $n\text{-C}_{22}$ region: (a) Upper Asmari Reservoir, (b) Lower Asmari Reservoir, and (c) Bangestan Reservoir.

The pairwise comparison of fingerprints for different samples using interparaffin peak ratios in the $n\text{-C}_9$ to $n\text{-C}_{13}$ and $n\text{-C}_{18}$ to $n\text{-C}_{22}$ regions is illustrated in a similarity matrix (Fig. 10) to reveal the connectivity or disconnectivity between each pair of studied wells in the Shadegan Field.

	UAS-1	UAS-2	UAS-3	UAS-4	LAS-1	LAS-2	LAS-3	LAS-4	B-1	B-2	B-3	B-4
UAS-1	YES	NO	NO	NO	NO	YES	NO	YES	NO	NO	NO	NO
UAS-2	NO	YES	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
UAS-3	NO	NO	YES	YES	NO	NO	NO	NO	YES	NO	NO	NO
UAS-4	NO	NO	YES	YES	NO	NO	NO	NO	YES	NO	NO	NO
LAS-1	NO	NO	NO	NO	YES	NO	NO	NO	NO	NO	NO	NO
LAS-2	YES	NO	NO	NO	NO	YES	NO	YES	NO	NO	NO	NO
LAS-3	NO	NO	NO	NO	NO	NO	YES	NO	NO	NO	NO	NO
LAS-4	YES	NO	NO	NO	NO	YES	NO	YES	NO	NO	NO	NO
B-1	NO	NO	YES	YES	NO	NO	NO	NO	YES	NO	NO	NO
B-2	NO	NO	NO	NO	NO	NO	NO	NO	NO	YES	YES	YES
B-3	NO	NO	NO	NO	NO	NO	NO	NO	NO	YES	YES	YES
B-4	NO	NO	NO	NO	NO	NO	NO	NO	NO	YES	YES	YES

YES Connectivity between wells NO Disconnectivity between wells

Fig. 10—Fingerprint-similarity matrix using the interparaffin peak ratios for studied samples from the Upper Asmari, Lower Asmari, and Bangestan reservoirs in the Shadegan Field to disclose reservoir connectivity or disconnectivity.

Light Hydrocarbons. Halpern (1995) defined several indices according to the different isomers of the C_7 hydrocarbon to provide valuable information regarding subtle differences between samples. He developed two star diagrams from the defined indices, with the first being the C_7 CSD. Five ratios of the C_7 CSD plot (i.e., C_1 through C_5) are not affected by secondary processes and are useful for the correlation of samples. The second diagram is called the C_7 oil transformation star diagram (C_7 OTSD). The C_7 OTSD plot is helpful in measuring the effects of secondary processes such as water washing, biodegradation, evaporation, or thermochemical sulfate reduction (TSR). This plot consists of eight ratios in which water washing is measured from the TR1 due to toluene in the numerator. The TR6 ratio assesses the evaporation, and biodegradation can be measured from other ratios (Halpern 1995). Fig. 11 shows the C_7 CSD plot for studied samples from different reservoir units. The UAS-3 and UAS-4 samples from the Upper Asmari show similar trends and values (Fig. 11a). This pattern suggested that they have identical fingerprints and are connected. These samples have different fingerprints from the UAS-1 and UAS-2 samples (Fig. 11a). Different trends appear in the C_7 CSD plot for the LAS-1 and other samples (i.e., LAS-2, LAS-3, and LAS-4) in the Lower Asmari, and signify that these samples have different fingerprints and are disconnected. The LAS-3 sample is completely different from the others, and the LAS-2 and LAS-4 samples have similar fingerprints (Fig. 11b). The Bangestan samples (i.e., B-2, B-3, and B-4) illustrate similar values, and they are connected. These wells are disconnected from the B-1 well (Fig. 11c). The C_7 OTSD plot was investigated to measure the effect of different secondary alterations on the studied samples. The UAS-2, UAS-3, and UAS-4 samples show completely similar values, and they have not been subjected to secondary processes (Fig. 12a). The UAS-1 sample is different in the TR1 and TR2, which implies the small effect of the secondary process. Some differences are also apparent in the Lower Asmari samples. The differences are in the TR1 through TR5, which is the sign of secondary effects. Increasing the severity of these phenomena causes a decrease in each of the TR indices. The pattern of Fig. 12b implies that the LAS-1 sample suffers from water washing or biodegradation effects. These processes are subtle because the effect of biodegradation is barely perceptible on the GC chromatogram of the LAS-1 sample (Fig. 5), or this sample has experienced water washing without biodegradation (Palmer 1984). The B-1 and B-2 samples have the same value and are different from B-3 and B-4 (Fig. 12c). The degree of the secondary processes for the B-1 and B-2 samples is more than that for B-3 and B-4. The possible reason for these differences is the effect of TSR, which can alter the hydrocarbon distribution and fingerprint. The TSR phenomenon causes depletion of normal alkanes and enrichment of aromatics (Peters et al. 2007). The Bangestan Reservoir has favorable conditions for the TSR phenomenon. The PVT-analysis results showed that this reservoir generally contains hydrogen sulfide lower than 5 mol%, and its amount differs in various wells. Although increasing the severity of TSR causes an increase in the C_1 and C_3 indices in the C_7 CSD, it decreases other indices. Hence, the pattern and differences in the C_7 OTSD and C_7 CSD plots for the Bangestan samples confirm that these samples are affected by TSR. But these differences are not severe and are not observed in other plots.

The pairwise comparison of studied samples by the C_7 CSD plot is summarized in a similarity matrix (Fig. 13). This matrix helps to investigate oil-fingerprint similarity between different samples and obtain information regarding reservoir connectivity or disconnectivity.

FTIR Analysis of Asphaltenes. The structure of asphaltenes is directly related to the source of reservoir oil. The investigation of the structural characteristics of these compounds provides a crucial parameter in the study of oil-fingerprint similarities or dissimilarities. Once the composition of asphaltene in the lateral or vertical scale is homogeneous, that field has lateral connectivity (Mullins et al. 2013; Pomerantz et al. 2013; Wu et al. 2014). Thus, the investigation of asphaltene composition and structure permits reservoir continuity or compartmentalization assessment (Asemani et al. 2020; Asemani and Rabbani 2020a).

The FTIR spectra of asphaltene samples for three reservoir units (i.e., Upper Asmari, Lower Asmari, and Bangestan) in the Shadegan Field was depicted in Fig. 4. Herein, in one sample from each reservoir unit (i.e., UAS-1, LAS-3, and B-3) asphaltene was extracted, and then FTIR analyzed six times separately. The threshold was calculated for each reservoir unit with Eq. 2, and the final threshold in the whole of the oil field is equal to the maximum of three thresholds. Table 2 shows the calculated relative standard deviations for the UAS-1, LAS-3, and B-3 samples. The maximum threshold for the UAS-1, LAS-3, and B-3 samples is 23.01, 22.46, and 22.79, respectively. Therefore, the defined threshold in the whole of this field is considered as 23.01. As the number of peak ratios higher than the threshold increases (for example, NO-7 for UAS-4 and LAS-2), the heterogeneity between two samples increases and implies higher discontinuity. The minimum, maximum, and average values of relative differences in defined peak ratios for each pair of studied samples are summarized in Fig. 14.

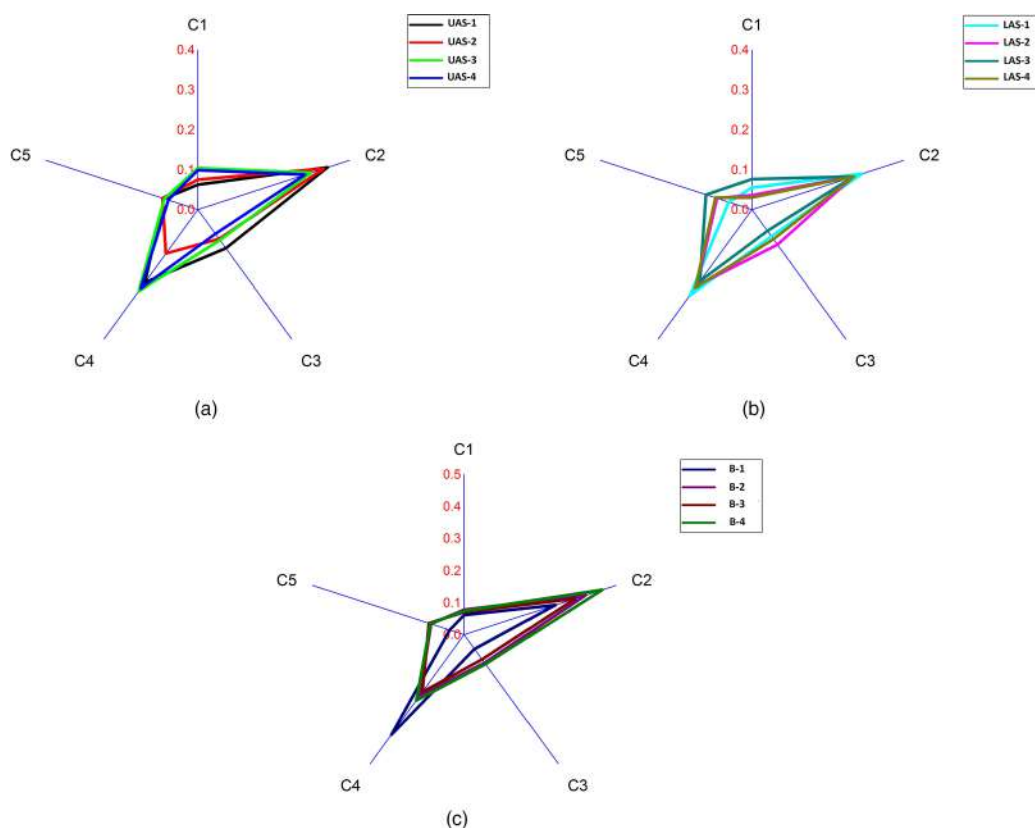


Fig. 11—C₇CSD: (a) Upper Asmari Reservoir, (b) Lower Asmari Reservoir, and (c) Bangestan Reservoir. C1 = 2,2-dimethylpentane/P3; C2 = 2,3-dimethylpentane/P3; C3 = 2,4-dimethylpentane/P3; C4 = 3,3-dimethylpentane/P3; C5 = 3-ethylpentane/P3; P3 = 2,2-dimethylpentane + 2,3-dimethylpentane + 2,4-dimethylpentane + 3,3-dimethylpentane + 3-ethylpentane.

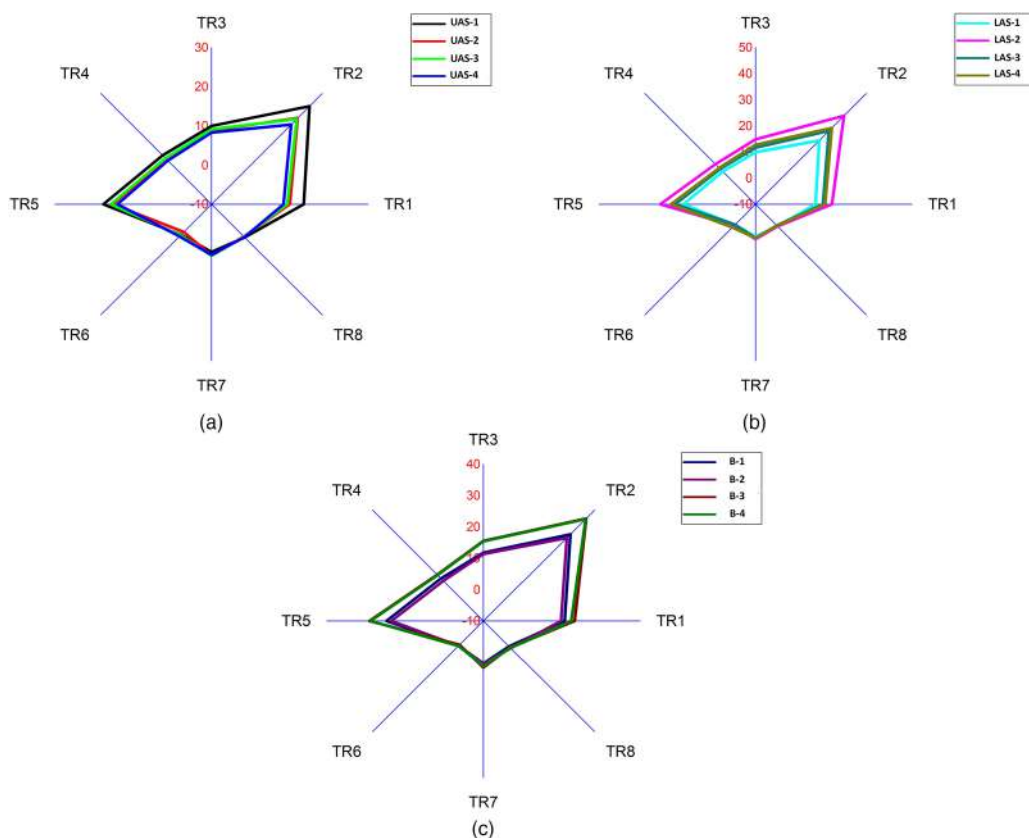


Fig. 12—C₇OTSD: (a) Upper Asmari Reservoir, (b) Lower Asmari Reservoir, and (c) Bangestan Reservoir. TR1 = toluene/X; TR2 = *n*-C₇/X; TR3 = 3-methylhexane/X; TR4 = 2-methylhexane/X; TR5 = P2/X; TR6 = 1-cis-2-dimethylcyclopentane/X; TR7 = 1-trans-3-dimethylcyclopentane/X; TR8 = P2/P3; X = 1,1-dimethylcyclopentane; P2 = 2-methylhexane + 3-methylhexane; P3 = 2,2-dimethylpentane + 2,3-dimethylpentane + 2,4-dimethylpentane + 3,3-dimethylpentane + 3-ethylpentane.

	UAS-1	UAS-2	UAS-3	UAS-4	LAS-1	LAS-2	LAS-3	LAS-4	B-1	B-2	B-3	B-4
UAS-1	YES	NO	NO	NO	NO	YES	NO	YES	NO	YES	YES	YES
UAS-2	NO	YES	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
UAS-3	NO	NO	YES	YES	NO	NO	NO	NO	NO	NO	NO	NO
UAS-4	NO	NO	YES	YES	NO	NO	NO	NO	NO	NO	NO	NO
LAS-1	NO	NO	NO	NO	YES	NO	NO	NO	NO	YES	NO	NO
LAS-2	YES	NO	NO	NO	NO	YES	NO	YES	NO	NO	NO	NO
LAS-3	NO	NO	NO	NO	NO	NO	YES	NO	NO	NO	YES	NO
LAS-4	YES	NO	NO	NO	NO	YES	NO	YES	NO	NO	NO	NO
B-1	NO	NO	NO	NO	NO	NO	NO	NO	YES	NO	NO	NO
B-2	YES	NO	NO	NO	YES	NO	NO	NO	NO	YES	YES	YES
B-3	YES	NO	NO	NO	NO	NO	YES	NO	NO	YES	YES	YES
B-4	YES	NO	NO	NO	NO	NO	NO	NO	NO	YES	YES	YES

YES Connectivity between wells **NO** Disconnectivity between wells

Fig. 13—Fingerprint-similarity matrix derived from the C₇CSD plot for studied samples from the Upper Asmari, Lower Asmari, and Bangestan reservoirs in the Shadegan Field to disclose reservoir connectivity or disconnectivity.

Samples Peak Ratios	UAS-1		LAS-3		B-3	
	RSD (for 6 Replicates)	Threshold	RSD (for 6 Replicates)	Threshold	RSD (for 6 Replicates)	Threshold
809/744	1.44	4.04	2.35	6.58	0.82	2.29
862/744	1.34	3.76	2.89	8.10	1.65	4.62
966/744	8.22	23.01	8.02	22.46	5.01	14.03
1,031/1,377	2.03	5.70	2.10	5.87	0.70	1.96
1,076/1,377	0.79	2.22	0.95	2.67	0.85	2.38
1,124/1,377	1.78	4.98	1.16	3.25	0.95	2.66
1,282/1,377	2.07	5.80	1.82	5.10	1.55	4.35
1,456/1,377	4.91	13.76	2.91	8.14	2.51	7.03
1,598/1,377	1.84	5.14	1.74	4.87	8.14	22.79
1,726/1,377	1.48	4.14	2.90	8.13	1.40	3.93
2,921/2,852	1.89	5.28	3.33	9.31	2.57	7.18
2,952/2,852	0.85	2.37	1.45	4.07	2.42	6.78
3,048/2,852	0.32	0.90	1.55	4.34	5.80	16.24
Maximum	8.22	23.01	8.02	22.46	8.14	22.79

Table 2—Replicate results of the UAS-1, LAS-3, and B-3 samples for determining the threshold in the Shadegan Oil Field.

Fig. 14 provides a general view of connectivity between wells in the Shadegan Field. At first glance, some heterogeneities are evident in the Asmari and Bangestan reservoirs. The UAS-1 sample has a different oil fingerprint from other samples in the Upper Asmari. The LAS-2 and LAS-4 samples in the Lower Asmari have a similar fingerprint, and these are different from LAS-3 and LAS-1. The B-1 sample has limited similarity with other wells in the Bangestan Reservoir. Some wells show limited connectivity, such as UAS-1/LAS-1, UAS-3/B-2, UAS-3/B-4, UAS-4/B-3, UAS-4/B-4, LAS-3/B-2, LAS-3/B-3, LAS-3/B-4, B-1/B-2, B-1/B-3, and B-1/B-4.

Compartmentalization Model for the Asmari and Bangestan Reservoirs in the Shadegan Oil Field. Different techniques using nonpolar and polar components of crude oil were used to assess reservoir continuity or discontinuity in different reservoir units (i.e., Upper Asmari, Lower Asmari, and Bangestan) in the Shadegan Oil Field. Peak ratios calculated from interparaffin peaks in the WOGC chromatograms in the *n*-C₉ to *n*-C₁₃ and *n*-C₁₈ to *n*-C₂₂ regions, as well as the C₇CSD plot, were used to obtain oil fingerprints from nonpolar components of crude oil. The FTIR analysis of asphaltene was used to obtain information about oil fingerprints from the polar components of crude oil. The integration of these different data sets helps to acquire the compartmentalization model in the Shadegan Oil Field. Thus, a matrix was used to integrate various data sets and obtain the compartmentalization model for this field. In this manner, the connectivity or disconnectivity between two studied wells is determined by integrating different applied methods. Disconnectivity or connectivity is shown by colors similar to traffic lights, in which green and red colors imply connectivity and disconnectivity between studied wells, respectively. Also, the yellow color represents limited connectivity between wells, and we suggest checking the connectivity with other methods further. If all techniques suggest disconnectivity, then the matrix will have a red cell for studied wells. If all techniques propose connectivity between studied wells, the matrix cell will be green. When various methods recommend different conclusions about the disconnectivity or connectivity between studied wells, the final decision about the occurrence or absence of continuity is determined using the worst-case scenarios from individual methods (Milkov et al. 2007).

	UAS-1	UAS-2	UAS-3	UAS-4	LAS-1	LAS-2	LAS-3	LAS-4	B-1	B-2	B-3	B-4
UAS-1	YES	NO-4 0.85* 72.86** 17.71****	NO-5 0.42 103.87 25.30	NO-7 1.72 113.86 28.14	NO-1 1.53 38.07 11.10	YES 0.32 19.82 6.86	NO-3 1.08 60.60 17.06	YES 0.65 18.24 4.75	NO-6 0.75 10.91 26.23	NO-6 0.33 116.70 26.67	NO-6 1.92 120.80 26.60	NO-6 1.04 104.99 26.74
UAS-2	NO-4 0.85 72.86 17.71	YES	NO-2 0.23 38.25 8.94	NO-2 0.60 71.59 11.33	NO-2 0.66 41.54 11.75	NO-2 0.03 62.97 15.07	NO-2 0.50 65.37 9.80	NO-7 0.48 82.61 20.72	NO-3 1.51 80.22 17.25	NO-4 1.09 88.45 20.14	NO-3 0.38 93.47 19.91	NO-3 1.26 74.35 19.94
UAS-3	NO-5 0.42 103.87 25.30	NO-2 0.23 38.25 8.94	YES	YES 0.49 14.18 4.55	NO-3 1.46 73.02 20.22	NO-6 5.66 95.47 23.53	NO-3 1.52 70.90 18.24	NO-7 1.65 112.01 28.45	NO-2 0.30 82.03 15.48	NO-1 0.11 71.18 11.95	NO-2 2.05 67.36 12.37	NO-1 1.48 76.97 10.39
UAS-4	NO-7 1.72 113.86 28.14	NO-2 0.60 71.59 11.33	YES 0.49 14.18 4.55	YES	NO-3 0.83 84.99 22.56	NO-7 1.00 106.06 25.39	NO-4 0.33 73.26 20.73	NO-8 0.56 121.37 30.77	NO-2 0.88 81.62 16.46	NO-2 0.97 70.75 12.83	NO-1 0.81 66.92 12.83	NO-1 0.62 76.56 12.83
LAS-1	NO-1 1.53 38.07 11.10	NO-2 0.66 41.54 11.75	NO-3 1.46 73.02 20.22	NO-3 0.83 84.99 22.56	YES	NO-2 2.18 29.90 10.07	NO-2 1.22 50.68 10.65	NO-2 0.17 49.02 13.23	NO-3 1.51 80.22 17.25	NO-4 1.09 88.45 20.14	NO-3 0.38 93.47 19.91	NO-3 1.26 74.35 19.94
LAS-2	YES 0.32 19.82 6.86	NO-2 0.03 62.97 15.07	NO-6 5.66 95.47 23.53	NO-7 1.00 106.06 25.39	NO-2 2.18 29.90 10.07	YES	NO-3 2.17 109.09 22.37	YES 0.14 22.57 7.18	NO-4 1.64 101.86 23.70	NO-3 2.17 109.09 22.37	NO-3 0.75 113.46 21.85	NO-3 1.26 96.66 22.14
LAS-3	NO-3 1.08 60.60 17.06	NO-2 0.50 65.37 9.80	NO-3 1.52 70.90 18.24	NO-4 0.33 73.26 20.73	NO-2 1.22 50.68 10.65	NO-3 2.17 109.09 22.37	YES	NO-3 0.89 61.86 17.62	NO-2 1.82 68.23 14.11	NO-1 0.13 76.92 10.80	NO-1 0.84 82.25 11.39	NO-1 0.04 62.06 10.39
LAS-4	YES 0.65 18.24 4.75	NO-7 0.48 82.61 20.72	NO-7 1.65 112.01 28.45	NO-8 0.56 121.37 30.77	NO-2 0.17 49.02 13.23	YES 0.14 22.57 7.18	NO-3 0.89 61.86 17.62	YES	NO-6 2.87 1117.68 27.37	NO-3 0.94 124.02 27.02	NO-5 0.21 127.85 26.65	NO-5 0.63 113.06 27.02
B-1	NO-6 0.75 10.91 26.23	NO-3 1.51 80.22 17.25	NO-2 0.30 82.03 15.48	NO-2 0.88 81.62 16.46	NO-3 1.51 80.22 17.25	NO-4 1.64 101.86 23.70	NO-2 1.82 68.23 14.11	NO-6 2.87 1117.68 27.37	YES	NO-1 0.42 37.78 7.88	NO-1 1.11 46.14 10.20	NO-1 0.13 44.76 8.24
B-2	NO-6 0.33 116.70 26.67	NO-4 1.09 88.45 20.14	NO-1 0.11 71.18 11.95	NO-2 0.97 70.75 12.83	NO-4 1.09 88.45 20.14	NO-3 2.17 109.09 22.37	NO-1 0.13 76.92 10.80	NO-3 0.94 124.02 27.02	NO-1 0.42 37.78 7.88	YES	YES 0.51 9.61 3.18	YES 0.30 16.88 3.63
B-3	NO-6 1.92 120.80 26.60	NO-3 0.38 93.47 19.91	NO-2 2.05 67.36 12.37	NO-1 0.81 66.92 12.83	NO-3 0.38 93.47 19.91	NO-3 0.75 113.46 21.85	NO-1 0.84 82.25 11.39	NO-5 0.21 127.85 26.65	NO-1 1.11 46.14 10.20	YES 0.51 9.61 3.18	YES 0.02 22.85 3.84	YES 0.02 22.85 3.84
B-4	NO-6 1.04 104.99 26.74	NO-3 1.26 74.35 19.94	NO-1 1.48 76.97 10.39	NO-1 0.62 76.56 12.83	NO-3 1.26 74.35 19.94	NO-3 1.26 96.66 22.14	NO-1 0.04 62.06 10.39	NO-5 0.63 113.06 27.02	NO-1 0.13 44.76 8.24	YES 0.30 16.88 3.63	YES 0.02 22.85 3.84	YES

YES Connectivity between wells **NO-1** Limited connectivity between wells **NO** Disconnectivity between wells

* Minimum relative difference in defined peak ratios for two specific samples
 ** Maximum relative difference in defined peak ratios for two specific samples
 **** Average relative difference in defined peak ratios for two specific samples

Fig. 14—Fingerprint-similarity matrix derived from the FTIR analysis of asphaltenes for studied samples from the Upper Asmari, Lower Asmari, and Bangestan reservoirs in the Shadegan Field to disclose reservoir connectivity or disconnectivity. A defined threshold in this field is 23.01.

Fig. 15 illustrates the compartmentalization model for the Shadegan Oil Field. The UAS-1 and UAS-2 samples are completely disconnected from each other, and other wells in the Upper Asmari and the UAS-1 well have connectivity with the LAS-2 and LAS-4 wells in the Lower Asmari reservoir. This matrix shows that the UAS-1 well will communicate with the LAS-2 and LAS-4 wells during production. UAS-3 and UAS-4 have a completely similar fingerprint, and these wells are connected. The LAS-1 sample is completely separated from other wells in the Lower Asmari, but the LAS-2 and LAS-4 are entirely similar and display similar fingerprints. LAS-3 is disconnected from the Upper Asmari and Bangestan reservoirs. B-1 displays disconnectivity with other wells in the Bangestan Reservoir, and other wells (i.e., B-2, B-3, and B-4) are entirely connected.

The representation of the obtained results from the compartmentalization model in the Shadegan Field is shown schematically in Fig. 16. According to the obtained results, the Upper Asmari Reservoir comprises three different zones: Zones UAS-I, UAS-II, and UAS-III. Like the Upper Asmari, the Lower Asmari included three distinct zones: Zones LAS-I, LAS-II, and LAS-III. Zone UAS-I consists of the UAS-3 and UAS-4 samples. Zones UAS-II and UAS-III include the UAS-2 and UAS-1 samples, respectively (Fig. 16a). The LAS-2 and LAS-4 are located in Zone LAS-II, and these samples are connected with UAS-1 in the Upper Asmari. These samples have similar compositions and signify lateral connectivity and vertical relation between the Upper Asmari and Lower Asmari in this part of the reservoir. No samples from the Bangestan Reservoir were collected in this zone to assess the vertical relationship between the Bangestan and Asmari reservoirs. The LAS-3 and LAS-1 are disconnected from each other and other wells in the Lower Asmari and are situated in Zones LAS-I and LAS-III, respectively (Fig. 16b). These samples are utterly different from the Upper Asmari and Bangestan samples and show no vertical relation. In the Bangestan Reservoir, Zones B-I and B-II occur because of oil-fingerprint homogeneity and heterogeneities. Zone B-I comprises the B-2, B-4, and B-3 samples and Zone B-II includes the B-1 sample,

disconnected from other samples of the Bangestan Reservoir (Fig. 16c). The defined compartmentalized regions provide a preliminary view of reservoir discontinuity in the Shadegan Field. The geochemical results will be complemented by investigating reservoir-engineering data (i.e., pressure and PVT data) in the next section.

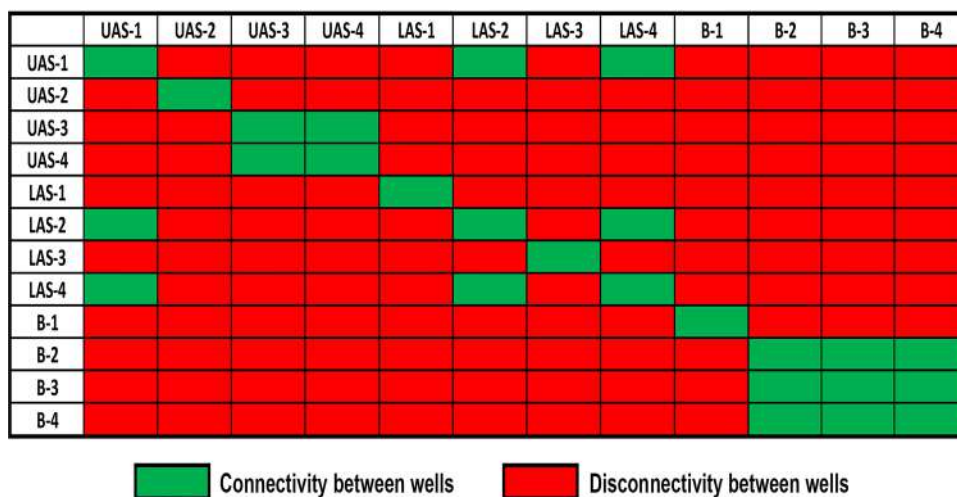


Fig. 15—The compartmentalization model for 12 studied wells from the Upper Asmari, Lower Asmari, and Bangestan reservoirs in the Shadegan Oil Field using integrating of different techniques.

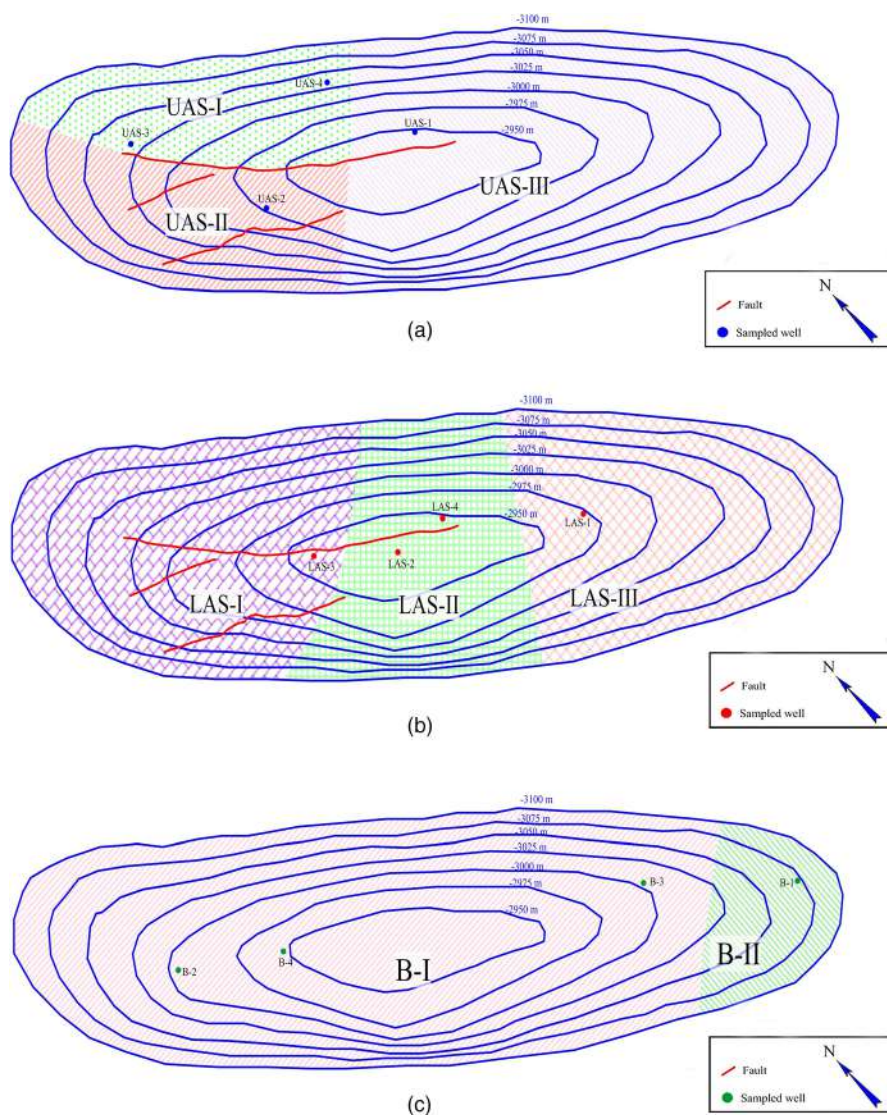


Fig. 16—Schematic of different compartmentalized zones: (a) Upper Asmari Reservoir, (b) Lower Asmari Reservoir, and (c) Bangestan Reservoir, using the suggested compartmentalization model for the Shadegan Field.

The occurrence of different faults around the UAS-2 well is the probable reason for reservoir compartmentalization in this part of the field. The other compartmentalized zones are independent of faults. The studied reservoirs (i.e., Asmari and Bangestan) are naturally fractured reservoirs, in which uneven compressional stress fields led to various network fractures in different parts. If the network fractures were not similar in different parts, the communication between different parts is restricted (Paredes et al. 2015). The unequal compressional stress field in different parts of the Shadegan Field is the most probable reason for reservoir compartmentalization in the Asmari and Bangestan Reservoirs.

Reservoir-Engineering Evidence. Geochemical data show that several compartmentalized regions have occurred in different reservoirs of the Shadegan Field. Reservoir-engineering data were also implemented to investigate the presence of reservoir compartmentalization. The repeat-formation-tester results were plotted vs. true vertical depth for each reservoir. Fig. 17a depicts three different pressure gradients, and these patterns are a sign of differences in fluid composition in different parts of the reservoir. UAS-3 and UAS-4 wells have a similar pressure gradient, implying that they are in pressure communication. UAS-1 and UAS-2 are not in pressure communication, and these wells have a different gradient from UAS-3 and UAS-4. The pattern of pressure data indicates three distinct reservoir zones that have not communicated with each other. The bubblepoint-pressure measurement obtained from constant-mass-expansion analysis at 135°F is 2,174 and 3,127 psi for UAS-1 and UAS-2, respectively. Also, the °API value of residual oil (27.22 and 33.18 for UAS-1 and UAS-2, respectively) and solution gas/oil ratio (511.96 and 914.05 scf/STB for UAS-1 and UAS-2, respectively) show large differences and are another indication of reservoir compartmentalization in the Upper Asmari. Fig. 17b reveals three different pressure gradients in the Lower Asmari Reservoir and confirms reservoir compartmentalization in this reservoir. The PVT measurements were not available from the Lower Asmari Reservoir. The Bangestan Reservoir indicates two distinct pressure gradients. Wells B-2, B-3, and B-4 have the same pressure gradient, and these wells have a different gradient from the B-1 well (Fig. 17c). The reservoir pressure in the region containing the B-1 well is lower than that in the region comprising the B-2, B-3, and B-4 wells. Two reservoir-compartmentalized regions are evident in the Bangestan Reservoir. The bubblepoint pressure, solution gas/oil ratio, and °API value of residual oil at 110°F for the B-1 well are 886 psi, 315.373 scf/STB, and 27.34, respectively. These values for the B-3 well are 482 psi, 150.19 scf/STB, and 22.12, respectively. Thereby, PVT measurements indicate discontinuity between the B-1 and B-3 wells in the Bangestan Reservoir.

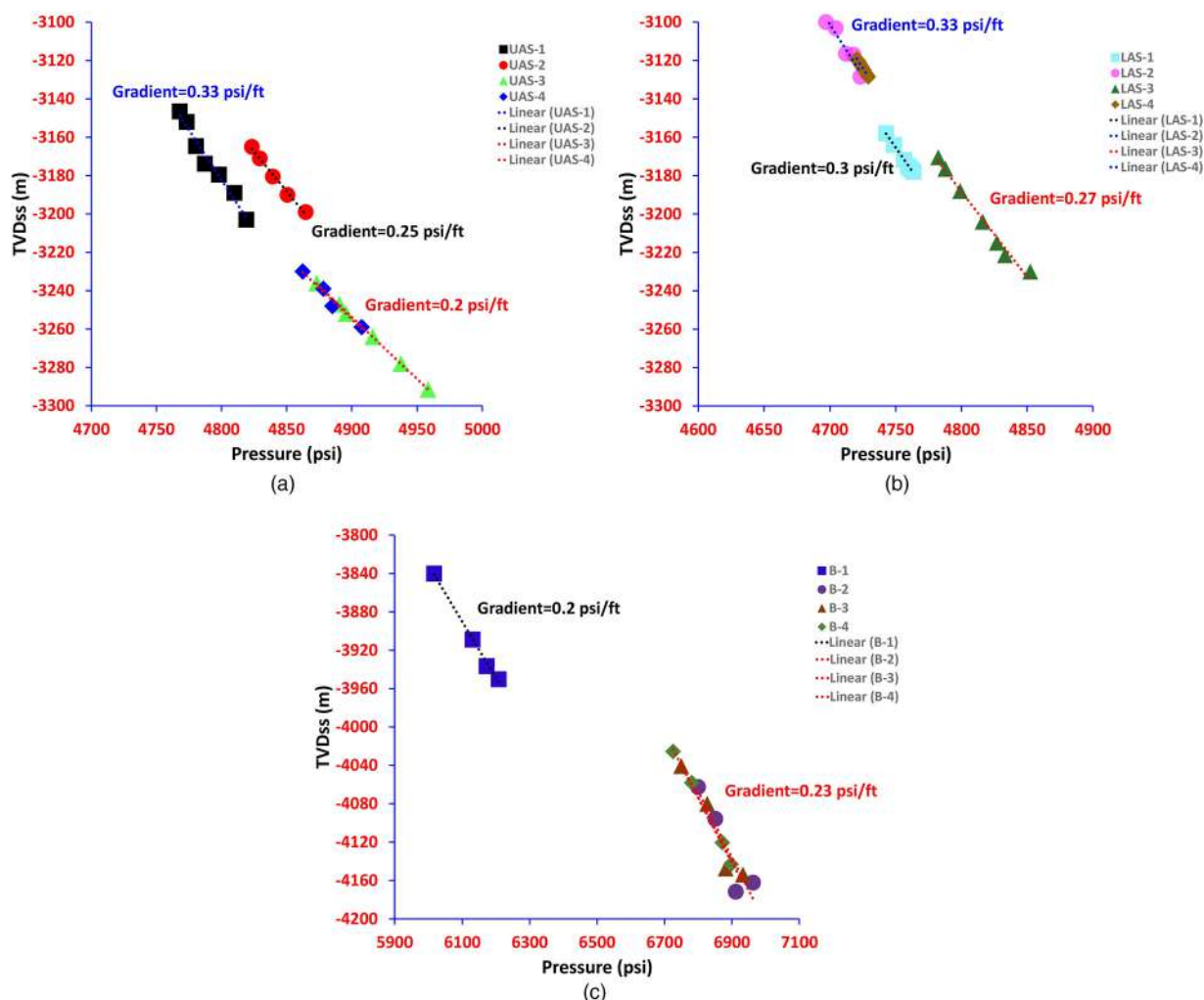


Fig. 17—Plot of true vertical depth vs. pressure for studied wells: (a) Upper Asmari Reservoir, (b) Lower Asmari Reservoir, and (c) Bangestan Reservoir. TVDss = true vertical depth subsea.

Pressure and PVT results were considered along with the geochemical data and corroborated previous results about reservoir compartmentalization in the Upper Asmari, Lower Asmari, and Bangestan reservoirs of the Shadegan Field.

Conclusions

This paper investigated reservoir continuity using an integrated geochemical approach in the Shadegan Oil Field in southwest Iran. The methodology included obtaining oil fingerprints from nonpolar (i.e., saturates and aromatics) and polar (i.e., asphaltenes) components of the oil. Finally, the obtained results were checked by reservoir-engineering data (i.e., repeat-formation-tester and PVT results).

The main conclusions of this paper include the following:

1. The interparaffin peak ratios in the n -C₉ to n -C₁₃ and n -C₁₈ to n -C₂₂ regions revealed that the Asmari and Bangestan reservoirs in the Shadegan comprise several compartmentalized regions.
2. The investigation of C₇ hydrocarbons by the (Halpern 1995) star diagrams provides valuable information about the similarity or dissimilarity of samples (the C₇CSD plot) and also secondary processes that have affected samples (the C₇OTSD plot). The C₇OTSD showed that the Upper Asmari samples had not been affected by secondary processes, but the Lower Asmari and Bangestan samples reveal some alterations by secondary processes in this field. These alterations are not severe and are not evident in other plots.
3. The FTIR spectra of asphaltenes were used to obtain oil fingerprints. The proposed methodology for obtaining oil fingerprints from asphaltenes permits the relative discontinuity measurement between two studied wells. In this methodology, the relative difference in the defined peak ratios for two specific samples is compared with the defined threshold. However, all relative differences lower than the threshold show similarity in fingerprint and connectivity. The number of relative differences higher than the threshold represents a relative measurement of the discontinuity between two studied wells. The oil fingerprinting by FTIR analysis of asphaltenes revealed several compartmentalized regions in the Asmari and Bangestan reservoirs of the Shadegan Field.
4. The integration of various techniques was used to propose a compartmentalization model for the Shadegan Field. According to this model, the Shadegan Oil Field contains three different zones in the Upper and Lower Asmari reservoirs and two distinct zones in the Bangestan Reservoir.
5. The discontinuity between Regions UAS-I and UAS-II is likely because of faults, and other compartmentalization regions are independent of faults.
6. The pattern of pressure data completely shows reservoir compartmentalization in three reservoirs of the Shadegan Field. Each compartmentalized region indicates different PVT values. The pressure and PVT data completely confirmed the obtained results of the geochemical approach.

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