



An integrated procedure for reservoir connectivity study between neighboring fields

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Received: 15 May 2020 / Accepted: 24 August 2020 / Published online: 29 August 2020
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Abstract

Reservoir connectivity has a considerable effect on reservoir characterization, plans for field developments and production forecasts. Reducing the uncertainties about the lateral and vertical extension of different pay zones is the main step in developing and managing the reservoirs. Nearly all the proposed methodologies for the verification of reservoir connectivity are limited to the study of the communication of different compartments in one field. In the presented paper, first a comprehensive procedure is proposed to study the reservoir connectivity between nearby fields. The steps in this procedure are not necessarily hierarchy, but all the considerations in each step are studied to cover all the uncertainties that affect the reservoir communication. This procedure mainly comprises the study of reservoir extension, pressure communication in the hydrocarbon column, fluid similarity, top seal efficiency and faults sealing. Then, to apply this procedure for proving the communication between nearby fields, a case study of Ilam Formation in southwest of Iran is presented. The results confirm the lateral connectivity of the three pre-explored distinctive oil fields in Ilam Formation. The established connectivity leads to an increase in the pre-estimated oil-in-place volumes. This incorporated case study demonstrates how different data including geophysics, structural and petroleum geology, production and reservoir engineering are integrated to prove the communication of Ilam reservoir between these fields. This manifested technique is a powerful road map for other cases worldwide and is extremely recommended to be performed before developing those fields that are suspicious to lateral connectivity.

Keywords Reservoir connectivity · Top seal · Fluid composition · Pressure communication · Free water level

Introduction

Limited connection between two hydrocarbon-producing zones is discussed under the subject of reservoir compartmentalization. Determination of connection between different compartments in a reservoir is highly helpful for well performance evaluation, field re-development and in-fill drilling programs (Vrolijk et al. 2005; Ajayi et al. 2019). Commonly lack of connectivity is determined from two factors of discontinuities in pressure gradients and differences in fluid similarities in the zones (Ventura et al. 2010; Mullins et al. 2005; Venkataramanan et al. 2006). Therefore, the results of drill stem tests, pressure transient analysis,

wireline formation testers like RFT/MDT/XPT/RDT and reservoir fluid analysis are supportive for determination of connectivity (Al-Obaid et al. 2004; Mukanov and Aldazhar 2019). In addition, downhole fluid analysis (DFA) is a fast and vigorous tool for vertical connectivity purpose (Mullins 2008). Nevertheless, there are many geological complexities that make it uncertain to draw conclusion about the communication of nearby fields by proving only the pressure communication and fluids' similarities. First, it should be noted that the observation of initial pressure equilibrium in different zones does not merely mean their flow communication during production (Pfeiffer et al. 2011). This is due to the fact that the equilibrated pressures result through geologic time. Different compartments of a reservoir may reach a pressure communication over geological time, but deplete independently throughout production (Walker and Evenick 2019). Second, the reservoirs may be in communication, but a heterogeneity in fluid properties may have been established over the geological time. Gravity segregation, thermal gradient, biodegradation, water washing, asphaltene

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precipitation during migration, charging from multiple source rocks and ongoing reservoir charging are the reasons for lateral and vertical fluid heterogeneity in the reservoirs (Høier and Whitson 2001; Ratulowski et al. 2003; Tian et al. 2008; Larter et al. 2003, Al-Shukairi 2019; Ghorayeb and Firoozabadi 2000; Lafargue and LeThiez 1996; Hirschberg, 1988). Mostly, the fluid comparisons are performed based on compositional similarities. Numerous approaches can be used to compare fluid composition. One common method is the definition of the distribution of components and biomarkers and also the fingerprints of hydrocarbons using GC–MS (Wang and Fingas 2003; Peters et al. 2005). For this purpose, applying the two-dimensional gas chromatography method is more accurate. (Ventura et al. 2010). However, due to probable fluid heterogeneity, only the comparison of compositions is not a powerful tool for connectivity determination. Oils accumulated in different zones of a reservoir or different reservoirs in the same field may face different geological and chemical histories. Sealing faults and stratigraphic alteration in a formation may result in altering filling histories or other secondary processes (Manzocchi et al. 1999). Also, slow intra-formation mixing may lead to vertical variation in petroleum composition (Smalley et al. 1994). Consequently, differences in fluid compositions do not guarantee the discontinuities of the reservoir zones, although equilibration in fluid composition normally means the mixing of the entire reservoir. It means that if the hydrocarbon charge has been terminated, after mixing the whole reservoir fluid an equilibrium is established. Hence, the whole reservoir bears a fluid similarity, and the fluid dissimilarity means the reservoir compartmentalization. Nevertheless, due to the reasons like ongoing charging, the fluid properties would differ through the reservoir even if there is no compartmentalization.

Static modeling coupled with sequence stratigraphy is considered as a prevailing methodology for the evaluation of reservoir connectivity (Ejoke et al. 2017). Nevertheless, in such approaches the well and reservoir dynamic data are not utilized. Since the subsurface data are open to several interpretations, the results from static modeling and sequence stratigraphy may be challenging. Well data against the seismic data are more precise with high resolution, but are limited to the small area around the borehole. Also, by 4D seismic monitoring, the reservoir dynamic changes can be precisely detected during hydrocarbon production (Johnston 2013). However, because of the problems related to the noise and repeating the seismic data, the uncertainties in these data are higher than well data. Moreover, the interpretation of seismic data carries non-uniqueness (Yin et al. 2016). Therefore, the best method to cover these weaknesses is the reconciliation of different dataset to create diverse models and modifying or dropping some models after acquisition of new data (Smalley et al. 2018; Walker and Evenick 2019).

In the case of smaller scale, i.e., the inter-well communication, reservoir simulation is commonly used. However, updating the simulation model using the new data through History Matching process is time-consuming. Therefore, mostly a direct relationship between injector and producers is built to integrate the flow rate, BHP or both data to evaluate inter-well connectivity (Albertoni and Lake 2003; Yousef et al. 2006; Tiab and Dinh 2013; Salehian and Cinar 2019). Similarity of the trends of the pressure changes in two reservoirs during production is a sign of the connectivity of the two reservoirs. One reported example is the communication of Arab-D and Hanifa Formations in Abqaiq Field. These two reservoirs are separated by thick tight carbonates (around 300 feet thickness), but the resemblance of pressure history patterns illustrated their communication through fractures (Al-Obaid et al. 2004). Rapid changes in fluid properties during production can be a sign of vertical communication of different reservoirs, as the gas in Maudud Formation was produced from overlaying Wara Oil Formation in Bahrain Field (Nemmawi et al. 2019).

Therefore, various geological and reservoir engineering aspects are simultaneously studied to accurately evaluate the connectivity of different zones in a field or communication of neighboring fields. Most of the researches have been conducted for determination of communication of different compartments of a reservoir just in one field. There is no all-inclusive procedure reported in the literature to study the communication of a hydrocarbon reservoir formation in neighboring fields. The main difference between connectivity study within a reservoir in one field and in multiple fields is related to the scale of the formation dimensions. In the case of connectivity survey in one field, the wells are not much distant from each other, and methods like interference well testing and also pressure studies are the main tools for this purpose. When two fields are studied, these methods are highly time-consuming and costly. The aim of this paper is to construct a procedure for reservoir connectivity between two or more fields considering all geological and petroleum engineering parameters. To illustrate the effects of all factors for this purpose, a field case study has been introduced with a successful connection between three nearby oil fields which resulted in a higher calculated oil-in-place volume for the whole structure. It is extremely recommended to apply this technique to those developing fields in which their communications are undefined to inhibit inappropriate reservoir management.

Methodology

In this paper, a comprehensive procedure is proposed for the assessment of reservoir connectivity in two or more adjacent fields. If the communication is proven, the

formation in the saddle between the fields will be hydrocarbon bearing and all the development plans and reservoir management strategies will be changed. This important procedure is highly recommended to be implemented before the development of the neighboring fields to manage the reservoir properly. The procedure consists of the following steps:

1. *Proving the extension of the specified reservoir formation in the studied fields without unexpected stratigraphic/facies changes:* The reservoir layer must be extended all over the structures under study without prompt variations in porosity and permeability in the distance between fields. This means the reservoir formation properties in the saddle or bridge between structures do not change to a tight layer which acts as a lateral seal. A correlation between key wells of the studied structures besides seismic data will give us information about the extension and property variation of reservoir layer. When the reservoir properties do not change significantly in key wells of the two structures and no major change is observed in different attributes taken from seismic data, the first step (reservoir extension) is verified. It is also imperative to consider that the reservoir extension and/or its properties may bear changes in other sides (rather than the saddle) of the structures which is not important for the purpose of this study.
2. *Initial recognition of the top and bottom seal layers using petrophysical logs, core description and pressure–depth data:* This step and the next one are required to guarantee the positive parts of the petroleum system. When the connectivity of two hydrocarbon fields is being studied, the source and migration parts of the petroleum system are regarded positive and also reservoir part of petroleum system is verified in the first step. Therefore, the extension and effectiveness of seal must be positive. Seal layers are tight (with near to zero effective porosity) and commonly cause a separation in pressure–depth trend above and underneath reservoir layers. Since NMR tools provide lithology-independent porosity and distinction between bound and free fluid porosities (Marquez et al. 2010; Gao and Li 2015; Zheng et al. 2018), the results obtained from the interpretation of such logs are extremely helpful. Furthermore, in decision for selection of pressure points in repeating formation testing jobs (like MDT/RFT/XPT), it is highly recommended to take the pressure of several depths in porous zones above top seals and even these porous zones are water bearing based on petrophysical logs data. This is because one of the main signs of the presence of the seal is the pressure separation of upper and underneath porous layers.
3. *Study the efficiency of top seal:* First, the absence of fracture system must be verified in the top seal layer. The fractures are detected using image logs, and such tools must certainly be run in the wells where the structure is bearing the maximum tension/compression (like the crest of the structure). Second, maximum hydrocarbon column through which the top seal can resist against leakage due to high buoyancy pressure is calculated. Therefore, capillary pressure data of core sampled from top seal layer are needed (Boulin et al. 2013; Dolson 2016). The weakest point for capillary entry in the top seal is the crest of the structure. For this purpose, core must be sampled from top seal layer in the highest depth in the whole structure regarding all the fields under study.
4. *Investigation on transmissibility of the fault/faults between fields:* Faults may act as a barrier to hydrocarbon flow, which results in compartmentalization, or they may be transmissible to flow and allow the communication between their both sides. Hence, the inspection of transmissibility of existing faults between the fields under study is a key step. The most rigorous method for the investigation of transmissibility of faults is the interpretation of transient pressure data in a nearby well. If there is no well near the fault, Shale Gouge Ratio (SGR) analysis is helpful. According to Bretan et al. (2003), a SGR cutoff value of 20–30% for a fault plane is required to hold a substantial column of oil and gas and act as a barrier to flow. These cutoff values of SGR are recommended to be modified by local calibration for any hydrocarbon basin (Walker and Evenick 2019).
5. *The depth of the bridge or saddle between two structures:* If the bridge or saddle between two fields is much deeper than the initial free water level (FWL) in the fields, the lateral connectivity will be negative, even if all other factors are positive.
6. *Pressure communication:* This step is imperative for decision on lateral connectivity of two fields. If initial pressure in the reservoir layer of the two neighboring fields is in the same gradient line, it typically means the oil and gas columns in both fields are in communication. Among other steps, providing water–hydrocarbon depth to be below the saddle depth, pressure communication is the strongest one for proving the lateral connectivity. Care must be taken when applying pressure data measured by different sources. In this case, first the type of gauges in well testing or wireline formation pressure testing data acquisition may bear different uncertainties. As an example, the strain gauges which had been utilized in older wells could have uncertainty in the pressure up to ± 14.5 –25 psi (Dewan 1983). Second, the extrapolated pressure

calculated from well testing transient data may carry its uncertainty due to non-uniqueness in the interpretation. This is more severe in the tighter formations which needs more time in buildup section of tests. In exploration wells in which the transient tests are performed when drilling rig is on-site, the time for these tests is minimized due to high costs of drilling rig. Therefore, the uncertainty for calculation of extrapolated pressure in these tests increases.

7. *Reservoir fluid similarity*: Normally, when two fields are in communication, their fluid properties are similar. However, due to some reasons like ongoing reservoir charging (Ghorayeb and Firoozabadi 2000) or thermal gradient (Tian et al. 2008), the reservoir hydrocarbons are heterogeneous. Even in these cases, the differences in fluid properties show a meaningful *trend*. It is of great importance to note that the reservoir hydrocarbon in two proximate fields may have been charged from different source rocks. Therefore, the differences in geochemical properties should not be used for this purpose. Instead, the fluid properties from reservoir engineering point of view must be considered which is fully explained in “*Results and discussion*” section.
8. *High difference between in-place results derived from material balance and volumetric calculations*: First, the results of the oil and/or gas in-place from both methods (volumetric and material balance) must be verified. In material balance method, such a sufficient volume of hydrocarbon should be produced from the reservoir to confirm the results. Also, validated data must be utilized as inputs into material balance model to make sure about the outputs. In the volumetric method, the data (UGC map, petrophysical and PVT data) must not be much uncertain. After achieving certainty about the outputs of the two methods, if the results obtained from material balance are much higher than volumetric calculations, the possibility of reservoir connectivity to neighboring fields will be promoted. It should be mentioned that even if each field has a well-defined FWL, the hydrodynamic potential can allow the connectivity between fields. In this regard, a thorough investigation has been conducted by Firmanto and Adachi (2019) on Paciran sandstone formation in four gas fields for possibility of field connectivity with hydrodynamic condition.
9. *The trend of pressure changes during production*: The pressure in two nearby fields which are in communication illustrates the same trend. It means any pressure change in one field (related to production or injection) shows its effects on the other field.
10. *High differences between the discovered hydrocarbon and oil expelled from source rock*: The estimated amount of oil expelled from source rocks (denoted

by Q_{EC}) is compared with the discovered initial oil in place (denoted by Q_R) of the corresponding field. The amount of Q_{EC} is one of the outputs of basin modeling and is calculated for each anticline in the area under study. To calculate this parameter, several uncertainties are encountered, but this parameter can be used comparatively. The Q_R/Q_{EC} ratio of different fields charged from the same source rock(s) in a specified region is calculated and compared to each other. The field with the lowest value of this ratio must be chosen for further study. There are many reasons to affect the reduction in this fraction. One factor is related to small value of Q_R , which can be due to uncertainty of FWL in these fields for in-place calculations. It should be mentioned that the execution of a basin modeling needs an extensive and time-consuming work as a widespread information is required, including geochemical, geophysical, geological and petroleum engineering data of many adjacent structures and fields. Hence, this step is not crucial to be performed for connectivity study, and if a parallel work has been performed for other purposes, its results must be utilized.

11. *Assurance about the depth of true FWL for each structure*: First, the depth of FWL of the reservoir layer must be verified. Sometimes, the depth of a perched water is mistakenly regarded as the true FWL. Perched water is the water-saturated zone located above the initial and regional FWL of the reservoir (Dolson 2016). Actually, this zone is a trapped water zone that is not expelled during oil migration in a structure. This fact is comprehensively documented by Gaafar et al. (2015) and Dolson (2016). Second, the hydrodynamic activity between two fields and beyond must be investigated. That is because even if each field has a well-defined FWL, the hydrodynamic potential may allow the connectivity between fields through tilted FWL (Firmanto and Adachi 2019).

To briefly show the type of data required for connectivity study between two or more contiguous fields and the results obtained from these data, a flowchart has been designed. This flowchart is demonstrated in Fig. 1 which simply shows the links between required data and resulted information for connectivity analysis. Due to deficiency of available data in green fields, the whole procedure may not be applicable. On the other hand, the lateral connectivity is vital for development of the field and its neighboring fields. Hence, for the green fields, it is highly recommended to manage the field development plans in such a way to gain the required data to prove the lateral connectivity.

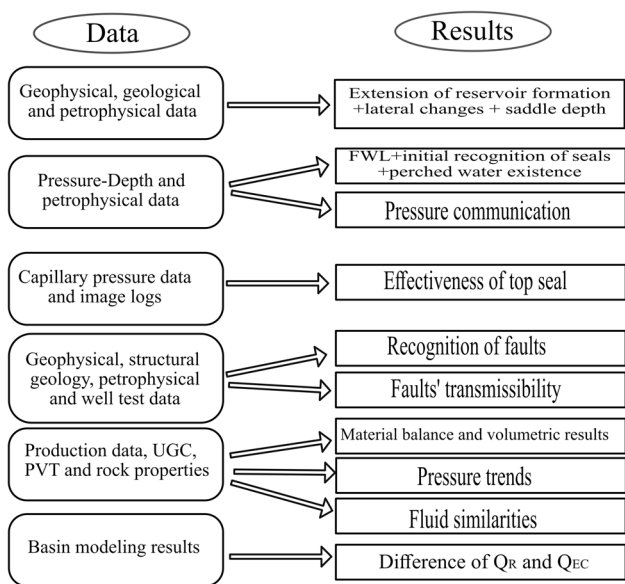


Fig. 1 Flowchart of the essential data and resulted information for confirmation of reservoir connectivity between adjacent fields

Geological setting

In order to apply the above-mentioned procedure for a real field case, the Ilam Formation in three pre-discovered neighboring oil fields named A, B and C is introduced. These fields have low-relief anticlinal structures located in SW of Iran. The Ilam Formation with

Coniacian–Santonian age (Navidtalab et al. 2016) is one of the key oil producers in the studied area (Fig. 2). The reservoir fluid in these fields is a highly undersaturated oil at initial reservoir condition. The lithology of this formation is mainly limestone with interbedded shale and clay limestone (Asadi et al. 2017). In the area under study, based on core, petrophysical logs and cutting studies, the Ilam Formation has been divided into three parts. The upper part with a thickness of around 40 m mainly consists of an alteration of limestone and claystone. The limestone interbeds with grainy facies and a high-energy depositional environment are regarded as a reservoir zone. The middle part with a thickness of nearly 60–100 m, known as Main Ilam, predominantly consists of limestone deposited in an outer ramp environment. This part is the main producing hydrocarbon reservoir in the studied area. The Lower Ilam is comprised of limestone and slightly argillaceous. The porous limestone of Main Ilam is sealed by a thickness of uppermost limestone and basal shaly section of Upper Ilam, from reservoir point of view. These facts are typically demonstrated in Fig. 3 in which the interpretation of petrophysical logs taken from Well A-X1 in Field A is presented.

Results and discussion

In the area under study, the Main Ilam Reservoir properties do not bear significant changes. In Field A, based on petrophysical logs and core data, the average effective porosity

Fig. 2 Geographical location and stratigraphy (Bordenave and Hegre 2010) of the fields under study

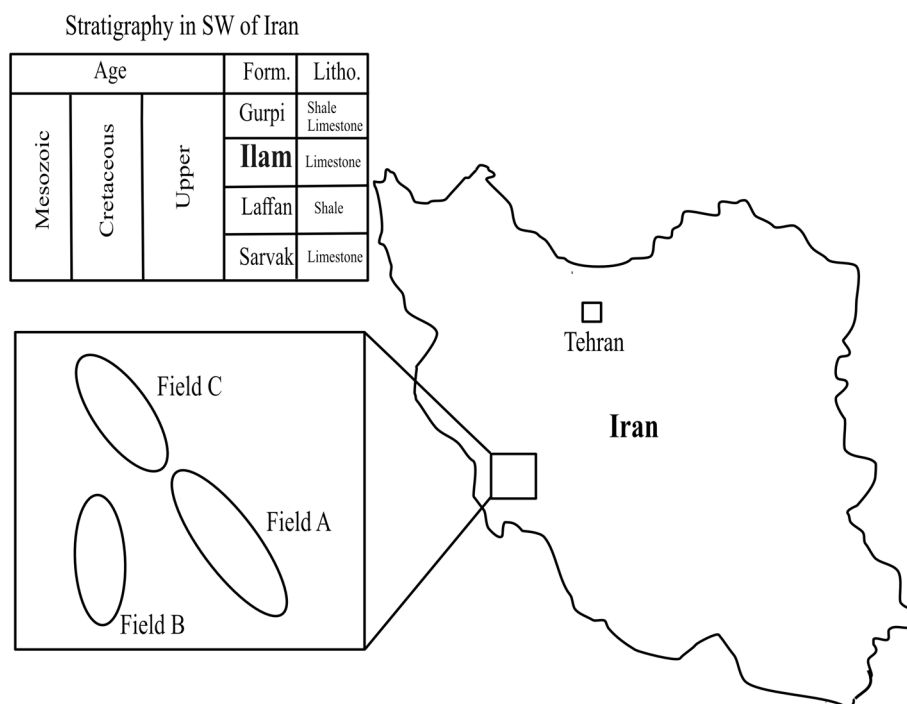
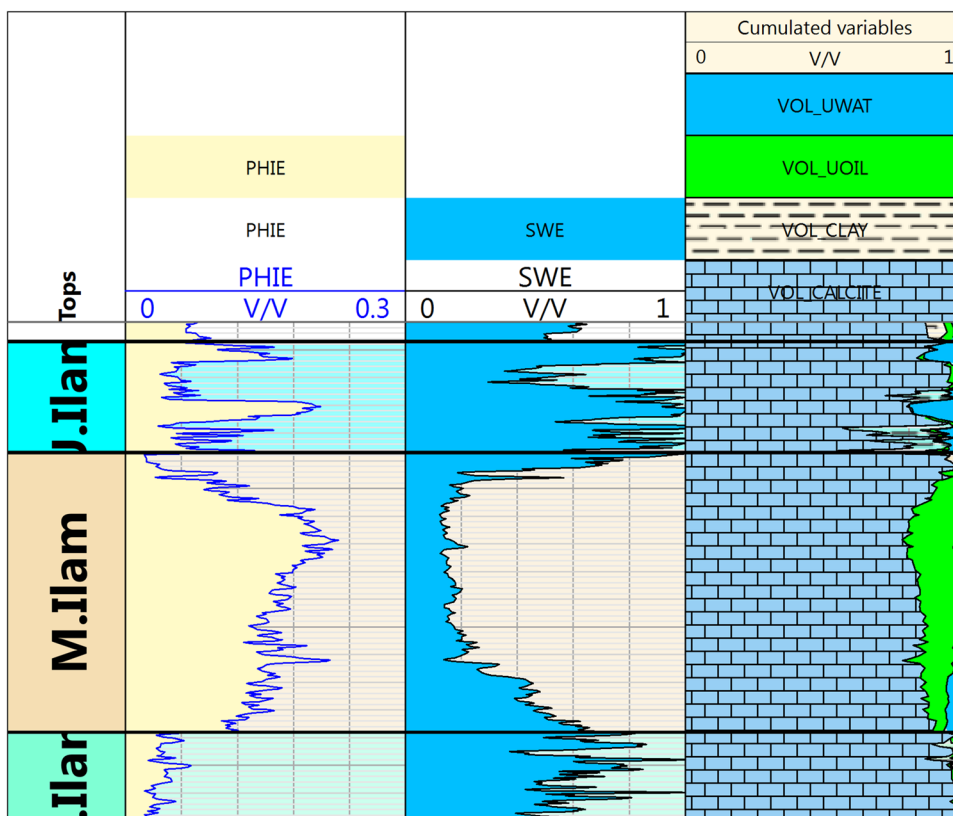


Fig. 3 Typical Ilam Formation in the region under study based on petrophysical logs (Well A-X1). The basal part of the Upper Ilam is the top seal, and the Lower Ilam part acts as the base seal for the Main Ilam Formation



is 20 percent. Also, with reference to transient data analysis besides core studies, the average reservoir permeability is in the range of 1–5 mD. In Fields B and C, the average reservoir effective porosity is estimated as 18 and 19.5 percent, respectively. Upper Ilam Formation in Field A is water bearing. Hence, its connectivity is not important and is not studied in this paper. The two reservoirs in Ilam sediment (Upper Ilam and Main Ilam) are characterized by different initial pressures and are separated by a non-reservoir unit. The non-reservoir unit which is a top seal for Main Ilam reservoir bears a little change in thickness in the aforementioned fields. The role of top seal has been proven by pressure data taken by different tools like MDT and RFT in the first wells of all three fields at initial condition. As an example, a pressure–depth graph in Well B-4 is illustrated in Fig. 4. As it is obvious from Fig. 4, the Upper Ilam part is separated from Main Ilam reservoir by a non-reservoir layer. This layer is composed of shale and argillaceous limestone with an effective thickness of around 10 m. The argillaceous limestone in the Upper Ilam part (the top seal of Main Ilam reservoir) does not show significant variation from the sealing efficiency point of view. A correlation chart through key wells in these three oil fields covering the lateral locations near saddles of the fields is illustrated in Fig. 5. It is evident from Fig. 5 that the possibility for lateral facies or stratigraphic changes of Main Ilam Formation to be implemented as lateral seal is near to zero. Therefore, the extension of

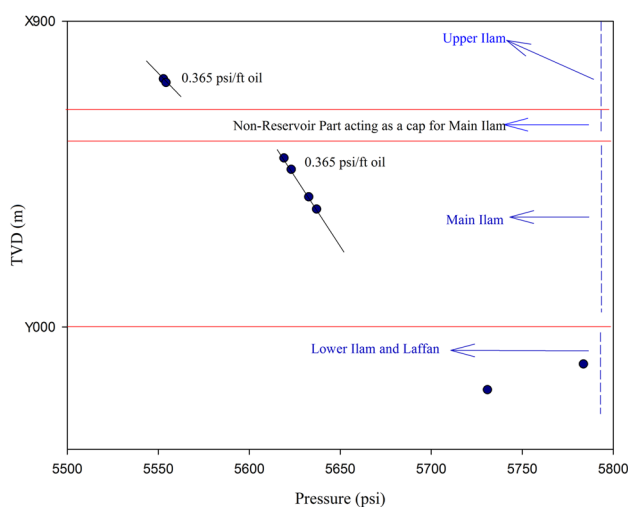


Fig. 4 Pressure–depth plot in Well B-4 in Ilam Formation before production from Field B. The pressure separations in Upper, Main and Lower Ilam prove the presence and effectiveness of basal Upper Ilam as a top seal for Main Ilam

reservoir formation with maintaining its properties through the locations between fields is validated by this correlation chart. Pressure–depth plots of initial wells in all three fields show a separation in pressure trend in three parts of Ilam Formation (Fig. 4). It means that the Upper Ilam, Main Ilam and Lower Ilam are separated from each other in all

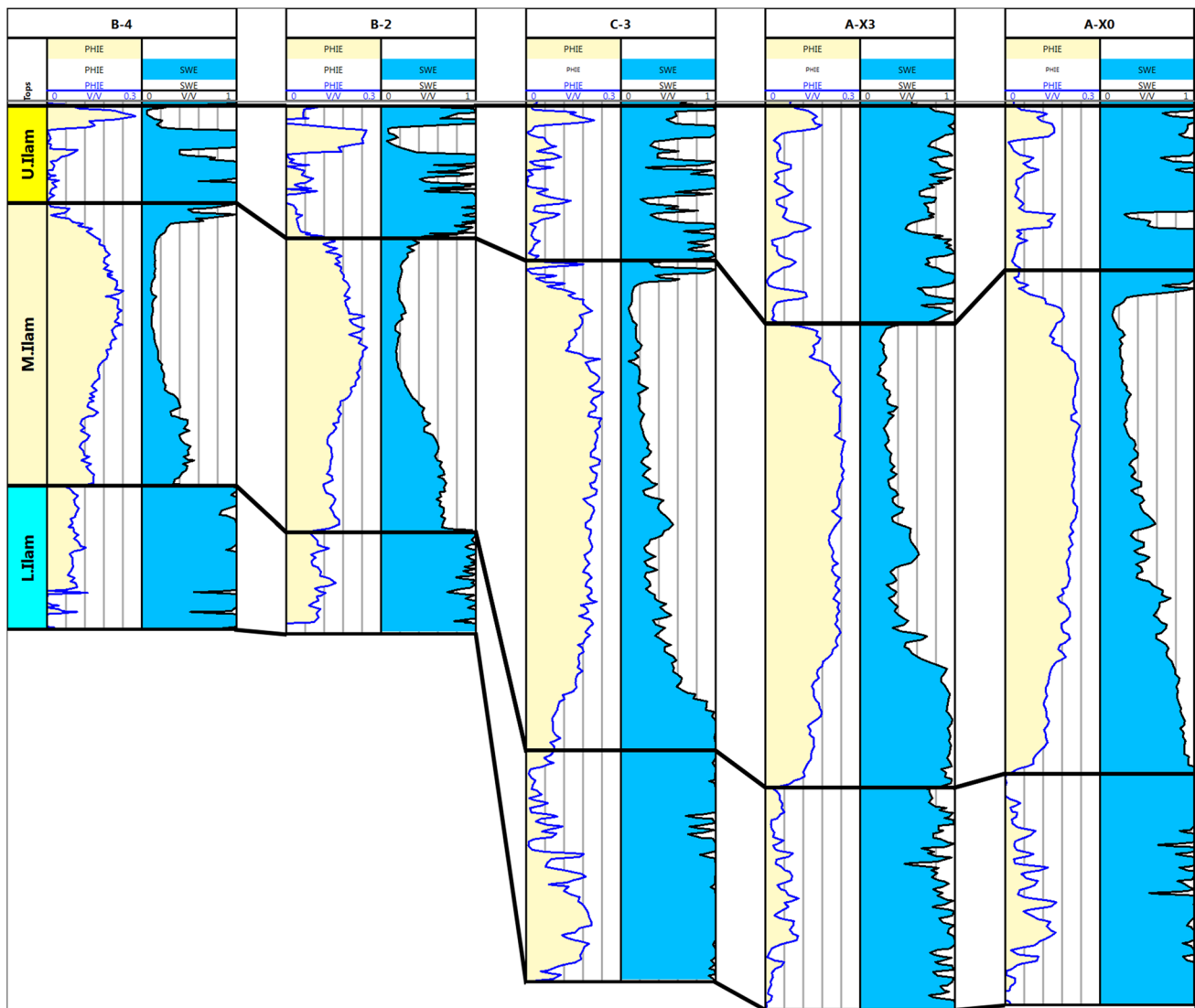


Fig. 5 Correlation of key wells in three fields under study. Although the thickness of Main Ilam as the main reservoir changes through these fields, the reservoir properties do not bear a rapid change so as to act as a lateral seal

three fields. Also, the correlation chart in Fig. 5 shows the extension of the tight interval in basal Upper Ilam without losing its sealing properties in three fields. Therefore, the conclusion is derived that the efficiency of argillaceous limestone as a cap rock all through the specified fields is verified. For more confidence, the seal efficiency of this cap rock was implemented by the capillary data taken from mercury injection pressure (MICP) measurement on core data. Since the top seal failure due to capillary leakage is severe at the highest depth, the core samples must be taken from wells located on the crest of the whole structure, i.e., considering all fields. In this case study, the cores were sampled from top seal in Field B which has the shallowest crest. The capillary pressure curves of these samples along with their porosity and air permeability after conversion to reservoir

oil–water condition are presented in Fig. 6. According to this figure, the displacement pressure of the cap rock is around 175 psi. For the oil and water in the area under study, this displacement pressure is equivalent to an oil column of around 440 m. Consequently, the non-reservoir unit on the top of Main Ilam reservoir acts as an efficient seal to hold a maximum of 440 m of oil column beneath without leakage.

The structures of all the three fields under study are low dip angled with no main faults between them in Ilam Formation. Therefore, there is no concern about the lateral separation of these structures due to sealing faults. Also, in these fields, there is uncertainty about the FWL of each field. In Fields B and C, no distinct FWL has been detected from pressure–depth and production testing data. FWL has only been detected in Field A using the pressure–depth data of

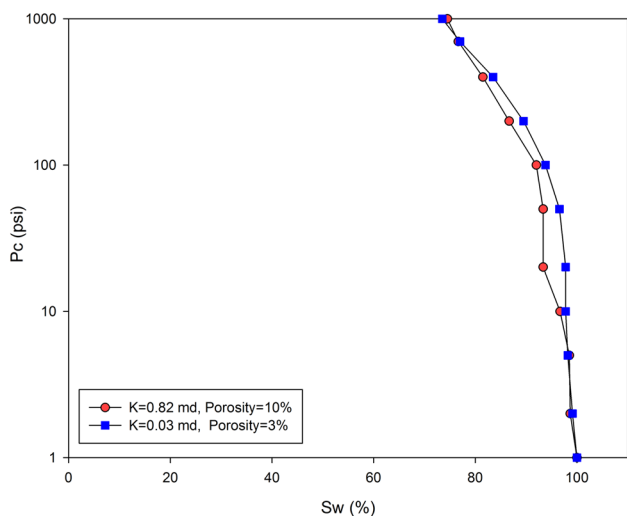


Fig. 6 Capillary pressure plots of the samples taken from top seal in Well B-2. Two samples show a high displacement pressure to be efficient as a seal for Main Ilam formation

one well. This FWL is deeper than the depth of the bridge between Fields A and B as well as Fields A and C. Hence, the probable negative aspects related to saddle depth and FWL are absent.

A very important issue about the FWL in Fields A and C is that in several peripheral wells, the features of perched water have been observed. These wells are located in/or near saddle between two structures and have the potential to trap water during oil migration and hence, creation of perched water zone. In these wells, the pressure plots of only Main Ilam reservoir have been analyzed to ensure that top and

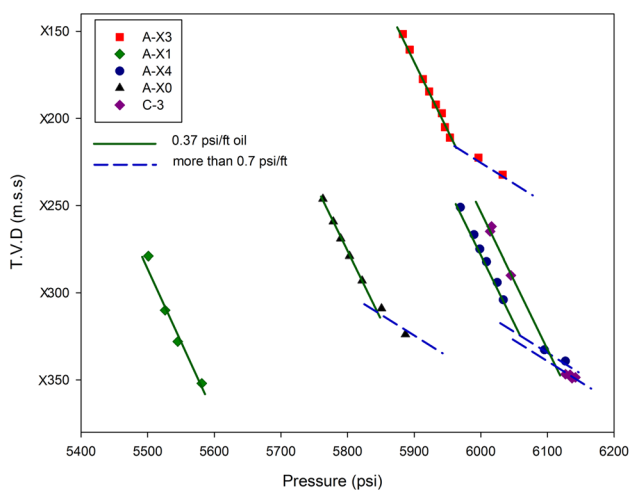


Fig. 7 Presence of perched water in peripheral wells in Fields A and C. Dashed lines represent a high gradient in the main reservoir which are not the regional FWL. An oil column in Well A-X1 has been established which is below the perched water depth in other wells

bottom zones are not included for studying the existence of perched water. In Fig. 7, the pressure–depth plots in these wells are represented. Since Field A has produced oil for more than decades and the wells in Fig. 7 are on different sides of the field, initial pressures in these wells are not equal. As it is obvious from Fig. 7, in the lower part of Main Ilam Formation in Wells A-X0, A-X3 and A-X4, a very high gradient (more than drilling mud gradient) is observed that is a sign of perched water. It should be noted that below this water zone in Well A-X3 (with high pressure gradient), an oil column has been proven in Wells A-X4 and A-X0 in the same formation without any faults or facies changes to compartmentalize the reservoir. In addition, below water zone in Wells A-X4 and A-X0, an oil column has been proven in Well A-X1. This fact is the second reason for proving the presence of perched water. Also, referring to a cross section of the reservoir which passes through two Fields A and B (Fig. 8), the Wells A-X0 and A-X3 are located in such a location that water could be trapped during oil migration and create perched water. Therefore, the water zone observed in these peripheral wells is not the true FWL of the field.

Furthermore, there are no lateral facies changes and no sealing faults in the region between three fields. Also, the saddle depths between fields are shallower than FWL of all the fields. As a result, the most promising steps for proving the reservoir connectivity in this case study are the pressure communication and fluid similarity. The reservoir pressure at initial key wells of the three fields is demonstrated in Fig. 9. A little difference in the initial pressure is observed in this plot, and it can be recognized to be due to the different tools applied besides gauge accuracy of each tool. The results in Fig. 9 show that all three fields are in pressure

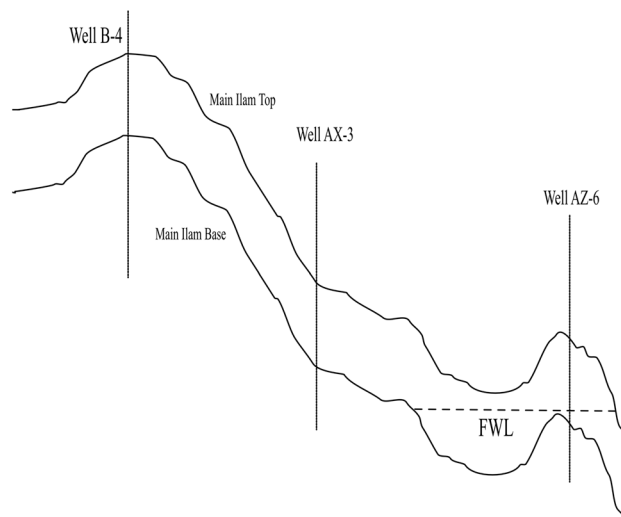


Fig. 8 Cross section of the Main Ilam reservoir between Fields A and B (view to Field C). Well A-X3 has the potential to trap water during oil migration and create a perched water

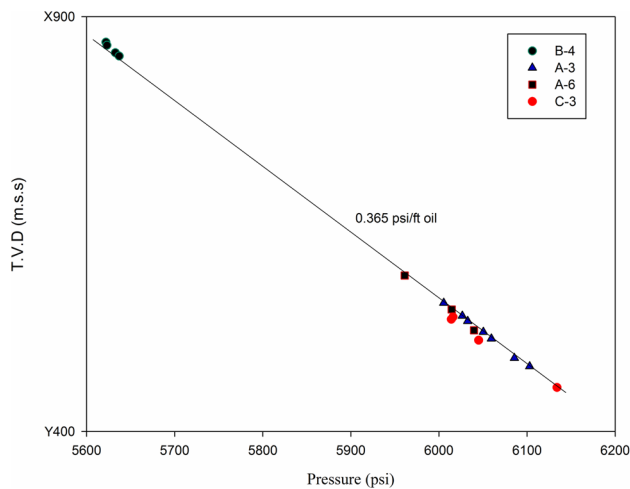


Fig. 9 Pressure–depth plot in the three fields before production from all fields. This plot illustrates the pressure communication between these fields at initial condition

communication, and since there is no lateral sealing factor between them, the reservoir connectivity is becoming more hopeful.

According to simulation results and analytical calculations done by Pfeiffer et al. (2011), the time required for compositional equilibrium is seven orders of magnitude more than the time for pressure equilibrium. Consequently, due to some factors like thermal gradient and ongoing migration, the reservoir fluids in two nearby fields show differences in fluid properties (not from geochemical point of view) even if the reservoirs are charging from the same source rock in the same depth. Hence, if connection is established, the fluid properties throughout the formation vary with a meaningful trend. It is of great importance to note that before fluid comparison, the PVT data measured in laboratory on the representative samples from each well must be validated. Here, to compare the fluid similarities all over the reservoir formation, two aspects are considered. First, the compositions of the reservoir hydrocarbon fluids at initial condition are compared. This is illustrated in Fig. 10 where the compositions of reservoir single-phase oil have been compared. The composition of the fluids in Fig. 10 shows that the oil in Field B is heavier than Fields A and C. This is thought to be for the reason that lateral migration has been performed from Fields A and C toward Field B through which the first heaviest components extracted from source rock are trapped in the porous reservoir in Field B. Also, no significant differences in the composition of the nonhydrocarbon components like H_2S were observed in the reservoir fluids of all the wells in three fields. Second, the overall properties of the fluids are compared. Since the studied cases in this paper are oil fields, the oil properties are regarded and the equivalent procedure is valid for gas fields.

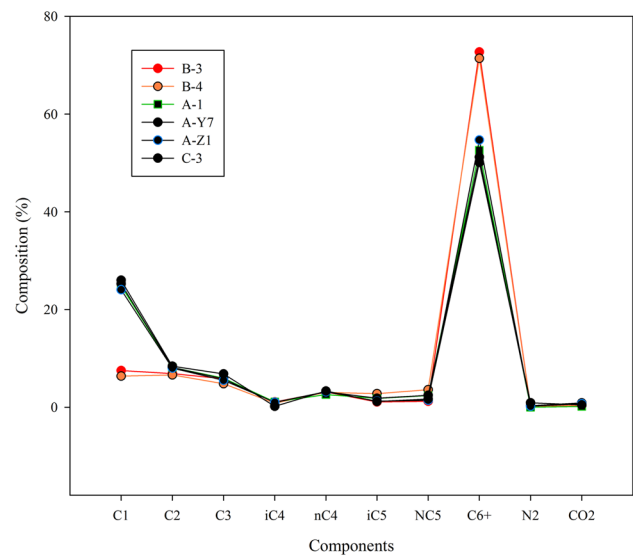


Fig. 10 Compositions of initial fluids of the three fields at reservoir temperature and pressure. The compositions of the fluids in Fields A and C are identical, and the fluid in Field B contains heavier components

Besides the composition of reservoir fluid, many researchers only consider the bulk properties of *crude oil* (API, viscosity and asphaltene content) for comparison (Pomerantz et al. 2010; Ghassal 2019). Actually, to cover the equilibration in reservoir condition, the parameters of live oil-like solution gas–oil ratio (R_s), bubble point pressure (P_b) and oil formation volume factor (B_o) at initial reservoir condition must be considered besides crude oil properties. Since the fluids are sampled from different depths in a field, the reservoir temperature (T) is a key factor. Among the above-mentioned parameters (B_o , R_s and P_b), the dependency of bubble point pressure on temperature is higher and a new parameter merging both P_b and temperature must be introduced. In the studied area, bubble point correlates linearly with temperature (Fig. 11) and hence, the parameter P_b/T is utilized as a new parameter containing both P_b and T . Then, the above fluid properties are plotted in a radar chart as shown in Fig. 12. In order to harmonize the values in the radar chart, R_s and API are divided by 100 and 5, respectively. It is noticeable that other parameters such as sulfur content, asphaltene content or oil formation volume factor at bubble point pressure can be used in the radar chart. As it is apparent from Fig. 11, the oil properties in the wells of each field are identical, but they are different in the three fields. Also, the fluid characteristics in Well A-X3 which has been drilled in the saddle of the Fields A and B show an average characteristic of the two fields. This average characteristic in Well A-X3 confirms the meaningful trend in these two fields. This trend results in an increase in heaviness of the oil (lower R_s and P_b) toward Field B. This can be explained by lateral oil migration from

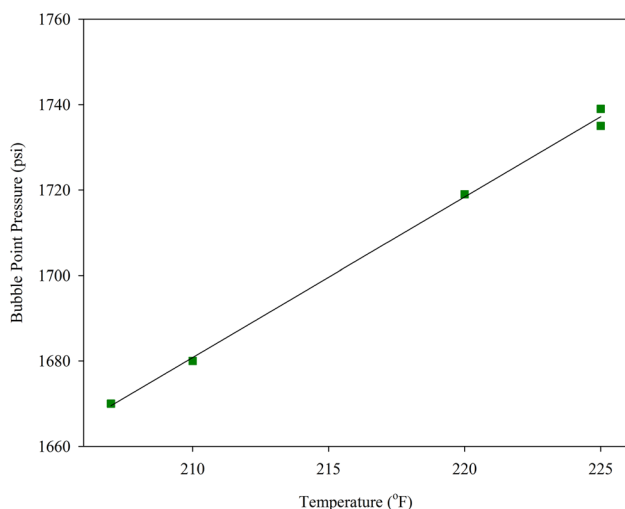


Fig. 11 Linear dependency of bubble point pressure to temperature in Fields A and C. This relation means that by dividing the bubble point pressure by the temperature, the effect of temperature is also considered

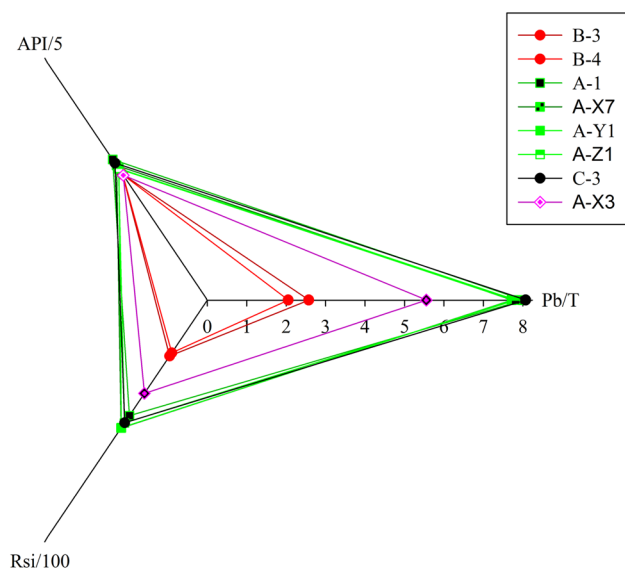


Fig. 12 Comparison of bulk oil properties of the three fields. The oil properties in each field are identical. There is a trend in oil properties from Fields A and C through Field B. The oil in Well A-X3 which is drilled in the bridge between Fields A and B bears average properties of oils in Fields A and B

Field A toward Field B in which the first oil (the heaviest one) extracted from source rock has been migrated to Field B. Unfortunately, no geochemical data are available at the moment to confirm this hypothesis. Nevertheless, the PVT data from a delineation well at southernmost part of Field B (which is far from Field A) proved a heavier oil with R_s near to 100 scf/STB. The solid content of the reservoir oils (the asphaltene content) is also a good parameter for the

comparison of fluid similarity. The average asphaltene contents of the reservoir fluids in Fields A and B are 4.9 and 5.5 weight percent, respectively, and that in the delineation well at southernmost part of Field B is 6.03 weight percent. Hence, the asphaltene contents in the reservoir oils approve the trend of increasing the heaviness of the oil toward Field B. Therefore, the fluid similarity is not a negative feature for communication of Main Ilam reservoir in the area under study.

To compare the Q_R and Q_{EC} resulting from basin modeling, the outputs obtained by Bordenave and Hegre (2010) are utilized. According to their work, the ratio Q_R/Q_{EC} for one of the fields under study was around 10 percent which was lower than the average of all fields introduced in their work. Accepting the uncertainties of basin modeling, one reason for the low value of Q_R/Q_{EC} is related to calculated oil in place, as there is uncertainty about FWL in this field. Hence, the results of basin modeling are positive for proving the connectivity of these fields.

Up to now, many factors have supported the lateral connectivity of the aforementioned oil fields. The other steps like comparison of material balance and volumetric estimations results can be performed for more confidence. Unfortunately, the production data were not available for comparison of oil-in-place volumes and also for studying pressure trends. In all, the results confirmed the lateral connectivity. In addition, the connectivity of Fields A and B has been confirmed through a delineation well known as A-X3 drilled in the bridge between the two fields.

Conclusions

A comprehensive procedure was constructed for reservoir connectivity study considering all geological and reservoir engineering features. The following conclusions are derived:

1. The geochemical view on fluid similarity is related to the source rock study, and a reservoir may be charged from different source rocks. Hence, for the aim of reservoir communication between near fields, the geochemical similarities of hydrocarbon fluids are not essential.
2. If the connectivity of reservoir between two or more fields are studied, the fluid in two fields must be similar or have a trendy variation. In this study, the similarity was not exact, but a meaningful trend was observed. This trend is thought to be due to migration and needs geochemical data for confirmation.
3. The top seal for Main Ilam reservoir in this study was recognized by petrophysical, core and pressure–depth data. The efficiency of this seal was verified based on capillary pressure of core data and separation of pres-

sure–depth trend in the porous parts above and beneath the cap rock layer.

- In several peripheral wells in Fields A and C, the presence of perched water was proved. The presence of the possible perched water must be studied in each field to avoid misunderstanding of real FWL.

Acknowledgements Authors deeply appreciate Dr. Hassani-Giv M. for his help to complete the lithology description in “Geological Setting” part of the present paper.

Compliance with ethical standards

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

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