



The new approach to establish a better match between obtained electrofacies and hydraulic flow units for oligo-Miocene reservoir rocks, North of Dezful Embayment, SW Iran

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Abstract

Routine core analysis data (porosity and permeability)—used in various methods for hydraulic flow unit (HFU) determination of reservoir rocks—are unavailable in all drilled wells. On the other hand, raw petrophysical wireline logs—applied to determine reservoir electrofacies (EF)—are usually available in all wells. Since cores provide accurate data on reservoir characteristics, the lack of cores has always interested petroleum geologists and engineers. Therefore, introducing a new method to give almost accurate data about reservoir rocks in uncored wells has always interested petroleum geologists and engineers. As the type of input data that was used to determine HFUs and reservoir EFs are fundamentally different from each other, providing an approach that can create a better match between the results of these two rock typing methods is always one of significant interest for researchers. In this research, capillary pressure (Pc) test results are vital in obtaining reservoir EFs compatible with HFUs for the Oligo-Miocene Asmari Formation in Qale Nar Oilfield. So that only EFs that are compatible with Pc test results are approved. Flow zone indicator (FZI) method was applied to determine five HFU including A (Log FZI > - 0.05, average of core porosity and permeability are 5.8% and 0.37 mD) to E (Log FZI < - 0.65, average of core porosity and permeability are 0.07% and 0.03 mD). Furthermore, based on raw petrophysical wireline logs and MRGC algorithm in Geolog software, five electrofacies (EF) were indicated containing EF 1 (average of core porosity and permeability are 5.91% and 0.38 mD) to EF 5 (average of core porosity and permeability are 0.08% and 0.02 mD). The correlation between HFUs and EFs shows that HFU A to HFU E is compatible with EF 1 to EF 5. Also, examining the obtained electrofacies in the modified Lorenz plot indicates that EF 1 and 2 perfectly match intervals with a high fluid flow regime. By this method, it is possible to provide an almost accurate estimation of hydraulic flow unit distribution for wells and intervals without cores.

Keywords The Asmari formation · Reservoir heterogeneity · Rock typing · Qale Nar Oilfield · Zagros Basin

List of symbols

K Core permeability (mD)
φ Core porosity (fraction)

Abbreviations

Amp. *Amphistegina* Sp.
Arc. *Archaias* Sp.
As. Asmari (formation)
CGR Corrected gamma-ray (well-log)

Dit. Ditropa
DT Delta-T (sonic transit time) (well-log)
Ech. Echinoids
Eul. *Eulepidina* Sp.
EF Electrofacies
Fav. Faverina
FZI Flow zone indicator
Gas. Gastropod
Gs. Gachsaran (formation)
HFU Hydraulic flow unit
KNN *K*-Nearest neighbor algorithm for machine learning
LBF Large benthic foraminifer
mD milli Darcy
Mil. *Miliolid* Sp.

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MRGC	Multi-resolution graph-based clustering
Neo.	<i>Neorotalia</i> Sp.
NPHI	Neutron porosity (well-log)
Num.	<i>Nummulites</i> Sp.
Ope.	<i>Operculina</i> Sp.
Pc	Capillary pressure
Pd.	Pabdeh (formation)
PEF	Photoelectric (well-log)
Pen.	<i>Peneroplis</i> Sp.
Perm.	Permeability
PHIE	Effective porosity (well-log)
Pla.	Planktonic foraminifera
PMR	Porosity to matrix ratio
Porosity	Porosity
RCA	Routine core analysis
Red A.	Red Algae
RHOB	Bulk density (well-log)
RQI	Reservoir quality index
S.Rot.	Small rotaliids
SWE	Effective water saturation
XPL	Crossed polarized light

Introduction

Zagros Basin, a long, fold-thrust belt, contains many of the world's hydrocarbon and mineral reserves between the Eurasian and Arabian plates. After the exploration of petroleum in the Middle East (Iran, Saudi Arabia, Iraq, Kuwait, etc.) and the detection of numerous hydrocarbon reservoirs in the Asmari Formation and its equivalent sequences (Sadouni and Alsharhan 2019), many researchers in different categories of geosciences were interested in evaluating this economic succession.

The presence of rocks with entirely different geological, reservoir quality, and producing characteristics—created due to other depositional and diagenesis conditions—caused reservoir heterogeneity in the Asmari Formation of Qale Nar Oilfield.

Unlike most sandstone reservoirs, which have low heterogeneity and often their porosity and permeability can be predicted easily (Nashawi and Malallah 2009; Shehata et al. 2021; Kassem et al. 2022), carbonate reservoirs have high heterogeneity and finding the relationship between porosity and permeability parameters is very complicated (Abdullah et al. 2022; Abouelresh et al. 2022; Radwan et al. 2021; Balaky et al. 2023; Karimian Torghabeh et al. 2023). Some sandstone reservoirs also have different volumes of clay and clay minerals, which act like heterogeneous carbonate reservoirs. So, predicting porosity and permeability in such reservoirs is difficult (Shedid 2018). Therefore, studying carbonate reservoirs has become challenging for reservoir engineers and petroleum geologists.

There are many heterogeneities in sedimentology, rock reservoir quality, and producing intervals in a hydrocarbon reservoir. So, it is necessary to determine reservoir rock types to perform quality classification and better understand the reservoir characterizations. Explanation of heterogeneities in a carbonate reservoir cannot be feasible by relying on either geological or petrophysical data alone. The combination and correlation of geological and petrophysical aspects would enable researchers to explain the variability of the reservoir more reliably.

Recently, clustering petrophysical data such as well-logs and core porosity–permeability data have become popular among engineers and geologists (Euzen and Power 2012; Noorian et al. 2017, 2020; Davis 2018).

Furthermore, the lack of core data in all drilled wells of a hydrocarbon field has encouraged scientists to employ new integrated methods. Estimation of hydraulic flow units using well-log data is one of the desirable methods for predicting producing intervals in uncored wells by Amaefule et al. (1993).

After Amaefule et al. (1993) so far, many researchers have tried to provide an accurate prediction of hydraulic flow units for wells and depth intervals without any core by using raw and evaluated petrophysical well-logs and applying various calculation methods, but the success rate of these methods is not very high, and sometimes the results have errors.

This study has tried to improve the compatibility between the reservoir electrofacies and hydraulic flow units by validating the obtained electrofacies with Pc test results. In other words, Pc test results have a controlling role in defining reservoir electrofacies.

The reservoir quality and sedimentary features of the Asmari Carbonate Formation (Oligo-Miocene) in Qale Nar Oilfield (north of Dezful Embayment) change in vertical and horizontal directions even at short distances. Hence, this reservoir is so complex and heterogeneous that petroleum geologists and reservoir engineers need help in oilfield development and planning improved and enhanced oil recovery programs. In many hydrocarbon fields of Dezful Embayment, including Qale Nar Oilfield, it is impossible to consider a uniform reservoir quality for a particular layer or reservoir zone in the Asmari Formation. Therefore, a specific horizon in the reservoir (with the same age throughout the oilfield) shows different petrophysical characteristics. The raw and evaluated petrophysical well-logs are proof of this claim.

Geological setting

The Zagros Basin is well-known as one of the most prolific fold-thrust belts in the world due to its numerous hydrocarbon reservoirs (Alavi 2004). This fold-thrust belt is situated

Fig. 1 Subdivisions of the Zagros Basin (modified from Alavi (2007)), location of Qale Nar Oilfield in the north of Dezful Embayment was illustrated by the black arrow



on the northeastern margin of the Arabian Plate (Allahkarampour-Dill et al. 2018; Noorian et al. 2021), which extends from Turkey to the Strait of Hormuz in the south of Iran (Alavi 2004). The lack of igneous activity, numerous and very rich source rocks, porous and permeable reservoirs, and suitable caprocks have provided appropriate conditions for the generation and accumulation of hydrocarbon in the Zagros Basin (Afshar Harb 2003). Its approximate length is about 1500 km, and its width is between 100 and 300 km (Alavi 2007). It is argued that the Zagros thrust belt is part of the Alpine-Himalayan orogeny belt, which had formed as a result of the closing of the Neo-Tethys Ocean basin (end of Mesozoic Era), resulting in a collision between the Central Iran Microplate and the remnants of the Gondwana Supercontinent (Alavi 2004; Talebian and Jackson 2004). Based on tectonic-sedimentary history, the Zagros Basin has been divided into several regions, including the Urumieh-Dokhtar Magmatic Assemblage, Zagros Imbricated Zone, and Zagros Fold-Thrust Belt. The last is subdivided into Lurestan, Dezful Embayment, Izeh, and Fars subzones (Alavi 2007) (Fig. 1). The Dezful Embayment, in the southwest of the Zagros Basin, comprises the giant Iranian hydrocarbon

reservoirs (Alavi 2007). This region is bounded by three essential structural lineaments as follows: the Balaroud Fault at the north, the Mountain Front Fault at the east and north-east, and the Kazerun Fault at the southeast (Sepehr and Cosgrove 2004) (Fig. 1).

Qale Nar oil field is located on the northern edge of the Dezful Embayment and south of the Balaroud fault (Fig. 1). On top of the Asmari reservoir, this oilfield is 22.5 km long and 4.5 km wide. It extends from 48°13' to 48°23' E longitude and 32°42' to 32°44' N latitude (Fig. 2). Asmari Formation and Bangestan Group are the main reservoirs in this oilfield.

Based on biostratigraphy studies, the Oligo-Miocene age has been assigned to the Asmari Formation (Adams and Bourgeois 1967; Laursen et al. 2009; Nikfard et al. 2020). In addition to biostratigraphy, high resolution (sampling rate) Sr isotope dating was used to define and separate the Oligocene stages in this formation (Ehrenberg et al. 2007; Van Buchem et al. 2010).

Asmari Formation comprises carbonate and siliciclastic successions in central and southern parts of the Dezful Embayment. Its siliciclastic content was known as the

Fig. 2 Subsurface contour map on top of Asmari Formation (in Sub Sea Depth) in Qale Nar Oilfield. Small black dots demonstrated the locations of the studied wells

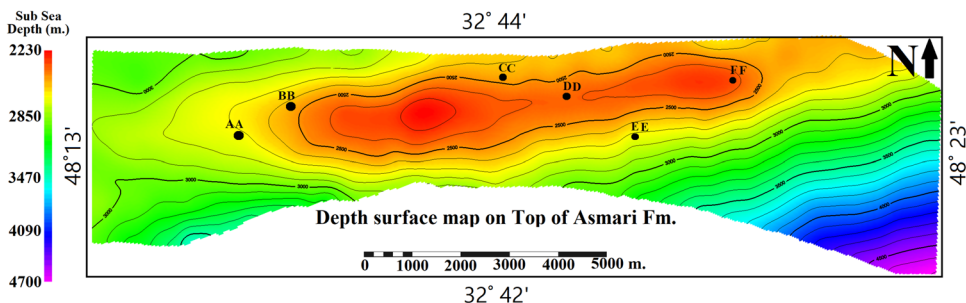
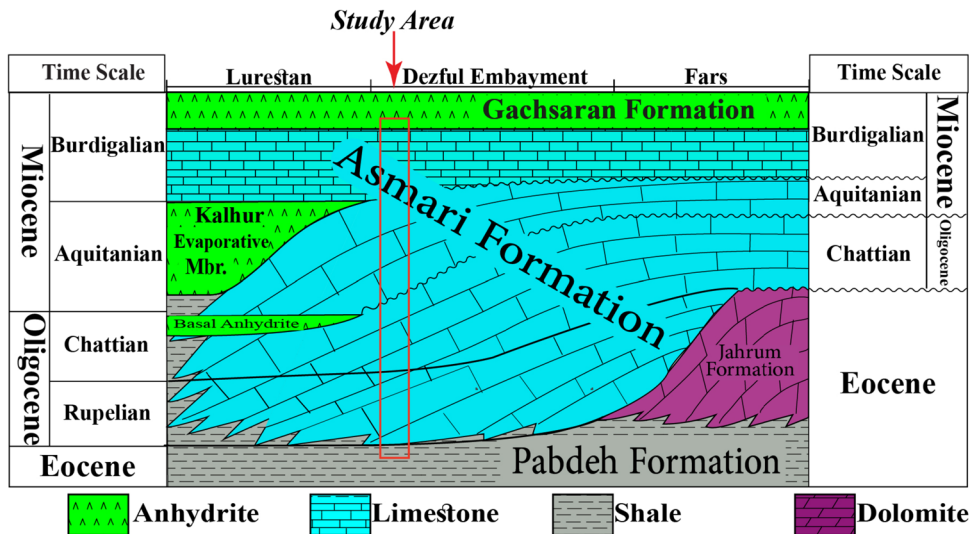


Fig. 3 Schematic cross section showing lithological changes of Asmari Formation throughout Zagros Fold-Thrust Belt (Ehrenberg et al. 2007). A red rectangle demonstrates the location of the study area



"Ahwaz Sandstone Member" (Chattian Age), mainly sourced from southeast of the Arabian Plate. (Van Buchem et al. 2010). However, in the Lurestan area, "Kalhur evaporative Member" was deposited simultaneously (Van Buchem et al. 2010). None of these members is presented in the Asmari Formation of Qale Nar Oilfield. Based on microfossil content and biostratigraphy studies, the Asmari Formation in this oilfield is divided into Rupelian, Chattian, Aquitanian, and Burdigalian stages (Neisi et al. 2017). The lower boundary of the Asmari Formation with marl and shale of the Pabdeh Formation (Eocene) is transitional. In contrast, its upper contact with evaporates (anhydrite) layers of the Gachsaran Formation (Miocene) is sharp (Fig. 3).

Asmari Formation thickness in Qale Nar Oilfield is about 400 m, including limestone, dolomite, and dolomitic limestone and marl.

Materials and methods

Sedimentological techniques

In this study, 2200 thin sections, which were obtained from 840 m of core samples (Well AA: 100 m, Well BB: 99 m, Well CC: 54 m, Well DD: 386 m, Well EE: 117 m, Well FF: 84 m),

were used for petrographic studies. Some of these thin sections were impregnated with blue epoxy resin for porosity study. Also, they were treated with Alizarin Red S to differentiate calcite from dolomite crystals by Dickson's (1966) method. Dunham (1962) and Embry and Klovan (1971) classifications were used to describe carbonate rocks under the microscope. Porosity types have been identified using Archie's (1952) and Choquette and Pray's (1970) classifications for core samples and thin sections, respectively.

Based on the presence and frequency of skeletal and non-skeletal grains, microfacies attributes (textural studies), and comparison between results of present studies and modern/ancient depositional models (Pomar 2001; Nebelsick et al. 2005; Flügel 2010; Shabafrooz et al. 2015) interpretation of obtained facies associations were made. Finally, the depositional model for the Asmari Formation in Qale Nar Oilfield was introduced.

Petrophysical techniques

Hydraulic flow unit (HFU)

Evaluation of reservoir quality is obtained through diverse methods. These methods are dominantly based on the

volume of rock pore spaces and their connection to each other (pore throats) (Abuamarah and Nabawy 2021).

Porosity data (1622 samples) of six cored wells (Wells AA, BB, CC, DD, EE and FF) were applied for hydraulic flow unit (HFU) determination using the flow zone indicator (FZI) technique. The FZI method for determining the hydraulic flow units is a valid method widely used by reservoir engineers and petroleum geologists nowadays. The Reservoir Quality Index (RQI) is another parameter affecting FZI (Amaefule et al. 1993). RQI is equal to an average hydraulic radius in rock and plays a crucial role in defining the hydraulic flow units by establishing a relationship between porosity, permeability, and capillary pressure (Amaefule et al. 1993; Abbaszadeh et al. 1996; Dakhelpour-Ghoveifel et al. 2019).

The Reservoir Quality Index (RQI) can be calculated through Eq. (1).

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

In Eq. (1), the Reservoir Quality Index is in micrometer (μm), K is permeability in milli Darcy (mD), and the porosity (φ) is fractional.

The ratio of the porosity to the volume of the solid rock (Porosity to Matrix Ratio known as PMR) can be obtained using Eq. (2).

$$PMR = \frac{\varphi}{1 - \varphi} \quad (2)$$

Finally, the flow zone indicator (FZI) was calculated using Eq. (3).

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

Electrofacies (EF)

A set of numerical responses to petrophysical well-logs that reveal specific features of the physics and composition of the rock is called Electrofacies (EF) (Davis 2018). According to this definition, different rocks with diverse shapes, sizes, and porosity types have different porosity and permeability values and different petrophysical well-log responses. Electrofacies can be distinguished by the set of these properties (Euzen and Power 2012; Karimian Torghabeh et al. 2014, 2015).

To identify reservoir electrofacies of Asmari Formation in Qale Nar Oilfield, raw petrophysical well-logs such as corrected gamma-ray (CGR), photoelectric (PEF), neutron

porosity (NPFI), bulk density (RHOB), sonic transit time (DT) in six wells together with capillary pressure (P_c) test results were used. Some corrections, such as depth matching and quantitative controls, were exerted on petrophysical well-logs to improve their quality. Multi-Resolution Graph-based Clustering (MRGC) algorithm was utilized for the analysis of reservoir rock clustering (rock typing) in Geolog Software (Paradigm™ Geolog 7.4).

To achieve such a goal, a detailed study of Asmari Formation microfacies was done to determine the depositional characteristics of each facies association. According to the evaluation and interpretation of microfacies, the depositional model for the Asmari Formation in Qale Nar Oilfield was shown in the final part of the microfacies study. Recognizing and describing the diagenesis processes that have affected the reservoir rocks is an essential part of sedimentological studies that is impossible to ignore. The results section includes determining reservoir rock types using hydraulic flow units and electrofacies. Determination of hydraulic flow units has also been done using core routine data (porosity and permeability) as input data and applying related equations (FZI method). A neural network (multi-resolution graph-based clustering algorithm known as MRGC) in Geolog software and raw petrophysical well-logs as input data were used to obtain reservoir electrofacies. To validate electrofacies, the results of this stage were compared with P_c test results. Then, in the discussion section, obtained hydraulic flow units and electrofacies have been compared. For this purpose, the abundance of each reservoir's electrofacies in specific hydraulic flow units was shown. The frequency distribution of hydraulic flow units and reservoir electrofacies for each facies association have been investigated to know the reservoir quality of each facies association. Changes in obtained electrofacies, hydraulic flow units, raw and evaluated petrophysical well-logs, core porosity, and permeability data in Qale Nar Oilfield wells through the Asmari Formation are also studied by figures. Since one of the wells (Well DD) has relatively complete core routine data in the Asmari Formation, cumulative production and cumulative storage curves (modified Lorenz Plot) were drawn and evaluated with the obtained electrofacies in this well. At the end of the discussion, the development and distribution of acquired hydraulic flow units and reservoir electrofacies are shown in a correlation chart from the west to the east of the Qale Nar Oilfield.

According to available data and methods used in sedimentology, reservoir electrofacies, and hydraulic flow unit determination, this research's general framework and flow-chart are demonstrated in Fig. 4.

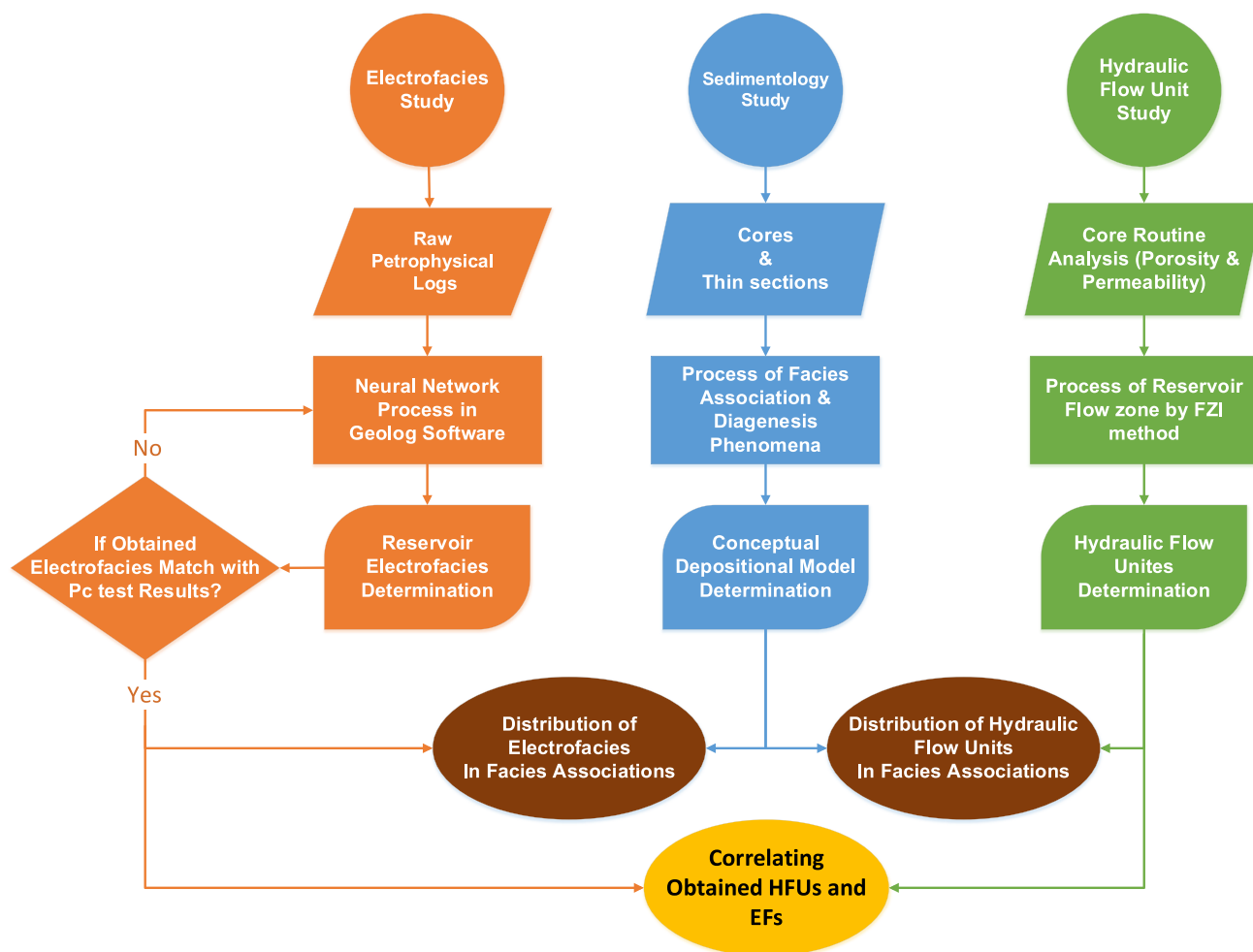


Fig. 4 Summarized schematic flowchart of this research

Results

Facies analysis

Due to the high importance of the Asmari Formation in southwest Iran, many studies have been focused on its stratigraphy and microfacies distribution so far (Seyrafian and Hamedani 1998; Amirshahkarami et al. 2007; Allahkarampour Dill et al. 2010; Adabi et al. 2015; Omidpour et al. 2021a). Depositional settings (such as depth, energy, and fauna of the sedimentary environment) (known as primary conditions) and diagenetic processes (such as karstification, dolomitization, and cementation) (known as secondary conditions) can affect pore types. These conditions always control the heterogeneities of the carbonate reservoir (Ranjbar-Karami et al. 2021; Khoshnoodkia et al. 2022, 2023; Karimian Torghabeh et al. 2023).

Based on a petrographic study (e.g., textural, skeletal, and non-skeletal grains and their presence and abundance) in 6 wells (Well AA to FF), 20 microfacies belonging to eight

carbonate facies association were identified within Asmari Formation in Qale Nar Oilfield (Table 1). These facies associations were deposited in the open sea to tidal flat settings of a homoclinal carbonate ramp (Jamilpour et al. 2021) as follows:

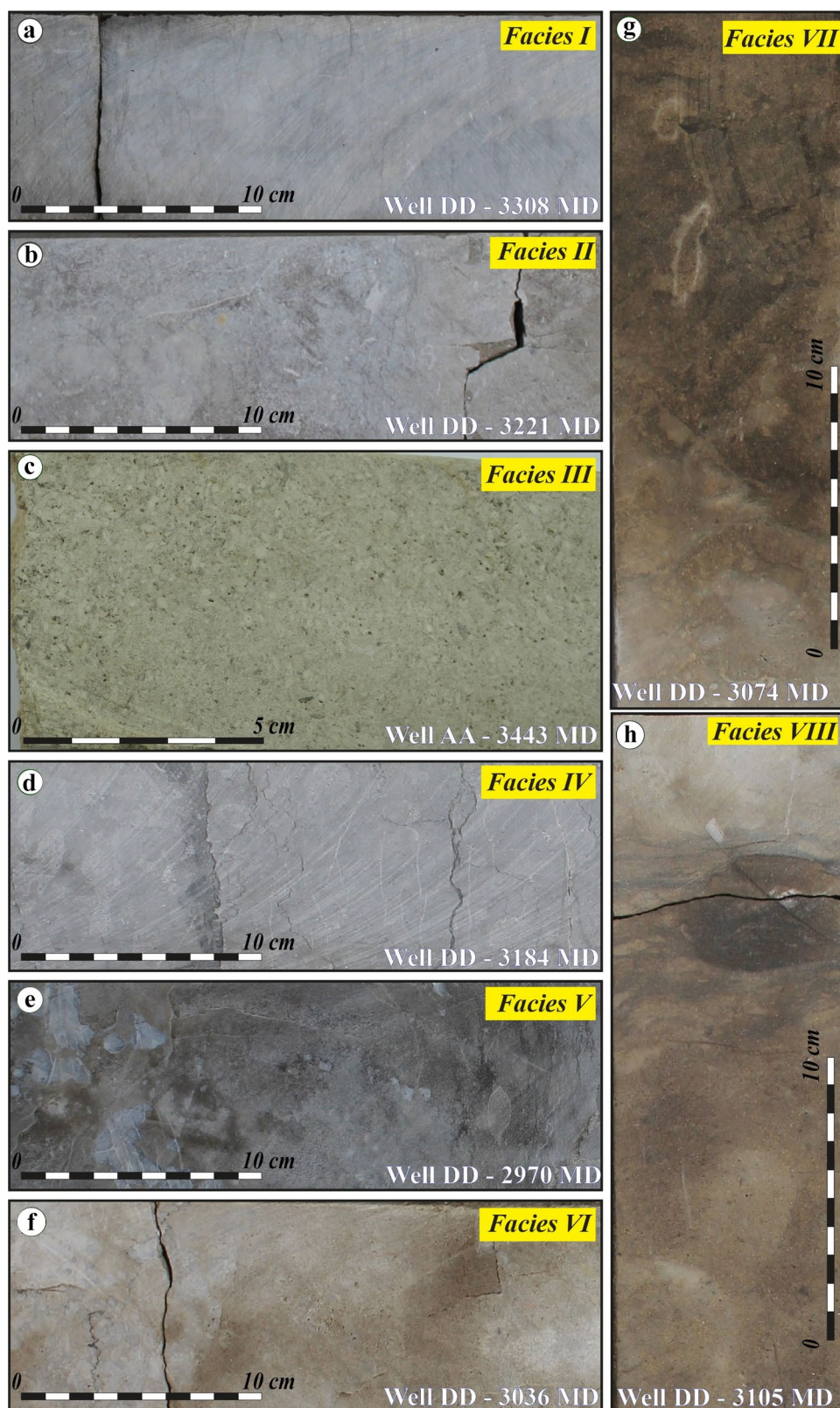
Facies association I (planktonic foraminifera packstone/wackestone)

Description: this facies association includes medium to thin-bedded very dense limestones almost without visible (with unarmad eye) porosity on core samples (Fig. 5a). Planktonic foraminifera (*Globigerina* sp.) with transported and broken *Lepidocyclinidae*, *nummulitidae*, *ditropa*, and red algae were found in a muddy and argillaceous matrix (Fig. 6a, b) (Jamilpour et al. 2021). Sometimes, opaque minerals (dominantly iron sulfides) are observed in the chamber of planktonic fauna. Dolomite rhombs are scattered in a micritic context

Table 1 Properties of Asmari Formation facies associations and microfacies in Qale Nar Oilfield (Jamilpour et al. 2021)

Facies association	Microfacies	Components	Sorting	Depositional setting
FA-I: planktonic foraminifera packstone/wackestone	FA-I-1: planktonic foraminifera packstone/wackestone FA-I-2: planktonic foraminifera Nannulitidae bioclast packstone	Planktonic foraminifera with transported and broken parts of Nannulitidae, Ditrupa and red algae	Moderate Poor	Deep shelf margin (outer ramp)
FA-II: nummulitidae-lepidocyclinidae rudstone/packstone	FA-II-1: nummulitidae-lepidocyclinidae floatstone/rudstone FA-II-2: neorotalia corallinacean packstone/grainstone FA-II-3: nummulites neorotalia corallinacean packstone	Operculina, neorotalia, nephrolepidina, eulopidina, Amphistegina, Miogypsina, and red algae, with some echinoid debris	Poor Poor Poor	Open sea shelf (distal middle ramp)
FA-III: nummulites packstone/grainstone	FA-III-1: bioclast corallinacean Nummulites packstone/grainstone FA-III-2: nummulites grainstone/rudstone FA-III-3: miliolid corallinacean nummulites packstone/grainstone	Large types of Nummulites (such as Fichteli and Vascus), Lepidocyclina, Operculina and Heterostegina	Moderate Very good Good	Open sea shelf (middle ramp)
FA-IV: coral-coraline red algae floatstone/rudstone	FA-IV-1: coral-coraline red algae floatstone/rudstone FA-IV-2: coral-coraline red algae boundstone/framestone FA-IV-3: corallinacean perforated imperforated foraminifer packstone	Parts of red algae and coral. Benthic foraminifers such as Miliolids, Archaias, Peneroplis, Amphistegina, and echinoids	Moderate Poor Poor	Open sea shelf (proximal middle ramp)
FA-V: bioclast ooid packstone/grainstone	FA-V-1: faverina ooid packstone/grainstone FA-V-2: bioclast ooid packstone/grainstone	Good sorted tangential ooids	Moderate Good	Distal inner ramp (Shoal)
FA-VI: benthic foraminifer wackestone/grainstone	FA-VI-1: high diversity imperforated foraminifer packstone/grainstone FA-VI-2: small rotalids echinoids wackestone/packstone FA-VI-3: gastropod/bivalve bioclast packstone/grainstone FA-VI-4: small miliolid wackestone/packstone	Various imperforated benthic foraminifera such as Borelis, Archaias, Peneroplis, etc., with Neorotalia, Amphistegina, Echinoid fragments with some bivalve and Gastropod	Moderate Moderate Poor Poor	Inner ramp (Lagoon)
FA-VII: mudstone/dolomudstone	FA-VII-1: mudstone/dolomudstone FA-VII-2: sandy mudstone/sandy dolomudstone	Good sorted and not rounded of very fine sand or silt	Poor Poor	Proximal inner ramp (close to the beach)
FA-VIII: crystalline dolomite	FA-VIII: crystalline dolomite	Planar-E, Planar-S, and rare nonplanar crystals of dolomite	–	Not allocated to special setting

Fig. 5 Core photomicrograph of Asmari Formation Facies Associations in Qale Nar Oilfield. As it is apparent in the figure, the cores of Facies Association VI (Benthic foraminifer wackestone/grainstone), VII (Mudstone/Dolomudstone), and VIII (Crystalline Dolomite) have the most oil staining



(Fig. 6a). This facies association was observed at the base of the Asmari Formation, near its lower contact with the Pabdeh Formation.

Interpretation: the presence of relatively abundant planktonic foraminifera and plenty of fine grain matrix indicates sedimentation of this facies association in a relatively deep,

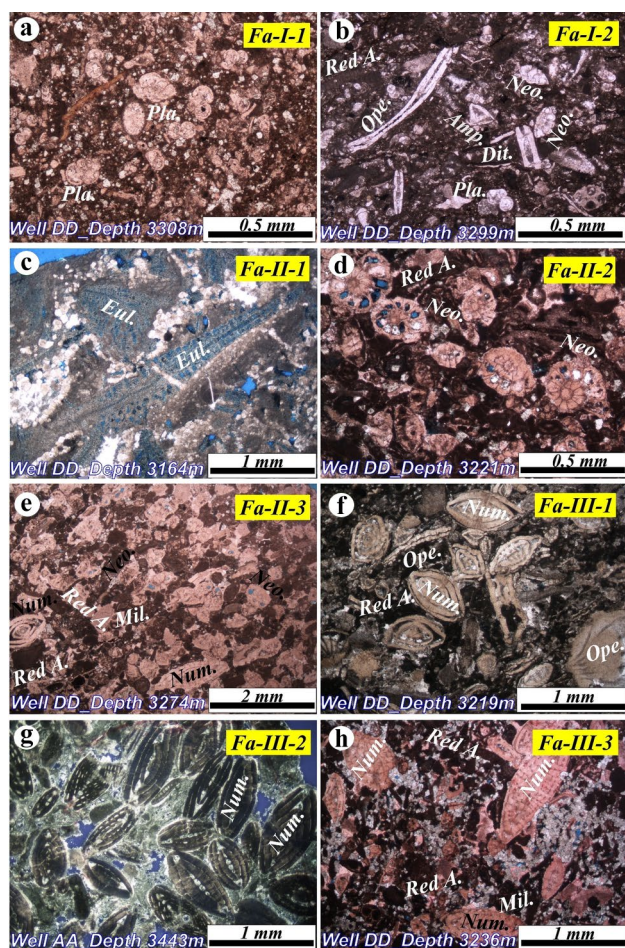


Fig. 6 Photomicrograph of Asmari Formation microfacies in Qale Nar Oilfield. Fa-I: Planktonic foraminifera packstone/wackestone (a, b), Fa-II: Nummulitidae-Lepidocyclinidae rudstone/packstone (c–e), Fa-III: Nummulites packstone/grainstone (f–h). All photographs are in XPL, and a, d, e, h were stained by Alizarin Red-S. Also, c, d, e, h were impregnated with Blue Epoxy Resin

calm, and low-energy marine environment under the wave's base level (Wilson 1975; Amirshahkarami et al. 2007; Flügel 2010; Omidpour et al. 2021b). The absence of sedimentary structures belonging to high energy conditions and lack of light-dependent organisms (red algae) in this facies association confirms its belonging to the aphotic zone in the outer ramp sector (Mateu-Vicens et al. 2008; Pomar et al. 2014).

Facies association II (nummulitidae-lepidocyclinidae rudstone/packstone)

Description: this facies association is composed of thin to medium-bedded limestone and dolomitic limestones containing vast amounts of Nummulitidae and Lepidocyclinidae shells, which can be seen in the lower parts of the Asmari Formation (Rupelian deposits). The presence of large benthic foraminifera (LBF) such as Operculina, Lepidocyclina,

Heterostegina, Nephrolepidina, and Eulepidina in a muddy matrix and grain-supported texture is the main feature of this facies association. Sometimes, the size of the allochems is more than two millimeters (Fig. 6c–e). These large benthic foraminifera (Nummulitidae and Lepidocyclinidae families) can be seen as elongated white grains in the core samples (Fig. 5b) (Jamilpour et al. 2021).

Interpretation: the abundance of large perforated benthic foraminifera (sometimes more than 2 mm) in a muddy matrix alongside the presence of open sea fauna (e.g., echinoid and red algae) suggests that deposition occurred within an oligophotic zone on mid ramp sector (Mateu-Vicens et al. 2008; Pomar et al. 2014). The presence of large benthic foraminifera with symbiotic algae indicates the photic zone (Beavington-Penney and Racey 2004; Amirshahkarami et al. 2007; Adabi et al. 2015; Omidpour et al. 2021b).

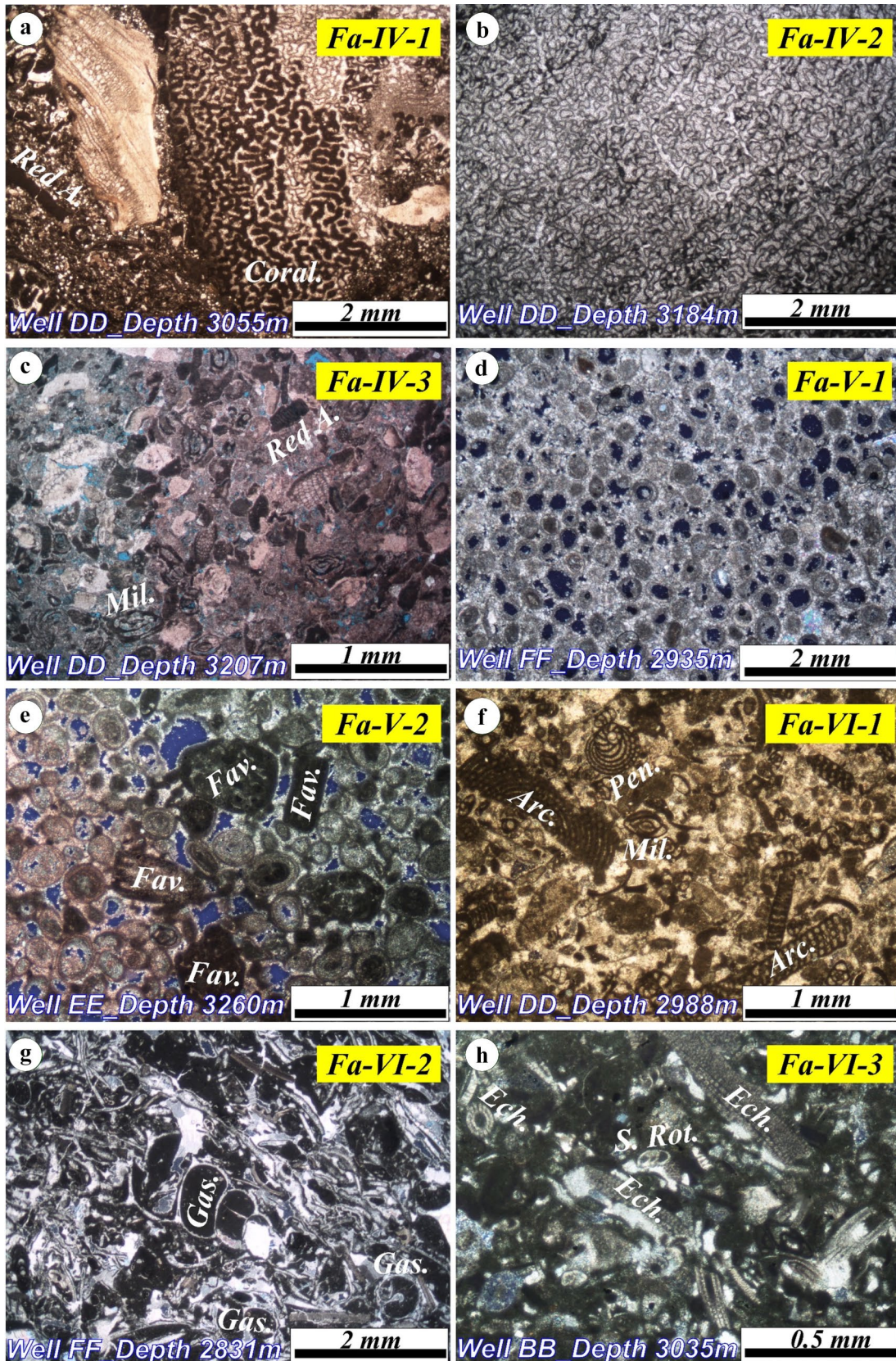
Facies association III (nummulites packstone/grainstone)

Description: abundance of Rupelian index *Nummulites* sp. (fichteli and vascus) as white lens form grains with pin-point porosity as black points have primarily been found in the core sample (Fig. 5c). The Nummulites are the main allochem of this facies association. Facies Association III has a little micritic matrix; hence, the grain-supported fabric is usual. Sometimes, the size of *Nummulites* sp. is more than two millimeters, and therefore, rock textures change to rudstone (depending on the density of the coarse grains) (Fig. 6f–h) (Jamilpour et al. 2021). Rarely, broken Nummulites tests are observed, and frequently, they are intact. This facies association is more frequent in the Upper Rupelian sequence. Fa-III-2 is only seen in Well AA.

Interpretation: according to Pomar (2001) and Baratolo et al. (2007), the high production rate of Nummulites occurred in the middle ramp. The high degree of grain sorting and lack of muddy matrix (Fa-III-2) is reminiscent of this facies association deposition near fair weather wave base level. The existence of miliolids together with Nummulites (Fa-III-3) represents the inner part (shallower part) of the middle ramp, while the elongated Nummulites with thin tests indicating deposition in the deeper part of the middle ramp, where water agitation and light dominance are low (Fa-III-1).

Facies association IV (coral-coralline red algae floatstone/rudstone)

Description: thick to massive bedding is the crucial indicator for this facies association in core samples. Generally, parallel to bedding solution seams and stylolites are abundant in its cores (Fig. 5 d). Coral and red algae (*Lithothamnion* and *Mesophyllum*) particles are the most frequent grains



◀**Fig. 7** Photomicrograph of Asmari Formation microfacies in Qale Nar Oilfield. Fa-IV: Coral-coralline red algae floatstone/rudstone (a–c), Fa-V: bioclast ooid packstone/grainstone (d, e), Fa-VI: Benthic foraminifera wackestone/grainstone (f–h). All photographs except f are in XPL, and c, e were stained by Alizarin Red-S. Also, c was impregnated with Blue Epoxy Resin

(Fig. 7a–c). *Amphistegina* and *Operculina* as perforated benthic foraminifers and *Peneroplis*, *Archaias*, and *Miliolids* as imperforated ones are other fauna of Facies Association IV. This Facies association has poor textural sorting since coral and algal fragments have different sizes. Due to the abundance of crushed and angular debris, this facies association is separated from the reef Facies Association of the platform edge (Jamilpour et al. 2021). The Chattian deposits have the most occurrence of Facies Association IV.

Interpretation: in situ presence of Corals, a remarkably well-preserved collection of coral symbiotic foraminifers, and finally, a large amount of carbonate mud indicates the formation of this facies association in a relatively low energy condition. The presence of baffle coral indicates low seawater energy in the lowest part of the euphotic zone (Morsilli et al. 2012; Pomar et al. 2014). Therefore, the depositional environment of this facies association is attributed to the open marine setting (Amirshahkarami et al. 2007; Allahkarampour Dill et al. 2010; Adabi et al. 2015; Omidpour et al. 2021b).

Facies association V (bioclast ooid packstone/grainstone)

Description: this facies association also includes dense limestones, almost without visible porosity, characterized by anhydrite nodules in core samples (Fig. 5e). The main constituents of this facies association are ooid grains. These tangential ooids have good sorting and rounding. Thin marine rim cement is hardly visible around the ooid grains. *Faverina* and imperforated foraminifer (*Miliolid*, *Elphidium*, etc.) are the other non-skeletal and skeletal components. Based on other frequent allochems, Fa-V-1 and Fa-V-2 are determined (Fig. 7d, e) (Jamilpour et al. 2021). This facies association was only observed in Aquitanian deposits of Asmari Formation.

Interpretation: some evidence, such as the absence of lime mud in the matrix and the presence of thin marine cement around ooids along with good textural sorting, suggest that deposition was done under high energy conditions in an oolitic shoal segment of a carbonate ramp (Wilson 1975). This facies association represents the boundary between the middle and inner ramp (Fair Weather Wave Base) settings introduced by Flügel (2010).

Facies association VI (benthic foraminifer wackestone/grainstone)

Description: this facies association has the highest biodiversity among others (Jamilpour et al. 2021). Facies association VI is composed of medium to thick-bedded limestone containing imperforated benthic foraminifer (*Archaias*, *Borellis*, *Meandropsina*, *Peneroplis*, *Astrotrilina*, *Dendritina rangi*, and *Miliolid*), coralline red algae and bioclasts. The textural changes of Facies Association VI are relatively vast, from wackestone to grainstone, and plenty of high diversity imperforated foraminifera is the essential feature of this facies association. Additionally, some other fauna such as *Neorotalia* and *Amphistegina* (as perforated foraminifer), red algae, Echinoid fragments, Bryozoans, bivalves, Gastropods, ostracods, and green algae are present as well (Figs. 7f–h, 8 a). Facies Association VI has been partially oil-stained in core samples (Fig. 5f) and has a wide time range in the Asmari Formation (Chattian to Burdigalian).

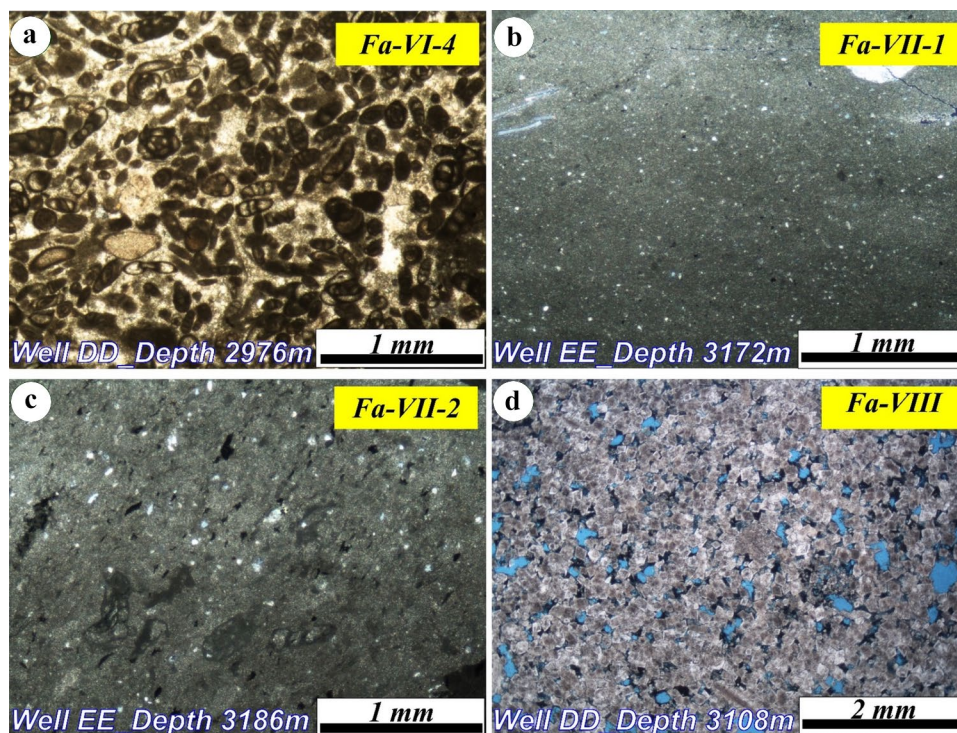
Interpretation: based on the sedimentary texture and fauna/flora content, this facies association is representative of the euphotic zone (Mateu-Vicens et al. 2008; Brandano et al. 2010; Pomar et al. 2014; Shabafrooz et al. 2015; Omidpour et al. 2021a, 2021b) in inner ramp segment which known as lagoon (in shallow and warm water, where high light dominance exists). Hence, the depth of the depositional setting has decreased from facies Fa-VI-1 to Fa-VI-4.

Facies association VII (mudstone/dolomudstone)

Description: basically, this facies association is composed of thin-bedded limy-dolomitic mudstone. Sometimes, carbonate mud (micritic matrix) is recrystallized to microspar. A few miliolids and ostracods are the only fauna observed in this facies association. Rarely, blue-green algae (*Stromatolite*) are also seen in this facies association, but they are not propagated. Bird's eye fabric and thin lamination are two crucial characteristics of Facies Association VII. This facies association has been largely oil-stained in some intervals (Fig. 5g) and affected by the dolomitization process. The maximum size of dolomite crystals is about the microspar range (Fig. 8b, c). Some anhydrite nodules and sand-to-silt-sized quartz grains were observed (Jamilpour et al. 2021). The presence or absence of sand grains is such that facies association VII can be divided into two microfacies: sandy and without sand. This facies association has mainly extended in the upper parts of the Asmari Formation and near its contact with the Gachsaran Formation (Burdigalian).

Interpretation: the presence of very fine crystalline dolomites, evaporite minerals (sub-aqueous anhydrite nodules), and fenestral fabric propose its deposition in a very shallow environment under low energy conditions (e.g., close to the

Fig. 8 Photomicrograph of Asmari Formation microfacies in Qale Nar Oilfield. Fa-VI: benthic foraminifera wackestone/grainstone (**a**), Fa-VII: mudstone/dolomudstone (**b**, **c**), Fa-VIII: crystalline dolomite (**d**). All photographs except **a** are in XPL. Image **d** was impregnated with Blue Epoxy Resin



beach) (Nebelsick et al. 2005; Rasser et al. 2005; Allahkar-pour Dill et al. 2010; Omidpour et al. 2021b).

Facies association VIII (crystalline dolomite)

Description: this facies association has good reservoir quality among others (the average core porosity and permeability are 6% and 0.41 mD). Also, it has the highest degree of oil staining in the core sample (Fig. 5h). The existence of a large volume of dead oil in microscopic thin-section photographs approved this statement (Fig. 8d). Due to the intense dolomitization process, the original facies association is not recognizable, and therefore this unit is considered a separate facies association. Although Facies Association VIII may be seen at any depth of the Asmari Formation interval, its concentration is related to the Rupelian and Burdigalian deposits in Qale Nar Oilfield (Jamilpour et al. 2021). The texture of dolomite crystals includes Planar-E, Planar-S, and rare Non-planar, and their size ranges from very fine (10 microns) to very large (500 microns).

Interpretation: since each of the already mentioned facies associations can be dolomitized, Facies Association VIII cannot be assigned to one of them. The interpretation of the dolomitization manner of sedimentary facies is beyond the scope of this manuscript, but generally, the dolomitization process of each depositional facies association depends on their innate features such as lithology, textural characteristics and diagenesis conditions (heat flow, overburden pressure and chemistry of diagenesis fluids).

Depositional setting

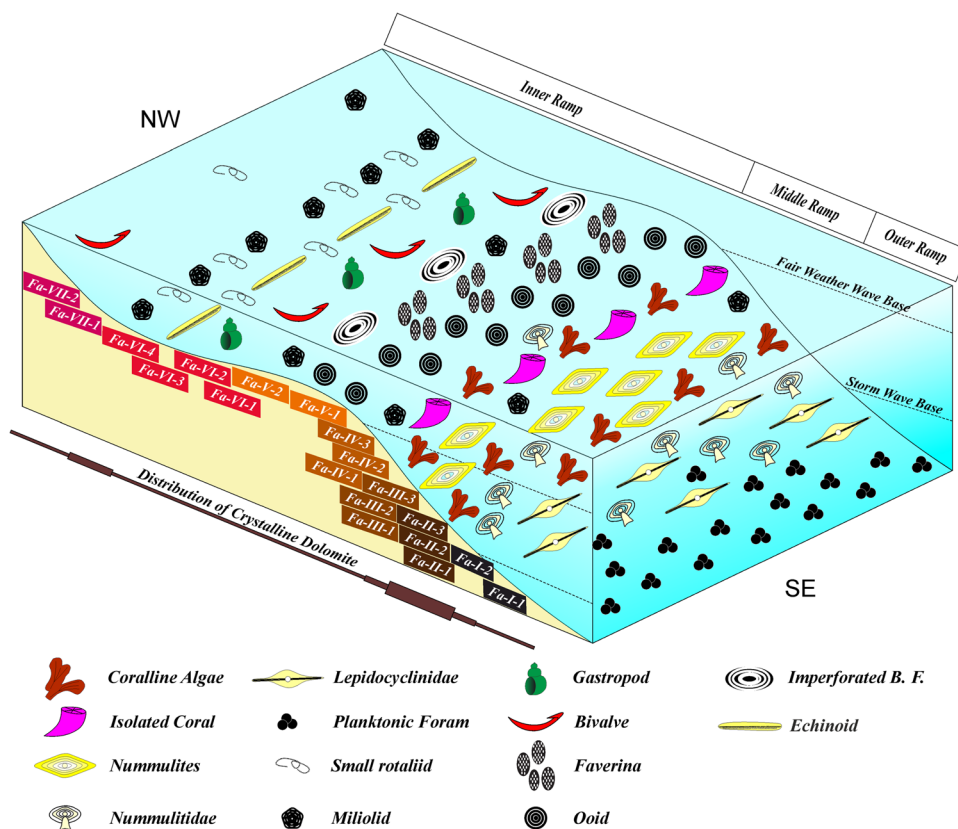
Based on the description and interpretation of each sedimentary facies association, absence of barrier reefs, gradual change of facies associations to each other, and the lack of submarine sliding and slumping facies association—which indicate deposition in steep areas—the carbonate ramp depositional model is proposed for Asmari Formation in Qale Nar Oilfield (Fig. 9) (Jamilpour et al. 2021).

Based on the facies associations principle (position of specific sedimentary facies in a normal stratigraphic rock record), it can be said that the crystalline dolomite is generated from dolomitization of Nummulitidae-Lepidocyclinidae rudstone/packstone and mudstone/Dolomudstone Facies Associations so that this phenomenon has destructed original fabric (non-mimic dolomitization).

Diagenesis

Sediments spend most of their life in the diagenetic environments. Therefore, it seems that this environment has a significant role in creating the final characteristic of rocks (Sharifi-Yazdi et al. 2020). All the features that sediments have acquired during deposition have changed during diagenesis. These changes are more severe for carbonate rocks than siliciclastic rocks, and therefore, the influence of diagenesis processes on carbonate reservoirs is always followed with great fear and hope. Unfortunately, most of the diagenesis processes occurring in carbonate rocks have

Fig. 9 Distribution of homo-clinal ramp microfacies of the Asmari Formation in Qale Nar Oilfield. A thick brown line below the ramp block diagram shows the presence and frequency of crystalline dolomite



reduced the reservoir quality of these rocks. However, few diagenetic processes increase the reservoir quality of rocks. These processes can generate occasional conditions for the economic accumulation of hydrocarbon in carbonate rocks.

Petrographic studies and core description showed that many processes related to different diagenesis realms have occurred in the Asmari Formation (Figs. 10, 11). The most important of these processes are compaction and cementation (as destructive¹ diagenesis processes) and dissolution, proper dolomitization, and fracturing (as constructive² diagenesis processes). The resultant of destructive and constructive diagenesis processes creates the final reservoir quality of the rock (Fig. 12).

The effect of destructive or constructive diagenetic processes on pore throats and pore spaces in different rock types has been specified for Asmari reservoir in other fields of Dezful Embayment (Moradi et al. 2017; Sharifi-Yazdi et al. 2020; Sadeghi et al. 2021).

Burial calcite cements as blocky and drusy fabrics are widely observed in this reservoir sequence. Blocky cement often fills intergranular and intragranular porosities (Fig. 10a), and the drusy types usually occupy the vugs

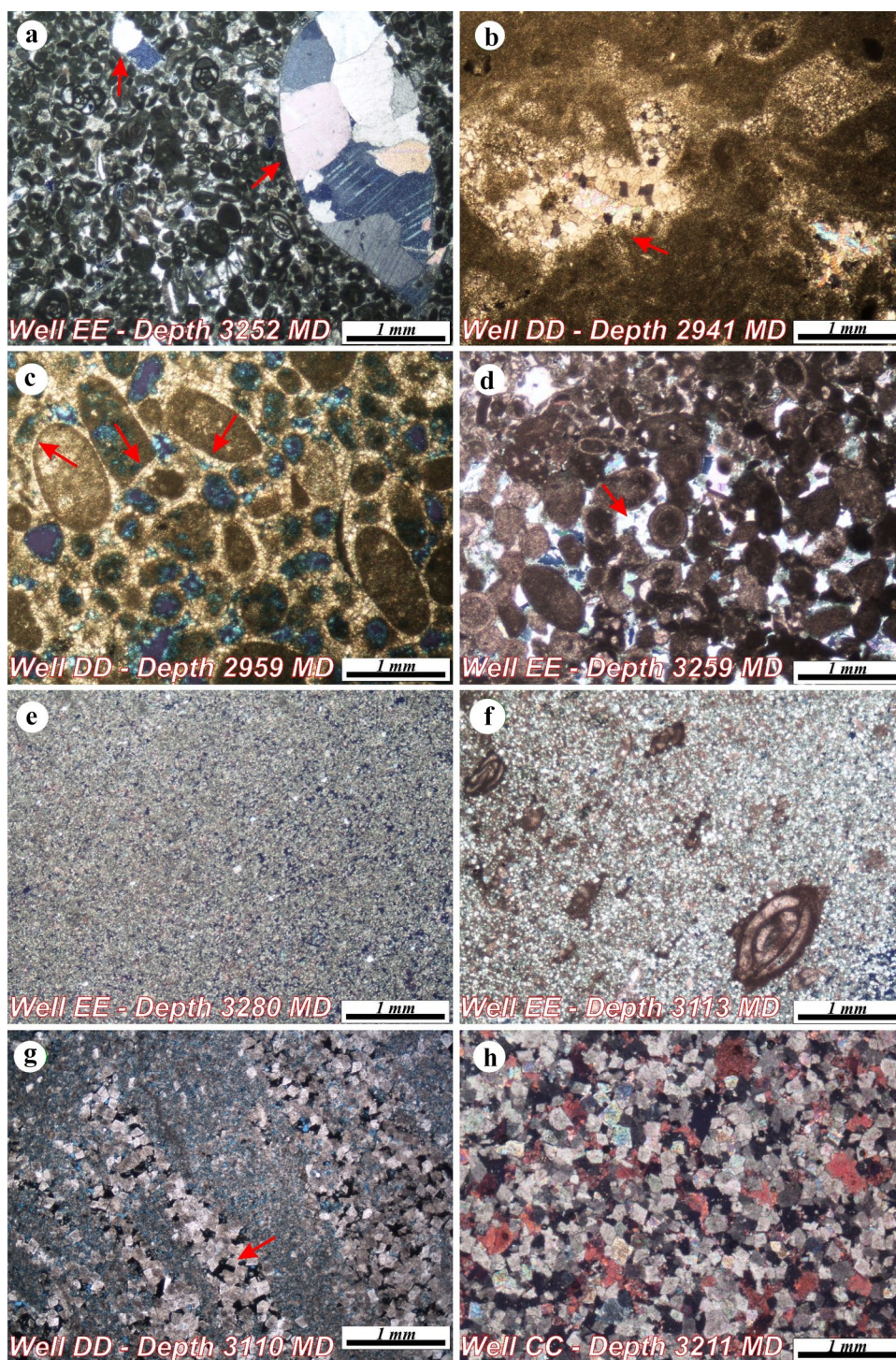
(Fig. 10b). According to the mineralogy, fabric, and appearance characteristics, these types of cement seem related to the burial diagenesis environment. Al-Aasm et al (2009) and Jafari et al. (2020) based on stable isotope analysis of calcite cement in the Asmari Formation, have made similar results. The marine cement, as delicate rim calcite cement, was observed only in Aquitaine grain-supported facies (Fig. 10c). Generally, this cement—formed under early diagenesis conditions (syn-depositional)—prevents the mechanical compaction of sediments during burial diagenesis, and therefore, the pore spaces were preserved. Due to the lack of proper development of this type of cement in the Asmari Formation, it could not play its role very well, and porosities were eliminated by physical (mechanical) compaction.

Although the cementation has strongly affected the Asmari Formation, dolomitization in this formation had a much more significant effect on the final reservoir quality of the rock. So far, some researchers have specifically investigated the dolomites of the Asmari Formation (Aqrabi et al. 2006; Al-Aasm et al. 2009; Noorian et al. 2022; Omidpour et al. 2022). The dolomitization process, according to its intensity, can play a dual role in the reservoir quality of carbonate sequences so that in the intervals where proper dolomitization has taken place, the reservoir quality is good, but in some intervals with over-dolomitization, the pore spaces are destroyed, and rock reservoir quality is decreased.

¹ Reducing reservoir quality of rocks.

² Increasing reservoir quality of rocks.

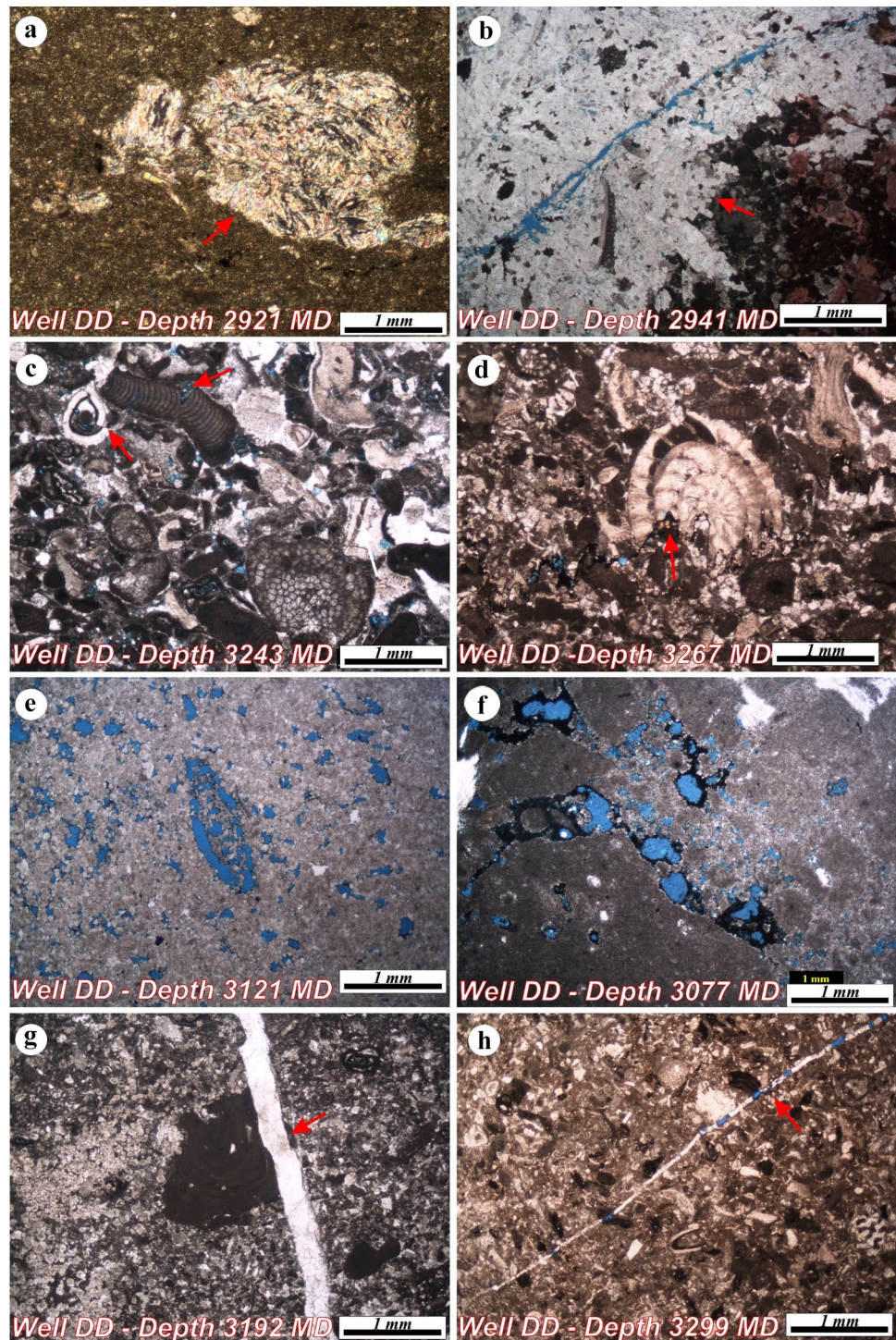
Fig. 10 Diagenesis processes in Asmari Formation of Qale Nar Oilfield. Burial blocky cement filled the shelter porosity (a), Drusy cement in mud-supported microfacies (b), marine rim cement around the allochems in grain-supported microfacies (c), anhydrite plugging (cement) in grain-supported microfacies (d), recrystallization of very fine dolomite crystal to microspar in tidal microfacies (e, f), proper dolomitization with Planar-E rhombs (g), over-dolomitization with Planar-s to Nonplanar crystals (h) all photographs except b, are in XPL and d, f, h were stained by Alizarin Red-S. Also, c was impregnated with Blue Epoxy Resin



This phenomenon includes a wide range of diagenesis stages (from early to late). It seems that rocks composed of very fine carbonate crystals (micrite) have more potential for this process. The syn-depositional proto-dolomites—which have a low crystalline array (order)—are found in muddy microfacies (related to the tidal flat and subtidal zone) (Gebelein et al. 1980) and have a high chance for

dolomitization during burial diagenesis. The size of dolomite rhombs is fine and rarely exceeds 20 microns in this type of dolomitization (Fig. 10e, f). But, dolomitization of the inner ramp grain-supported microfacies by dolomitizing fluids during the late diagenesis formed coarse dolomite crystals usually greater than 20 microns (Aqrabi et al. 2006; Al-Aasm et al. 2009) (Fig. 10g, h).

Fig. 11 Other diagenesis processes in Asmari Formation in Qale Nar Oilfield. Anhydrite nodules in mud-supported microfacies (a), non-selective anhydritization of limy microfacies (b), Broken and deformed *Ditropa* sp. and green algae in grain-supported facies by physical compaction (c), chemical compaction and development of stylolite (d), moldic porosity of Nummulitidae family microfossil in Rupelian deposits (e), Vuggy porosity in mud-supported microfacies of Aquitanian Deposits (f), filled fracture by calcite cement (g), semi-filled fracture by calcite cement (h). All photographs are in XPL and were impregnated with Blue Epoxy Resin



According to Flügel (2010), the formation of sulfate cement (Anhydrite and Gypsum) in carbonate rocks also has similar conditions to dolomitization (from early to late), so in the Asmari Formation of Qale Nar Oilfield, often, small anhydrite nodules which are observed in the tidal flat muddy microfacies are related to early diagenesis (Fig. 11a). Porosity filling anhydrite cement (Anhydrite Plugging) occurred

during the late diagenesis phase (Fig. 10d). Note, sometimes anhydritization (in the form of replacement anhydrite) acts as the non-selective process, replacing both allochems and orthochems in the Asmari Formation (Fig. 11b).

Compaction has two types: physical (mechanical) and chemical. It is another destructive diagenesis process that widely affects this reservoir interval. The existence of

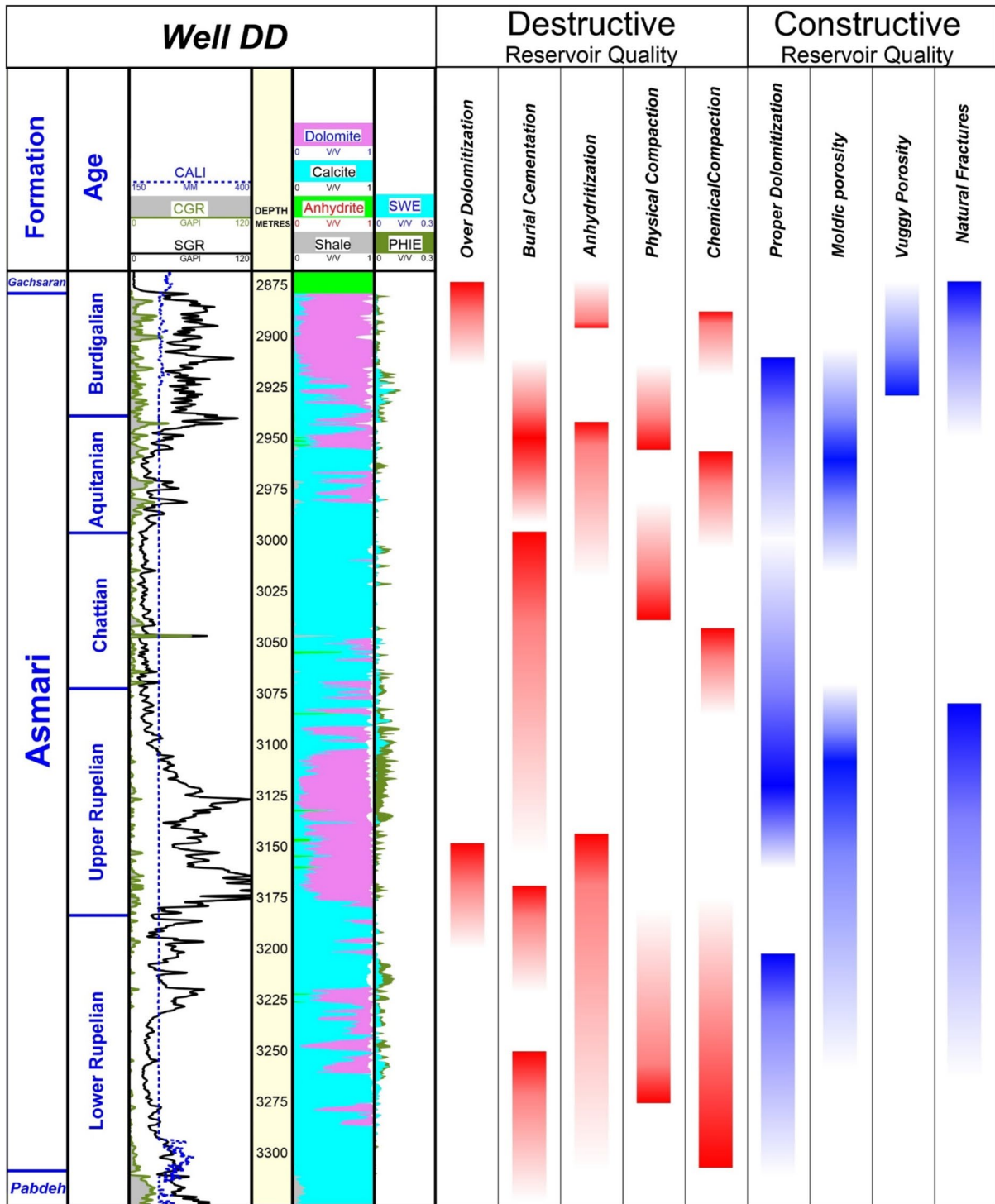


Fig. 12 Schematic image of occurrence and intensity of important diagenesis processes in different parts of Asmari Formation, well DD-Qale Nar Oilfield

deformed or broken allochems such as miliolids and ooids (Fig. 11c), representing physical compaction, enormously reduces rocks' primary porosity and permeability. Chemical compaction creates bad conditions for reservoir quality. The very fine pores that remained from physical compaction

were completely extinct at this stage, and tight rocks were formed. Moreover, the products resulting from the pressure dissolution of these compacted rocks provide cations and anions needed for the constitution of burial cement in other layers. Development of stylolite and solution seams

(Fig. 11d) indicating effects of chemical compaction in the Asmari Formation. Although it is impossible to consider a clear boundary between physical and chemical compaction during diagenesis, both types of them may act simultaneously in sediments. Generally, it can be said that physical compaction mainly occurs in early diagenesis and shallow burial conditions, while chemical compaction starts gradually from shallow burial and maximized during deep burial.

Dissolution is another diagenesis process that increases the reservoir quality of rocks. It is often observed in moldic and vuggy forms in the Asmari Formation. The moldic porosity is an indication of heterogeneous (selective) dissolution and includes skeletal and non-skeletal grains. It is more common in dolomitized sequences (Fig. 11e). However, homogeneous (non-selective) dissolution has been observed in the form of vuggy porosity and is usually found in muddy carbonate facies related to tidal flats (Fig. 11f). Another constructive diagenesis process in the Asmari Formation is natural fracturing. Although the total porosity value of rocks does not increase by the fracturing process (Based on the fracture model, the fracture porosity average is 0.045% for Asmari Reservoir), they increase the overall permeability and fluid flow by connecting different porosities. Natural fractures are created during the delayed diagenesis phase, during uplift (folding) in the reservoir rock. In the Asmari Formation of Qale Nar Oilfield, the dolomitized rocks are fractured more than the limestone ones. Some of these fractures are filled or semi-filled by carbonate (calcite) or sulfate (anhydrite) types of cement (Fig. 11g, h). Based on petrographic studies, the grain-supported facies have suffered more natural fractures than the mud-supported types.

Reservoir rock types

Hydraulic flow unit (HFU)

Usually, porosity and permeability are two fundamental factors for the quality determination of reservoir rock. At first, a good reservoir rock must be porous to contain a significant volume of hydrocarbons. Then, to have hydrocarbon movement (inside of the reservoir) toward the production wells, reservoir rocks must have a considerable permeability. Since the size of the pore throats has an essential role in the hydrocarbon movement inside reservoir rocks (Al-Dujaili et al. 2021), permeability plays a more critical role than porosity in determining hydraulic flow units and rock quality. Rock permeability is greatly influenced by sedimentological factors (depositional environment and diagenetic processes conditions). In many cases, permeability is independent of total porosity. High-permeable rocks have huge numbers and large sizes of connected pore throats. Therefore, for easy hydrocarbon movement through the reservoir rocks, a suitable size of pore throats is needed (Abuseda et al. 2015;

Moradi et al. 2017, 2019; Al-Dujaili et al. 2021; Khazaie et al. 2022a; Fallah-Baghtash et al. 2022). According to Abbaszadeh et al. (1996), a flow unit is a part of a reservoir rock that is vertically, laterally continuous, and predictable. Specific geological (sedimentological) and petrophysical characteristics affect fluid flow behaviors. So, each rock unit with an individual flow unit also has particular petrophysical characteristics. These features are different from other hydraulic flow units in the reservoir rock. It should be noted that the rocks with the same flow unit do not necessarily have the same sedimentological specific (such as the same sedimentary facies or the same diagenetic processes).

Although the determination of hydraulic flow units by the FZI method is a traditional method to know the good reservoir quality intervals and producing areas, the efficiency of this method in hydrocarbon field development has made oil and gas companies continue using this method (Thai et al. 2017; Elnaggar 2018; Yusuf and Padmanabhan 2019; Al-Jawad and Saleh 2020; Khalid et al. 2020; El Sayed et al. 2021; Radwan et al. 2021; Nabawy et al. 2022; El-Gendy et al. 2022; Ismail et al. 2023).

As already mentioned, a large number of connected pores via the large size of pore throats make highly permeable reservoir rocks that fluids can pass easily through them. The Log FZI versus Probability diagram (known as cumulative density plot) should be drawn to determine the numbers of hydraulic flow units. The curve breakpoints (turning points) on this diagram determine hydraulic flow units (Fig. 13a). Five hydraulic flow units (HFUs) (labeled as A–E) were determined for the Asmari Formation in Qale Nar Oilfield (Table 2). The permeability versus porosity diagram for each HFU shows that the permeability to porosity ratio decreases from HFU A toward HFU E (Fig. 13b). The relationship between RQI versus permeability values and porosity values confirms a similar trend for HFUs (Fig. 13c, d).

The petrophysical properties (porosity and permeability averages) of each HFU are as follows.

Hydraulic flow unit A This hydraulic flow unit has the highest reservoir quality and is most frequent among others. The highest values of average porosity (5.8%) and permeability (geometric averages) (0.37 mD) are observed in this HFU (Table 2). It is mainly seen in Crystalline Dolomite, Nummulites packstone/grainstone, and Mudstone/Dolomudstone Facies Associations. In this hydraulic flow unit, the main porosities are intercrystalline, moldic, and dissolution types and less intergranular porosity is observed. Generally, the highest frequency of HFU A is in the sequences related to the Upper Rupelian and Burdigalian of the Asmari Formation.

Hydraulic flow unit B Despite the very low frequency of this hydraulic flow unit, it has a good reservoir quality. The val-

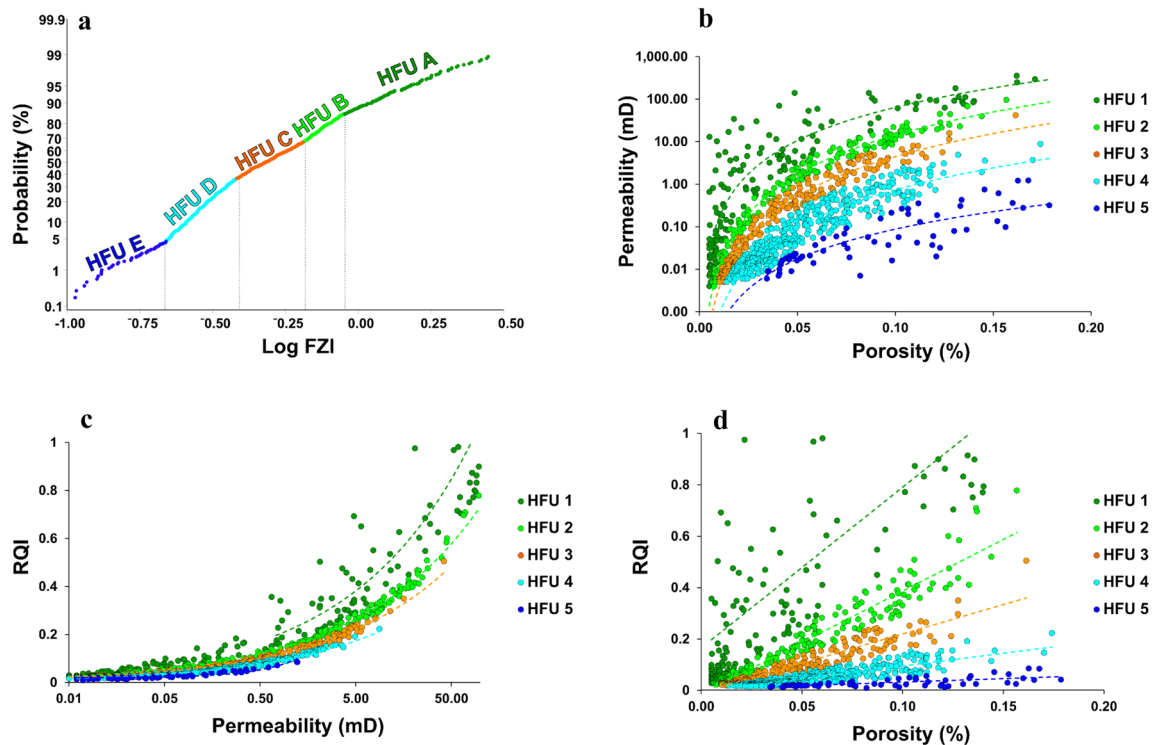


Fig. 13 Separating hydraulic flow units by logarithm of FZI (Vs) normal probability diagram (a). The relationship between permeability (Vs) porosity (b), RQI (Vs) permeability (c), and RQI (Vs) porosity (d) was demonstrated by diagrams

Table 2 The petrophysical properties of obtained hydraulic flow units for the Asmari Formation in Qale Nar Oilfield

HFUs	Log FZI value	Average porosity (%)	Average permeability (geometric) (mD)
HFU A	Log FZI > -0.05	5.8	0.37
HFU B	-0.2 < Log FZI < -0.05	4.8	0.32
HFU C	-0.4 < Log FZI < -0.2	3.4	0.09
HFU D	-0.65 < Log FZI < -0.4	1.09	0.05
HFU E	Log FZI < -0.65	0.07	0.03

ues of average porosity and permeability (geometric averages) are 4.8% and 0.32 mD, respectively (Table 2). Benthic foraminifera wackestone/grainstone (intergranular porosity) and Crystalline Dolomite (intercrystalline porosity) are two of the Facies Associations where the highest concentration of HFU B can be seen. Generally, the highest frequency of HFU B is in the sequences belonging to the Rupelian (Upper and lower) deposits of the Asmari Formation.

Hydraulic flow unit C Hydraulic flow unit C has a relatively high frequency in Asmari Reservoir succession and it is mostly observed in Lower Rupelian and Burdigalian strata. The average values of porosity and permeability in HFU C have significantly decreased compared to HFU B. This

reduction is more severe for permeability, so the values of average porosity and permeability are 3.4% and 0.09 mD, respectively (Table 2). HFU C can be seen in Mudstone/Dolomudstone, Nummulites packstone/grainstone, and benthic foraminifer wackestone/grainstone Facies Associations.

Hydraulic flow unit D This HFU has a high frequency in Asmari Formation, which is not assigned to a particular age. But generally, it can be said that Rupelian, Aquitanian, and Chattian deposits have a high frequency of this flow unit. The average values of porosity and permeability in HFU D are 1.09% and 0.05 mD, respectively (Table 2). HFU D can be seen in Nummulitidae-Lepidocyclinidae rudstone/packstone, Bioclast ooid packstone/grainstone, and Coral-coraline red algae floatstone/rudstone Facies Associations where poor development of intergranular and growth porosities was observed.

Hydraulic flow unit E Hydraulic flow unit E has the lowest reservoir quality among others. The average values of porosity and permeability in HFU E are 0.07% and 0.03 mD, respectively (Table 2). Similar to HFU D, HFU E also is observed in all Asmari succession and it is not assigned to the particular stage. This HFU has the most frequency in Planktonic foraminifera packstone/wackestone and Coral-coraline red algae floatstone/rudstone Facies Associations.

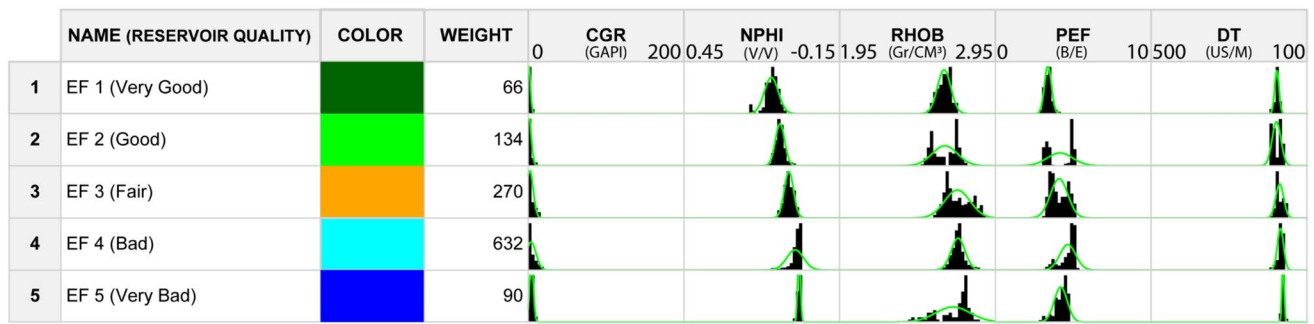


Fig. 14 Values distribution of raw petrophysical well-logs in reservoir electrofacies of Asmari Formation in Qale Nar Oilfield

Table 3 Some petrophysical properties of each electrofacies (Jamilpour et al. 2021)

EFs	SGR (API)	CGR (API)	NPHI (v/v)	RHOB (gr/cm ³)	DT (μs/f)	PEF (B/E)	SWE (%)	PHIE (%)	Core ϕ (%)	Core k (mD)
EF 1	77.33	2.98	0.08	2.69	51.38	4.86	32.8	8.9	5.91	0.38
EF 2	69.66	2.68	0.07	2.72	50.29	3.45	40	4.3	4.82	0.31
EF 3	42.62	3.61	0.03	2.74	50.05	3.67	61.7	2.6	3.35	0.08
EF 4	24.27	0.96	0.04	2.67	52.56	3.65	84.9	0.9	1.08	0.04
EF 5	59.99	9.55	0.14	2.64	55.77	4.78	99.2	0.1	0.08	0.02

The porosity is hardly seen in this hydraulic flow unit. There is only an isolated form of porosity (intragranular or intra-fossil types) in HFU E.

Electrofacies (EF)

Five raw petrophysical well-logs such as CGR, PEF, NPHI, RHOB, and DT of six wells through the Asmari Formation were selected as input data to build an electrofacies model in the Qale Nar Oilfield. Clustering was performed by selecting the aforementioned petrophysical logs and trying to group them using the MRGC approach in different classes by Geolog software. During this phase, several clusters were built (40 clusters) initially. Then, clusters that have almost similar petrophysical properties (well-logs responses) were merged. Finally, five clusters (electrofacies) petrophysical model was made (Fig. 14).

It should be noted that due to the direct effect of petrophysics interpreter opinions on final reservoir electrofacies results, evaluated petrophysical well-logs such as effective porosity (PHIE) and effective water saturation (SWE) were not used. Therefore, in this research, only raw petrophysical logs were used for the electrofacies model.

The petrophysical attributes in each electrofacies have maximum similarity and minimum difference to each other and also have the maximum difference and minimum similarity with the attributes in other electrofacies (Li et al. 2014; Farshi et al. 2019; Wang et al. 2019). The average values of petrophysical logs are listed in Table 3. Based

on these values, the reservoir quality decreases from EF 1 to EF 5 (Table 3). Exactly similar to HFUs, the rocks that have the same electrofacies do not necessarily have the same sedimentological features (such as the same sedimentary facies or the same diagenetic processes).

Capillary pressure (P_c) test results are very important data in reservoir evaluation and caprock efficiency. This test provides valuable and valid data in the study of hydrocarbon fields by separating the pay zones from impermeable (barrier) zones in the reservoirs. Utilizing such data, the relative permeability and distribution of pore spaces can be understood. Determining the recovery factor of hydrocarbon reservoirs and choosing the optimal method for planning secondary recovery methods (improved or enhanced recovery methods) are among the other applications of this test results. Today, reservoir engineers use the results of these data to provide more accurate estimates for dynamic modeling, production intervals, and development scenarios of fields (Thai et al. 2017; Dakhelpour-Ghoveifel et al. 2019; Kadkhodaie et al. 2019; Khataniar et al. 2022; Khazaie et al. 2022b; Wang et al. 2022).

The distribution of P_c test results within electrofacies was assessed to validate the trend of reservoir quality of obtained electrofacies. These curves confirm the decreasing trend in reservoir quality from EF 1 toward EF 5 (Fig. 15).

The main petrophysical attributes of each electrofacies will be discussed below.

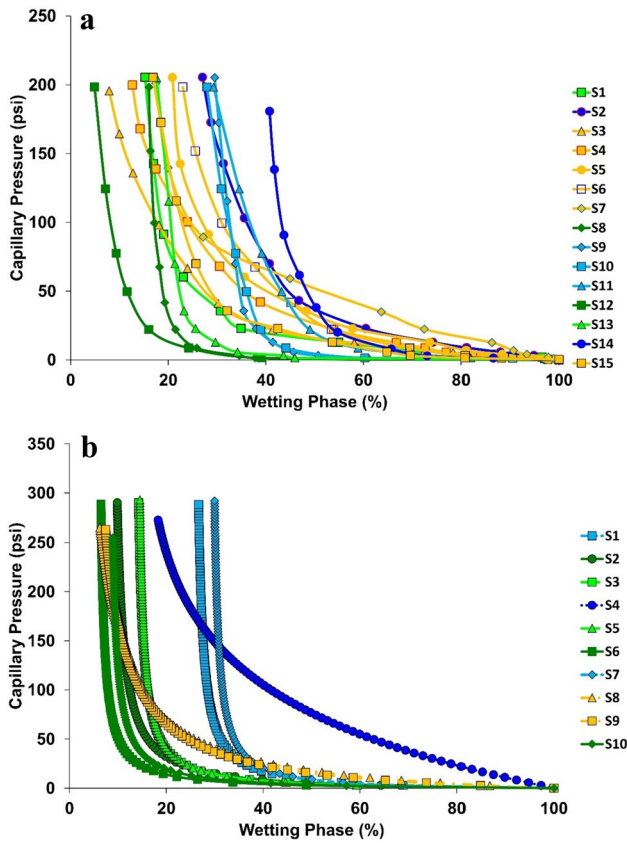
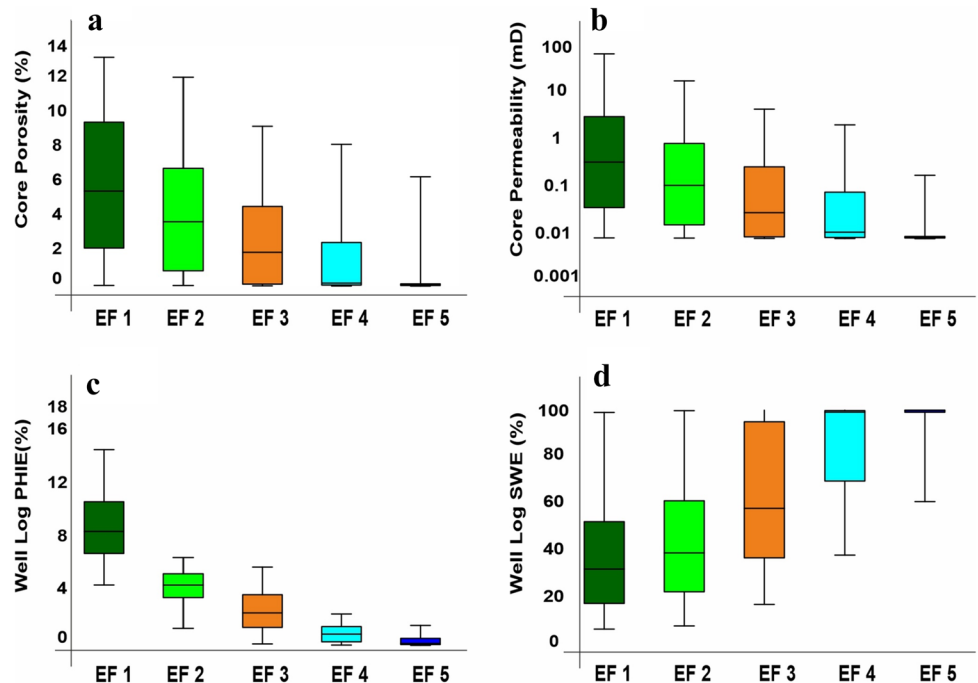


Fig. 15 The results of Pc test for each electrofacies in wells BB (a) (15 samples) and CC (b) (10 samples). Note, the curve line color of each sample in Pc diagrams refers to its assigned reservoir electrofacies (Jamilpour et al. 2021)

Electrofacies 1 This electrofacies has the highest reservoir quality, but, the lowest frequency among obtained electrofacies of the Asmari Formation in Qale Nar Oilfield. Measured porosity and permeability data reveal that core porosity changes between 2.23 to 9.55% (average: 5.91%) (Fig. 16a), and core permeability is between 0.04 to 3.35 mD (geometric average: 0.38 mD) (Fig. 16b). Based on evaluated petrophysical logs (Table 3), effective porosity values (PHIE) for EF 1 change between 6.7 and 10% (average: 8.9%) (Fig. 16c); effective water saturation values (SWE) situated between 19 and 53% (average: 32.8%) in this electrofacies (Fig. 16d). EF 1 has a high frequency in Rupelian and Burdigalian sequences. Also, EF 1 has a high frequency in Crystalline Dolomite, Nummulites packstone/grainstone, and benthic foraminifer wackestone/grainstone. The shape of capillary pressure curves (Pc test) for this electrofacies shows large volume of the wetting phase (more than 90%) was decreased under low pressure (< 50 psi) (Fig. 15).

Electrofacies 2 In this EF, the variations range of core porosity values is between 0.91 and 6.86% (average: 4.82%) (Fig. 16a), and permeability values vary between 0.02 and 0.90 mD (geometric average: 0.31 mD) (Fig. 16b). The values of petrophysical logs for EF 2 (Table 3) show that effective porosity (PHIE) values range between 3.6 and 5.4% (average: 4.3%) (Fig. 16c). Also, effective water saturation (SWE) values change between 23.1 and 61.7% (average: 40%) in EF 2. (Fig. 16d). According to petrophysical attributes, this electrofacies is also classified as electrofacies of good reservoir quality. EF 2 prevails in the Upper Rupelian and Chattian stages of the Asmari Formation and

Fig. 16 The properties variations range of each electrofacies. Core porosity (a), core permeability (b), well-log effective porosity (c), and well-log effective water saturation (d)



its frequency decreases toward the top of the succession. Mudstone/Dolomudstone, Crystalline Dolomite, and Benthic foraminifer wackestone/grainstone are Facies Associations which have more frequency in EF 2 among others. According to the capillary pressure curve (Pc test) of samples assigned to this electrofacies, the volume of irreducible water in EF 2 is more than EF 1 (20% or more). Also, more pressure than EF 1 (50 psi or more) is needed to reach this point (irreducible water volume) (Fig. 15).

Electrofacies 3 Electrofacies 3 has a relatively high abundance among others. This electrofacies can be found in almost all stages of Asmari Formation. Therefore, it is not limited to a specific stage. Core data show that porosity values vary from 0.12 to 4.63% (average: 3.35%) (Fig. 16a), and permeability represents values of 0.01 to 0.28 mD (geometric average: 0.08 mD) (Fig. 16b). According to evaluated petrophysical Logs (Table 3), effective porosity (PHIE) in EF 3 changes between 1.4 and 3.8% (average: 2.6%) (Fig. 16c), whereas effective water saturation (SWE) values situated in the range of 37.6–95.1% (average: 61.7%) (Fig. 16d). Pc test results of EF 3 show a wide range of irreducible water content (8–25%) in different samples. Also, the difference in the volume of irreducible water was obtained in different pressures (150–200 psi) (Fig. 15). On the other hand, the curve dip angle of EF 3 Pc test results is very low which is different from other electrofacies Pc test results. Similar to EF 2, Mudstone/Dolomudstone, Crystalline Dolomite, and Benthic foraminifer wackestone/grainstone are Facies Associations that have high frequency for EF 3.

Electrofacies 4 Core porosity values of EF 4 change between 0.07 and 2.54% (average: 1.08%) (Fig. 16a), while those of permeability vary between 0.01–0.08 mD (geometric average: 0.04 mD) (Fig. 16b). Based on petrophysical log values (Table 3), effective porosity (PHIE) represents changes from 0.3 to 1.5% (average: 0.9%) (Fig. 16c), while effective water saturation (SWE) changes between 70.4–100% (average: 84.9%) for this EF (Fig. 16d). EF 4 is the most abundant electrofacies in the reservoir. The high values of water saturation and low effective porosity indicate that EF 4 has low reservoir quality. This electrofacies is almost found in all stages of Asmari Formation but it seems that EF 4 has more frequency in Upper Rupelian and Chattian stages. Frequently, EF 4 is found in Nummulitidae-Lepidocyclinidae rudstone/packstone and Bioclast ooid packstone/grainstone Facies Associations. Capillary pressure (Pc) test results of EF 4 represent the high value of irreducible water (more than 35%) which is not discharged even under high injection pressure (more than 200 psi) (Fig. 15).

Electrofacies 5 This electrofacies has the lowest reservoir quality and also relatively low frequency among others. The

highest values of water saturation and the lowest values of effective porosity suggest that EF 5 has very bad reservoir quality. Measured core porosity and permeability data show that porosity values vary between 0 and 0.14% (average: 0.08%) (Fig. 16a) and permeability values change from 0 to 0.02 mD (geometric average: 0.01 mD) in EF 5 (Fig. 16b). Also, effective porosity (PHIE) values change between 0.1 and 0.2% (average: 0.1%) (Fig. 16c), while values of effective water saturation (SWE) change between 98 and 100% (average: 99.2%) for this EF (Fig. 16d). EF 5 was mostly encountered through the lower Rupelian and Chattian successions. Planktonic foraminifera packstone/wackestone and Coral-coraline red algae floatstone/rudstone are two facies associations that have more frequency of EF 5 among others. Moreover, the volume of irreducible water in EF 5 is very high (37–47%) (Fig. 15).

Discussion

One of the major problems in the hydrocarbon fields is determining accurate reservoir characterization. Due to the high costs of coring and increased well drilling time and risk, it is not possible to obtain the core—which demonstrates real data of the reservoir—in all drilled wells or full reservoir thickness. Therefore, petroleum engineers are always looking for methods to obtain almost correct knowledge about the reservoir for intervals or wells without cores.

Establishing a relatively good correlation (match) between the results of hydraulic flow units (using routine core analysis data that are usually not available in all drilled wells) and reservoir electrofacies (using raw petrophysical well-logs that are often available in all drilled wells) caused to true estimation of reservoir characterization and solving the petroleum engineers' problem.

To create a logical relationship between hydraulic flow units and reservoir electrofacies, it is necessary to set the electrofacies according to the obtained hydraulic flow units. Because the determination of reservoir hydraulic flow units by the FZI method is constant, these electrofacies should be determined in such a way that they have the most compatibility with hydraulic flow units. For this purpose, this research has tried to select the electrofacies algorithm (MRGC model), settings parameters (MRGC model parameters), and propagator (KNN facies propagation) in Geolog software in such a way so that obtained electrofacies have the most similarity and compatibility with the hydraulic flow units.

Generally, due to intensive changes in depositional environment conditions and also, the performance of various diagenetic processes, the carbonate reservoir of the Asmari Formation is highly heterogeneous even in certain horizons throughout Qale Nar Oilfield. These heterogeneities are so much that it is not possible to follow a constant trend of

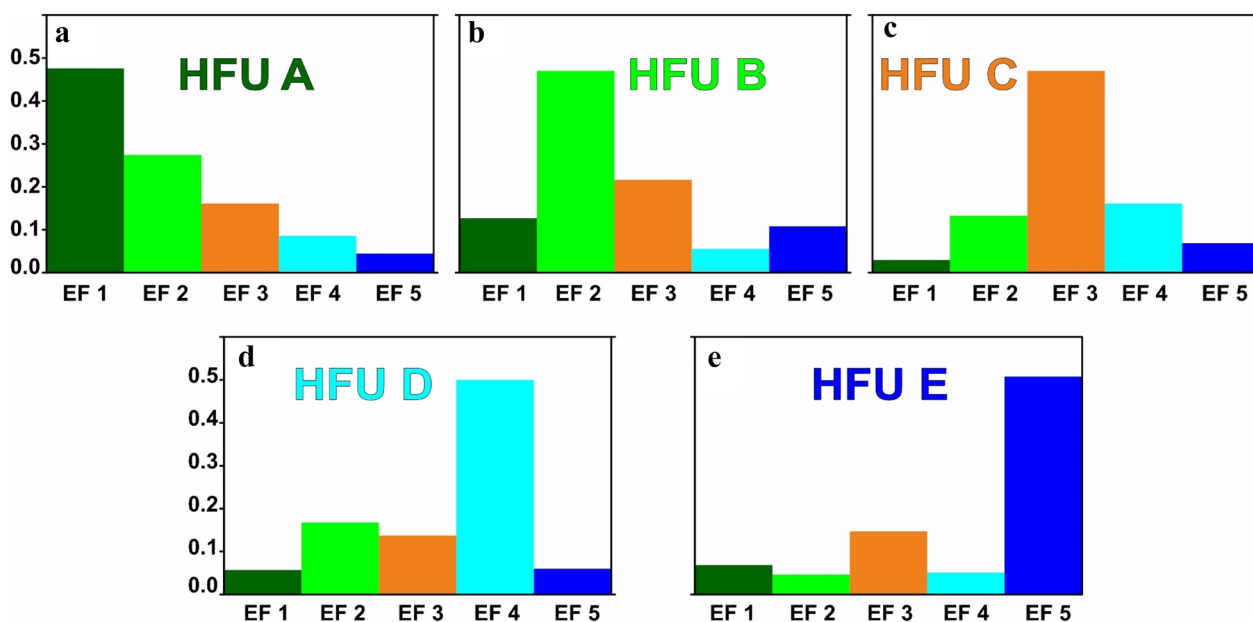


Fig. 17 Frequency of electrofacies in each hydraulic flow unit

reservoir quality (increasing or decreasing) for a particular horizon through the oilfield. For example, Burdigalian deposits from west to east of the oilfield (from Well AA to Well FF) show different conditions from reservoir quality view point. Petrophysical evaluation well-logs and core routine data are proofs for this claim. Due to the presence of such heterogeneities, dividing the reservoir succession into different rock types that have distinct reservoir quality could be beneficial for reservoir characterization. It is a misconception that specific microfacies should have constant quality and petrophysical properties throughout the oilfield. Hence, particular microfacies may be observed in many EFs or HFUs.

Distribution of electrofacies frequency in hydraulic flow units

Figure 17a–e demonstrates that the obtained electrofacies have a good match with hydraulic flow units so that the most abundant electrofacies correlate to its equivalent HFU from reservoir quality viewpoint. Since raw petrophysical logs have a principal role in electrofacies determination and routine core data are not used, therefore, there are some incompatibilities between obtained electrofacies and determined hydraulic flow units. The critical point is that the frequency of non-matching electrofacies should not be higher than that of matching electrofacies in a particular HFU. Despite such contradictions between HFUs and EFs, the obtained correlation can be used to reach better reservoir characterization in wells without core data.

Distribution of reservoir rock types in facies associations

Due to the different conditions of the sedimentary environment and diagenetic processes, assigning a specific type of reservoir rock quality with certain HFU or EF to each of the sedimentary facies associations does not seem to be the right job; however, examining the frequency of electrofacies and hydraulic flow units in specific facies association shows it is possible to define the reservoir quality status in that facies association to some extent. Figure 18 shows the frequency of HFUs and EFs in each facies association. The reservoir quality conditions of each facies association are examined as follows:

Facies Association I (Planktonic foraminifera Packstone/Wackestone) has a muddy matrix, a very dense texture, and some argillaceous without visible porosity. There is rare intra-particle or intragranular porosity in pelagic microfossil chambers, which are only detectable under the microscope. This facies association has inherently low porosity and permeability. High capillary pressure due to small rock pores and tight pore throats caused a high volume of irreducible water (about 47%) in the Pc test results (Fig. 15a, S14 sample). Clay minerals placement in pores and pore throats leads to a severe reduction in porosity and permeability of this facies association. On the other hand, the presence of clay minerals in this facies association facilitates the physical compaction under overburden pressure, which finally leads to tight pores in reservoir rock. The content of dolomitization in this facies association is too low, so separate dolomite

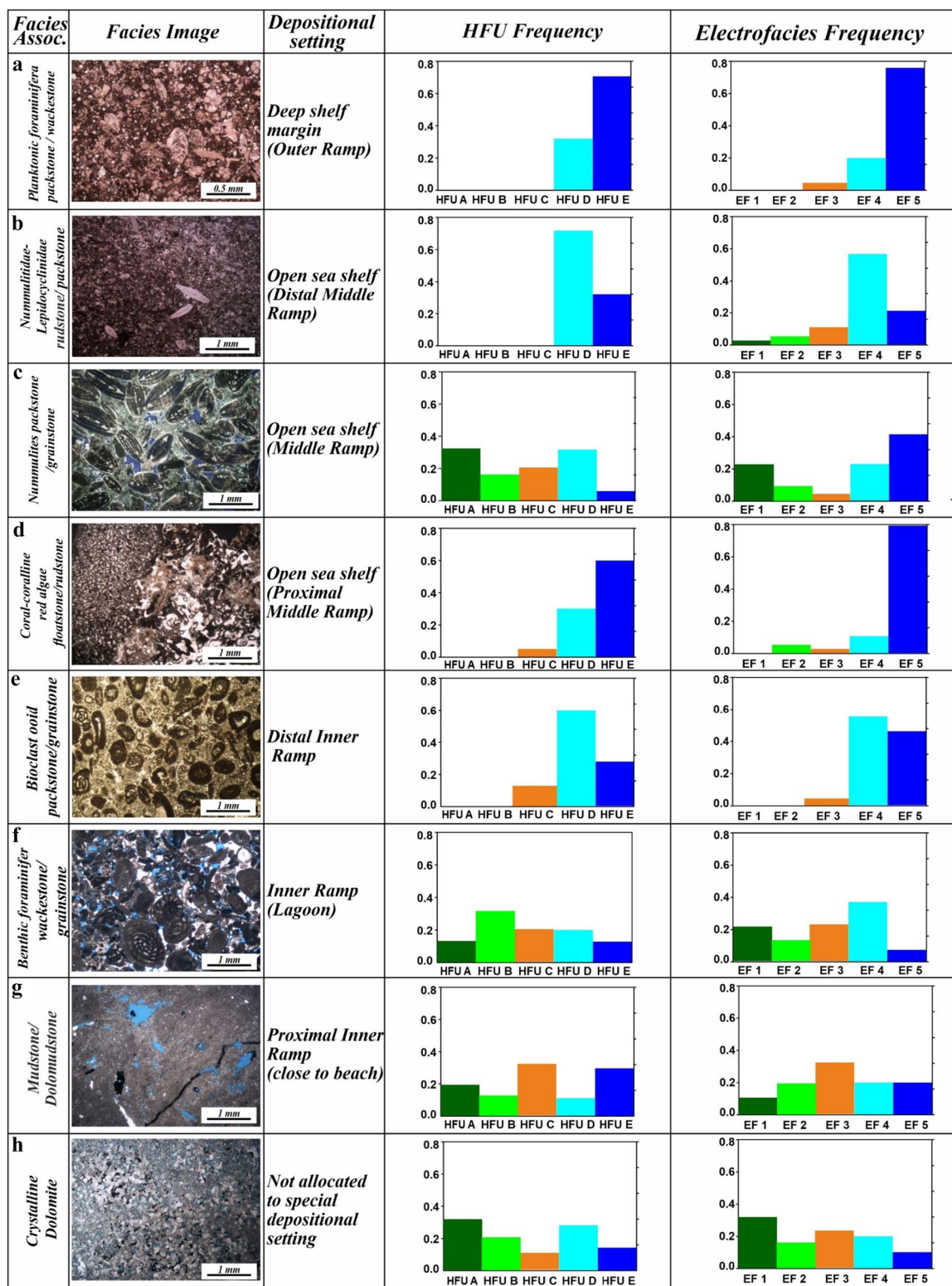


Fig. 18 Frequency of electrofacies and hydraulic flow units in each facies association

rhombs were scattered in the muddy matrix; therefore, this low dolomitization has no effect on reservoir quality increase. Hence, both microfacies (Planktonic foraminifera

packstone/wackestone and Planktonic foraminifera Nummulitidae bioclast packstone) of Facies Association I are considered poor reservoir quality. EF 4 and EF 5, moreover,

HFU D and E are most abundant in this facies association (Fig. 18a).

The reservoir quality conditions in Facies Association II (Nummulitidae-Lepidocyclinidae rudstone/packstone) are different from the previous. The volume of dolomitization in this facies association has increased sharply compared to the facies association I, but it does not have an interconnected network of intercrystalline porosity. In some cases, Nummulitidae and Lepidocyclinidae microfossils were dissolved, and their casts have been left as moldic porosity. Unfortunately, much of the moldic porosity has been filled by anhydrite cement. Generally, improvement of reservoir quality in this facies association has occurred due to constructive diagenesis processes (dissolution and proper dolomitization). In other words, constructive diagenesis processes slightly overcome destructive ones (cementation and compaction), and thus, reservoir quality in Facies Association II—which initially has few porosities and permeability—somewhat improved. Although, like the previous facies association, high frequency of EFs 4 and 5 and HFUs D and E—correlated to poor reservoir quality—are observed in Facies Association II, the frequency of very good and good EFs (EF 1 and 2) slightly increased. The limited development of intercrystalline and moldic porosities in Nummulitidae-Lepidocyclinidae floatstone/rudstone microfacies has caused propagation of good reservoir quality electrofacies. The other two microfacies have no reservoir quality (Fig. 18b). According to previous facies association, Pc test results in Facies Association II also show a high volume of irreducible water (about 40%), which indicates tight pores and pore throats (Fig. 15a, S10, S11 and S15 samples and b, S7 sample).

Due to the preservation of interparticle porosity (as primary porosity), the Facies Association III (Nummulites packstone/grainstone) has good reservoir quality conditions. The cement/matrix between nummulites is often dolomitized, but the Nummulites have retained their calcite mineralogy. Unfortunately, this facies association has no significant expansion in the reservoir and can only be seen in the west of the oilfield (Wells AA, BB and CC). EFs 1 and 2, moreover, HFUs A and B have good development in this facies association (Fig. 18c). Pervasive cementation reduced the reservoir quality and has led to an abundance of poor reservoir quality EFs and HFUs. The Pc test results of this facies association show two utterly different reservoir conditions. So in the samples that have maintained the original interparticle porosity (almost observed in Nummulites packstone/grainstone and Miliolid corallinean nummulites packstone/grainstone microfacies), the amount of irreducible water is low (less than 20%) (Fig. 15a, S12, S13 samples and b, S3, S9 samples). But, in samples with the development of cementation and compaction processes (Bioclast coral-linean Nummulites packstone/grainstone microfacies),

the volume of irreducible water increased (more than 40%) (Fig. 15a, S9 sample).

Facies Association IV (Coral-coralline red algae floatstone/rudstone) generally has poor reservoir quality. Facies Association IV is more influenced by destructive diagenetic processes in rocks that initially had good reservoir quality. Destructive diagenetic processes such as chemical compaction (abundant solution seam and stylolite) and cementation are two processes that have drastically reduced the reservoir quality in Coral-coralline red algae floatstone/rudstone and Corallinean perforated imperforated foraminifer packstone microfacies. Pc test results for these microfacies demonstrate a high volume of irreducible water (Fig. 15b, S1, S4 samples). Facies Association IV has some preserved growth porosity (as primary porosity), which was observed in petrographic studies of Coral-coralline red algae boundstone/framestone microfacies, but probably most of these pores were also separated and, therefore had no effect on reservoir quality improvement. Based on the mentioned points, a high frequency of HFU E and D and EF 5 and 4 (poor reservoir quality rock types) is not unlikely for this facies association (Fig. 18d).

Facies Association V (Bioclast ooid packstone/grainstone) has similar conditions to Facies Association IV. Although this facies association could have a good reservoir quality by maintaining interparticle porosity between ooids, destructive diagenetic phenomena such as pervasive cementation has reduced the reservoir quality. Consequently, poor connection between pore networks in facies association V caused low reservoir quality rock types to be prevalent. Hence, EF 4 and HFU D are abundant (Fig. 18e). Based on the Pc test curves dip (Fig. 15a, S6, S7 samples), the size of pores and pore throats are not well sorted in this facies association, and there are different pore sizes. This phenomenon causes the smaller pores of the rock to be occupied by water and the larger ones by oil, which is not desirable from a reservoir engineering and production zone viewpoint.

Because of the mud-dominant nature of Facies Association IV (Benthic foraminifer wackestone/grainstone), it does not have any primary porosity. However, dissolution as a constructive diagenetic process developed secondary porosity and increased reservoir quality. Therefore, this facies association has a high frequency of EF 1 and 2 and also HFU A and B. Still, pervasive cementation (dominantly anhydrite) and compaction as two destructive diagenetic processes reduced reservoir quality and caused an increase of EF 3 and 4 and HFU C and D in this facies association (Fig. 18f). Pc test results also confirm the presence of rocks with different reservoir quality in this facies association. The development of the dissolution process has caused the formation of large interconnected cavities and pores (Fig. 15a, S8 sample). The low development of this process, along

with cementation, has caused the emergence of fair reservoir quality facies (Fig. 15a, S5 samples).

Similar to Facies Association VI, Facies Association VII (Mudstone/Dolomudstone) initially has (primary) low porosity. However, due to the dissolution process's performance and vuggy pores' expansion, this facies association has a good reservoir quality in some cases. However, EF 3 and HFU C have the highest frequency in this facies association. Still, the operation of the dissolution phenomenon in this facies association is significant (extension of EF 1 and 2 and HFU A and B) (Fig. 18g). The inner surface of some vugs is lined by dead oil, and this facies association appears to have acted as a pathway for hydrocarbon fluids flow (Fig. 11f), which are detectable on Pc test results (Fig. 15a, S1–S4 samples). Anhydrite cementing reduced the reservoir quality of Facies Association VII (Fig. 15a, S2 sample).

Facies Association VIII (Crystalline Dolomite) has the proper reservoir quality. In this facies association, the presence of moldic porosities related to the dissolution of perforated foraminifera (Rupelian Index microfossil) together with the intercrystalline porosities between dolomite rhombs has created an interconnected network of pore spaces with large pore throat size. Although many Facies Associations (I to VII) may be dolomitized during diagenesis stages, Facies Associations II (Nummulitidae-Lepidocyclinidae rudstone/packstone) and III (Nummulites packstone/grainstone) appear to have the proper conditions for dolomitization (Fig. 18h). Dolomitization in this facies association, along with low nucleogenic centers, form large dolomite rhombs. This factor has caused large pores and pore throats generation. The number of nucleuses plays a vital role in the dolomitization process. So, in high nucleogenic centers dolomitization, the size of dolomite crystals naturally is small (microspar), and therefore, no suitable pores are formed or pores size is very fine and cannot pass hydrocarbon fluid easily. In this case, the process of dolomitization cannot be effective in improving the rock's reservoir quality. Figure 10g shows the effect of dolomite crystal size on oil movement in the reservoir. The passage of hydrocarbon fluids through the intercrystalline pore space (between the large dolomite rhombs) has caused dead oil coating in pore spaces, which is not seen among the smaller dolomite crystals. Over-dolomitization (subhedral to anhedral dolomite without any porosity) and pervasive anhydrite cementation are two destructive processes that reduce the reservoir quality of crystalline dolomite Facies Association.

The presence of networked intercrystalline porosities with some moldic porosity (created by the dissolution of large benthic foraminifera) caused abundant proper reservoir quality rocks in Facies Association VIII. The Pc test result also shows low irreducible water in the crystalline dolomite samples (Fig. 15b, S2, S5, S6, S10 samples). Over-dolomitization and anhydrite cement are observed in the crystalline

dolomite sample, which has relatively high irreducible water (Fig. 15b, S8 sample).

Since the Pc test results provide good information about the size of pore throats and their distribution in the reservoir rock, these data were used for electrofacies determination and to create a better correlation (match) between the determined electrofacies and hydraulic flow units in the reservoir.

The Pc test results in EF 1 and 2 demonstrate that large pore throats have caused a low volume of irreducible water. That means most of the pores and pore throats in these EFs are big and filled by oil in the reservoir. Also, the high angle dip of the Pc diagram curve line shows that pore throats size is well sorted. According to all the mentioned about EF 1 and 2, the movement of hydrocarbon fluid in these reservoir electrofacies will be done quickly (Fig. 15a: S1, S8, S12–S13 samples and b: S2–S3, S5–S6, S10 samples).

The Pc test results in EF 3 show different conditions compared to EF 1 and 2. Capillary pressure curves illustrate that EF 3 has various sizes of pore throats (Fig. 15a: S3–S7, S15 samples and b: S8, S9 samples). In the Pc test of this rock type, any increase in injection pressure will lead to a significant decrease in water saturation. In other words, the range of pore size (or probably pore throat size) distribution is wide. Thus, the pore size distribution in EF 3 was badly sorted, and curve lines have low dip angles on the Pc diagram. Hence, depending on the size of the pores, the porosity of EF 3 is filled by both oil (in large pores) and water (in small pores).

High injection pressure in EF 4 and 5 Pc test results and a high volume of irreducible water can reflect the presence of very fine pores and pore throats, which have high capillary pressure. These fine pores in reservoir rock usually are occupied by water. Based on the PC test diagram (dip of curve line) in these rock types, the distribution of pores and pore throat size is the clear difference between EF 4 and 5. So, EF 4 has well-sorted fine pores and pore throats (Fig. 15a: S9–S11 samples and b: S1, S7 samples), but the sorting of pores and pore throats in EF 5 is very bad (Fig. 15a: S2, S14 samples and b: S4 sample).

Petrophysical attribute of electrofacies and hydraulic flow units in reservoir interval

Comparison of routine core analysis data, evaluated petrophysical well-logs (lithology, effective porosity, and water saturation), and finally, the distribution of hydraulic flow units (HFUs) and electrofacies (EFs) in Qale Nar Oilfield wells are shown in Figs. 19 and 20. It seems that there is a relatively good match between HFUs and EFs. Generally, based on these figures, the reservoir quality of dolomitic units of the Asmari Formation in Qale Nar Oilfield is much better than that of the limestone units. The dominance of constructive diagenetic processes over destructive ones was caused by such a good

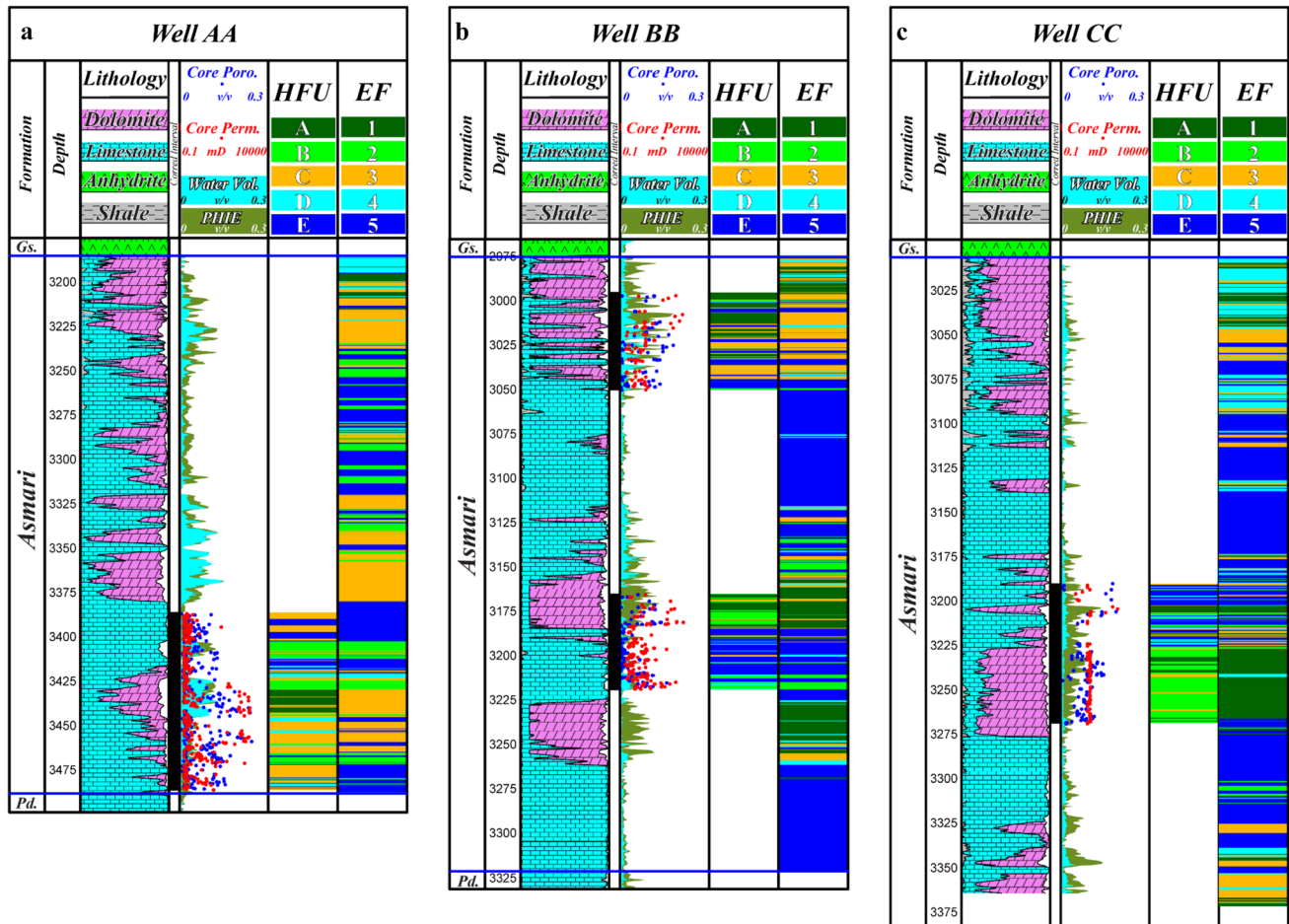


Fig. 19 Distribution of lithology, core porosity, and permeability, evaluated PHIE and water volume well-logs, HFUs, and EFs in the Asmari Succession of Wells AA (a), BB (b), CC (c)

reservoir quality in these rocks. Conversely, the dominance of destructive diagenetic processes over constructive ones in limestone successions has led to poor reservoir quality.

Also, a comparison of obtained HFUs distribution versus routine core analysis shows that rock permeability value directly affects HFU ordering. Meanwhile, core porosity alone cannot be considered an influential factor in the HFU determination of reservoir rock, and its ratio with permeability is essential.

Without proper pore throat size, the rock cannot pass hydrocarbon easily. Therefore, despite high core porosity values, the reservoir rock that has low permeability is classified as low reservoir quality hydraulic flow unit orders.

Compatibility of electrofacies with producing intervals of reservoir

Predicting the well cumulative production (through its reservoir thickness) in a heterogeneous reservoir that has diverse producing layers is one of the essential considerations in

reservoir management and field development plans which prevent the wastage of funds (Wang et al. 2019; Neto et al. 2021). In wells that have complete and continuous core routine analysis data (porosity and permeability) in the reservoir, one of the valuable diagrams for determining production intervals is the modified Lorenz Plot. Flow capacity and storage capacity are used to assess the quality of reservoir rock (especially in carbonate reservoirs, which show a high degree of heterogeneity) (Mohammed Sajed et al. 2020). Generally, by increasing the ratio of the flow capacity of the rock over its storage capacity, the reservoir quality also increases. The analysis of the distribution of EFs in the framework of the modified Lorenz plot (cumulative percentage of flow capacity versus cumulative percentage of storage capacity) in Well DD shows that high dip of the curve (high fluid flow zones in the reservoir) are consistent with good and very good EFs (EF 1 and EF 2 in Upper Rupelian succession), while reservoir intervals with low fluid flow are compatible with low quality EFs (EF 4 and EF 5 in Chattian and Aquitanian stages) This diagram also shows a

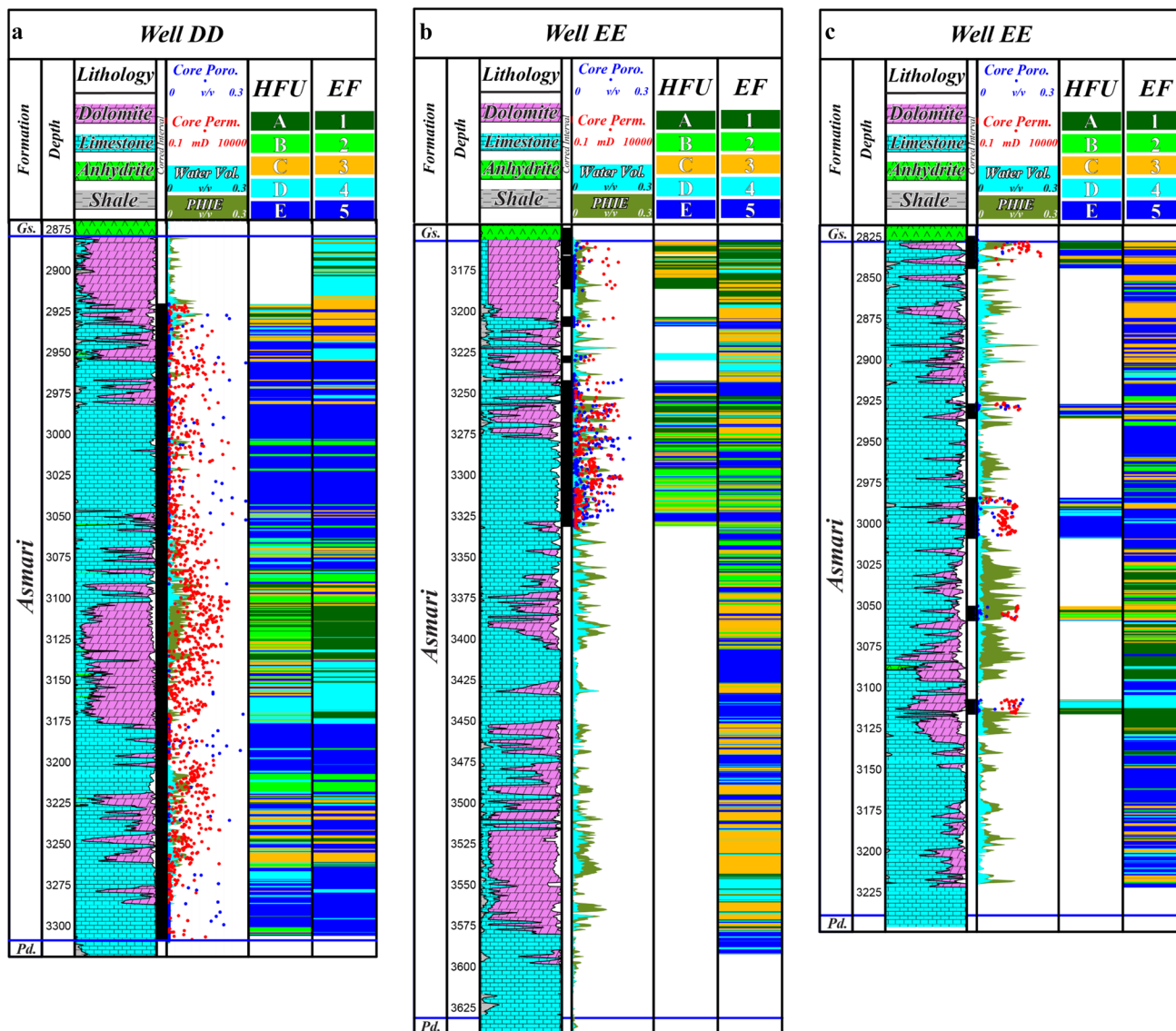


Fig. 20 Distribution of lithology, core porosity, and permeability, evaluated PHIE and water volume well-logs, HFUs, and EFs in the Asmari Succession of Wells DD (a), EE (b), FF (c)

high degree of heterogeneity in the Asmari reservoir (Lorenz Coefficient: 84.15%) (Fig. 21).

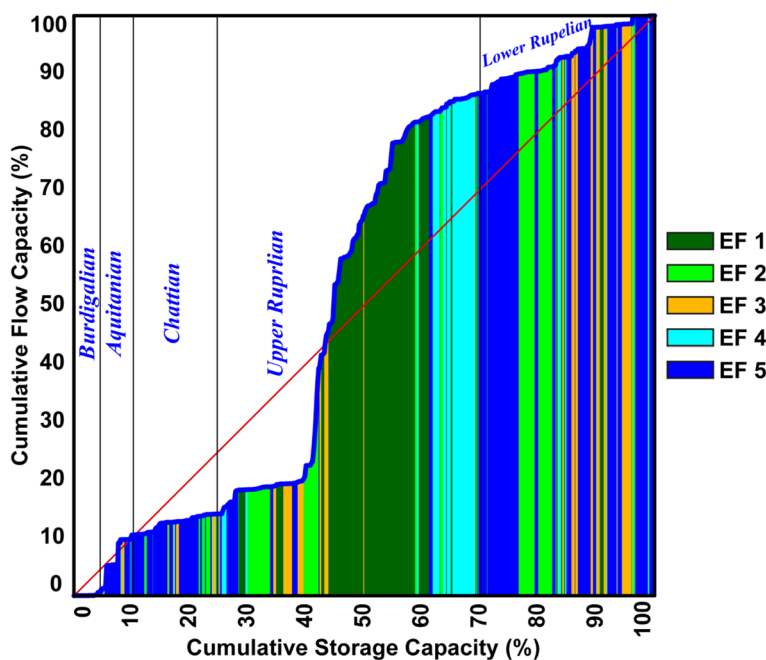
Figure 22 shows the distribution of reservoir EFs in the stratigraphic column of the Asmari Formation, along with some petrophysical raw and evaluated well-logs in Well DD. As shown in this figure, Upper Rupelian succession represents the proper reservoir quality since EFs with high reservoir quality are abundant in this succession. Dolomitization and dissolution increased porosity and permeability (by developing intercrystalline and moldic porosities, respectively), which increased reservoir quality in this zone. Due to the physical and chemical compaction as a destructive diagenetic process, porosity and permeability decrease, and consequently, the reduction of reservoir quality through

limestone intervals is more significant than dolomites (Kake-mem et al. 2021). In other words, the low frequency of dolomites and the high frequency of limestone depict very low reservoir quality rocks since poor EFs are dominated through them (Chattian and Aquitanian successions).

Rock types correlation chart in Asmari Reservoir of Qale Nar Oilfield

Figure 23 shows a correlation map between Qale Nar Oilfield wells about the distribution of electrofacies and hydraulic flow units through each stage of the Asmari Formation. Although obtained electrofacies and hydraulic flow units show relatively intense variations due to

Fig. 21 Modified Lorenz Plot, which shows cumulative flow Vs cumulative storage in Well DD through Asmari Formation thickness. Good reservoir quality electrofacies (EF 1 and EF 2) were in high flow capacity (especially in Upper Rupelian succession). Note that the difference between the thick blue line and the thin diagonal red line shows reservoir heterogeneity



extreme reservoir heterogeneity in the Asmari Formation stages, the Aquitanian deposits have fewer changes throughout the oilfield. The thickness of the Asmari Formation increases from west to east of the oilfield. It has more thickness changes for the Rupelian and Chattian stages, while Aquitanian and Burdigalian sediments have fewer changes.

Benefits of establishing a match between electrofacies and hydraulic flow units

Correct recognition of reservoir characteristics is an important parameter for reservoir development and improved/enhanced recovery plans. Core data are the best kind of data to know the features of reservoir rocks and fluids, but due to the high cost of coring operation, it is collected in only some drilled wells or parts of reservoir thicknesses. On the other hand, wireline logs in most wells are taken quickly and easily; therefore, this type of data is more available than core data. By establishing a logical relationship between hydraulic flow units (obtained from routine core analysis data) and reservoir electrofacies (obtained from petrophysical well-logs), it is possible to provide an approximately accurate prediction of reservoir properties in uncored wells and intervals. Utilizing Pc test results in determining reservoir electrofacies helps to establish a logical relationship between reservoir hydraulic flow units and electrofacies.

Conclusions

Investigating the status of hydraulic flow units, electrofacies, and reservoir quality of Asmari formation in Qale Nar Oilfield revealed the following results:

- Five electrofacies (EFs) and five hydraulic flow units (HFUs) were identified in the Asmari reservoir in the Qale Nar Oilfield. Reservoir quality in EFs and HFUs has decreased from 1 to 5 and A to E, respectively.
- The calibration of obtained electrofacies with Pc test results has an essential effect on establishing a good match between hydraulic flow units and reservoir electrofacies.
- Based on the petrophysical evaluation, petrographic studies, routine core analysis, obtained EFs and HFUs, and the value of the Lorenz coefficient, the Asmari Formation in Qale Nar Oilfield has high heterogeneity.
- Examination of the obtained electrofacies in the modified Lorenz plot shows that the EF 1 and 2 adapt well to the intervals with a high fluid flow regime. Other EFs (3, 4, and 5) increased storage capacity and do not have a unique effect on hydrocarbon flow (producing intervals).
- Due to the thickness and abundance of good and very good reservoir facies (EF 1 and 2, HFU A and B), it is better to consider Upper Rupelian deposits as a top priority to plan future drilling and well completion interval.
- Generally, high reservoir quality rocks (HFU A, B, and EF 1, 2 categories) were found in porous sedimentary

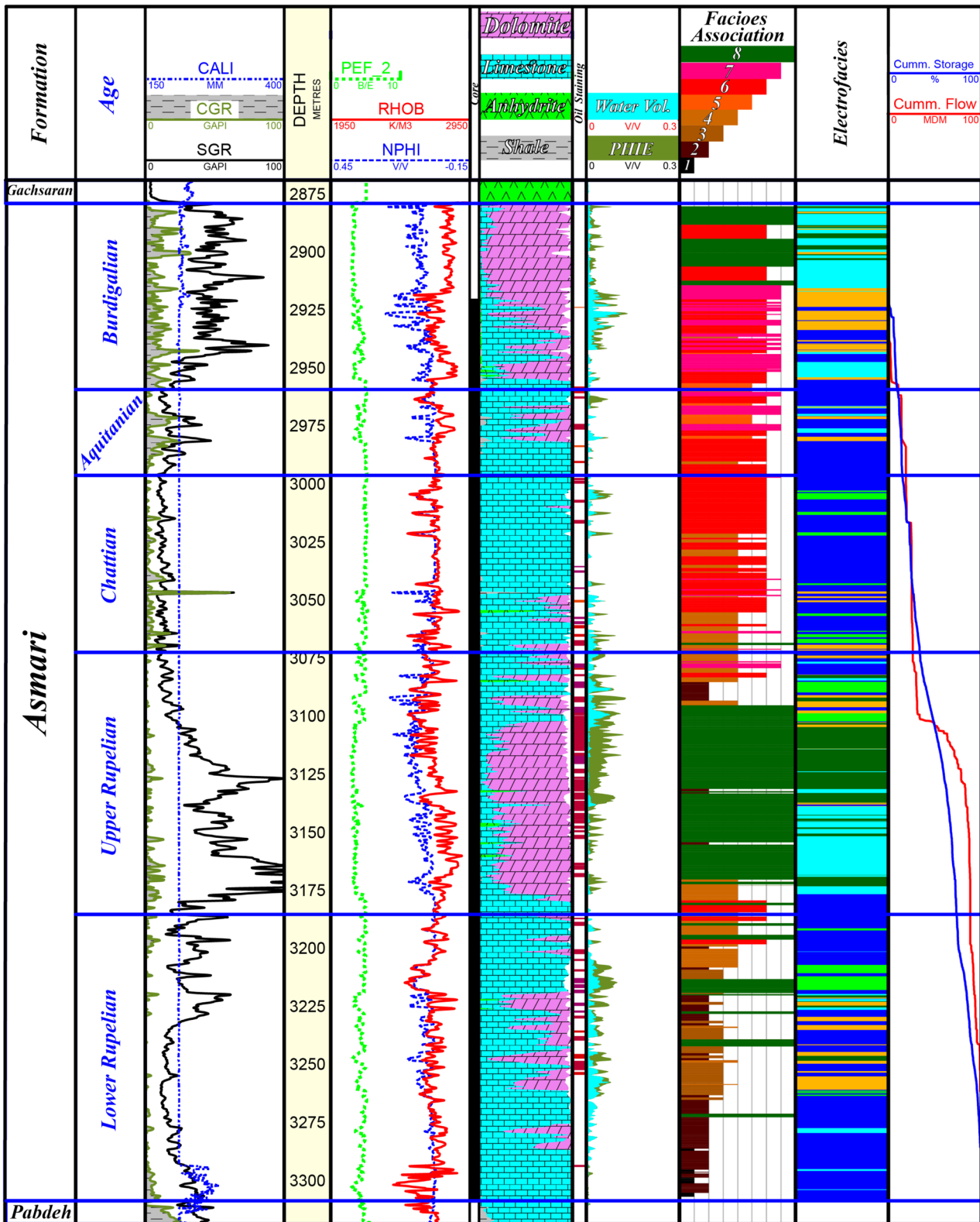


Fig. 22 Lithostratigraphic column of Asmari Formation in Well DD along with some petrophysical well-logs, time zone (stages), facies associations, and vertical distribution of electrofacies. Obtained EFs

have good consistency with the cumulative flow and oil-stained intervals of the core

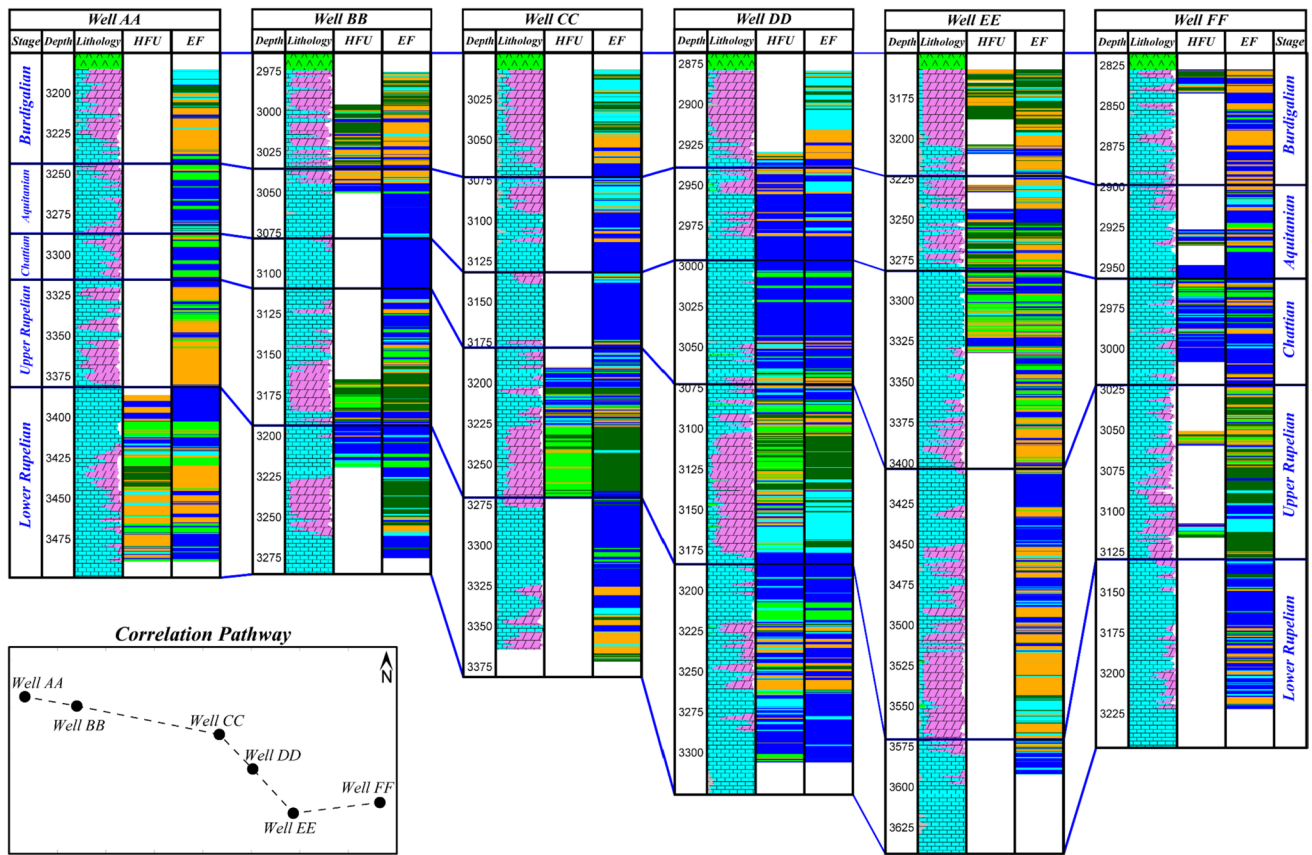


Fig. 23 Distribution of identified electrofacies and hydraulic flow units of Asmari Formation stages through Qale Nar Oilfield

facies associations where intercrystalline and vuggy porosities are common. While low reservoir quality rocks were mainly observed in depth intervals where types of compactions, cementation, and over-dolomitization processes strongly influenced the reservoir (HFU D, E and EF 4, 5 categories).

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Authors' contributions All the authors have fully reviewed the manuscript. Mahmood Jamilpour, Asadollah Mahboubi, and Reza Mousavi-Harami have written the main content, and they planned the manuscript framework. Mohammad Khanehbad and Hamed Hooshmand Koochi prepared the figures and tables and helped other authors provide more accurate scientific results.

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Declarations

Conflict of interest The authors declare that they have no competing interests as defined by Springer or other interests that might be per-

ceived to influence the results and discussion reported in this paper. Also, the authors pledge that there is no conflict of interest between them and this manuscript does not prioritize their personal interests over others.

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