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Petrophysical Evaluation and Reservoir Quality of Ilam Formation (late Cretaceous), Ahvaz Oil Field, Dezful Embayment, SW Iran

Mohammad Sadegh Ravanshad[1], Bahman Soleimani[2], Ehsan Larkee[3], Masoud Soleimani[1]

[1] *Geology Department, Shahid Chamran University of Ahvaz, Iran*
[2] *Petroleum Geology, Earth Sciences Faculty, Shahid Chamran University of Ahvaz, Iran.*
[3] *Geophysics-Seismic Exploration, Well logging NIDC, Ahvaz*

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Abstract

Petrophysical characteristics such as porosity, permeability, saturation, shale volume, and lithology are important in evaluating the petroleum potential of a reservoir. In this research, Ilam Formation (late Cretaceous age) in Ahvaz oil field, (SW Iran) has been evaluated using petrophysical parameters. Therefore, the available integrated digital petrophysical logs, and core analysis data consisted of input data of Geolog software (7.1). Petrographic thin sections studies were also made. The results indicated that limestone, dolomite and shale are main components. All documents revealed that the lithology is composed of clean porous limestone with a less quantity of shale (sporadically) and dolomite as well. Average effective porosity and water saturation of Ilam Formation are 15% and 27%, respectively. The shale volume, calculated using gamma ray logs as a shale indicator, is less than 10% indicating a clean formation. The estimated permeability is 8 mD, which is accommodated with the petrophysical logs and core analysis data. Pores are commonly including of intercrystal, cavity and fracture types. Reservoir fluids are distributed in a differentiated pattern (light oil in upper part and heavy oil in lower part) that water saturation degree and gravity derive mechanism (second migration) can be considered as the responsible factors.

Keywords: Ahvaz oil field; Ilam Formation; Shale volume; Reservoir characteristics; Gravity derivation.

1. Introduction

Physical rock properties and fluids flow in the reservoir are the main purposes of petrophysical studies. Factors such as geometry, temperature, pressure and lithology of the formation can play an important role in assessment, completion and exploitation of the hydro-carbon reservoir. The main reason of applying well logs is the low cost operations than other methods such as coring process. In fact, well logs are continuous recording of rocks properties of the well [1].

The variation distribution of petrophysical parameters in reservoir intervals can lead to revise zonation and change the pay zone thickness. Because of the reservoir passed behind the main production phase, primary assessments need to review and re-evaluate, so it may be beneficial for the field development. Porosity and permeability of reservoir rocks are the most important petrophysical characteristics related to storage and transport of fluids in the reservoir. The proper understanding of these two features along with fluid properties is necessary to predict future performance of the oil field [2]. Neutron, density and acoustic logs are the most important petrophysical logs of porosity.

Since determining the permeability associates with low accuracy by petrophysical logs, the core data should be used. To identify porosity types and porosity relation to permeability, petrographic thin sections can be used [3].

2. Geological setting of Ahvaz oil field

The Ahvaz oil field (Fig. 1) is located at the south west of Dezful Embayment in 48° 30' northern latitude and 30° 30' eastern longitude. According to the top of Ilam horizon, the Ahvaz oil field shows 75 km length and 8 km width [4]. The Ahvaz field is bounded between Ramin and Sardarabad fields in north, Marun field in east, Band Karkheh in West and Susangerd, Ab-Timor and Mansouri fields in South. The slope of water-oil contact in Ahvaz field is approximately 8 meters per km from the north to the southern edge of the field. Based on structural dip changes, the field is divided into three sectors: Western part with the average of 9°-11° to 15° in the central part as the highest level of the field structure; northern flank is 26°-34° and southern flank is between 14°-21°. Also, the higher fracture density has been observed in the middle sector of the Bangestane reservoir [4].

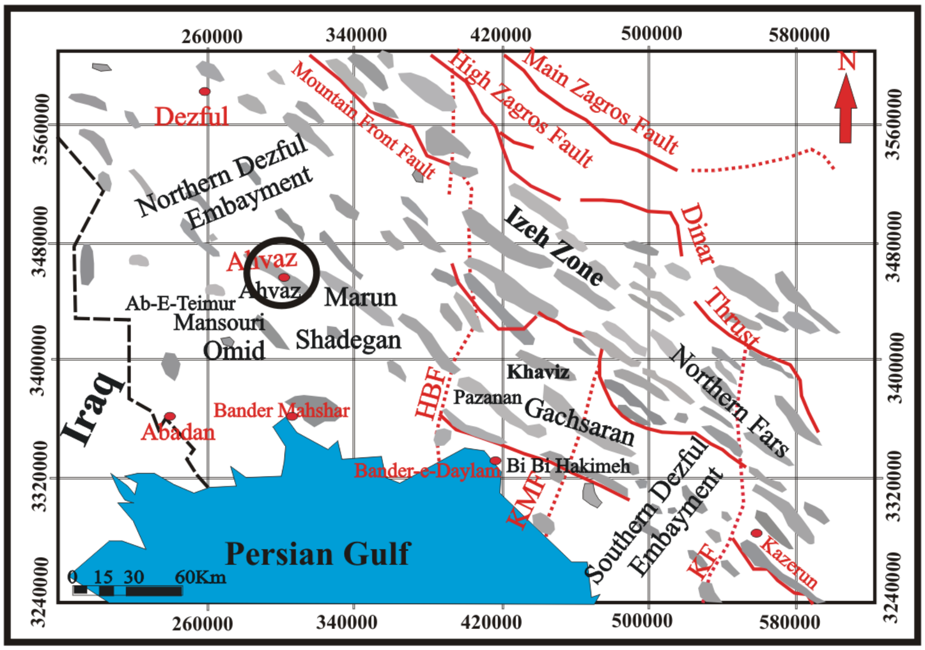

Fig. 1.Geographical position of Ahvaz field in Dezful Embayment [5]

2.1. Stratigraphy of Ilam formation

The formation is also called rudist limestone, hippuritic limestone, Lashetgan limestone, Bangestan limestone and mid- Cretaceous limestone. The type section of Ilam Formation was selected for the first time in Grub canyon at the South West edge of Surgah mountain, 45 km south of Ilam City [6-7]. Ilam Formation shows deep pelagic facies (in original cross-section) in Lorestan and shallow facies in Khuzestan and Fars areas.

Ilam Formation thickness in cross-section is 190 m which is consisted of pelagic facies, and in view of lithological aspect, it includes gray granule clay limestone with thin layers of black shales [6-7]. The age of Ilam deep facies was determined in the range of Santonian to Campanian (late Cretaceous) (Fig. 2). Inter-fingering relationship between two of the pelagic and shallow facieses is observable in some points. From Lorestan towards the South East areas, Surgah Formation disappears and Ilam Formation overlies Sarvak Formation. The main useful porosity of the formation is fracture type. This formation consisted of small and subsidiary oil reserves in Ab-Timor, Ahvaz, Imam Hassan, Mansouri and Darkhoein fields and also it has gas reserves in the Halush field. Ilam Formation in the Ahvaz oil field is consisted of limestone, dolomitic limestone and very minor and scattered amounts of shale. The correlation stratigraphic column in Zagross area is given in Figure 2.

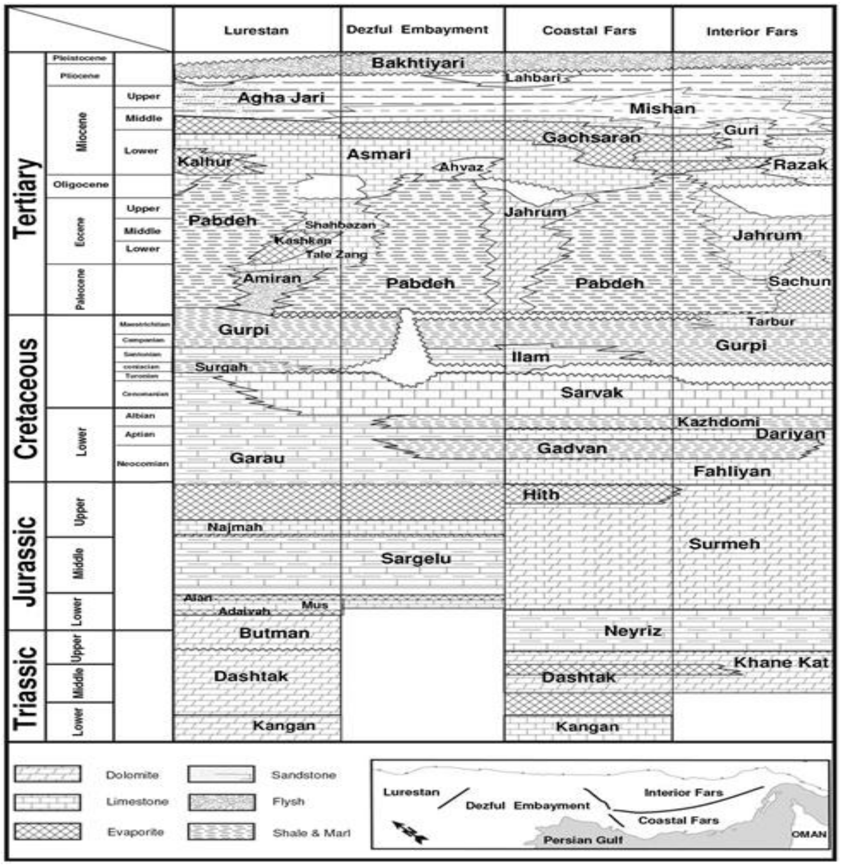

Fig. 2. Correlation stratigraphic column of Zagros, Iran [8]

3. Methodology

In this research, the analysis and evaluation of reservoir properties was made with application of Geolog (7.1) software. Before doing the quantitative processing of data, well logs were calibrated to depth. Corrections were made on all logs using provided standard logs. In the absence of gamma ray, the neutron and density logs were used as the basis for depth corrections of other logs. All data were run in Geolog software as input data. The software has two main methods for petrophysical evaluation includes:

1. The definitive calculation method which is continuous and phase computing consists of the calculation of shale volume, porosity, saturation of water and hydrocarbon.
2. Multimin method.

In this research, possible method used to assess the well data. On the basis of fluids, matrix and available logs, Multimin model was used. Based on this model it can be determined the effective and total porosity, permeability, water saturation, shale volume (Vsh) and lithology of the reservoir [9]. The used logs in this study are neutron (NPHI), density (RHOB), acoustic (DT), well diameter (CAL), gamma-ray (GR, CGR, SGR) and photoelectric factor (PEF).

To determine the permeability and porosity types of the reservoir, core data and petrographic thin sections have been used, respectively.

3.1. Petrophysical properties of Ilam formation

Many petrophysical parameters of formations such as shale volume, effective porosity, water saturation, lithology and irreducible water saturation are measured directly with specific logging tools. However, the permeability can be also determined using logging tools, but this is not a very accurate method and so this parameter is estimated indirectly and according to (NMR) logs, experimental relations, core data, multiple regression and intelligent methods [10]

To determine the permeability values, the core analysis data were used. The lithological study results are revealed that Ilam Formation is consisted of clean porous limestone with sporadic occurrence of very little quantity of shales and low volume of dolomite using thin sections and petrophysical logs.

3.1.1. Volume of shale

Shale volume is defined as the total volume of dry clay particles, silt and water band in clays of formation. This quantity has several effects on other petrophysical features such as porosity and water saturation based on logs analysis, so it should be calculated with accuracy and its effect should be deleted from those parameters. Calculation the volume of shale is commonly done by using of gamma ray log (GR). This log measures natural gamma rays of formation and its standard scale is API [11]. Gamma rays are emitted from different elements of uranium (U), thorium (Th) and potassium (K). These elements have different levels of energy. According to the different measurements of natural gamma radioactivity, there are three different types of gamma ray logs are available:

1. Gamma ray log known as GR that completely shows gamma ray emitted from formation.
2. Gamma ray spectrometer log known as SGR that produces a chart similar to the total gamma ray log (GR).
3. Corrected gamma-ray log (CGR) that filters the gamma rays emitted by uranium.

It is also known as U-free GR. The measured natural gamma radioactive conclusion ray CGR by log is always less or equal with the amount of SGR log. Radiation gamma from uranium is not an index for the presence of shale, because unlike potassium and thorium, uranium generally concentrates within organic materials in sediments. For calculating the volume of shale, it is appropriate to use the amount of gamma emitted from K and Th. In the case of availability of CGR log, SGR and GR logs are not necessary to use for determination of shale volume [12]. According to the following relation volume of shale were determined [13]:

$$Vsh = \frac{CGR-CGRclean}{CGRsh-CGRclean} \quad (1)$$

In this dimensionless (or unit) equation, clean is referred to the lowest reading at non-shale formations (Clean) and Sh is the reading at 100% shale formation. According to this, Kamel and Mabrouk [14] have divided formations based on shale volume into three categories:

A) Clean formation with volume of shale less than 10%.
B) Shale formation with a shale volume of 10 to 33%.
C) Shale formation with more than 33% shale content.

Ilam Formation in this reservoir has containing less than 10% shale (7.5%), it can be considered as a clean formation (Fig. 3). The main clay minerals detected by Th/K ratio, are montmorillonite and kaolinite and clay volume is high in upper part (Fig. 3).

3.2. Lithological identification

3.2.1. Petrophysical logs

One of the main applications of petrophysical logs is lithological identification. In an unknown area, an interpreter cannot acquire the lithology just according to the log data [10] but can make some guesses. Therefore, without the number of variables is relatively impossible to have a good interpretation of mineralogy and lithology. Involving the geological data is required to interpreting of graphs. Most methods used to determine the lithology are given the selected applicable specification of the lithology [15]. In general, at least two logs are required to make an estimate of lithology. Different cross-plots like neutron-density, neutron-sonic, density-sonic and density- photoelectric can be used. With using these cross plots, two mineralogical compositions such as, dolomite- limestone or lime - sand can be determined. It should be noted that porosity determination without the knowledge of lithology is not accurate [16].

Density- neutron cross plot is a common cross plot that before using, it is necessary to be corrected in view of shale and hydrocarbon effects [17]. In this cross-plot three drawn curves are related to lithology of limestone, sandstone and dolomite which are called matrix lines. Points outside of this range, implies the existence of minerals apart from dolomite, lime and quartz. Determining the correct lithology is dependent to other geological data. It is noticed that there are different neutron-density cross-plots based on different types of neutron's logs [18-20].

According to the neutron–density cross plot and logs, the lithology of Ilam Formation is limestone, dolomite (Fig. 4) and small sporadic amounts of shale (Fig. 3). The shale volume is increased in upper and lower sections but is negligible in middle part. These results show high conformity with petrographic studies of thin sections.

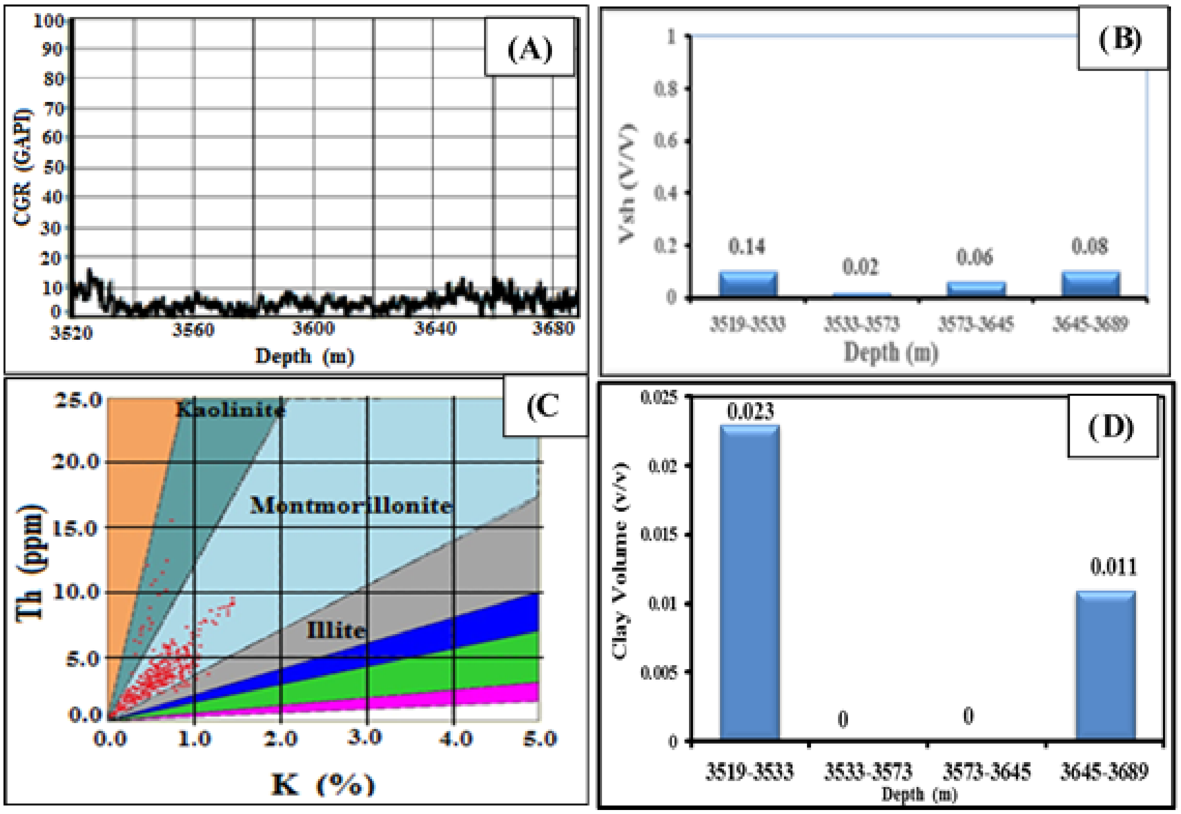

Fig.3. Shale and clay analyses in the formation: (A) Gamma ray (CGR) variation vs depth (m); (B) histograms of shale volume distribution; (C) clay type based on Th/K ratio; and (D) clay volume variation against depth.

3.3. Porosity

Porosity can be studied using petrophysical logs, core analysis and also the seismic data [21-22]. In this study, neutron, density and acoustic logs data were run to estimate the porosity through multimin method. Without lithological information, determining process is not accurate. Different cross-plots like neutron-density, neutron-acoustic, density- acoustic can be used to determine porosity [10]. Based on the results appeared that the middle section of Ilam Formation has higher porosity than other parts (Fig. 4) and consequently this part will be interesting in view of hydrocarbon reservoir potential and showing the potential condition for oil production in future programs. Effective factor seems to be existence of more fractures. In terms of lithology, this part is made of limestone-dolomitic limestone (Fig. 4C). This lithological feature makes a chance to generate brittle behavior of the formation against the environmental stresses which is an important factor in fracturing.

Distribution of facies in the reservoir has also played a role in creating heterogeneity. The Ilam reservoir in this horizon reveals an average useful porosity about 15% which is classified the reservoir as a relatively good class.

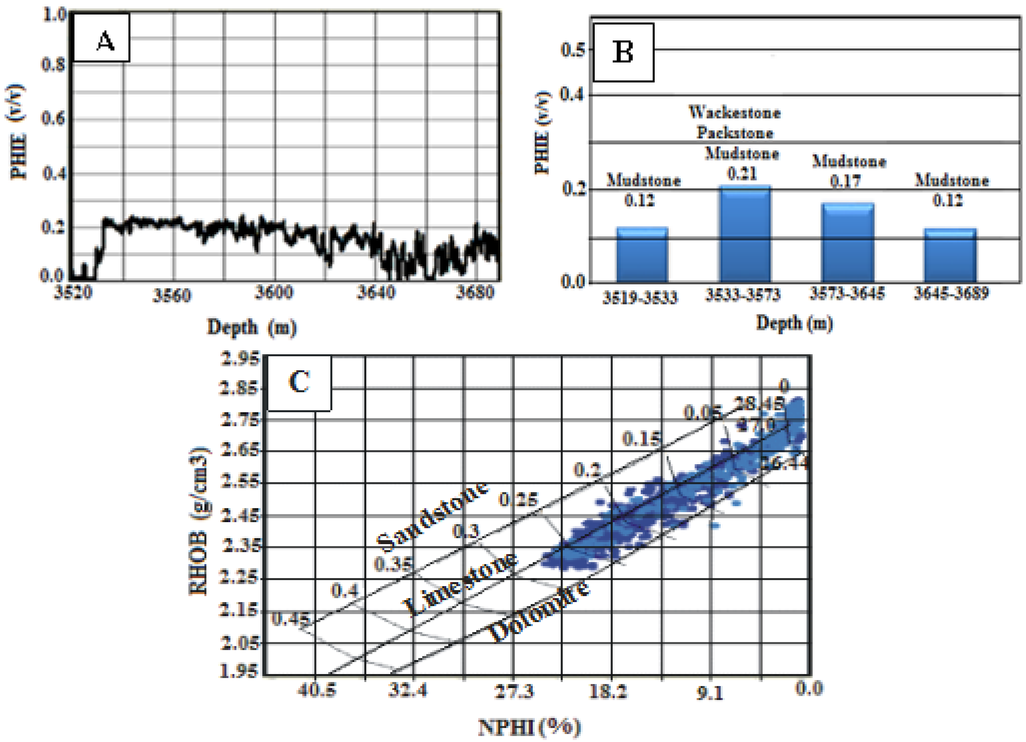

Fig. 4. The variation of porosity effective (PHIE) to depth (A, and B) and cross plot of RHOB-NPHI (C) to determine the lithology

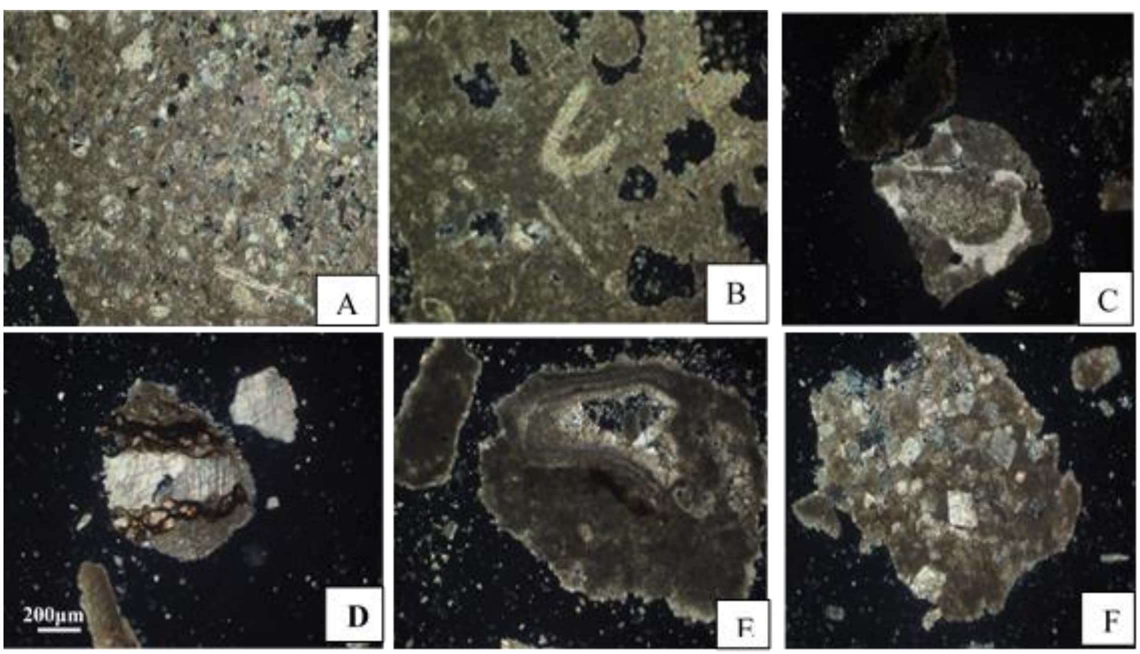

Fig. 5. Photomicrographs of thin sections (well no. Az-36) are presenting pore filling and major diagenetic processes: (A) pore filling by anhydrite (depth-3530m); (B) pores in packstone (depth-3556m); (C) calcite cementation in grainstone (depth-3580m); (D) fracture filling by calcite spar associated with dolomite and bitumen (depth-3630m); (E) pore filling (depth-3641m); and (F) dolomitization (depth-3659m).

3.3.1. Porosity types

To review the petrography and porosity of the Ilam reservoir, 200 thin sections were studied under petrographic crossed polarized microscope. To facilitate the study, the formation divided into four parts that is discussed from upper to lower (Fig. 4B).

1) Zone 1 (depth from 3519-3533 m) of the formation is made of mudstone, dolomitic limestone with small amount of dispersed shale and anhydrite (Fig. 5A); it seems to have higher porosity and also hydrocarbon staining.
2) Zone 2 (depth from 3533-3573m) is made of wackestone, packstone and dolomitic mudstone, which is showing a good porosity development and hydrocarbon production potential (Fig.5B).
3) Zone 3 (depth of 3573-3645m) is consisted of mudstone that in some cases composed of dolomite (Fig.5D) which is generated a good porosity. This part is considered as a hydrocarbon potential zone (Figs. 5C, D and E).
4) Zone 4 (depth of 3645-3689 m) is including mudstone, dolomitized horizons (Fig.5F) with negligible amounts of shale and marked by developing of porosity that is verified by petrographic thin sections study. Intercrystal, vuggy and fracture types are dominant (Fig. 5).

3.4. Water saturation

The saturation in a formation is defined as a fraction of empty spaces filled by the fluid. If something other than water, such as oil doesn't exist in formation, then water saturation would be 100%. Fluid saturation is denoted as S_f which is calculated by a general equation [23]:

$$S_f = \frac{V_f}{PV} \qquad (2)$$

where V_f is the volume of fluid, and PV is volume of pores.

All values of saturation degrees are on the basis of pores volume, and they are not on the basis of gross volume of the reservoir. This equation can be stated for all three phases in the reservoir by replacing the fluid type instead of *f* in the equation.

Water saturation (S_W) percentage is one of the important parameters for calculating the storage volume of hydrocarbon reserve. Total saturation value of all involving fluids in a reservoir is always equal to one. By knowing the percentage of S_W, oil and gas saturations can be calculated:

$$Sw + So + Sg = 1 \qquad (3)$$

In the reservoir under study, average of effective water saturation in different zones, 3519-3533, 3533-3573, 3573-3645 and 3645-3689, are 27.6%, 21%, 23.3% and 33.8%, respecttively (Figs. 6A and 6B). Since the average water saturation value in the Ilam Formation is about 27%, so the remaining part of the pores should be accounted for hydrocarbons. As it is indicated in Figures 6A and 6B, water saturation of lower part is higher than other parts. Effective water saturation is increased in lower effective porosity values (Fig. 6C) due to lithological changes.

3.4.1. Irreducible Water Saturation (Sw_{ir})

In general, the behavior of fluids in a tank is such that they tend to reach equilibrium with each other [24]. How to achieve balance by these fluids in the reservoir is a function of their density so that oil is located below the gas and above the water. In addition to the lower water, the bound water is also distributed in the oil and gas sectors of the reservoir. The saturation value of this water decreases from one hundred percent in utmost lower water of the reservoir toward the top of reservoir until finally it reaches to its minimum amount in whole of hydrocarbon sector. This water saturation is the lowest and will be irreducible. Water conservative forces in these areas are known as capillary forces since they are only important in pore size. The amount of irreducible water saturation is one of the important factors of the reservoir, because it decreases the available space for oil and gas in a porous medium [25].

Thus as much as decreases the irreducible water saturation increases the reservoir hydrocarbon saturation. Irreducible water saturation in this reservoir is estimated to be 3.5% (Figs. 6D and 6E).

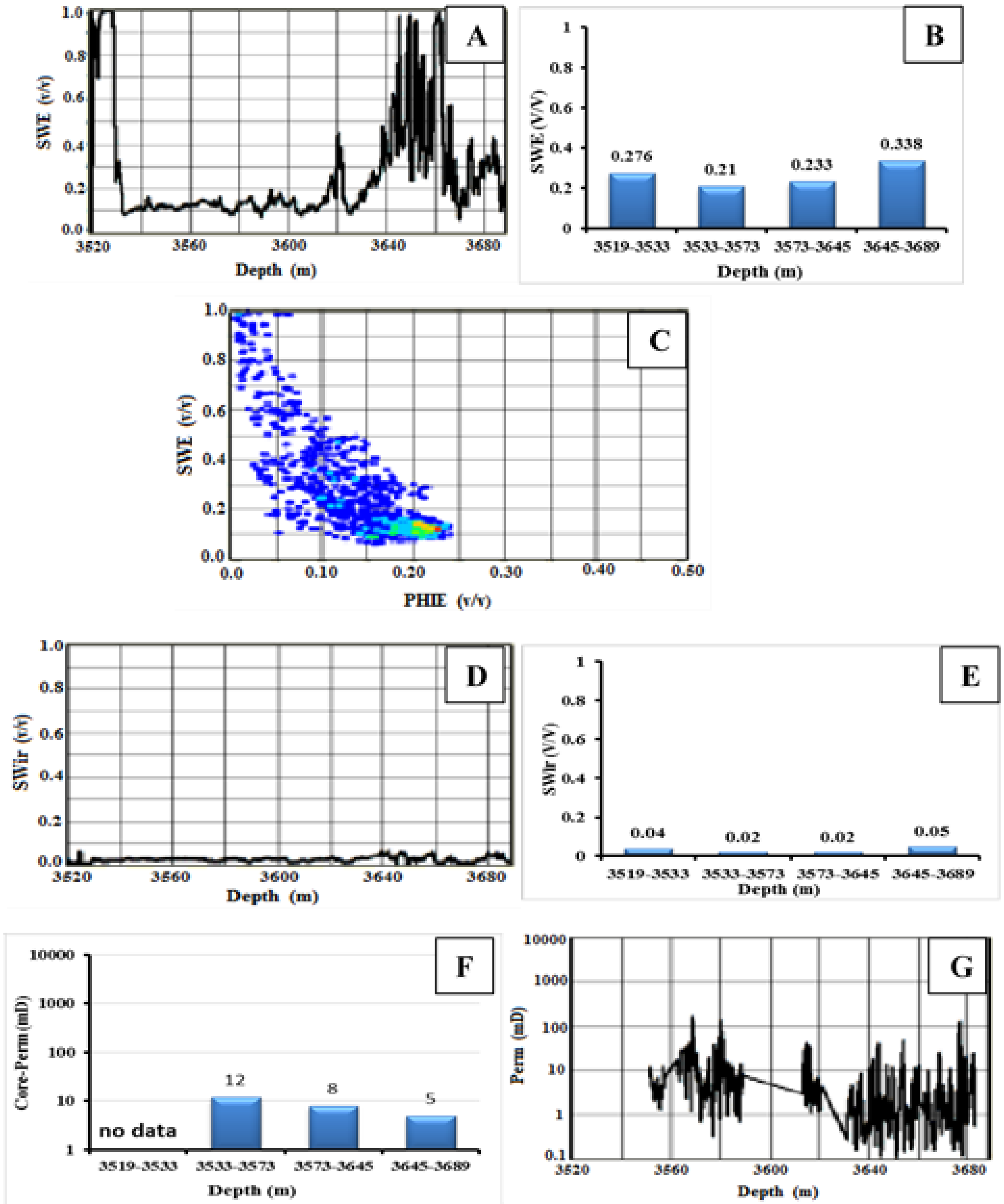

Fig. 6. The variation of different petrophysical parameters through the formation and separated zones: (A and B) water saturation effective (SWE) to depth (m); (C) water saturation effective (SWE) to effective porosity (PHIE); (D and E) water saturation irreducible (Sw_{ir}) to depth (m); (F and G) permeability variation to depth (m).

Well test data revealed that the field is characterized by existing of the heavy oil (API ≤ 13) in the lower part and lighter oil (API ≥ 24) in upper part which can be considered as an in-situ oil differentiation. We suggest that pore pressure (due to water saturation degree) and gravity derive may be more influencing in this process. In fact this seems to be a second migration within the reservoir. This subject was also discussed in details in literature [26-29].

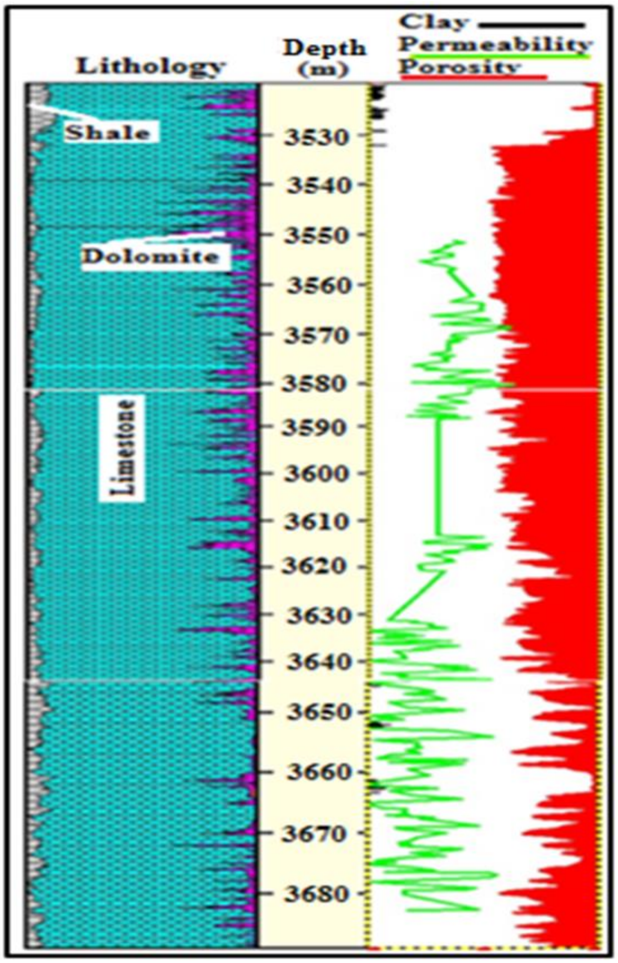

Fig. 7. Lithological variation and its effects on porosity and permeability

3.5. Permeability

Permeability is one of the two most important parameters in describing the specifications of the reservoir. For being a formation permeable, it is necessary to be porous and also empty spaces must be interconnected [30]. However it is expected that with increasing of porosity, the permeability is also increased, but it always does not have a positive effect. In other words, the permeability is directly related to the effective porosity and controlled by different factors other than porosity itself such as pore spaces size, shape, and their consistency [31]. The unit of measurement of permeability is Darcy. In definition, when a rock is allowing a fluid to flow under the following conditions: 1cm^3 of a fluid flows with a cm-poise viscosity during a second of time over a square centimeter of surface area under one atmosphere pressure is known as one Darcy [32]. The relationship of permeability [33-34]:

$$Q = K\frac{A\times\Delta P}{\mu\times L} \quad (4)$$

This parameter that tells the ease of fluid flow through porous media, typically is obtained by the core analysis, well tests or by its compatibility with other parameters that can be measured more easily (porosity).

Determination the permeability is also done from petro-physical logs. But the job is too difficult due to involving many parameters that affect the fluid flow in the reservoir including: matrix characteristics, fracture, sedimentary structures, fluid properties [35].

Based on the permeability results of core analysis and petrophysical logs, it became apparent that the middle section of Ilam Formation has more permeability than other parts (Figs. 6F, 6G; and 7) and thus it is suggested to be in a better reservoir potential than other parts. It seems the effective factor in this part is the existence of more fractures. In terms of lithology, this part is lime-dolomitic limestone. Dolomitization process can be played a major role and so there is a correlation with increasing permeability. This feature makes the behavior of formation to be brittle in responses to the stresses that is an important factor in fracturing. Lithological variation also plays a role in reservoir heterogeneity. The permeability obtained in middle section (parts 2 and 3) of Ilam reservoir is about 12-8 mD.

4. Conclusion

Petrophysical parameters investigation and modeled terminated to the main point that the middle section of the Ilam Formation is prone for petroleum potential due to having higher porosity values than other parts and can be interested for more studies in view of drilling and oil production programs. One of the main controlling effective factors in generating this position is fracturing of the formation influenced by its lithology. The formation is consisted lithologically of limestone-dolomitic limestone. Dolomitization as a sparse phenomenon plays an important role in creating the reservoir heterogeneity. These factors, fracturing, lithological effect and dolomitization, are apparently impacts the permeability parameter in middle section of Ilam Formation which is more than other parts. The permeability value ranges from 12 to 8 mD in middle section of the reservoir. Water saturation value is averaging 27% in the Ilam Formation indicating a large remaining part of the pores should be accounted for hydrocarbons reservation. The lower part of the formation is indicating higher Sw comparing the other parts that can be related to lower effective porosity values due to lithological changes. The presence of high Sw in lower part as well its irregular distribution is also affected in differentiating state.

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To whom correspondence should be addressed. E-mail: soleimani_b@scu.ac.ir