Geologically based integrated approach for zonation of a Late Jurassic–Early Cretaceous carbonate reservoir; a case from Persian Gulf

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Abstract

In this study, our attempt is to integrate sedimentological and petrophysical data for reservoir evaluation in the sequence stratigraphic framework. Petrographic analysis of the Late Jurassic–Early Cretaceous Fahliyan Formation reservoirs of two oilfields in the northwest of the Persian Gulf led to recognition of twelve microfacies. They can be classified into four facies associations, including open marine, shoal, lagoon and tidal flat, which are deposited in a homoclinal ramp carbonate. Sequence stratigraphy of the studied successions led to the recognition of three third-order depositional sequences based on vertical changes in microfacies and gamma ray analysis. Except for the upper boundary of the third sequence, the other sequence boundaries are type I (SBT.1). Dissolution is the most important diagenetic feature that affected the lower depositional sequence which is caused by the development of subaerial exposure after the deposition of the Fahliyan Formation, whereas cementation is the main diagenetic feature affecting the second- and third depositional sequences, causing their lower reservoir quality. In order to identify the flow units, the flow zone index methods, porosity throat radius (R35) and modified Lorenz based on stratigraphy were applied. The key wells studied in this area have shown good correlation throughout the studied oilfields which may potentially be used for hydrocarbon exploration and field development in the Late Jurassic–Early Cretaceous deposits of the Persian Gulf. This study integrates geological and petrophysical data (rock typing) toward sequence stratigraphic framework.

Keywords Reservoir zonation · Diagenetic impact · Sequence stratigraphy · Flow unit · Late Jurassic–Early Cretaceous · Iran

Introduction

Carbonate reservoir features, external geometry and their internal architecture are generally controlled by spatial distribution of depositional facies, diagenetic imprints and sequence stratigraphic position. To understand reservoir quality and its governing factors, facies analysis along with diagenetic studies (e.g., Dunnington 1967; Slatt 2006; Lucia, 2007; Ahr 2008) should be considered. Integration of geological and petrophysical data improved our understanding

of carbonate reservoir anatomy, especially when this combination is in the sequence stratigraphic framework of the field (Enayati-Bidgoli and Rahimpour-Bonab 2016; Andrieu et al. 2017; Assadi et al. 2018). Facies analysis and diagenetic studies associated with pore system analysis are the essential steps for reservoir properties characterization including determination of reservoir heterogeneity, flow units and their spatial distribution along with correlation of reservoir zones (Enayati-Bidgoli and Rahimpour-Bonab 2016; Assadi et al. 2018). It has been shown that the diagenetic trends and the general anatomy of reservoirs are affected, at least indirectly, by relative sea level (RSL) changes and the sequence stratigraphic framework (Taghavi et al. 2006; Rahimpour-Bonab et al. 2012; Kordi et al. 2017). In short, RSL changes indirectly controlled depositional and diagenetic features of the carbonate successions in various scales (Zecchin and Catuneanu 2015). Earlier, a reservoir zonation scheme, based on these geological attributes, is applied for

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the Permo-Triassic successions of the eastern Persian Gulf area (Enayati-Bidgoli and Rahimpour-Bonab 2016). In addition, rock types for the Grainstone Facies of Jurassic Arab Formation in the Persian Gulf are identified by Assadi et al. (2018). Riazi (2018) worked on the rock typing and flow unit classification of some Iranian carbonate reservoirs and Mirzaei-Paiaman et al. (2019) used Asmari Formation data for petrophysical rock typing indices. In the current research, the Late Jurassic–Early Cretaceous carbonate reservoir of the Fahliyan Formation in the northwest of Persian Gulf is the subject of the study. This formation is one of the most important hydrocarbon reservoirs in the Arabian Platform including the Persian Gulf and Zagros basins. Geochemistry, sedimentary environments, sequence stratigraphy, biostratigraphy and petrophysical features of the Fahliyan Formation have been studied by many investigations (Hosseini and Conrad 2008; Adabi et al. 2010; Maleki and Lasemi 2011; Sahraeyan et al. 2013; Ameen and Gharib 2014; Jamalain and Adabi 2015; Soleimani, et al. 2017). The main purpose of this study is to investigate the reservoir characteristics of the Late Jurassic–Early Cretaceous Fahliyan Formation in the sequence stratigraphic framework using the combination of facies/diagenetic studies and petrophysical analysis. The results of core descriptions, petrographic studies and petrophysical diagrams are used to determine and correlate flow units and reservoir zones in the studied area.

Geological settings

Most of the world petroleum reserves (65% oil and 35% gas) are located in the Middle East; in addition, the world's largest and huge oilfields (Ahwaz and Marun in Iran, Qawar in Saudi Arabia, Burgan in Kuwait, Romila in Iraq, Dukhan in Qatar and Bob in the UAE) are located in the Arabian plate (Sharland et al. 2001). The studied reservoir in the northwest of the Persian Gulf is located in the northeast of the Arabian plate. The Fahliyan Formation in some oilfields in this area shows many similarities in terms of sedimentary environment, lithology and other features. In addition, the lower boundary of this unit is identified by the Manifa carbonates which are unconformably deposited over the Hith Formation. In contrast, the lower contact of the Fahliyan in other fields, that are located in the northwest of the Persian Gulf, due to deposition in the Gotnia basin (outer ramp), is composed of mud-supported facies. Most of them are similar to oilfields located in the Abadan Plain. In the southern part of the Persian Gulf, within the borders of Saudi Arabia, Bahrain, Qatar and Iraq, this formation is equivalent to the Sulaiy, Yamama and Ratwai formations, respectively. However, in Kuwait, it is equivalent to the Minagish Formation. Comparisons of the Fahliyan facies associations with their counterparts in the neighboring Arab countries indicate a

ramp-type or low-slope carbonate platform (Sadooni 1993; Davis et al. 1997). The Upper Jurassic–Lower Cretaceous Fahliyan Formation is the most important petroleum reservoir of the studied fields (Hosseini et al. 2008). The thickness of this unit is about 350 m in the studied subsurface sections (key wells). It is divided into Manifa (Late Tithonian) and Yamama (Berriasian–Valanginian) carbonate members, underlain by the Gadvan Formation and overlain by the Hith evaporate formation (Fig. 1a). The Hith Formation extends from the northeastern Saudi Arabia to Doroud field in the northwest of the Persian Gulf and is underlain by Manifa carbonates (Hughes and Naji 2008). The upper contact of the Fahliyan with the Gadvan shales is distinct and based on regional studies (Sharland et al. 2001; Ziegler 2001) corresponds to the Late Valanginian unconformity. Although various reservoir zonations are represented for the Fahliyan Formation in the northwest of the Persian Gulf (Fig. 1b), in this study we used the Elf (Bohler and Gustin 2000) zonation which is based on petrophysical characteristics. In this zonation, the Manifa section is divided into two zones *L1* and *L2* and the middle Yamama is divided into nine zones *K–J–I2–I1–H2–H1–G3–G2–G1*. Moreover, the upper Yamama is divided into four zones *F2–F1–E–CD*. In addition, each of these sections indicates exclusive facies changes, diagenetic history, pore system and their own reservoir characteristics.

Material and methods

In order to analyze microfacies and investigate the diagenetic processes and considering the limitations of the core accessibility in the Fahliyan Formation, from a total of 9 selected key wells, core data of 7 wells were used from two neighboring oilfields (4 are from O oilfield and 3 other wells from K oilfield) situated in the northwest of the Persian Gulf. From a total of 808 m of taken core, 859 thin sections were prepared by Iranian Offshore Oil Company and National Iranian South Oil Company. Moreover, some of them were stained with Alizarin Red S and some were prepared by injection of blue epoxy adhesive in order to investigate porosity. Based on available data, *B*, *C*, *F* wells were used as key wells for petrophysical studies and *A*, *B*, *C*, *D*, *E*, *F* wells were considered as key wells for petrographic examinations. From this number of thin sections, 25,262 images were prepared, all of which were evaluated for this study. After collecting the well logging diagrams, the results of studied cores and drawing stratigraphic columns, the sedimentary facies are classified using Dunham's (1962) method. In addition, the percentage of skeletal and non-skeletal grains is determined using Flügel comparison charts (Flügel 2010) by the help of SLDS software. Then, the types of microscopic facies are identified and classified based on the standard facies of Flügel (2010)

Fig. 1 **a** Stratigraphic column of Upper Jurassic–Lower Cretaceous and lithostratigraphic rock units at the studied area (modified from Sharland et al. 2001), **b** reservoir geology study comparison between

INTERA, ELF 95, IPAC Layering and ELF2000 (modified from Bohler and Gustin 2000)

as well as Wilson (1975), and after microfacies analysis and their sedimentary environment, a conceptual depositional model is suggested. Then, by detailed petrographic examinations, diagenetic processes and their history are determined. Sequence stratigraphic boundaries and the sedimentary cycles are determined by applying CycloLog software using gamma ray diagram (CGR or SGR); then each sequence is separated based on facies evidence and diagenetic results.

Moreover, the main stratigraphic levels and system tracts of each sequence in the third order are identified and interpreted. After identifying and separating the sequences, the porosity types and their frequency are recognized. In addition, using available data such as cores porosity–permeability (poroperm) values and reservoir quality index (RQI), the reservoir quality of each sedimentary sequence is calculated. Finally, using methods such as stratigraphic modified Lorenz

plot (SMLP) (Amaefule et al. 1993), pore throat radius (R35) (Kolodzie 1980) and flow zone index (FZI) (Gunter et al. 1997), the flow units of this sequence are determined by sedimentary sequence separation and compared with each other. Eventually, the final analysis is performed according to the combination of the results of the studies. This research was carried out using the following software applications: SLDS, for the preparation and processing of qualitative and quantitative data of thin sections; CycloLog, for determining the facies of the logs; Geolog, for displaying petrophysical graphs, stratigraphic columns and graphical data interpretations; CorelDRAW, for drawing figures, graphs, models and preparing sedimentary logs, and Microsoft Office software for writing the article.

Facies analysis and sedimentary environment

Investigation of carbonate facies can provide invaluable information on the physical and chemical conditions of the ancient sedimentary environment (Colombie and Strasser 2005). The most efficient instrument for identifying the sedimentary environment and the affecting processes is the facies analysis (Catuneanu 2013; 2020). From a petroleum reservoir perspective, sedimentary facies analysis plays an important role in studying the expansion of reservoir zones and can be very effective in discovering new hydrocarbon traps and drilling new wells (Jahnert and Collins 2012). Petrographic studies of the Fahliyan Formation were carried out, aiming to identify microfacies and sedimentary environment based on facies differentiation, type and frequency of skeletal and non-skeletal components, sediment texture and structures and also comparison with the standard facies models (Wilson 1975; Flügel 2010). According to our petrographic examinations and comparison with the standard models, 12 microfacies were distinguished that belong to four facies associations, including tidal flat, lagoon, shoal and open marine realms (Table 1).

The gradual change from deep facies (A1) to shallow facies (D3) and the absence of re-sedimented deposits and deep marine facies and fauna reflect the low-angle profile and deposition in a homoclinal carbonate ramp in studied areas. The facies associations indicate that the Fahliyan Formation is deposited in inner to middle ramp settings (Fig. 2).

Diagenesis

Diagenetic processes generally affect the petrophysical properties of carbonate units including poroperm, throat size and capillary pressure (Ahr 2008; Moradi et al. 2019). The most important diagenetic processes influencing the

Fahliyan reservoir include micritization, cementation, dissolution, physical and chemical compaction, dolomitization, bioturbation, neomorphism, pyritization and fracturing (Fig. 3a). Some of these processes, especially cementation and compaction, are accounted as the most important reservoir destructive processes. In contrast, dissolution and fracturing are known as processes to improve the reservoir poroperm and exert a major impact on the pore system and reservoir characteristics. The history of diagenetic events determines the relative time and order of diagenetic processes on a given sedimentary sequence (Fig. 3b). The proposed paragenetic sequence of diagenetic events indicates diagenesis in eogenetic, mesogenetic and telogenetic realms. In addition, most of the diagenetic processes are eogenetic in origin and so occurred in a situation where the diagenetic environment was under influence of the depositional environment (Fig. 3c).

Sequence stratigraphy

To better understand the sedimentary basin changes, it is necessary to examine the effect of tectonic events and global sea-level changes in the formation of stratigraphic sequences. Sequence stratigraphic models and frameworks can be used to interpret facies changes over time and space (Catuneanu 2020; Assadi et al. 2016). By combining the information obtained from the study of cores and logs, well logging diagrams and drawing logs, an attempt was made to separate sedimentary sequences into related genetic units. In order to differentiate the sequences, sequence boundary (sb) and maximum flooding surface (MFS) were identified. Moreover, for this purpose, the sequence stratigraphic framework provided by Wagoner and Vail is used (Van Wagoner et al. 1990; Vail and Wornardt 1991). On this base, three third-order sequences were identified, the main stratigraphic levels of which include four sequence boundaries (SBs) and three maximum flooding surfaces (MFSs). All of these sequences identified in the studied sequences are part of the second-order transgressive–regressive sequence (Sharland et al. 2001).

Sequence I

This third-order sequence with a mean thickness of 50 m is limited to the Manifa member and includes all the Manifa stromatolite carbonates at the base of the Fahliyan Formation. This sequence can be divided into two fourth-order sequences (FS1–a and FS1–b) and its lithology is mainly carbonate. Its lower boundary places on the Hith Formation (Late Tithonian) were identified as a regional unconformity by Sharland et al. 2001. The upper boundary of sequence I which coincides with the top of the L1

Table 1 Description of recognized microfacies for the Fahliyan Formation in the studied wells

Facies code	Facies associations	Facies	Frequency	Lithology	sorting	Roundness	Energy level	Components skeletal non-skeletal
A1	Sallow open marine	Bioclast mudstone to wackestone	9.15	Limestone	Fine	–	Low	Bioclast, Foraminifera, algae, echinoderm, -
A2		Sponge spicule bioclast wackestone	5.50	Limestone	Poor sorted	Poor	Low	Bioclast, Sponge spicule, foraminifera, algae, echinoderm, -
B1	Shoal	Coral and Lithocodium Boundstone	12.5	Limestone	–	–	Medium/High	Algae and coral, Bivalve debris, foraminifera. -
B2		Bioclast Intraclast Grainstone	7.80	Limestone	Moderately sorted	Poor	High	Ostracod, Gastropods, echinoderm, intraclast, Ooid, Peloid
B3		Ooid grainstone	5.50	Limestone	Very well sorted	Good	High	Foraminifera, Ostracod, Gastropods, echinoderm Ooid, Peloid
B4		Bioclast and peloid grainstone	15.0	Limestone	Well sorted	Good	High	Bioclast, foraminifera, Ostracod, Gastropods Peloid, Ooid
C1		Bioclast peloid packstone	16.6	Limestone	Well sorted	Medium	Medium/High	Bioclast, foraminifera, algae, echinoderm Peloid, Ooid
C2	Lagoon	Peloid packstone	7.20	Limestone	Moderately sorted	Good	Medium/Low	Echinoids, Bivalve debris Peloid, intraclast, Ooid
C3		Trocholina bioclast wackestone	10.8	Limestone	Poor sorted	Poor	Low	foraminifera, Gastropods, Bivalve Peloid
D1		Ooid and Peloid Grainstone	5.00	Limestone	Moderately sorted	Medium	High	Ostracod Peloid, Ooid, pisoid
D2		Stromatolite boundstone	3.40	Limestone	–	–	Low	Ostracod Peloid, Ooid
D3		Evaporate and fenestral ostracod mudstone	1.65	Anhydritic Limestone	Fine	–	Low	Ostracod Peloid

reservoir zone (Late Tithonian–Berriasian) is characterized by an abrupt change from low-energy mud-dominated tidal deposit (zone L1 of Manifa) to high-energy grainstones of shoal deposit (Zone K of Yamama) and shows evidence of subaerial exposure, such as karstic diagenetic features, pervasive dissolution, development of pore and intergranular porosity, and finally development of meteoric

cements. The maximum flooding surface of the Manifa member is correlated with the MFS of J110 which is reported in the Kuwait within the calcareous shales of the Macul Formation, the carbonates of the upper part of the Hith Formation in the central parts of the Arabian Plate, and the carbonates of the Solai Formation in southern Iraq by Sharland et al. 2001.

Fig. 2 Conceptual depositional model and relative positions of defined microfacies and facies associations in the studied intervals

Fig. 3 **a** Pie diagram of diagenetic processes frequency in the studied wells. **b** Schematic of diagenetic history (b1), warm and arid climate during deposition of the Hith Formation and its subsequent subaerial exposure during the Tithonian (stage 1), the dominance of marine environment during deposition of the Manifa member in the Late Tithonian (stage 2), (b2) followed by subaerial exposure and meteoric conditions, (b3) deposition of the Yamama member, then its meteoric diagenesis during the Berriasian to Valanginian, (b4) the Manifa

and Yamama were in shallow to mid-burial diagenetic environments during deposition of the Gadvan, Dariyan and Kazhdumi formations (from the Late Hauterivian to Albian) (b5) deep burial during the Cenozoic (from the Late Cretaceous to present), **c** paragenetic sequences of diagenetic events occurred in three diagenetic environments including marine, meteoric and burial realms and their tentative effects on porosity

The TST of sequence I with an approximately 20 m thickness is started by mud-dominant tidal facies alternations such as ostracod mudstones and stromatolite boundstone with anhydritic nodules in the lower part. The beginning of this sequence correlated with the PB4000 sequence boundary (Fig. 4a). These parts of the sequence are characterized by increasing gamma values close to the top of the L2 zone. Consequently, the grain-supported sediments migrated in a retrogradational pattern toward the shoreline. The maximum flooding surface in this sequence is characterized by ooid grainstones which are indicating maximum landward migration of shoal facies and correlate with the maximum flooding surface of J110, introduced by Sharland et al. 2001. The output of the CycloLog diagram in *A*, *B* and *D* wells (INPEFA) shows good correlation with NB3000 maximum flooding surface (Fig. 4b). The HST of sequence I with an approximate thickness of 30 m predominantly comprises aggrading ooid grainstone of shoal facies and mudstone of tidal-related facies (Early HST) that change upward to the prograding ostracod mudstones, stromatolite and dolomudstone of tidal-related facies without anhydrite nodule (Late HST). The Late HST of sequence *I* shows intense dissolution features which reflect the subaerial exposure at the top of Zone L1 and represent the SBT-1 (SB-2). This sequence boundary is correlated with PB3000 and characterized by a sharp low gamma response in the most studied wells in O oilfield (Fig. 4c). In this sequence, average tidal facies frequency is about 60.3%, followed by the lagoon and shoal facies with an average frequency of 30.1% and 9.6%, respectively.

Sequence II

The sequence II (Berriasian–Valanginian) with an average thickness of 200 m within the middle part of the Fahliyan Formation (Middle Yamama) comprises six fourth-order sequences (FS2-a to FS2-f). Its lithology is predominantly carbonate and consists of shoal, lagoon and shallow open marine facies. The lower contact of the Seq. II, at the base of the *K* reservoir zone, correlates with the PB3000. This zone is deposited discontinuously on the stromatolite layers of the Manifa. The upper boundary of Seq. II at the top of the G1 reservoir zone correlates with the PB2000 surface, shows dissolution features such as moldic porosity (Fig. 4d) and is considered as the SBT-1. The maximum flooding surface (MFS-2) in this sequence is characterized by shallow middle ramp facies. Gamma ray analysis of the wells *A* and *B* indicates the highest sea-level rise places in the open marine-related facies (in the zone I1). The transgressive system tract (TST) with approximately 80 m thickness overlies the stromatolite beds of the Manifa member. It shows deepening upward and consists predominantly of lagoonal and open marine mud-dominated sediments with a minor amount of shoal microfacies with retrogradational stacking

pattern, toward the shoreline. The maximum flooding surface of sequence II (MFS-2) is characterized by bioclastic wackestone and mudstone of the open marine microfacies which can be identified by an increase in gamma ray value in the I1 reservoir zone. This surface (MFS-2) can be correlated with the maximum flooding surface of NB2000 in all studied wells (Fig. 4e), especially *D*, *B* and *H*.

The high stand system tract (HST) of sequence II, with approximately 120 m thick, includes repeating cycles of open marine and shoal microfacies in the lower part (Early HST) (Pb2300 surface), followed by shoal and lagoonal microfacies in the upper part (Late HST) which shows a shallowing upward trend. The HST of sequence II is bounded by SBT-1 (SB-3) at the top and characterized by karstification features such as development of moldic porosity which indicates the short-term subaerial exposure. The sequence boundary (SB-3) is correlated with the PB2000 surface and is identified by a decrease in gamma ray (Fig. 4f). Generally, the gamma ray analysis (by CycloLog software) and thin-section studies show good correlation with sequence stratigraphic surfaces. In this sequence, the most shoal-related facies show average frequency of about 47.8%, followed by the lagoonal facies (42.5%) and open marine facies with about 8.8% frequency. Consequently, this sequence is distinguished from the other sequences by the abundance of the shoal facies. Petrographic analysis of *A*, *B*, *C*, *G* and *H* wells is used for recognition of the third-order sequence boundaries.

Sequence III

The sequence III (Valanginian) with an average of 100 m thickness includes the upper Yamama member of the Fahliyan Formation. This sequence comprises TST and HST which have been deposited within five fourth-order sequences (FS3-a to FS3-e). The lower boundary of sequence III places between *F2* and *G1* zones which is specified by SBT-1 (Fig. 4g); the upper boundary of sequence III is characterized by low gamma value at the top of the CD zone without any evidence of subaerial exposure (SBT-2). It can be correlated with PB-1000, as a correlative conformity. The maximum flooding surface of sequence III (MFS-3) is characterized by the shallow middle ramp microfacies and is located in reservoir zone *E*; it can be correlated with NB-1000 which can be identified as a specific peak in gamma ray in most of the studied wells (Fig. 4h). The transgressive system tract (TST), with about 30 m thickness, is comprised of organic-rich mud-dominated lagoonal microfacies with retrogradational stacking pattern and deepening upward trend. The high stand system tract (HST) of sequence III, with an average 70 m thickness, is composed of alternation of shoal and open marine microfacies at the lower part (Early HST) and followed by lagoonal mud-dominated microfacies showing shallowing upward trend

Fig. 4 Identification of sequence boundaries (SB) and maximum flooding surface (MFS) based on gamma ray analysis (INPEFA) with petrographic description of the Fahliyan Formation in the studied wells (for details refer to the text)

and progradational stacking pattern (Late HST). There is no evidence of karstification at the top of HST. The grain-supported microfacies has low presence in this system tract. This sequence is characterized by the abundance of lagoon and shallow open marine microfacies; the facies are mainly related to the lagoon environment with a frequency of 51.2%, followed by the shallow open marine facies (31.4%) and the shoal-related facies with about 17.1% frequency (Fig. 4 j, k and l). Tidal-related microfacies are rare in the sequence III. Sequence stratigraphic studies of the Upper Jurassic–Lower Cretaceous sediments in the studied oilfields showed that the identified sequences in all five wells have good correlation (Fig. 5). The sequence stratigraphy and facies analysis of the sequence III are based on the data available in *B*, *D*, *E* and *G* wells.

Reservoir quality

Despite high complexity and heterogeneity of carbonate rocks, careful study of controlling reservoir quality parameters plays a very important role in hydrocarbon exploration and production. Generally, factors leading to complexity and heterogeneity in the carbonate reservoir are multidimensional including depositional facies variations, complex diagenetic evolution and their tectonic history (e.g., fracturing) (Dou et al. 2011; Rong et al 2012; Enayati-Bidgoli et al. 2014; Mehrabi et al. 2015). Porosity values less than 5% barely make hydrocarbon reservoirs and 0.1 millidarcy is the minimum permeability for oil production (Lucia 2007).

Here, the porosity types are classified using Choquette and pray (1970) and their frequencies, obtained by investigation of core and cuttings. Consequently, the reservoir quality of each sedimentary sequence is discussed, separately. The main types of visible porosity in the Fahliyan Formation include moldic (Fig. 6a), interparticle (Fig. 6b₁ and b₂),

dissolution and enlarged vuggy (Fig. 6c), intercrystalline (Fig. 6d), fracture (Fig. 6e), growth framework (Fig. 6f), intraparticle (Fig. 6g) and fenestral (Fig. 6h). The total frequency of each porosity type and their frequencies in various facies associations are also shown (Fig. 6i and j).

The reservoir zonation and third-order stratigraphic sequences are used for demonstration, determination and correlation of the reservoir quality in the studied wells. Due to the compatibility of the upper Yamama sections with the reservoir zones (*CD*, *E*, *F1*, *F2*), the middle Yamama with the reservoir zones (*G1*, *G2*, *G3*, *H1*, *H2*, *I1*, *I2*, *J*, *K*) and the Manifa with the reservoir zones (*L1* and *L2*), the results of this study can be extrapolated to the other wells in this oilfield and even the adjacent fields, providing that their sequence stratigraphic framework is already established. In order to evaluate the reservoir quality for each sequence, parameters such as reservoir quality index (RQI) and Lucia's classification diagrams are used. Thus, hydraulic flow units and reservoir zones in the Fahliyan Formation were determined using the flow zone indicator (FZI), the porosity throat radius at 35% mercury saturation (R35) and stratigraphic modified Lorenz plot (SMLP) approaches, respectively. (See Gunter et al. 1997 and Gomes et al. 2008 for details of the methodology.) The column diagrams illustrate core porosity (routine core analyses by helium injection method) values for each reservoir zone along with the permeability values. The special core analyses (SCAL) including mercury injection and capillary pressure data of 242 samples were used in order to obtain permeability (Fig. 7 a, b).

Reservoir quality assessment: reservoir quality index (RQI) and Lucia classification (1995)

One of the best physical parameters used to quantify the microscopic structure of cavities is the Reservoir Quality

Fig. 5 Sequence stratigraphic correlation of detected depositional sequences (third order) between the studied well and oil fields (Northwest of the Persian Gulf)

Fig. 6 Thin-section photographs of the porosity types of the Fahliyan Formation. **a** moldic, **b₁** and **b₂** interparticle, **c** vuggy, **d** intercrystalline, **e** fracture, **f** growth framework, **g** intraparticle, **h** fenestral that

has been locally occluded by anhydrite cement, **i** pie diagram of total frequency percentages of porosity, **j** diagram showing the frequency of each porosity type vs. facies associations

Index (RQI); the higher the values, the better the distribution of rock voids (Jin et al. 2013). In other words, higher RQI values indicate higher reservoir quality (Xupeng 2010) (Fig. 7c). RQI values are affected by rock poroperm and are calculated through the following equation (Amaefule et al. 1993):

$$RQI = 0.0314 \sqrt{k/\Phi}$$

In this regard, RQI is in microns, K is permeability in terms of millidarcy; in addition, Φ is porosity in terms of fraction percentage. Table 2 represents the reservoir

Fig. 7 **a**, Diagrams of core porosity, **b**, core permeability and **c**, RQI by reservoir zones. **d**, Lucia's petrophysical classifications for the first sequence (Manifa member), **e**, in second sequences (middle Yamama)

and **f**, in the third sequence (upper Yamama) in the Fahliyan Formation in the studied area

Table 2 Reservoir quality values for the third-order sequences

Reservoir quality	RQI	Porosity %	Porosity % (ave.)	Permeability (md.)	Permeability (md.) (ave.)
Sequence I	0.81	4.9 ~ 30.9	20.50	0.25 ~ 2496	199.6
Sequence II	0.13	0.6 ~ 29.3	15.00	0.005 ~ 836	7.40
Sequence III	0.22	0.75 ~ 22.5	8.83	0.005 ~ 250.5	8.87

quality values for the third-order sequences which are extracted based on core and well-log studies.

The sequence I includes the Manifa member and comprises two reservoir zones (*L1* and *L2*), which show a high reservoir quality that is considered to have the best reservoir quality of Fahliyan Formation. Seemingly, the reservoir quality of this sequence is improved due to meteoric diagenesis of the tidal facies by development of dissolution features. The sequence II, which includes the middle Yamama section, consists of nine reservoir zones (*G1*, *G2*, *G3*, *H1*, *H2*, *I1*, *I2*, *J*, *K*). These values show a sharp dissimilarity of the reservoir quality with respect to the former sequence. Most of the reservoir quality of this sequence is limited to *G* series and *J* reservoir zones, and the other zones show lower quality under similar conditions. The sequence III includes the upper Yamama member and consists of four reservoir zones (*CD*, *E*, *F1*, *F2*). In this sequence, despite the lower average porosity than the sequence II, it shows higher average permeability and reservoir quality index, which, evidently, is limited to *F* series reservoir zones. Other zones in this sequence generally show poor poroform values.

To appreciate the relationships between petrophysical properties of various microfacies, as well as the impacts of diagenesis, Lucia (1995) petrophysical classification is considered. Accordingly, using poroform values of SCAL tests (wells *B*, *C* and *F*) and on base of the relationship between particle size and interparticle porosity, sorting and permeability, three petrophysical categories have been introduced.

The Lucia diagram in sequence I indicates much higher quality due to dissolution impact. This led to development of separate and interconnected cavity porosity in the subtidal facies association (ostracod Mudstone and Stromatolitic facies). In addition, this sequence is sandwiched between the two sequence boundaries of the type I (with meteoric diagenesis) causing this obvious distinction. Although, in the lower boundary of this sequence (zone *L2*), anhydrite cements have partially eliminated these pores, this destructive effect on reservoir quality has been compensated by dissolution. A large amount of poroform data of this sequence are placed at the top of the class 3 in the Lucia (1995) diagram, testifying its high reservoir quality (Fig. 7d). In addition, the RQI values reconfirm this distinction and its higher reservoir quality.

For sequence II, the Lucia's class represents its lower quality (Fig. 7e). Some data in this diagram showing better reservoir quality are limited to the G series reservoir zones, and, generally, the other zones have low reservoir quality. Most samples are located in the middle of the Lucia diagram (Class 2 and 3) and generally show medium poroperm values. The shoal and lagoon facies are dominant facies in this sequence.

Most of the data points are located in the bottom of the diagram at the sequence III, indicating lower reservoir quality compared to the first and second sequences (Fig. 7f). However, in this sequence, the reservoir zone F has a higher quality. In order to achieve these results, poroperm data of wells, C, B and F were applied. General correlation of poroperm values and RQI parameters indicates that in the sequences I and II, HST intervals show higher reservoir quality, while the higher reservoir quality of sequence III occurs in the LST interval.

Flow units

A flow unit should be relatively homogeneous in terms of petrophysical, reservoir and geological characteristics (Skalinski and Kenter 2015). So far, various methods for determining flow units have been introduced and applied by petrophysicists, petroleum engineers and geologists which are based on several approaches and data in different sandstone and carbonate reservoirs (Amaefule et al. 1993; Gunter et al. 1997; Al Tooqi et al. 2014; Chehrizi et al. 2011; Aliakbaroust and Rahimpour-Bonab 2013; Skalinski and Kenter 2015). In the present study, for reservoir zonation and flow unit identification (using for management and reservoir horizon development strategy), three methods of flow zone index (FZI), porosity throat radius (R35) and stratigraphic modified Lorenz plot (SMLP) have been used.

Flow zone index (FZI) method

Fluid flow units can be identified based on flow zone indicator values. Sedimentary environment and diagenetic processes control the reservoir geometry and the flow zone index. In other words, the flow zone index is a special parameter that consists of the geological characteristics and traits of the mineralogy and texture tribes in the structure of facies with distinct pore geometry (Tiab and Donaldson 2003). The ratio of reservoir quality index (RQI) to normalized porosity and the formulas below the flow zone index are calculated and determined (Tiab and Donaldson 2003).

$$RQI = 0.0314 \sqrt{\frac{K}{\varphi_e}} \quad (1)$$

$$\varphi_2 = \frac{\varphi_e}{1 - \varphi_e} \quad (2)$$

$$FZI = \frac{RQI}{\varphi_2} \quad (3)$$

In the above relation, RQI is the reservoir quality index, K permeability (millidarcy), φ_e effective porosity and φ_2 normalized porosity. After calculating FZI values (separately for each sequence) and plotting (FZI values), the flow units, which are separated, are shown in three selected key wells C, B and F (Fig. 8a, b and c). As shown, at least three flow units for each of the sequences are identified and discerned.

The FZI diagram for the sequence I indicates that this sequence has higher FZI values and better reservoir quality than the second and third sequences (which have somewhat similar conditions). Despite using poroperm parameters for calculation of FZI, the flow zone index values do not show a clear relationship with the porosity values (Fig. 8d, e and f). In contrast, permeability is almost directly related to the values of the flow zone index. This situation is further indicated in the diagrams of sequence I (Fig. 8g).

In carbonate reservoirs, complete separation and detection of flow units by the FZI method alone will not be sufficiently accurate. Therefore, in order to make the separation more understandable, methods such as stratigraphic modified Lorenz plot (SMLP) should be considered. However, before that, the petrophysical method of porosity throat radius in saturation of 35% of mercury (R35) was used.

Method of porosity throat radius (R35)

In this method, the radius of the porosity throat is calculated through the capillary pressure diagrams when 35% of the pores are saturated with mercury. Due to the high cost of performing capillary pressure analyzes, in situations where sufficient capillary pressure graphs are not available, the following equations are used to calculate the parameter R35 (Pittman 1992; Tiab and Donaldson 2003).

- (1) Winland $\text{LOGR}_{35} = 0.732 + 0.588 \cdot \text{LOG } K_{\text{air}} - 0.864 \cdot \text{LOG } \varphi$
- (2) Pitman $\text{LOGR}_{35} = 0.255 + 0.565 \cdot \text{LOG } K_{\text{air}} - 0.523 \cdot \text{LOG } \varphi$

In these relationships, R35 is the throat radius at 35% saturation of mercury in microns, K permeability in millidarcy and φ porosity in percentage. In the present study, the Pittman formula (Pittman 1992), which is in fact the corrected Winland equation, was applied to determine the flow units. Flow units are divided into four groups based on the R35 range as follows: micro port, meso port, macro port and mega port. Pores with larger throat radius show greater permeability (Bliefnick and Kaldi 1996).

Fig. 8 a-b-c, Schematic diagram for the logarithmic values of FZI and three flow unit types for each of the sequences in the studied wells, d-e-f, FZI–porosity cross-plot for each of the sequences in

the studied wells. j-h-i, FZI–permeability cross-plot for each of the sequences in the studied wells

Mega ports are only seen in sequence I. In this sequence, the highest frequencies are related to macro, mega and meso ports and finally micro ports. In the second and third sequences, the highest frequency is related to micro ports (Table. 3).

Therefore, the distribution of pore size with low to medium reservoir quality of the second and third sequences can be interpreted compared to the higher reservoir quality of the sequence I (Fig. 9 a, b and c). Similar to the index (FZI), the values of the porosity throat radius (R35) have little to do with the porosity (Fig. 9 d, e and f); however, the permeability increases by increasing the pore radius size (Fig. 9 g, h and i); furthermore, the highest

permeability values are observed in the samples with mega port sizes in the sequence I.

Stratigraphic modified Lorenz Plot (SMLP)

This method is an efficient technique for identifying flow units in hydrocarbon reservoirs and their zonation due to the thickness of the units and the petrophysical properties of the rock (Rahimpour-Bonab et al. 2012). Initially, porosity, continuous permeability and the ratio of permeability to porosity (K / Φ) are sorted in a stratigraphic arrangement and then the product of permeability multiplication at the relevant depths ($K * h$) and porosity at the relevant depths ($\Phi * h$) is calculated. In this method, the Y-axis shows cumulative

Table 3 Frequency of porosity throat radius by sedimentary sequences

R35 Parameter	Throat size (microns)	Sequence I	Sequence II	Sequence III
Micro port (Frequency)	<0.5	Low	High	High
Meso port (Frequency)	0.5~2	Medium	Medium	Medium
Macro port (Frequency)	2~10	High	Low	Low
Mega port (Frequency)	10 <	High	—	—

Fig. 9 a-b-c, Schematic diagram for the logarithmic values of R35 and three flow unit types for each of the sequences in the studied wells. d-e-f, R35/porosity cross-plot for each of the sequences in

the studied wells. j-h-i, R35/permeability cross-plot for each of the sequences in the studied wells

flow capacity that is the product of permeability multiplied by the layer thickness (Kh), and in the X-axis, the cumulative storage capacity, which is the product of porosity multiplied by the layer thickness (Φh). The cumulative storage and flow capacity is calculated by the following formulas:

$$kh = \frac{\sum_{j=1}^J k_j h_j}{\sum_{i=1}^I k_i h_i} \quad \phi h = \frac{\sum_{j=1}^J \phi_j h_j}{\sum_{i=1}^I \phi_i h_i}$$

Lorenz diagrams for the permeability-to-porosity ratio can show the degree of heterogeneity of the reservoir rock. This diagram can separate the flow units in different wells and indicates the ability of each area to produce from the well. In this method, units are determined based on the amount of reservoir capacity and flow capacity. The curve turning points separate different flow units (Gunter et al. 1997).

The distribution of separated flow units in each of the studied sequences is shown by the data of three key wells C, B and F (Fig. 10). In the first sequence, the distribution

Fig. 10 a-b-c, Stratigraphic modified Lorenz plot of cumulative flow capacity versus cumulative storage capacity for each of the sequences in the studied wells

of identified flow units showed that there were at least seven units separated according to the Lorenz method and the obtained diagram indicates heterogeneities in reservoir properties. Due to the general slope of the diagram, units 3, 4, 5 and 7, compared to the other flow units, have a better reservoir quality and are considered as the normal flow unit (Fig. 10a). Generally, this higher quality could be ascribed to the extensive dissolution in the tidal facies and so development of mold porosity and associated cavities.

The logarithm values of FZI and the throat radius (R35) generally show high values in these flow units. In the second sequence, the distribution of identified flow units showed that there are at least eight units separated according to the Lorenz method. Moreover, the obtained diagram indicates major heterogeneities in the reservoir characteristics. According to the slope of the diagram, units 1, 3, 5 and 7 are baffle units (low flow capacity but high storage capacity) in contrast to units 2, 4, 6 and 8 that are super-permeable units (high flow capacity and low storage) (Fig. 10b). In these flow units, the development of permeable units is justified by domination of the grainstone facies which shows meteoritic dissolution as well as intergranular porosity. Furthermore, the higher values of the FZI logarithm and the throat radius (R35) are only limited to small intervals and do not include the whole sequence. On the other hand, units with high storage capacity and low permeability are related to isolated porosities such as moldic pores.

In the third sequence, the distribution of identified flow units showed that there were at least nine units separated according to the modified Lorenz method based on stratigraphy. In addition, the resulting diagram shows major heterogeneities in their reservoir characteristics. According to the slope of the diagram, units 1, 3, 5 and 9 are considered

normal-quality units (Fig. 10c). Generally, in these flow units, the development of higher-quality units is related to the combination of two factors of intergranular porosity and micro-fractures, which has increased the quality of the reservoir. In these flow units, higher values of FZI logarithm and throat radius (R35) are generally limited to small intervals and do not cover the whole sequence. All the measured parameters in each of the wells are graphically displayed in a composite log (Fig. 11).

Discussion

In this research, the Fahliyan Formation of Late Jurassic–Early Cretaceous age was studied based on its depositional environment, diagenesis history and reservoir properties. Detailed petrographic examinations showed that the entire formation thickness comprises carbonate facies that are deposited in four facies associations in a shallow carbonate ramp, including tidal flat, lagoon, shoal and open marine. Reservoir destructive processes are cementation and compaction, while dissolution and fracturing generally improved the poroperm values by exerting a major impact on the pore system. Seemingly, most of the diagenetic processes were eogenetic in origin.

Three third-order sequences are distinguished; the first sequence (equivalent to Manifa) includes L1 and L2 reservoir zones and has the best quality as compared to the other sequences (Fig. 7). In spite of domination of the matrix-supported tidal facies and due to its location between two unconformity boundaries of type I, meteoric dissolution resulted in its highest quality. This superiority is clearly apparent in the Lucia, FZI and R35 diagrams (Figs. 7d, 8a

Fig. 11 A comparison between the results of three applied reservoir zonation schemes in the studied wells

and 9a). In this sequence, the inferior reservoir quality of L2 zone (compared to the L1 zone) is due to penetration of anhydrite-saturated fluids from the underlying Hith evaporites. The slope of the Lorenz curves modified based on stratigraphy indicates that most of the curves are of type of normal flow units and the storage and flow capacities are correspondent (Fig. 10a).

The second sequence is equivalent to the Middle Yamama member which includes reservoir zones G1–K. Despite the abundance of grain-supported facies of the shoal environment and the occurrence between two unconformity boundaries of type 1, most of the dissolution cavities have been plugged by the calcite cement, reducing the reservoir quality. This reduction is easily observable in the Lucia, FZI and R35 diagrams (Figs. 7e, 8b and 9b). In this sequence, the reservoir zones of series G and J display better quality as compared to the others. The slope of the stratigraphic modified Lorenz plot demonstrates that most of the curves are of baffle unit types with high storage capacity and low flow capacity (Fig. 10b). This interpretation can be explained by obstruction of the flow units by calcite cement and the predominance of unconnected porosities such as moldic pores.

The third sequence is equivalent to the Upper Yamama comprising CD–F series. This sequence is very much similar to the second sequence, and it is distinguished from the sequence I due to the predominance of lagoon facies and the absence of meteoric dissolution at its upper boundary of type II unconformity. The FZI and R35 diagrams for this sequence are similar to those of the second sequence; however, according to the Lucia diagram, the third sequence shows a lesser reservoir quality as compared to the second sequence (Figs. 7f, 8c and 9c). The slope of the stratigraphic modified Lorenz plot for the third sequence is of type normal flow unit (Fig. 10c). However, this positive aspect is only characterized for the thin laminas and is due to the existence of small intraparticle porosities and micro-fractures. Table 4

represents various parameter values for the reservoir zones and third-order sequences which are extracted based on core and well log studies.

Conclusion

According to this study, the Late Jurassic–Early Cretaceous Fahliyan Formation in the northwest of the Persian Gulf is composed of twelve microfacies belonging to four facies associations of shallow open marine, shoal, lagoon and tidal flat. Considering observations such as the gradual facies change from deep to shallow and the absence of turbidites, and by comparison with their modern counterparts, the studied successions are formed in a homoclinal carbonate ramp. The main recognized diagenetic processes that influenced the reservoir quality are compaction, cementation, neomorphism, dissolution and fracturing that occurred in three stages of eogenesis, mesogenesis and teleogenesis. The cementation and compaction processes are the most important reservoir destructing processes, and the dissolution and fracturing are responsible for development of reservoir quality.

Interpreting the gamma ray log using CycloLog software indicated that the recognized sequence boundaries are in good correlation with each other at the studied well locations. By integrating the data obtained from the petrographic studies of the core samples and the well log data, the unconformity and the maximum flooding surfaces were determined. On these bases, three third-order sequences and 13 fourth- or fifth-order sequences were determined. The sequence stratigraphy of the Fahliyan Formation shows that the recognized depositional sequences in studied subsurface sections have a good correlation in the studied oilfields. The sequence boundaries of the studied depositional sequences are type I and can be identified by

Table 4 The interpreted sequences and their associated properties

Parameter and methods	Sequence I		Sequence II										Sequence III			
	Zonation	L2	L1	K	J	I2	I1	H2	H1	G3	G2	G1	F2	F1	E	CD
Porosity (ave.)		20.50%											8.83%			
Permeability (ave.)		199.6 md											8.87 md			
RQI (index)		0.81											0.22			
LUCIA (method)		Very good											bad			
Diagenesis (effect)		dissolution											cementation			
PTR (micron)		0.01–100											0.01–2			
FZI (method)		good											fair			
R35 (method)		good											fair			
LORENZ (method)		Normal flow unit											Normal flow unit			
FACIES (dominant)		Tidal flat											lagoon			
Best reservoir zone		L1 > L2											F1–F2			

evidence of subaerial exposure, except for the third depositional sequence which can be identified by microfacies changes in the upper boundary.

By integrating the results from routine and SCAL analysis of the core plugs with the petrophysical data, parameters such as FZI, R35 and Lorentz modified based on stratigraphy were used to analyze the reservoir quality of each sequence. Best zones for the first sequence are *L1–L2*, for the second sequence are *G1–G2–G3–J*, and for the third sequence are *F1–F2*. The petrographic studies indicated that both factors of facies changes and diagenetic processes are affecting the reservoir quality.

This study shows that regardless of the primary texture and sedimentary environment, the quality of the reservoir is strongly affected by the diagenetic processes. Despite the predomination of the mud-supported microfacies in the first sedimentary sequence, the good reservoir quality is due to the predominant effect of dissolution. On the other hand, despite the predominance of grain-supported textures of the microfacies in the second sedimentary sequence, this sequence has a lower reservoir quality than the first sequence due to extensive cementation. What distinguishes this study from the other similar studies is the detailed and comprehensive analysis of the Fahliyan carbonate reservoir horizons by combining geological and petrophysical (rock typing) approaches in the sequence stratigraphy framework. The correlation based on the sequence stratigraphic framework of studied key wells enabled us to identify flow units in the neighboring wells where available petrographic and petrophysical data are limited. Considering the general sequence stratigraphic framework of the area, the results of this study can be extrapolated to the adjacent oilfields.

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Declarations

Conflict of interest On behalf of all the co-authors, the corresponding author states that there is no conflict of interest.

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