Original article

Improved reservoir characterization by employing hydraulic flow unit classification in one of Iranian carbonate reservoirs

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Abstract:

Capillary pressure curves is of great importance in reservoir characterization. Due to the reservoir heterogeneity, no single capillary pressure curve can be used for the entire reservoir depth. This paper aims to examine the application of different techniques of hydraulic flow unit (HFU) classifications in overcoming the extreme heterogeneity of the reservoir in order to improve normalization of capillary pressure in one of the Iranian carbonate oil reservoirs. In this study, well log, routine and specific core analysis lab data have been used to identify flow units by employing different techniques in a heavy oil carbonate reservoir in the south of Iran. These techniques include gamma ray and density log method, flow zone indicator, capillary pressure curves and Winland parameter. Then, mercury injection data has been used by employing Desouky's method to normalize capillary pressure curves for each identified flow unit. According to this study HFU classification significantly improved normalizing of capillary pressure curves.

1. Introduction

Providing a sufficiently detailed characterization of the overall geological complexity of a reservoir would require a definition of a structural, stratigraphic and a lithological model (Brigaud et al., 2014; Goda et al., 2014; Chang et al., 2015; Hingerl et al., 2016). However, such characterization is proved to be unsatisfactory when the dynamic performance of the field is considered. The geological description should capture the main features related to the fluids flow in the reservoir. Otherwise, reservoir heterogeneity that is regarded as one of the most relevant factors affecting the dynamic behavior of the field, will not be taken into account properly. As known, reservoir heterogeneity is not totally a static issue, and its impacts are strongly related to non-geological parameters, like mobility ratio, PVT properties, and aquifer strength and development strategy (Goda et al., 2014; Pyrcz et al., 2014). Therefore, accurate heterogeneity description seems a critical issue in reservoir studies. Different techniques can be used to identify the presence of reservoir heterogeneity. One of the efficient techniques to address the reservoir heterogeneity in macro scale is hydraulic flow unit (HFU) zonation (Davies et al., 1996; Schatz et al., 2007; Nooruddin et al., 2011; Mirzaei-Paiaman et al., 2015).

The concept of flow unit has been developed as an in-tegrating tool for petrophysical description of the reservoir (Stolz et al., 2003; Izadi et al., 2012; Mirzaei-Paiaman et al., 2015, 2018). Based on this concept, rocks with similar petrophysical and flow properties are categorized within the same unit (Pittman, 1992; Amaefule et al., 1993; Soto et al., 2001; Kaydani et al., 2011; Ngo et al., 2015; Rabiller, 2017). Interpretation of flow units based on the petrophysi-cal properties, well log data, and stratigraphy are routinely done for reservoir characterization. As reported by several researchers, this technique provides a better input data set for numerical flow simulation, when compared to those provided by lithological or depositional facies (Chen et al., 1950; Davies et al., 1996; Soto et al., 2001; Bagci et al., 2007; Schatz et al., 2007; Kadkhodaie-Ilkhchi et al., 2009; Nooruddin et al., 2011; Izadi et al., 2012, 2013; Mirzaei-Paiaman et al., 2015). Different methods can be applied for interpreting the flow units and their corresponding petrophysical properties (Bagci et al., 2007; Banga et al., 2007; Schatz et al., 2007; Brigaud et al., 2014; Goda et al., 2014; Pyrcz et al., 2014; Rebelle, 2014). The amount and the type of information required by each method; however, varies depending on the data and the tools available (Jaya et al., 2005; Bagci et al, 2007; Askari et al., 2011; Rebelle, 2014; Tiab et al., 2015; Abdallah et al., 2016; Mirzaei-Paiaman et al., 2018). This may lead to different flow unit interpretation of the same reservoir. Several valuable re-
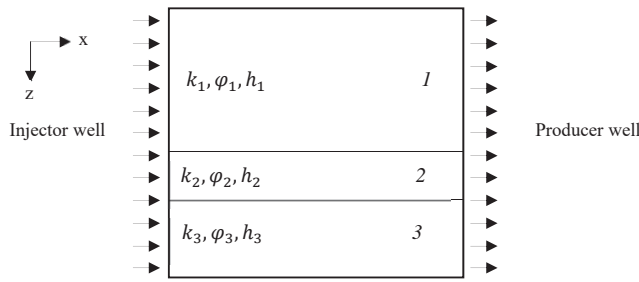
Fig. 1. Schematic of subdivision of a reservoir to different flow units (Stolz et al., 2003).

searches have been conducted on the evaluation of different flow unit identification techniques (Ali-Nandalal et al., 2003; Hamon, 2003; Frank et al., 2005; Guo et al., 2005; Salman et al., 2009; Hollis et al., 2010; Kale et al., 2010; Rebelle, 2014; Mirzaei-Paiaman et al., 2018). However, a comparative study that includes applications of different methods in reservoir description is lacking (Kadkhodaie-Ilkhchi et al., 2009; Izadi et al., 2013; Mirzaei-Paiaman et al., 2015; Chen et al., 2017).

2. Hydraulic flow unit concept

The concept of flow unit has been developed to integrate geological and petroleum engineering data which is defined as group of reservoir rocks with similar properties that effect fluid flow. Interpretation of flow units based on petrophysical properties, logs, and stratigraphy are routinely done for characterization of a reservoir that provides a better input into numerical flow simulation when compared to lithologic or depositional facies. The grouping of rocks based on their fundamental geological flow attributes is the basis of HFU classification (Al-Ajmi et al., 2000; Stolz et al., 2003).

As shown in Fig. 1, hydraulic flow units have the following characteristics (Rafiei, 2007):

1) A flow unit is a specific volume of reservoir, composed of one or more reservoir quality lithologies.
2) A flow unit is correlative and mappable at the interval scale.
3) A flow unit zonation is recognizable on wire-line log.
4) A flow unit may be in communication with other flow units.

HFU is characterized based on the following parameters and equations (Tiab et al., 2016):

$$RQI = \varphi_n \times FZI \tag{1}$$

where RQI is reservoir quality index; φ_n is normalized porosity; and FZI is flow zone indicator:

$$FZI = \frac{1}{\sqrt{F_s}\,\tau S_{gv}} \tag{2}$$

$$RQI = 0.0314\sqrt{\frac{k}{\varphi_e}} \tag{3}$$

$$\varphi_n = \frac{\varphi_e}{1 - \varphi_e} \tag{4}$$

where k is permeability in μm^2 and φ_e is effective porosity in fraction. The term $F_s\tau^2$ is known as the Kozeny constant, which is usually between 5 and 100 in most reservoir rock. The term $F_s\tau^2 S_{gv}^2$ is a function of geological characteristics of porous media and varies with changes in pore geometry (Stolz et al., 2003).

Taking the logarithm of Eq. (1) on both sides yields:

$$\log RQI = \log \varphi_n + \log FZI \tag{5}$$

Eq. (5) yields a straight line on a log-log plot of RQI versus φ_n with a unit slope. The intercept of this straight line at $\varphi_n = 1$ is FZI. Samples with different FZI values will lie on other parallel lines. Samples that lie on the same straight line have similar pore throat characteristics and, therefore, constitute a flow unit.

FZI is a unique parameter that includes the geological attributes of the texture and mineralogy in the structure of distinct pore geometrical facies. In general, rocks containing authigenic pore lining, pore filling, and pore bridging clay as well as fine grained, poorly sorted sands tend to exhibit high surface area and high tortuosity, hence low FZI. In contrast, less shaly, coarse-grained, and well-sorted sand exhibit lower surface area, low shape factor, lower tortuosity, and higher FZI. Different depositional environments and diagenetic processes control the geometry of the reservoir and consequently the flow zone (Rafiei, 2007). The objective of this study is to determine the suitable HFU zonation technique for improving capillary pressure (P_c) curve normalization on available log and core data of one well in one of the Iranian carbonate heavy oil reservoirs. The studied methods are gamma ray and density logs, FZI, Winland r_{35} and capillary pressure curves. To do this, one of the Iranian carbonate oil reservoirs was selected. Collected well log, and core data related to one of the wells in this reservoir were used as input data set.

3. Reservoir properties

The studied carbonate reservoir, which is located in southern Iran, is a part of giant oil field with about 90 km length and 16 km width in the surface. The reservoir rock consists of mainly dolomite with some interbedded shaly layers. The reservoir formations are considered for heavy oil and also highly fractured rocks.

4. Case study

The data set corresponds to one of the wells located in a carbonate heavy oil reservoir in the south part of Iran. Conventional well log information was available for the 90 m-deep well, in addition to petrophysical measurements on approximately 19 selected core plug samples. These data included: Gamma ray log, bulk density log, compensated neutron log, air permeability, helium core porosity and capillary pressure analysis.

Different hydraulic flow unit zonation methods were applied to the prepared data set in order to identify the flow units. After dividing the reservoir layer to different flow units, the Desouki's approach has been employed to normalize available
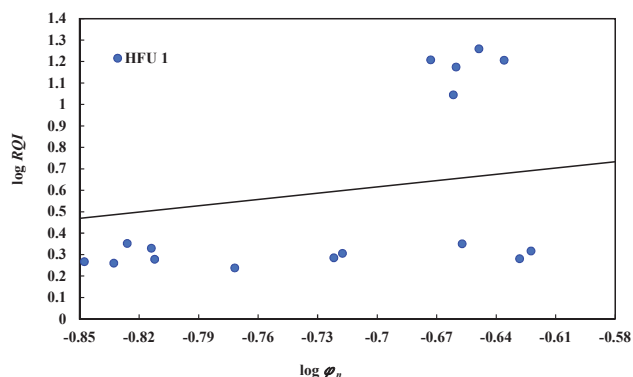
Fig. 2. Determination of *FZI* when reservoir is considered to be one big flow unit.

P_c curves for each hydraulic flow units.

To have a better understanding of the HFU classification, a brief explanation of studied methods is explained as follows.

4.1 Homogeneous reservoir with one flow unit

In order to evaluate the effect of HFU zonation on improving normalization of P_c curves, the reservoir is assumed to be one general big flow unit, then the results of HFU zonation from other techniques have been compared with this method.

The data source for this method consisted of core measurements of permeability and helium porosity from 19 core plug samples. In this very simple method, the entire depth of the well has been homogeneous, as if it was one big flow unit. Then *RQI* has been plotted versus n on log-log scale. Intercept of the line with unit slop that crosses the RQI/φ_n points present the *FZI* value of the flow unit which is 21.98 μm (Fig. 2).

4.2 Gamma ray and density log

Gamma ray logs measure natural radioactivity of the formations. In general, it can help differentiate shales (high radioactivity) from sands, carbonates, and anhydrites (low radioactivity) (Tiab et al., 2015). Also, the formation density log is a porosity log that measures electron density of a formation. It can be used to identify evaporate minerals, detect gas bearing zones, determine hydrocarbon density, and evaluate shaly-sand reservoirs and complex lithology (Stolz, et al., 2003; Tiab et al., 2015).

Gamma ray log can be used as a simple tool to distinguish between sandstones and shales, and it establishes zones with different flow properties. By observing similarities in the gamma ray signature it is possible to further divide reservoir into different groups, which can be considered as flow units. The density log can be used to confirm the flow unit zonation and to calculate average porosity values for the depth intervals (Stolz et al., 2003).

In this method flow units are interpreted using the gamma ray (GR) log, and the density log (DL). The applied method includes the following steps:

1) Zones with similar GR signature were grouped and interpreted as single flow units.
2) A flow unit number was assigned to each of these groups based on HFU definition (Fig. 3).
3) The density log was then used to confirm the zonation. To reach this goal, both gamma ray and density log were normalized and plotted versus depth (Fig. 4).

In this category total reservoir depth divided in to three flow units as illustrated in Figs. 3 and 4. It can be seen that the same hydraulic flow unit identified in different depth by both gamma ray and density logs. The result of GR can be integrated with other techniques to extrapolate results of them to un-cored intervals.

4.3 Flow zone indicator

The method for the flow unit zonation was developed using *FZI* concept. All samples with similar *FZI* values belong to the same flow unit because of the similarities in their pore throat attributes. Iterative multi-linear clustering regression (IMLR) technique is used by HFUA software to find the optimum number of flow units.

HFUA is a self developed software for clustering. Indeed, this software uses an iterative multi linear, regression algorithm to identify HFU clusters of a certain core sample. It loads an ASCII file of permeability and porosity data. Ones the calculation procedure is done, *RQI* is then plotted versus normalized porosity. All calculations are done by using visual basic programming. Data clustering is based on user decision by clicking on a desired point of the plotted figure. This makes the software to pass an optimized line through the data by considering the minimum sum of error. To minimize the impacts of outlier points, the data should be fitted using robust least squares regression. This is addressed by software using a robust Levenberg-Marquart (Bisquare weights) regression scheme. The scheme finds a curve that minimizes the absolute weight of sum squares, rather than the squared differences. Therefore, extreme values have minimum impact on the results.

The HFU classification process using core data requires the following steps:

1) Compute *RQI* and normalized porosity φ_n from core information.
2) Plot *RQI* versus φ_n in logarithmic space.
3) Use a reasonable initial guess of the intercept each straight-line equation, the mean *FZI* value of each HFU.
4) Assign core sample data to the nearest straight line.
5) Recalculate the intercept of each HFU using Levenberg-Marquart regression equations.
6) Compare the new and old values of the intercept for every straight line. If the difference is within the acceptable tolerance, update intercept values and go to step 4).
7) The procedure above should be repeated until the optimal location of each straight line is found in which the error sum of squares is a minimum for the desired number of hydraulic flow units (Fig. 5).

To find the optimum number of flow units, sensitivity analysis has been conducted on different number of flow units.
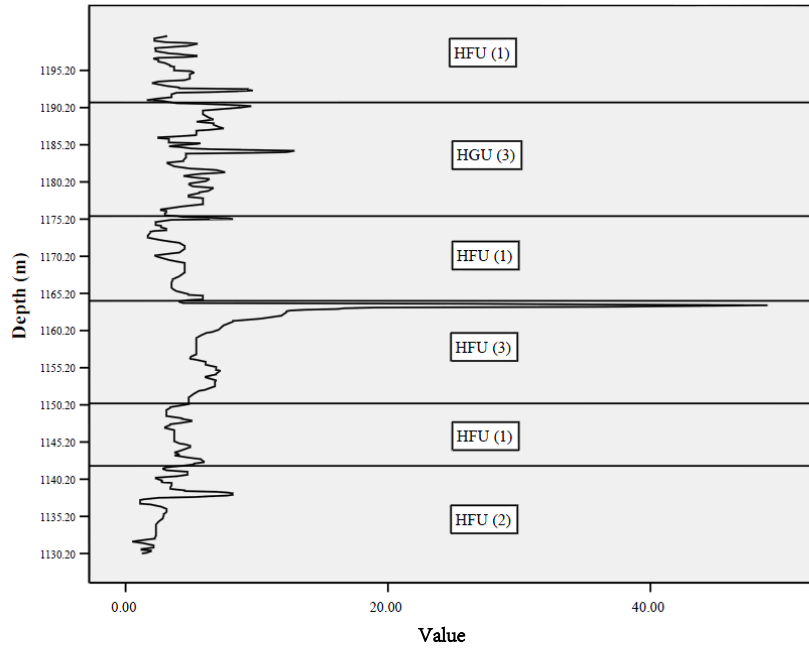
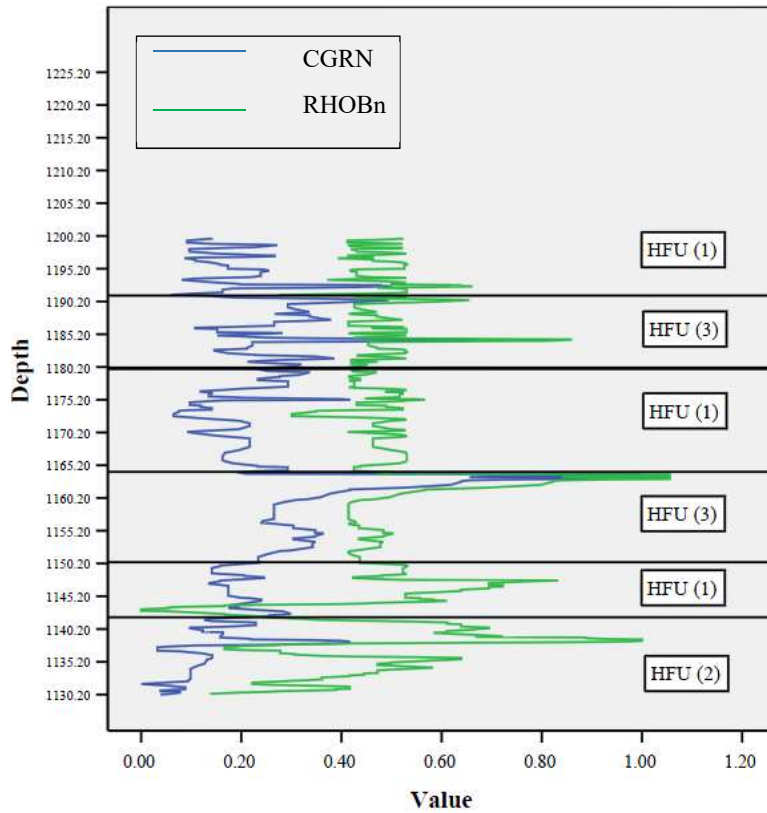**Fig. 3.** Identification of flow units from gamma ray log.

Fig. 4. Flow unit zonation using both gamma ray and density logs (CGRN means compensated gamma ray neutron; RHOBn means neutron density log).
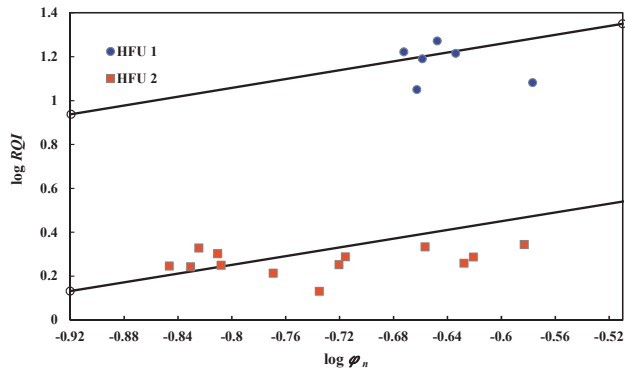
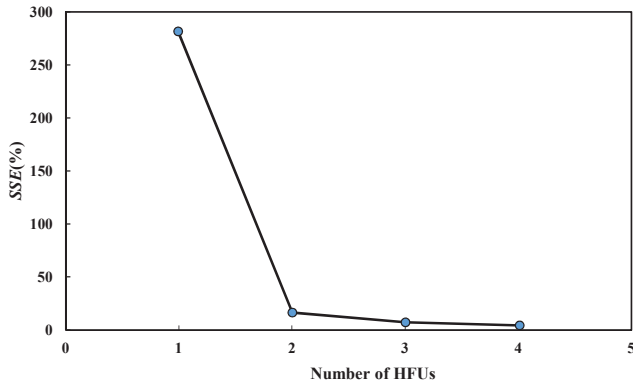**Fig. 5.** Hydraulic flow unit identification based on *FZI* method.

Fig. 6. Total *SSE* versus number of flow units.

Table 1. Distribution of each HFU with its correspondent *FZI* value.

HFU groups	FZI (μm)	Depth intervals (m)
HFU 1	12.23	1113.0-1125.0, 1150.4-1200.0
HFU 2	78.02	1142.0-1150.4

Adding more HFUs should cause a reduction in the sum of square error (*SSE*). However, as we continue to add more HFUs, we will reach a point where error reduction is getting smaller and smaller. The *SSE* in this case can be used as a criterion for determining when we have enough HFUs to describe the data. A plot of error sum square versus the number of HFUs is shown in Fig. 6. This clearly shows a declining *SSE* curve with adding more HFUs until it gets to 2 where the *SSE* curve will be flat. This indicates that two HFUs are fair representations of the number of HFUs in the formation.

The distribution of these units in different depth and the *FZI* values are shown in Table 1.

4.4 Winland's r_{35}

Winland, H.D. (Aguilera, 2002; Mirzaei-Paiaman et al., 2018) used mercury injection capillary pressure curves and multiple regression analysis to develop an empirical equation. The proposed equation included porosity, air permeability, and the pore aperture corresponding to a mercury saturation of 35% from over 300 sandstone and limestone samples. He ran regressions for other percentiles (30, 40, and 50), but the best correlation (highest R^2) was obtained for the 35th percentile. The Winland's equation, which was used and published by Kolodzie (Jaya, 2005) is as follows:

$$\log r_{35} = 0.732 + 0.588 \log k - 0.846 \log \varphi \qquad (6)$$

where r_{35} is the pore aperture radius (μm) corresponding to the 35th percentile mercury saturation, k is air permeability in mD, and φ is porosity in percentage.

According to Slotz et al. (2003), five petrophysical flow units with different reservoir performances can be distinguished by ranges of r_{35}, which are introduced in Table 2. The steps included in this method can be summarized as follows:

1) The r_{35} for each sample was calculated by Eq. (6).
2) A plot of r_{35} versus sample number was drawn. The r_{35} radii were classified into macro-porous, meso-porous, and micro-porous. The results are shown in Fig. 7.
3) The groups were interpreted as flow units.
4) Samples were assigned to their corresponding flow unit. Corresponding *FZI* values were calculated from plot of *RQI* versus φ_n for each flow unit. Results are shown in Fig. 8.
5) These HFU definitions extrapolate to the entire depth of

Table 2. Flow unit classification by Winland r_{35} method.

Group name	r_{35} (μm)
Mega-porous	> 10
Macro-porous	2.5-10
Meso-porous	0.5-2.5
Micro-porous	0.2-0.5
Nano-porous	< 0.2

Table 3. Calculated *FZI* values for each HFU definition based on r_{35}.

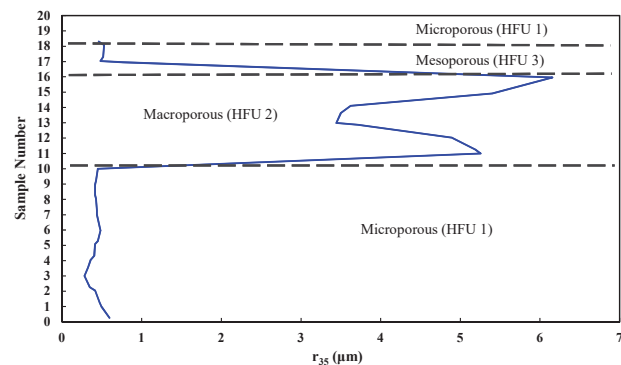| HFU Groups	FZI
HFU 1	11.22
HFU 2	72.13
HFU 3	17.13

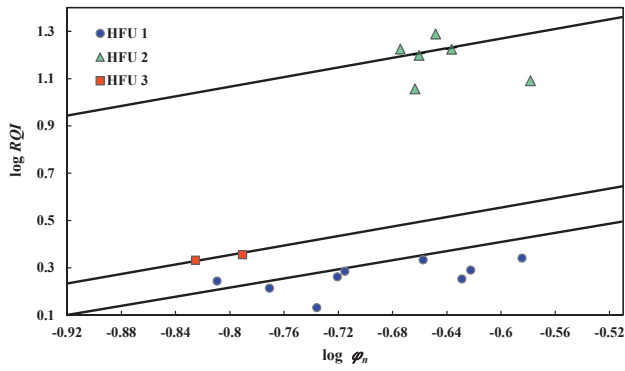**Fig. 7.** Hydraulic flow unit classification based on r_{35}.

Fig. 8. Plot of *RQI* versus normalized porosity for HFUs identified by r_{35} technique.
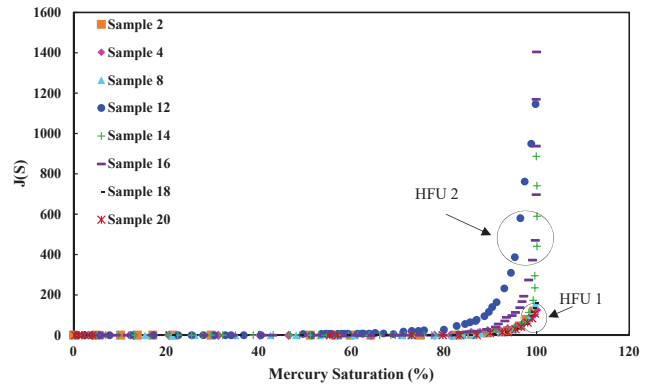

Fig. 9. Plot of *J*-function versus mercury saturation for different samples.

the reservoir based on GR and DL as discussed before.

Three hydraulic flow units have been defined based on r_{35} model (Fig. 7). The *FZI* values for each unit are shown in Table 3.

4.5 Capillary pressure curves

Knowing that capillary pressure should depend on the porosity, interfacial tension, and mean pore radius, Leverett defined the dimensionless function of water saturation, which he called *J*-function (Leverett, 1941). This function was originally formulated as follows:

$$J\left(S_w\right) = \frac{P_c\left(S_w\right)\sqrt{\frac{k}{\varphi}}}{\sigma\cos\theta} \quad (7)$$

where P_c is capillary pressure (psia) at a saturation S_w (fraction), σ is the interfacial tension (dyne/cm), k is permeability (mD), θ is wettability angle and φ is porosity (fraction). In order to characterize the capillary pressure curves by contact angle, Swanson (Swanson, 1981) developed another parameter that can be used as single point method for comparing capillary pressure curves. He stated that the maximum curvature of the hyperbolic equivalent of a capillary pressure curve is found at the intersection of the hyperbola with a 45° line passing through the origin of the hyperbolic axes. The ratio of the coordinates of this point, $(S_b/P_c)_{A,Hg}$, has a maximum value at the apex of the hyperbola. According to Swanson, the capillary pressure at this point corresponds to the pore sizes that effectively interconnect the total major pore system that dominate fluid flow. Wells et al. (1985) presented alternative method for calculating the Swanson parameter. Swanson observed that a plot of $(S_b/P_c)^{1/2}$ versus log S_b (the bulk volume occupied by mercury) resulted in a well-defined minimum, which is a unique petrophysical parameter (ψ_{Hg}) for a given sample (Swanson, 1981):

$$\psi_{Hg} = \left(\frac{P_c}{S_b}\right)^{\frac{1}{2}} \quad (8)$$

This parameter is related to Swanson Parameter by (Swanson, 1981):

Table 4. Calculated values of ψ_{Hg} for each sample.

Samples	ψ_{Hg}	HFU groups
2	15.28	HFU 1
4	15.57	HFU 1
8	15.96	HFU 1
12	7.83	HFU 2
14	5.70	HFU 2
16	7.63	HFU 2
18	13.84	HFU 3
19	13.68	HFU 3

$$\psi_{Hg} = \left(\frac{P_c}{S_b}\right)^{\frac{1}{2}}_{A,Hg} \quad (9)$$

The data source for this was Specific Core Analysis Lab data, mercury injection data (10 capillary pressure curves), gamma ray, and density logs. The steps followed in this method are explained as follows:

1) The capillary pressure curves were normalized using the $J(S_{Hg})$-function.
2) The $J(S_{Hg})$-function was plotted as a function of mercury saturation (S_{Hg}) in logarithmic scale. By visual inspection, the curves with similar shapes were grouped.
3) To interpret the flow units, both similarity in shape and location along the depth of the well were taken into account. Curves that were similar and located within a certain depth interval were considered to be a flow unit. Two flow units were defined as shown in Fig. 9.
4) To confirm this flow unit definition, the petrophysical parameter ψ_{Hg} of the samples were calculated. These values were compared to check that they were similar within the flow units. It was observed that the ψ_{Hg} values of samples in each flow units are in a certain range. The results are shown in Table 4.
5) The primary flow units were extrapolated to the un-cored depths of the well by using the gamma ray and the density logs.

The results of HFU classification by this method were the same as the one obtained previously by *FZI* model with the

same *FZI* values for each flow unit.

After determining the HFUs, capillary pressure curves were normalized for each HFU using Desouky's approach (Desouky, 2003). The method requires the measurements of capillary pressure, irreducible water saturation, and routine core data such as permeability and porosity.

5. Normalization of capillary pressure curves

In order to evaluate the effect of flow unit classification on the capillary pressure normalization, P_c curves for each flow unit were normalized using Desouky's method (Desouky, 2003). Desouky modified *J*-function to incorporates the effects of pore geometry (pore size distribution index (λ) and *FZI*), lithology index (J^*) and irreducible water saturation. Desouky's method generally accounts for simplification of the heterogeneity. From Eq. (1) and Eq. (3) the term $\sqrt{k/\varphi}$ is given by:

$$\sqrt{\frac{k}{\varphi}} = FZI \times \varphi_n \qquad (10)$$

Desouky derived the following equation by substituting Eq. (10) into Eq. (7) (Desouky, 2003):

$$J(S_w) = P_c \times FZI \times \frac{\varphi_n}{\sigma \cos \theta} \qquad (11)$$

where $J(S_w)$ is Leverett *J*-function, P_c is capillary pressure in psi, σ is interfacial tension in dynes/cm, θ is contact angle.

For capillary pressure data of a constant pore geometry (i.e., a fixed value of *FZI*), the relationship between the values of $J(S_w)$ and normalized water saturation (S_{wn}) is given by (Desouky, 2003; Tiab et al., 2015):

$$J(S_w) = J^* \times S_{wn}^{\frac{-1}{\lambda}} \qquad (12)$$

where (Tiab et al., 2015):

$$S_{wn} = \frac{S_w - S_{wi}}{1 - S_{wr}} \qquad (13)$$

The term J^* is known as the lithology index and its value equals to $J(S_w)$ when $S_{wn} = 1$. The term λ is the pore size

distribution index, which is equal to the reciprocal of the slope.

Substituting Eq. (12) in Eq. (13) and re-arranging it, one obtains (Desouky, 2003):

$$P_c = J^* \times S_{wn}^{\frac{-1}{\lambda}} \frac{\sigma \cos \theta}{FZI\varphi_n} \qquad (14)$$

Eq. (14) is the normalized capillary pressure equation for each identified flow unit of a given reservoir.

Given the routine core data (k and φ), capillary pressure data (P_c - S_w), and irreducible water saturation (S_{wr}), the following steps will be taken to normalize the capillary pressure curves for each flow units of different HFU classification as obtained in previous parts:

1) Capillary pressure data of each flow unit were identified. The capillary pressure data of each flow unit are corresponding to the core data of that unit.
2) Capillary pressure data and core data were used to calculate the values of *J*-function and normalized water saturation from Eq. (10) and Eq. (12), respectively.
3) The values of *J*-function against normalized water saturation were plotted on log-log scale, and then J^* and λ, for each flow unit were determined. Results for each HFU models are shown in Fig. 10(a), Fig. 11(a) and Fig. 12(a). The normalized P_c curve equation for each unit was determined, using Eq. (13). The normalized capillary pressure curves are illustrated in Fig. 10(b), Fig. 11(b) and Fig. 12(b).

6. Results and discussion

6.1 HFU classification

Various flow units were identified by applying different HFU classification methods on available log and core data. *FZI* and capillary pressure methods resulted in two HFUs, while reservoir was divided into three flow units when GR/DL and Winland's r_{35} were employed. Since pore size distribution index varies considerably through different flow units, it would play a key role in defining HFUs. Hence, a desirable method would be the one that is more sensitive to the pore geometry
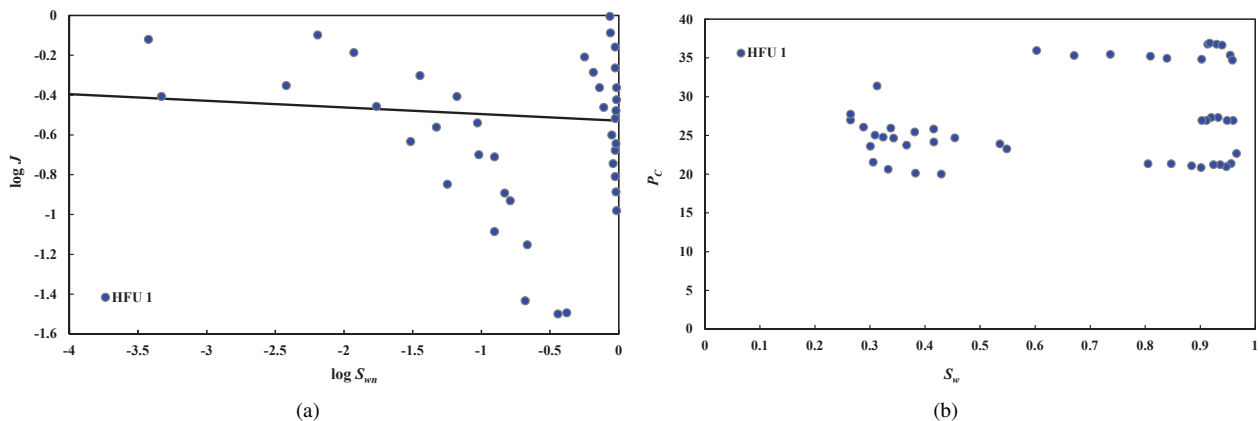

Fig. 10. (a) *J*-function versus normalized saturation when one flow unit is defined; (b) Normalized P_c curve of the reservoir (one HFU model).
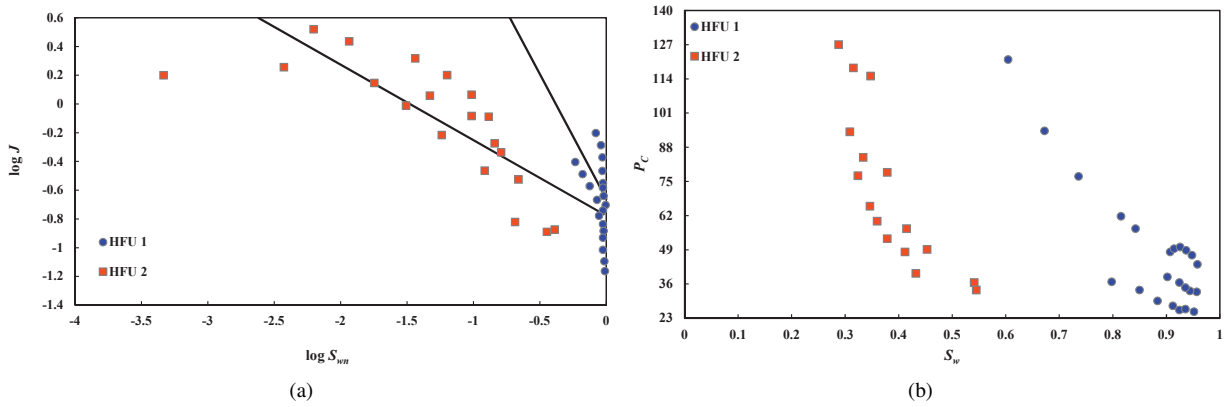
Fig. 11. (a) *J*-function versus normalized saturation when two flow unit is defined; (b) Normalized P_c curve for all flow units (two HFU model).
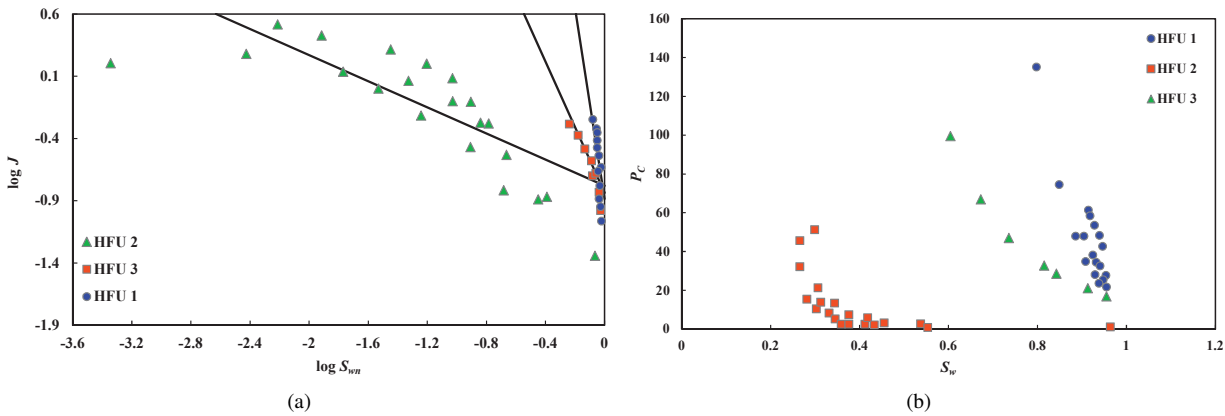

Fig. 12. (a) *J*-function versus normalized saturation when three flow unit is defined; (b) Normalized P_c curve for all flow units (three HFU model).

Table 5. Summary of the results for each model.

Models	HFUs	*FZI*	*J**	λ
One HFU	HFU 1	21.98	0.3244	27.3219
Two HFUs	HFU 1	12.23	0.2149	0.58
	HFU 2	72.13	0.1685	1.92
Three HFUs	HFU 1	11.22	0.1203	0.1189
	HFU 2	72.13	0.1685	1.92
	HFU 3	17.13	0.1317	0.367

Table 6. Summary of total sum of square errors and correlation coefficients between measured P_c and normalized one.

Models	Total *SSE* (%)	R^2
One HFU	8.67	0.245
Two HFUs	3.39	0.557
Three HFUs	2.46	0.741

of the rock. In this study, Winland's method is a more robust technique, as it divided the reservoir into three flow units. Although three HFUs can be also defined using GR and DL, this division is highly relying on visual accuracy, so it would be recommended to use more advanced clustering methods along with GR and DL. The results of HFU classification are summarized in Table 5.

6.2 Normalizing P_c curves

An increase in the number of flow units reduces the total sum of square errors and causes the correlation coefficient (R^2)

between measured values of capillary pressure in the lab and normalized values to go up Table 6, therefore, subdivision of the reservoir into hydraulic flow units significantly improve the normalization of P_c curves. This is due to the fact that the capillary pressure curves are dependent upon the pore geometry and pore size distribution.

In order to have more accurate results, those models which are more sensitive to pore size distribution index should be used to define flow units. In this study the third method has higher accuracy compared to the other techniques, so that Winland's r_{35} will be recommended to use for normalization of P_c curves.

7. Conclusions

1. Different HFU techniques resulted in different HFU

classification. This is because: (a) Employing different sources of data. (b)Application of different interpretation techniques: *FZI* was based on sensitivity analysis on number of HFUs and interpretation on reduction of *SSE*, Windland r_{35} was a rigorous empirical equation, GR was based on visual interpretation and was more qualitative.

2. Pore size distribution index is an important parameter that change significantly between different flow units.

3. Those techniques that are more sensitive to this parameter were classified reservoir into more flow units.

4. Classification of reservoir into different flow units, improved normalization of capillary pressure curves.

Acknowledgement

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