

An Efficient and Straightforward Procedure for Rapid Investigation of Reservoir Compartmentalization by Fourier Transform Infrared Spectroscopy of Asphaltenes

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Summary

Reservoir compartmentalization is an essential phenomenon in the different life cycles of oilfield production. This concept is crucial for the economic assessment of field development plans because it influences future decisions and designs. Hence, early and fast identification of reservoir compartmentalization is highly appreciated in the oil industry. The routine techniques based on the light-end fraction of crude oil [e.g., gas chromatography (GC) fingerprinting] are relatively time-consuming, high-cost, and sometimes affected by secondary processes. The suggestion of an efficient, straightforward, and rapid technique for obtaining the reservoir architecture, especially in giant and supergiant fields, is an acceptable attempt in the oil industry. Although the concentration of asphaltenes shows a gradient in the reservoir, the chemical composition of these compounds is constant in connected and equilibrated reservoirs. Hence, investigation of the chemical composition of asphaltenes with a precise method for revealing subtle differences comprises the underlying of every efficient method in reservoir continuity assessment. Here, the application of the relative root-mean-square deviation (RMSD) technique on the Fourier transform infrared (FTIR) data was used to compare the structural characteristics of asphaltenes in two case studies (i.e., Ahwaz and Shadegan oil fields) from the Dezful Embayment, southwest Iran. The 12 highest difference characteristic peak ratios were determined in the studied sample suit from the calculated variations in 5 replicates of a sample. The comparison between samples was performed based on these peak ratios, and the RMSD method was used to compare the studied samples. The samples with RMSD values higher than the defined threshold were considered samples with different fingerprints, and these wells will not be communicated during production. Results showed that the Ahwaz and Shadegan fields were subjected to reservoir compartmentalization in the Bangestan reservoir. At least three compartmentalized regions have occurred in the Bangestan reservoir of the Ahwaz field, and two distinct zones are observed in this reservoir from the Shadegan field. The pressure/volume/temperature (PVT) data (i.e., fluid property and composition) and repeat formation tester (RFT) measurements confirmed that these proposed regions in the Ahwaz field are distinct and will not be communicated during production. The FTIR results in the Shadegan field were completely corroborated by PVT and RFT results and indicated two distinct zones with no flow communication during production in the Bangestan reservoir. The obtained results showed that the suggested procedure is robust, trustworthy, simple, rapid, and cost-effective for investigating reservoir compartmentalization.

Introduction

The segmentation of the reservoir into different divisions with distinct flow unit behavior during production is named reservoir compartmentalization (Smalley et al. 1994; Jolley et al. 2010). This phenomenon occurs laterally or vertically, depending on the placement of flow barriers in the reservoir. Although sealing faults and changing reservoir quality are the main reasons for lateral compartmentalization, vertical compartmentalization occurs as an impact of vertical barriers between reservoir layers such as shales, low-permeability layers, or tar mats (Smalley et al. 1994). Chen (2013) mentioned that, however, faulting and lateral stratigraphic changes are the main causes of lateral discontinuity, other phenomena such as facies variation, depositional control (e.g., downlapping and backstepping process in the deepwater turbidite deposition), diagenesis impacts (e.g., generation of zeolite following reaction of volcanic ash materials with alkaline groundwater, cementation in certain direction, and variation of compressional stress in different locations), geochemistry variations (e.g., asphaltene deposition), and nonturbidite events (e.g., deposition of debrites, slumps and slurry flows, or mass-transport complexes development) can also lead to reservoir compartmentalization. Furthermore, there are two types of barriers in reservoir compartmentalization based on the impermeability of barriers in geological times. If compartmentalized regions have imperceptible crossflow through low- or very-low-permeability boundaries during geological time scales, called baffles, the flow barrier between these regions is known in terms of the dynamic seal. The seal term is due to its role as a seal in the production lifetime. But, static seals, generally called barriers, refer to the completely impermeable seals that occlude the hydrocarbon column during geological time scales in each compartmentalized region (Jolley et al. 2010).

Reservoir compartmentalization is one of the most critical issues in making a field commercially effective or uneconomic due to improper designs or decisions. Hence, the vital step in the reservoir management, reserve estimation, development, design of recovery scheme, a decision about the number and location of wells, and design of surface facilities, or in the overall, obtaining architecture of reservoir to properly planning and decision in the future, is the identification of reservoir barriers and compartmentalized regions in the studied reservoir (Dromgoole and Speers 1997; Rahimpour-Bonab 2007; Muggeridge and Smalley 2008; Smalley and Muggeridge 2010).

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Various techniques have been used in the literature to provide information about reservoir compartmentalization (Dembicki 2022). These techniques could be categorized roughly into three classifications: (1) methods based on compositional heterogeneity of samples (e.g., Ahanjan et al. 2017; Monge et al. 2022), (2) methods based on reservoir engineering data (e.g., pressure, PVT, well test, and petrophysics) (e.g., Nabawy et al. 2018), and (3) other methods (e.g., seismic, high-resolution stratigraphy, and natural gas tracer) (e.g., Zecchin and Catuneanu 2015; Kadkhodaie-Ilkhchi et al. 2019). As each method has pros and cons, using an integrated technique can positively synergize different methods. Smalley and Hale (1996) used the integration of different techniques such as maturity parameters, GC fingerprinting, PVT, pressure, well test, and fault seal analysis data to determine fluid barriers in the lateral scale. On the vertical scale, they used maturity parameters, GC fingerprinting, the composition of formation water (e.g., residual salt analysis), and high-resolution stratigraphy to reveal a barrier in terms of the continuous shale layer. Gill et al. (2010) stated that the variation in the formation water in the Nelson field, Central North Sea is related to reservoir barriers. Páez et al. (2010) utilized 3D seismic amplitude vs. offset data to predict fluid compositions and inferred compartmentalized regions. Scott et al. (2010) used 3D seismic data to determine the location of barriers in a reservoir. The geochemical fingerprint of oil also corroborated their results. Ventura et al. (2010) applied comprehensive 2D GC (GC×GC) to reveal slight differences between samples for reservoir continuity. Dong et al. (2012) obtained asphaltenes gradient by the Flory-Huggins-Zuo equation of state and other fluid gradients [such as gas/oil ratio (GOR) and composition] by downhole fluid analysis to assess reservoir compartmentalization. Asemani et al. (2021a) proposed the structural characteristics of asphaltene for obtaining information about compartmentalized regions. They showed this method has comparable results with routine GC fingerprinting and reservoir engineering data (e.g., pressure and PVT data). In addition to the studies mentioned above, numerous studies dedicated to reservoir compartmentalization and different techniques have been implemented (e.g., Milkov et al. 2007; Permanyer et al. 2007; Asemani and Rabbani 2020a; Asemani et al. 2021b; Monge et al. 2022).

In methods based on compositional heterogeneity, the fingerprint of crude oil in different wells from a reservoir is compared, and the heterogeneities or homogeneities are realized (Larter and Aplin 1995). It is an accepted rule that the composition of crude oil is not constant in different parts of the reservoir. Whereas the crude oils at the top of the reservoir have higher enrichment of light-end compounds (e.g., saturates and aromatics), the heavy-end compounds (i.e., resins and asphaltenes) have a higher concentration at the bottom of the reservoir. This fluid compositional gradient is also evident in the connected and equilibrated reservoirs (England et al. 1987; Pomerantz et al. 2013; Asemani and Rabbani 2020a). Different mechanisms contribute to this observed gradient in the crude oil composition: gravity, solubility, and entropy (Zuo et al. 2013). The main question is: How to differentiate the observed heterogeneity in the composition related to reservoir compartmentalization or the natural compositional gradient? Does the occurrence of crude oil compositional gradient allow assessing reservoir connectivity or compartmentalization by using compositional heterogeneities?

Different authors have answered these questions. Pomerantz et al. (2013) investigated the chemical composition of asphaltenes in two stack reservoirs that were completely equilibrated and connected but had a large asphaltene content gradient in the reservoir column. The study of sulfur compounds using K-edge X-ray absorption near-edge structure spectroscopy showed surprising results. Although crude oil has a large asphaltene gradient, the chemical composition of asphaltenes is similar in different parts of a connected and equilibrated reservoir. Wu et al. (2014) observed unlike a large asphaltene concentration gradient in the studied reservoirs, the molecular weight of asphaltenes shows similar values. Asemani et al. (2021a) showed that the chemical composition of each polar (e.g., asphaltenes) and nonpolar (e.g., saturates and aromatics) component of crude oil is similar in a connected reservoir, and they have differences in compartmentalized reservoirs. These studies and many similar studies unanimously imply that although the concentration of different crude oil fractions shows a gradient throughout the reservoir (laterally or vertically), the chemical composition within each fraction of crude oil is constant in equilibrated and connected reservoirs. Hence, comparing the compositional differences is an acceptable attempt to achieve information about barriers in the reservoir. But most of the time, the differences are subtle. Generally, two principal issues must be considered in an efficient and precise reservoir continuity assessment by using compositional heterogeneities or homogeneities. First, a complete picture of the chemical composition of the studied fraction should be obtained. Second, a precise and efficient method should compare the acquired structural characteristics and reveal subtle differences between samples.

The primary goal of this paper is to propose a novel, efficient, and straightforward procedure for investigating reservoir compartmentalization based on the chemical composition of asphaltenes. The structural characteristics of asphaltenes were applied for investigating crude oil fingerprint heterogeneities in two oil fields, namely Ahwaz and Shadegan fields, to disclose possible compartmentalized regions. The FTIR spectroscopy method was used to achieve detailed structural characteristics of asphaltenes, and then a precise method based on RMSD was used for the pairwise comparison of studied samples. The novelty of this paper is that instead of using all peak ratios of FTIR data of asphaltenes, only 12 peak ratios with the highest variation are used for comparing different samples. Also, the highest variation peaks are combined with the RMSD method to reveal subtle differences between oil fingerprints. The accuracy of obtained results was checked with PVT data and pressure model. The last novelty of this paper is that the investigation of reservoir continuity in the supergiant Ahwaz field is investigated for the first time.

Geological Setting

Dezful Embayment is an essential subdivision of the Zagros fold-thrust belt located in the SW of Iran. This region includes several giants and supergiant oil fields that produce most Iranian crude oils (Fig. 1a, Hatzfeld et al. 2010; Asemani and Rabbani 2020a). Two studied oil fields, namely Ahwaz and Shadegan, are situated in the central part of the Dezful Embayment, surrounded by Ramin field in the north, Mansuri field in the south, Marun field in the east, and Susangerd field in the west. The Ahwaz supergiant field is the third largest field by oil reserves globally and contains more than 65 billion barrels of oil reserves. This field has an asymmetrical anticline structure (Fig. 1b). The Shadegan field is located in the vicinity of the Ahwaz field but has a lower oil reserve. The structure of this field is an asymmetrical anticline with 23 km in length, and 6 km in width (Fig. 1c). The Asmari Formation and Bangestan group (i.e., Ilam and Sarvak formations) are the primary oil reservoirs in both fields (Fig. 2, Karimi et al. 2016). Although the Kazhdumi Formation is the main source rock (Alipour 2022), these fields belong to different oil families due to various contributions from other source rocks (Asemani and Rabbani 2021).

Materials and Methods

Samples. Eight samples in the Ahwaz field and four samples in the Shadegan field from different wells across the Bangestan reservoir were sampled. The location of sampled wells is pointed out in Figs. 1b and 1c. The sampled wells have been producing for more than 25 years, and any well treatments were stopped 2 weeks before sampling. All samples were collected from the wellhead under atmospheric conditions. The asphaltene extraction from the studied fields was not performed simultaneously, so one sample from each field (i.e., AZ-B3 and SG-B2) was extracted several times to measure repeatability.

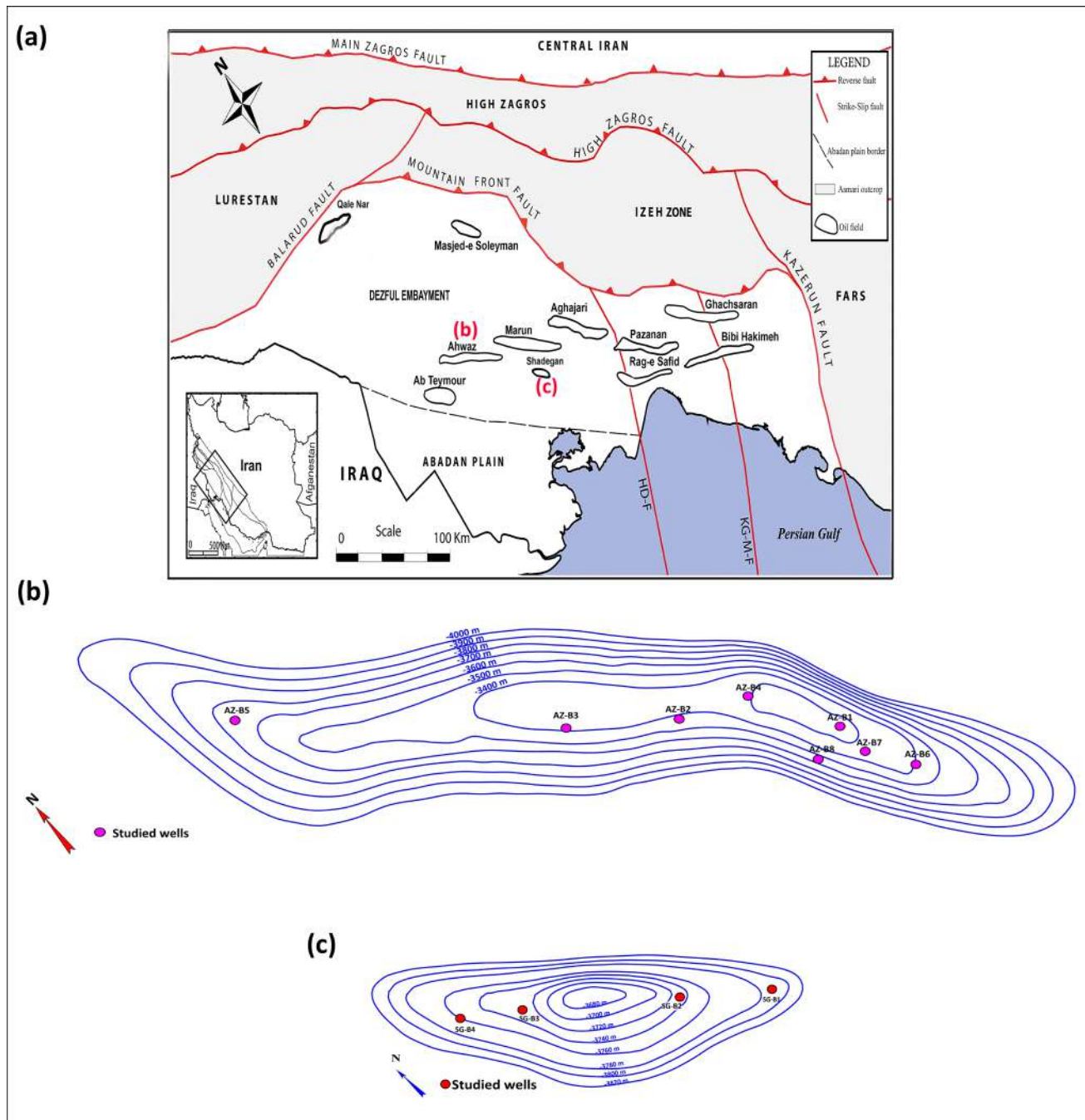


Fig. 1—(a) Distribution of oil fields in the Dezful Embayment [after Esrafil-Dizaji and Rahimpour-Bonab (2019)], (b) a contour map of the Ahwaz field based on the top of the Bangestan reservoir, and (c) a contour map of the Shadegan field based on the top of the Bangestan reservoir.

Analysis. Saturates, Asphaltenes, Resins, and Aromatics Analysis. Asphaltenes were extracted from the crude oils conforming to the D6560-17 standard (ASTM D6560-00 2017). Crude oil was mixed with *n*-hexane (1 g:30 mL) and heated under reflux for 1 hour. The mixture was placed in a dark place overnight after cooling at room temperature. Then, the precipitated compounds were filtered with Whatman Grade 42. The filter paper was washed with hot *n*-hexane under reflux to remove all impurities except asphaltene. Finally, pure asphaltenes were washed from the filter paper with toluene. Asphaltenes were recovered after evaporating solvent and heating at 100°C for 1 hour. The *n*-hexane soluble part of the crude oil was fractionated into saturates, aromatics, and resins. The fractionation was performed with activated silica gel packed in a chromatography column. The first fraction (i.e., saturates) was eluted from the column with *n*-hexane. *n*-hexane/DCM (70/30) and DCM/MeOH (dichloromethane/methanol) (50/50) were used to recover aromatics and resins.

FTIR Spectroscopy. Asphaltenes were prepared as a 13-mm pellet by mixing with KBr powder at a ratio of 1:100 wt:wt and pressing under high pressure. FTIR spectra were recorded with a Bruker Tensor 27 spectrometer in the range of 4000–400 cm^{-1} with 32 scans at 4 cm^{-1} resolution. The FTIR spectra acquisition was performed three times for each sample, and the average of three measurements was reported. The second derivative of FTIR spectra was calculated with GRAMS AI software. This software provides a simple and intuitive user interface for processing spectroscopic data, especially FTIR data [Grams AI (9.2) 2014]. The GRAMS AI software is the product of ThermoFisher Scientific Inc.

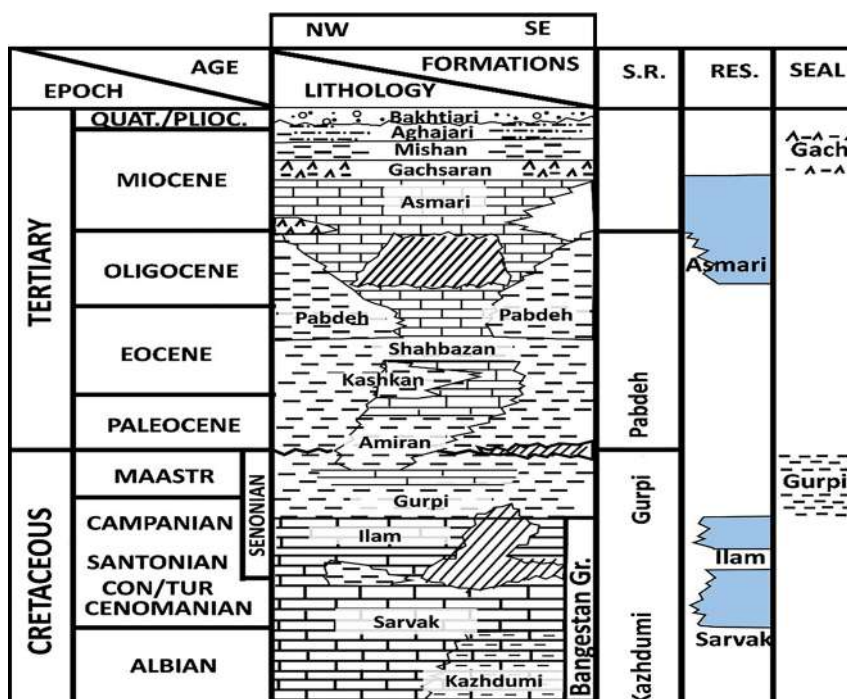


Fig. 2—Schematic of the stratigraphic column from northwest to southeast of Iran (after Bordenave and Burwood 1995; Kobraei et al. 2019).

Furthermore, asphaltene extraction was performed six times on one sample from each studied field (i.e., AZ-B3 and SG-B2). Then FTIR spectra were recorded to measure the test's reproducibility and determine the threshold for comparing samples.

RMSD Method. FTIR spectroscopy of asphaltenes has been used to obtain crude oil fingerprints and is a well-organized technique for obtaining information about reservoir continuity or compartmentalization (Asemani and Rabbani 2020a; Asemani et al. 2020, 2021a). Generally, quantitative-based techniques have a higher efficiency than graphical-based techniques (e.g., star diagrams) in revealing subtle differences and determining similar or different samples. Here a simple and efficient procedure is proposed to compare oil fingerprints based on FTIR spectra of asphaltenes. The details of the proposed technique are explained in the following.

The characteristic bands in the second-derivative FTIR spectra of asphaltenes are selected, and peak ratios are generated from these bands. These bands produce peak ratios with a low SD in a data set including similar samples and a high SD in data sets containing dissimilar samples. Routinely, the characteristic bands include 3052, 2958, 2923, 2850, 1600, 1460, 1375, 862, 808, and 746 cm^{-1} (Asemani and Rabbani 2020a, 2021). Asphaltene extraction in one of the samples is performed six times and is utilized to obtain the reproducibility of analysis and determine peak ratios with the highest variations. The highest variation peak ratios are helpful for the comprehensive comparison of samples. The variation in each peak ratio is calculated from Eq. 1 (Al-Meshari et al. 2007).

$$\text{Variation of } Ri = [Ri(\max) - Ri(\min)]/[Ri(\max)/2 + Ri(\min)/2], \quad (1)$$

where R is the calculated peak ratio, and i ranges from 1 to 90 if 10 characteristic peaks are selected.

Twelve peak ratios with the highest variation are determined to compare samples. The reproducibility of analysis shows that these 12 peak ratios are suitable for comprising samples in the studied suit. It is noteworthy to mention that the effective and most variation peak ratios should be calculated for each sample suit separately or all samples that are analyzed simultaneously by considering the reproducibility of asphaltene extraction and FTIR analysis. Subsequently, the differences between samples based on the selected 12 peak ratios are calculated. A relative RMSD (Eq. 2) is suitable for measuring differences between samples (Al-Meshari et al. 2007).

$$RMSD_{AB} = 100 * \sqrt{\frac{\sum (RA_i - RB_i)^2 / (RA_i/2 + RB_i/2)^2}{12}}, \quad (2)$$

where $RMSD_{AB}$ is the calculated relative root-mean-square deviations between A and B samples, i ranges from 1 to 12, and RA_i and RB_i are i th defined peak ratios for A and B samples, respectively.

The threshold for deciding the similarity or dissimilarity of studied samples is defined based on the reproducibility of asphaltenes extraction and FTIR analysis. The replicates of a sample, replicated six times in the previous step, are used for defining the threshold. The RMSD is calculated for pairwise comparison of different replicates, and the threshold is equal to the maximum calculated RMSD. Then, the comparison of all studied samples in a sample suite is performed based on the 12 defined peak ratios, and the calculated RMSD is compared with the specified threshold. Two samples with an RMSD higher than the threshold have different oil fingerprints, and a barrier may exist between these wells. Two samples with an RMSD lower than the threshold are considered samples with the same oil fingerprints and are likely connected during production.

Results and Discussion

Case Study I: Ahwaz Field. Bulk Characteristics. Saturates, asphaltenes, resins, and aromatics analysis results for the studied samples are reported in **Table 1**. The nonpolar fraction of crude oil (i.e., saturates and aromatics) has a higher concentration than the polar fraction (i.e., resins and asphaltenes) in all studied samples from the Ahwaz field. Saturate fraction ranges from 37.59% (i.e., AZ-B3) to 65.17% (i.e., AZ-B5), with an average of 43.68%. The average concentration of aromatics, resins, and asphaltenes shows a descending order with an average value of 31.25, 15.71, and 9.35%, respectively. Except for two samples (i.e., AZ-B7 and AZ-B5), all samples have asphaltene contents higher than 10%. The lowest asphaltene content relates to the AZ-B5 sample with a low value of 0.8%, and the highest asphaltene content is associated with the AZ-B8 sample with a value of 12.35%.

No.	Samples	Reservoir	Saturate (wt%)	Aromatic (wt%)	Resin (wt%)	Asphaltene (wt%)
1	AZ-B1	Bangestan	41.35	30.8	17.72	10.13
2	AZ-B2	Bangestan	38.6	37.25	12.57	11.58
3	AZ-B3	Bangestan	37.59	33.41	17.54	11.45
4	AZ-B4	Bangestan	39.92	33.68	14.55	11.84
5	AZ-B5	Bangestan	65.17	23.48	10.54	0.80
6	AZ-B6	Bangestan	42.99	27.32	18.81	10.88
7	AZ-B7	Bangestan	46.1	33.43	14.69	5.78
8	AZ-B8	Bangestan	37.74	30.61	19.29	12.35

Table 1—Bulk characteristics results for the studied samples from the Ahwaz field.

FTIR Assignments. FTIR spectra of asphaltene samples are illustrated in **Fig. 3**. The spectra were converted to the second derivative to discard possible variations in the baseline (Asemani et al. 2020). Peaks in the FTIR spectra are observed as the valleys in the second-derivative spectra (**Fig. 4**). All samples show similar bands, and the differentiation of samples visually is complicated. A broadband in a region higher than 3100 cm^{-1} is related to O-H and N-H groups in the asphaltenes. The hydroxyl group in the H_2O may also contribute to this band due to the moisture absorption of KBr pellets during analysis. Aromatic C-H stretching occurs as a small shoulder band in 3050 cm^{-1} . A $3000\text{--}2750\text{ cm}^{-1}$ region is an aliphatic region attributed to the symmetric and asymmetric C-H stretching of methyl, methylene, and methine groups. A band in the 1730 cm^{-1} appears due to C=O stretching in compounds such as carboxylic acids, ketones, esters, and secondary amides. As can be seen in the FTIR spectra of different samples, most of the samples do not show the carbonyl peak, and this peak is not a characteristic band in the FTIR spectra of asphaltenes for differentiation of similar or dissimilar samples (Asemani and Rabbani 2020a, 2021). A 1600 cm^{-1} band is the characteristic of C=C stretching in aromatic compounds. The 1460 and 1375 cm^{-1} bands attribute to CH_2 and CH_3 groups. The S=O stretching of sulfoxide groups appears in 1030 cm^{-1} . The C-H out-of-plane bending (wagging)

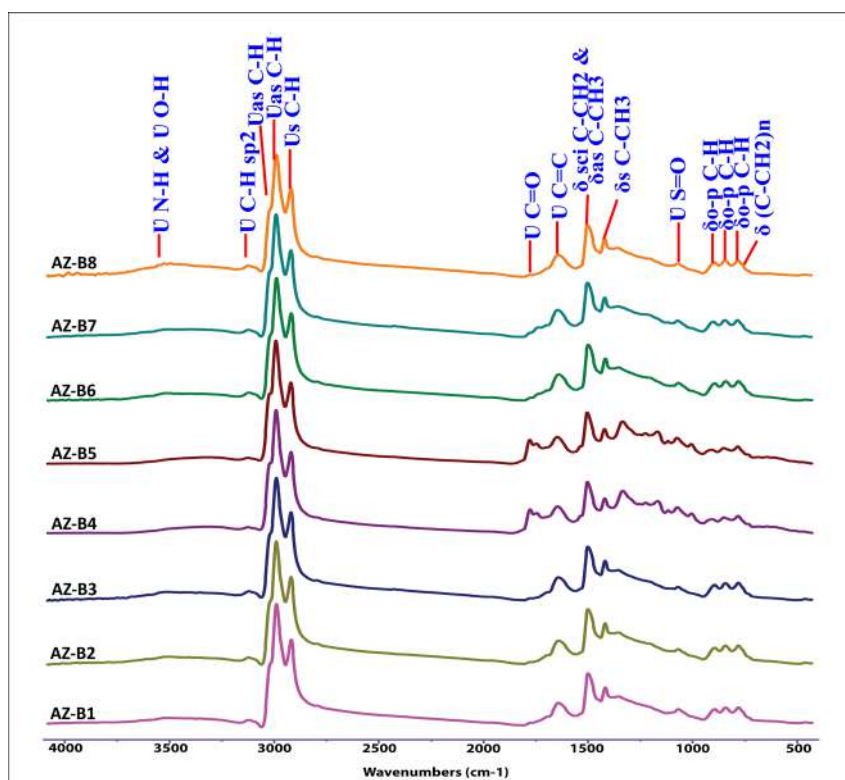
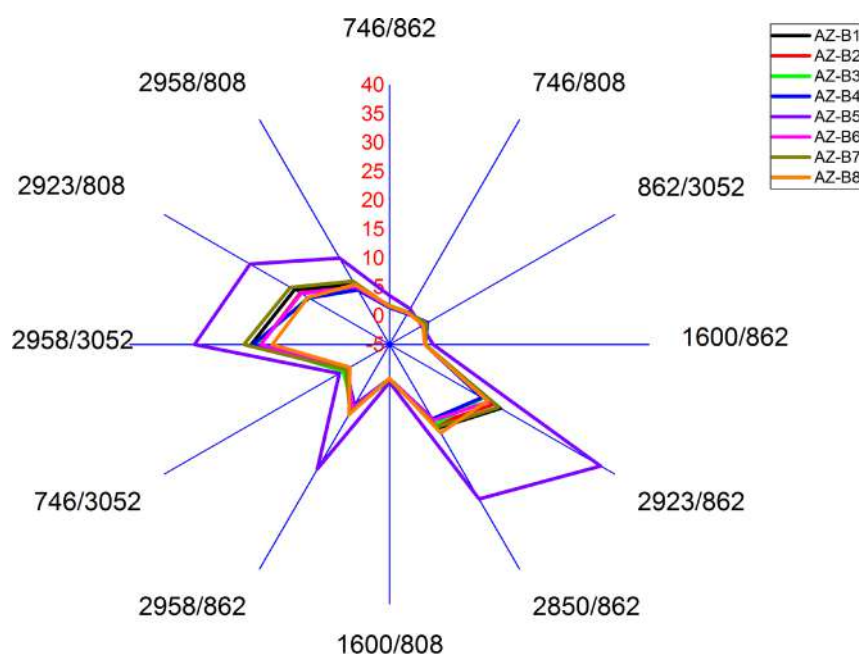


Fig. 3—FTIR spectra of studied asphaltene samples from the Ahwaz field. The assignment of bands is summarized as U, stretching; δ , bending; o-p, out of plane; s, symmetric; as, asymmetric; sci, scissors.

Reservoir Compartmentalization Assessment. *FTIR Data of Asphaltenes.* There was no previous information about reservoir architecture in the studied field. Hence, eight oil samples across the Bangestan reservoir were collected to obtain preliminary information about reservoir compartmentalization or continuity. The collected samples are distributed in different parts of the reservoir to gain a thorough understanding (**Fig. 1b**). Ten characteristic bands in the second-derivative FTIR spectra from the six replicates of the AZ-B3 sample were selected, and 90 (10×9) peak ratios were calculated by dividing the intensity of each band by others. The selected bands comprising 3052,



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2958, 2923, 2850, 1600, 1460, 1375, 862, 808, and 746 cm^{-1} . The peak ratios with the highest variation were calculated with Eq. 1, and the 12 peak ratios with the highest variation were 746/862, 746/808, 862/3,052, 1,600/862, 2,923/862, 2,850/862, 1,600/808, 2,958/862, 746/3,052, 2,958/3,052, 2,923/808, and 2,958/808 in descending order of the calculated variation. It was revealed that these 12 peak ratios are efficient for pairwise comparison of all samples and to reveal subtle differences. Two procedures were followed for the comparison of samples. The first method was plotting the calculated peak ratios in a star diagram, and the second applied a quantitative-based method (i.e., the RMSD method) for better comparison of samples. **Fig. 5** shows a star diagram based on the calculated peak ratios for all studied samples. This figure indicates that AZ-B5 is completely different from other samples. But this figure fails to reveal the subtle difference between other samples. Also, decision-making about how much differences should be considered as two different samples is impossible.

Hence, an RMSD technique was implemented. **Table 2** shows the calculated RMSD values based on Eq. 2 for six replicates of the AZ-B3 sample. The defined threshold based on the reproducibility of tests is an RMSD equal to 14.29%. The calculated RMSDs for each pairwise of samples in the studied suit are summarized in **Fig. 6**, and this figure is called a compartmentalization matrix. Two wells with an RMSD value higher than the threshold are considered different fingerprints and will not be communicated during production. These samples are shown with red cells in the compartmentalization matrix. The communicated wells, during production, have an RMSD value lower than the threshold and are shown with green color in the compartmentalization matrix. This matrix shows that some differences have occurred between samples, which are signs of reservoir compartmentalization in the Bangestan reservoir of the Ahwaz field.

Sample	Replicates	RMSD (%)
AZ-B3	1 and 2	11.36
	1 and 3	7.54
	1 and 4	8.76
	1 and 5	12.39
	1 and 6	12.64
	2 and 3	10.36
	2 and 4	8.46
	2 and 5	9.67
	2 and 6	12.7
	3 and 4	8.77
	3 and 5	13.4
	3 and 6	9.93
	4 and 5	8.59
	4 and 6	10.3
	5 and 6	14.29
Total	Minimum	7.54
	Average	10.61
	Maximum	14.29

Table 2—The calculated RMSD values for pairwise comparison of different replicates of the AZ-B3 sample in the Ahwaz field.

	AZ-B1	AZ-B2	AZ-B3	AZ-B4	AZ-B5	AZ-B6	AZ-B7	AZ-B8
AZ-B1	0.00	17.30	15.83	16.18	58.80	9.06	5.51	14.15
AZ-B2	17.30	0.00	7.97	14.50	62.54	16.35	18.21	19.11
AZ-B3	15.83	7.97	0.00	12.48	65.29	16.22	14.62	17.58
AZ-B4	16.18	14.50	12.48	0.00	71.57	15.18	17.47	20.18
AZ-B5	58.80	62.54	65.29	71.57	0.00	66.29	57.60	63.27
AZ-B6	9.06	16.35	16.22	15.18	66.29	0.00	11.47	13.90
AZ-B7	5.51	18.21	14.62	17.47	57.60	11.47	0.00	12.26
AZ-B8	14.15	19.11	17.58	20.18	63.27	13.90	12.26	0.00

Fig. 6—The prepared compartmentalization matrix based on the RMSD method for studied samples in the Bangestan reservoir of the Ahwaz field.

The results of the compartmentalization matrix are visually illustrated in **Fig. 7**. At least three compartmentalized regions have been revealed based on FTIR spectroscopy of asphaltenes. The first region (i.e., B-I) is located in the northwest part of the field and includes the AZ-B5 well. This region is completely different from other parts of the reservoir. The second region is B-II and involves AZ-B2,

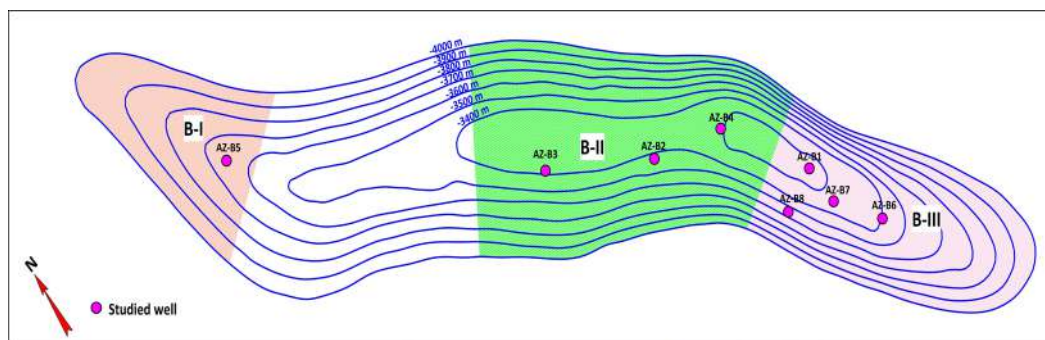


Fig. 7—Schematic of compartmentalized regions in the Bangestan reservoir of the Ahwaz field.

AZ-B3, and AZ-B4 wells, located in the central parts of the field. The third region (i.e., B-III) is situated in the southeast part of the field and consists of AZ-B1, AZ-B6, AZ-B7, and AZ-B8 wells.

Reservoir Engineering Data. PVT analysis was performed on the five bottomhole samples collected from the selected wells. The PVT data were used to investigate fluid properties in the Bangestan reservoir. It is believed that wells in the different compartmentalized regions have different fluid properties, which are reasonable ways to obtain information about reservoir compartmentalization. The measured fluid properties and composition of the studied samples are listed in **Table 3**. The PVT measurements were conducted at 110°C, and the measured fluid properties include saturation pressure (P_b), solution GOR, oil formation volume factor (B_o , i.e., at saturation pressure), and American Petroleum Institute gravity ($^{\circ}\text{API}$). **Figs. 8a through 8c** show solution GOR, B_o , and API vs. P_b for the studied samples. The AZ-B5 sample from Zone B-I has completely different fluid properties from other samples (**Fig. 8**). The differences between Zone B-II and Zone B-III samples are not as significant as in Zone B-I. Still, the differentiation between these zones is entirely evident. The fluid compositions also show the separation between different zones (**Table 3**). AZ-B5 sample (i.e., Zone B-I) has a higher content of light components than other zones. Zone B-III (e.g., AZ-B1 and AZ-B7) shows the highest H_2S content, and Zone B-I (e.g., AZ-B5) has the lowest content. The composition of reservoir fluid has also confirmed the separation between defined zones. Hence, the PVT results, including fluid properties and composition, confirmed previous conclusions that the Bangestan reservoir in the Ahwaz field involves several compartmentalized regions.

Characteristics		Zone B-I	Zone B-II		Zone B-III	
		AZ-B5	AZ-B3	AZ-B4	AZ-B1	AZ-B7
Reservoir fluid properties	Saturation pressure (psia)	3,626	1,465	1,365	1,135	1,112
	Solution GOR (scf/STB)	1,161	388	319	347	335
	Oil formation volume factor (rbbl/STB)	1.53	1.16	1.15	1.22	1.2
	API gravity (°)	35.1	23.29	21.61	24.11	24.84
Components (mol%)	H ₂ S	1.76	0.62	0.44	2.04	2.77
	N ₂	0.23	0.2	0.22	0.22	0.12
	CO ₂	4.05	3.7	2.99	4.36	5.99
	C1	46.64	25.24	25.35	22.21	20.56
	C2	7.26	7.76	7.93	6.84	6.79
	C3	4.52	6.35	5.5	5.11	5.9
	iC4	1.07	1.47	1.11	0.84	0.96
	nC4	2.63	3.84	3.14	2.48	3.19
	iC5	1.17	0.92	1.25	0.81	1.72
	nC5	1.32	0.88	1.34	0.95	2.02
	C6	3.8	4.83	4.99	0.92	7.47
	C7	3.44	4.09	3.72	6.36	4.92
	C8	1.05	2.92	3.46	4.36	3.63
	C9	1.79	3.61	3.05	2.62	4.2
	C10	1.83	2.68	2.74	3.16	3.04
	C11	1.69	2.35	3.1	2.33	2.74
	C12+	15.75	28.54	29.67	34.39	23.98

Table 3—The calculated reservoir fluid properties and composition for the bottomhole samples in the Bangestan reservoir of the Ahwaz field.

Furthermore, reservoir pressures measured by an RFT tool were used to construct a pressure model in the Bangestan reservoir. The cross section from NW to SE of the reservoir is shown in **Fig. 9**. This cross section illustrates three distinct zones based on pressure in the

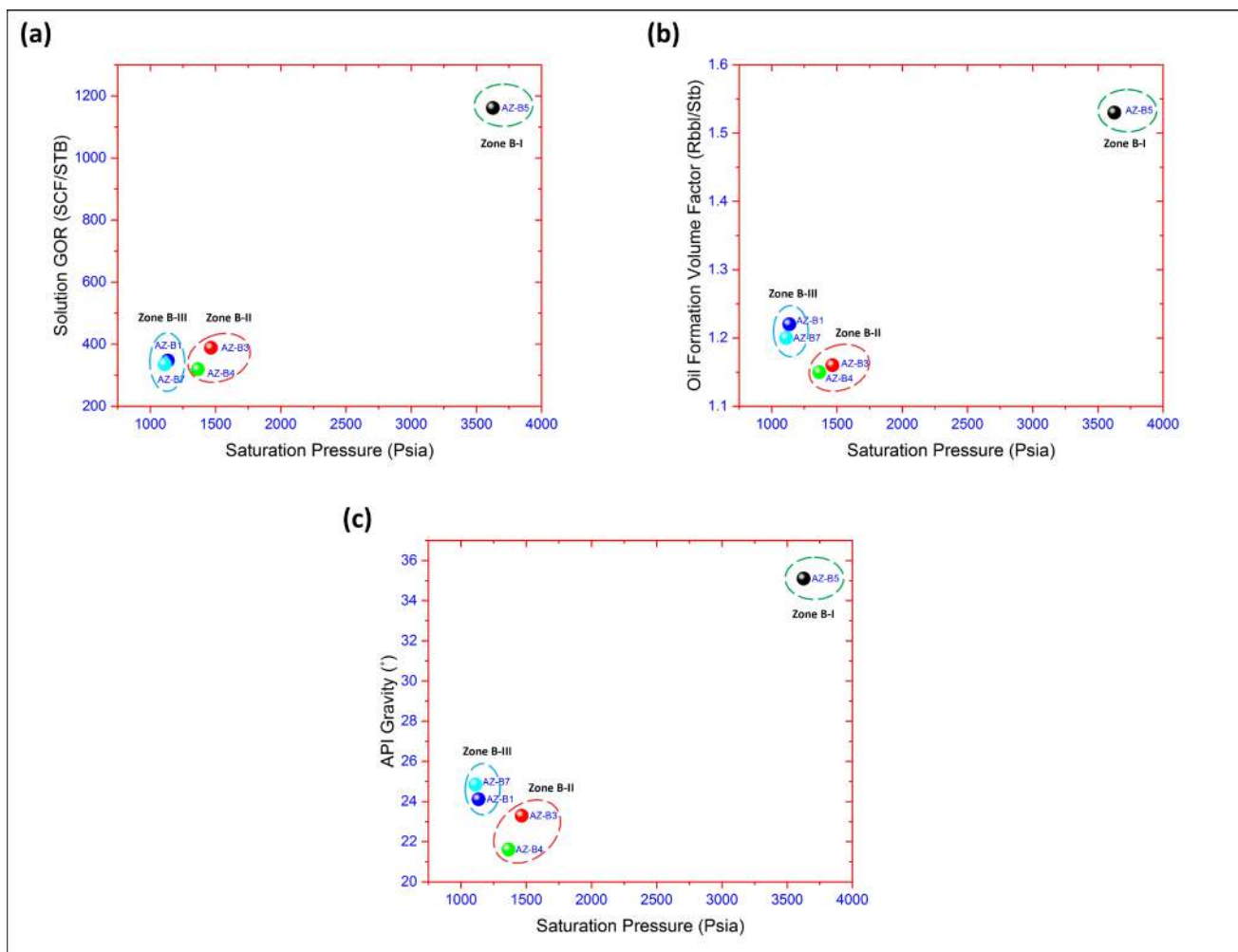


Fig. 8—The plot of different fluid properties vs. saturation pressure for the studied samples from the Bangestan reservoir in the Ahwaz field. (a) Solution GOR vs. Pb, (b) Bo vs. Pb, and (c) API vs. Pb.

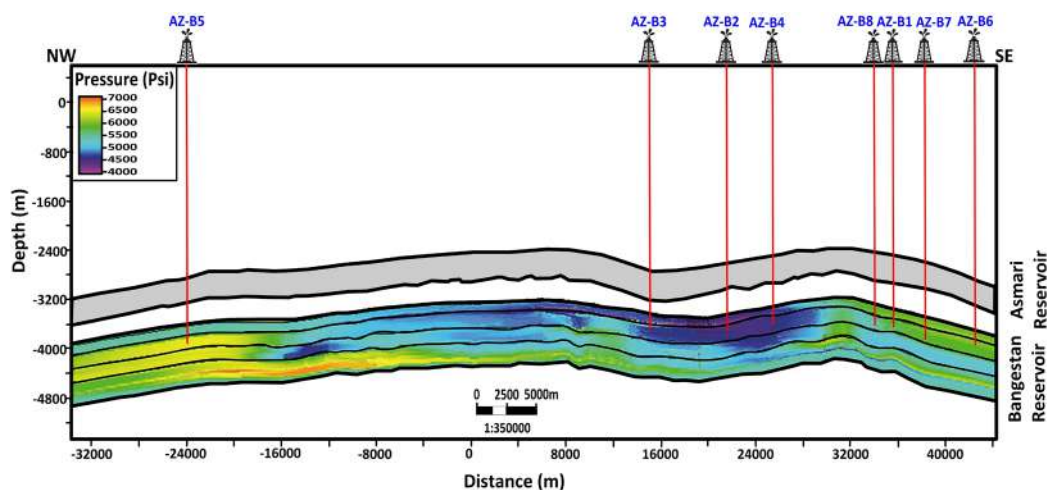


Fig. 9—Distribution of pressure in a cross section from the NW to SE of the field.

east, center, and west parts of the Bangestan reservoir. The western zone shows higher pressure than other zones, and the central zone indicates the lowest pressure. The studied wells are shown in the cross section and indicate the created pressure zones in the reservoir are completely consistent with previous results. These zones have no lateral connectivity and represent reservoir compartmentalization in the Bangestan reservoir.

Structural interpretation of 3D seismic data revealed that the faulting and folding styles differ in different parts of the field. A fault propagation caused folding in the eastern part, and a detachment fold was formed in the western parts of the field. Hence, the observed reservoir compartmentalization is related to the Ahwaz field's structural styles and tectonic characteristics.

Case Study II: Shadegan Field. Bulk Characteristics. Table 4 represents the saturates, asphaltenes, resins, and aromatics analysis results of studied samples from the Shadegan field. The asphaltene content of samples ranges from 2.20 to 10.46%. This fraction has an average of 7.99% in the Bangestan reservoir. The average value of other fractions is 36.39, 43.30, and 12.33% for saturate, aromatic, and resin components, respectively. The aromatic fraction has the highest values among other fractions in all studied samples.

No.	Samples	Reservoir	Saturate (wt%)	Aromatic (wt%)	Resin (wt%)	Asphaltene (wt%)
1	SG-B1	Bangestan	39.82	41.97	8.61	9.60
2	SG-B2	Bangestan	37.96	47.61	12.23	2.20
3	SG-B3	Bangestan	35.49	42.28	12.53	9.70
4	SG-B4	Bangestan	32.28	41.32	15.93	10.46

Table 4—Saturates, asphaltenes, resins, and aromatics analysis results for the studied samples from the Bangestan reservoir in the Shadegan field.

FTIR Assignments. Fig. 10 shows the raw and second-derivative FTIR spectra of studied asphaltene samples in the Shadegan field. The visual appearance of these spectra is similar to the FTIR spectra of the Ahwaz field. This issue implies similar characteristic functional groups in asphaltenes of both fields. The differences in asphaltenes are related to the abundance of each specific functional group, not their functional groups. Hence, the assignments of FTIR spectra are similar to the Ahwaz field samples.

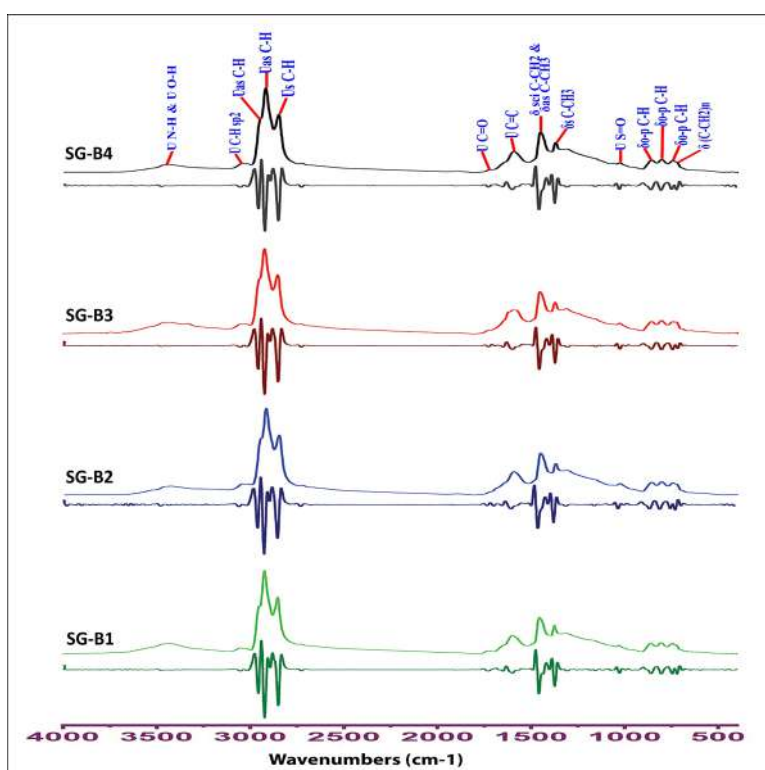


Fig. 10—Raw and second-derivative FTIR spectra of asphaltenes for studied samples from the Bangestan reservoir in the Shadegan field. The assignment of bands is summarized as U, stretching; δ , bending; o-p, out of plane; s, symmetric; as, asymmetric; sci, scissors.

Reservoir Compartmentalization Assessment. FTIR Data of Asphaltenes. Four different wells across the Bangestan reservoir in the Shadegan field were sampled. The studied wells are distributed throughout the field and are suitable for obtaining satisfactory information about different zones if the reservoir has been subjected to compartmentalization. Ten characteristic bands comprising 3052, 2958, 2923, 2850, 1600, 1460, 1375, 862, 808, and 746 cm^{-1} were selected from FTIR spectra of studied samples, and 90 (10×9) peak ratios were calculated. These bands are observable in all samples and are beneficial for revealing heterogeneities or homogeneities between different samples. Six replicates of SG-B2 were considered for determining the highest variation peak ratios for comparing samples across the reservoir and defining the threshold in the RMSD method. The variation of peak ratios was calculated from Eq. 1, and the highest variation peak ratios in order of descending variation are 2,923/862, 2,923/1,600, 2,958/862, 2,850/862, 2,958/1,600, 2,850/1,600, 2,923/746, 1,460/862, 2,923/808, 2,958/3,052, 2,923/3,052, and 1,375/862. These peak ratios can reveal the subtle differences between studied samples, which are prerequisites of a successful reservoir compartmentalization study. The RMSD method based on Eq. 2 was used to compare the peak ratios between different samples. The highest calculated RMSD in pairwise comparison of different replicates

Sample	Replicates	RMSD (%)
SG-B2	1 and 2	13.28
	1 and 3	12.73
	1 and 4	11.6
	1 and 5	13.38
	1 and 6	9.54
	2 and 3	10.3
	2 and 4	11.23
	2 and 5	13.67
	2 and 6	12.81
	3 and 4	14.11
	3 and 5	9.44
	3 and 6	5.48
	4 and 5	10.09
	4 and 6	5.48
	5 and 6	11.32
Total	Minimum	14.58
	Average	13.28
	Maximum	12.73

Table 5—The calculated RMSD values for pairwise comparison of different replicates of the SG-B2 sample in the Shadegan field.

	SG-B1	SG-B2	SG-B3	SG-B4
SG-B1	0.00	16.48	18.72	17.36
SG-B2	16.48	0.00	4.52	13.35
SG-B3	18.72	4.52	0.00	12.78
SG-B4	17.36	13.35	12.78	0.00

Fig. 11—The compartmentalization matrix based on the RMSD method for revealing communication between different wells in the Bangestan reservoir from the Shadegan field.

of the SG-B2 sample is equal to 14.58% and assigned as the threshold for comparison of different studied samples (Table 5). The RMSD value for different pairwise samples was calculated and compared with the threshold (14.58%) for disclosing samples with a similar or different fingerprint. The results of RMSD values are summarized in Fig. 11. The cell of the matrix with green color implies similarity in the fingerprint of two specific wells, and the red color states the opposite. The compartmentalization matrix for the Bangestan reservoir in the Shadegan field shows that the SG-B1 well has a different fingerprint from other wells. Hence, the Bangestan reservoir was segmented into two different zones: The first zone comprises SG-B1 well, and the second zone consists of SG-B2, SG-B3, and SG-B4 wells. The schematic of these zones is illustrated in Fig. 12.

Reservoir Engineering Data. The reservoir engineering evidence was also used to corroborate previous results about reservoir compartmentalization in the Bangestan reservoir from the Shadegan field. The pressure gradient was calculated for studied wells based on RFT measurements. Three wells of SG-B2, SG-B3, and SG-B4 show a similar pressure gradient (Fig. 13a). This phenomenon resulted from the connectivity of these wells during production. The pressure gradient of the SG-B1 well is entirely different from these wells and implies this well has no communication with other wells in the Bangestan reservoir during production (Fig. 13a). The PVT results show the composition of SG-B1 is different from the SG-B2 (Table 6). The composition of reservoir oil for SG-B1 and SG-B2 samples is contrasting. Although the SG-B1 shows H₂S and a relatively higher abundance of light components, the SG-B2 is completely sweet oil and has a higher concentration of heavier components. The reservoir fluid properties also indicate distinct characteristics, and their differentiation is evident in crossplots (Figs. 13b through 13d). Hence, the reservoir engineering evidence corroborates previous results that the Bangestan reservoir from the Shadegan field has been subjected to reservoir compartmentalization. This reservoir has been segmented

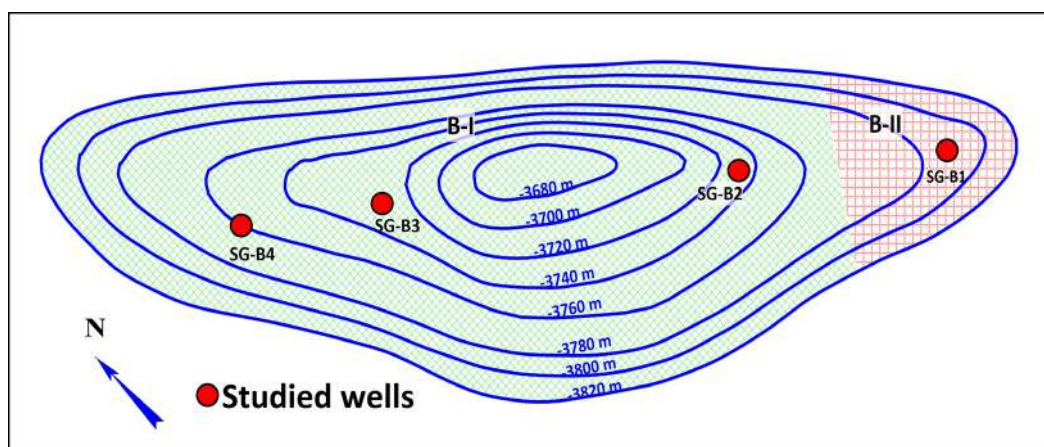


Fig. 12—Schematic of compartmentalized regions in the Bangestan reservoir of the Shadegan field.

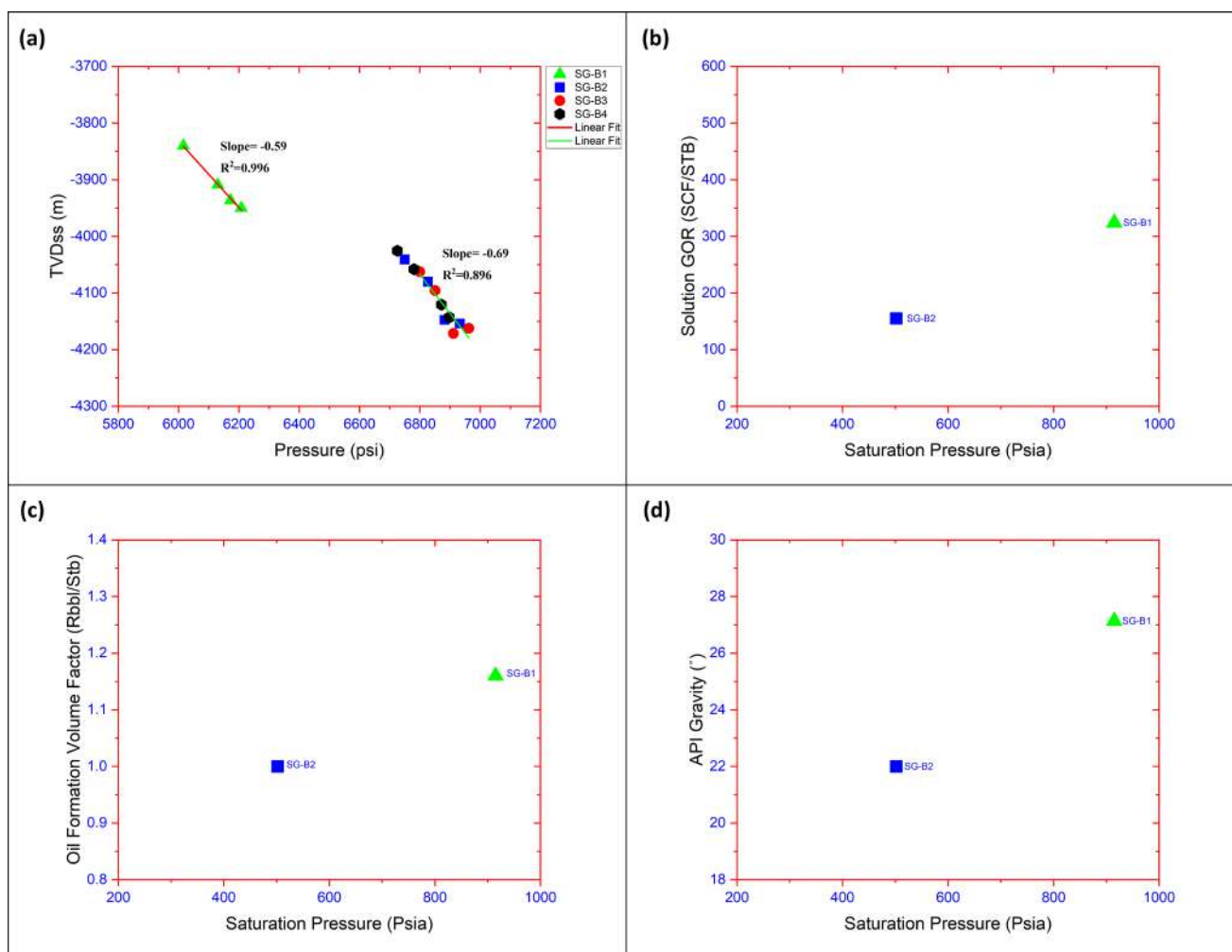


Fig. 13—(a) RFT results vs. true vertical depth (TVD) for studied wells, (b) solution GOR vs. Pb, (c) Bo vs. Pb, and (d) API vs. Pb for studied samples; from the Bangestan reservoir in the Shadegan field.

into two distinct zones that are not in communication during production. The geological interpretation of seismic results confirms several faults in this reservoir.

Characteristics		Zone B-I	Zone B-II
		SG-B2	SG-B1
Reservoir fluid properties	Saturation pressure (psia)	502	915
	Solution GOR (scf/STB)	155	324
	Oil formation volume factor (rbbl/STB)	1	1.16
	API gravity (°)	22	27.14
Components (mol%)	H ₂ S	0.01	2.25
	N ₂	0.09	0.26
	CO ₂	2.53	7.53
	C1	10.77	22.46
	C2	5.64	9.65
	C3	4.54	9.37
	iC4	0.65	1.98
	nC4	2.21	6.85
	iC5	1.51	3.22
	nC5	1.87	3.47
	C6	6.39	1.77
	C7	3.86	0.63
	C8	5.01	2.64
	C9	6.7	2.73
	C10	4.47	1.79
	C11	3.9	1.73
	C12+	39.85	21.66

Table 6—The measured reservoir fluid properties and composition for bottomhole samples collected from the Bangestan reservoir in the Shadegan field.

Conclusions

This paper suggested an efficient and straightforward method for evaluating reservoir compartmentalization based on the chemical composition of asphaltenes. This technique was tested in the Bangestan reservoir from the supergiant Ahwaz and Shadegan oil fields. The main findings of this paper are summarized in the following:

- The structural characteristics of asphaltenes provided valuable information about the homogeneity or heterogeneity of crude oil composition, and these phenomena are related to reservoir compartmentalization.
- The applied technique for comparing asphaltene structure between studied samples was based on the 12 highly different characteristic peak ratios calculated from FTIR spectra. These peak ratios help in revealing subtle differences, and this issue has great worth in reservoir compartmentalization studies.
- The calculated relative RMSD values provide a straightforward method for decision-making about similarity or dissimilarity between different samples.
- The results showed three compartmentalized regions in the Bangestan reservoir from the Ahwaz field. These zones were verified with reservoir engineering data such as fluid properties, the composition of reservoir crude oil, and pressure data. The 3D seismic data disclose the compartmentalization in the Bangestan reservoir related to structural styles and tectonic characteristics in the Ahwaz field.
- The proposed method also successfully revealed two distinct regions in the Shadegan field, and these results were corroborated with reservoir engineering data (i.e., pressure and PVT data).
- Although simple, the proposed method is rapid and provides efficient and trustworthy information about reservoir continuity or compartmentalization, which is necessary for making early decisions in the different life cycles of a field.

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