Specifying Quality of a Tight Oil Reservoir through 3-D Reservoir Modeling

Nagham Jasim[*1], Sameera M. Hamd-Allah[1], Hazim Abass[2]
[1]Petroleum Engineering Department, University of Baghdad, Baghdad, Iraq
[2]University of Houston

Abstract

Increasing hydrocarbon recovery from tight reservoirs is an essential goal of oil industry in the recent years. Building real dynamic simulation models and selecting and designing suitable development strategies for such reservoirs need basically to construct accurate structural static model construction. The uncertainties in building 3-D reservoir models are a real challenge for such micro to nano pore scale structure. Based on data from 24 wells distributed throughout the Sadi tight formation. An application of building a 3-D static model for a tight limestone oil reservoir in Iraq is presented in this study. The most common uncertainties confronted while building the model were illustrated. Such as accurate estimations of cut-off permeability and porosity values. These values directly affect the calculation of net pay thickness for each layer in the reservoir and consequently affect the target of estimating reservoir initial oil in place (IOIP). Also, the main challenge to the static modeling of such reservoirs is dealing with tight reservoir characteristics which cause major reservoir heterogeneity and complexities that are problematic to the process of modeling reservoir simulation. Twenty seven porosity and permeability measurements from Sadi/Tanuma reservoir were used to validate log interpretation data for model construction. The results of the history matching process of the constructed dynamic model is also presented in this paper, including data related to oil production, reservoir pressure, and well flowing pressure due to available production.

Keywords: Tight Reservoir, Static Model, Dynamic model, History matching, Reservoir Quality.

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تحديد نوعية مكمن نفطي قليل النفاذيه من خلال موديل جيولوجي

نغم جاسم*[1]، سميرة حمد الله[1]، حازم عباس[2]

[1]قسم هندسة النفط، كلية الهندسة، جامعة بغداد، بغداد، العراق

[2]جامعة هيوستن

الخلاصه

تركز الاهتمام في السنوات الاخيرة في الصناعه النفطيه حول البحث عن مصادر اخرى للهيدروكربون غير المكامن التقليديه. ان بناء موديل يمثل وبشكل حقيقي حركة الموائع داخل المكمن الغير تقليديه قليلة النفاذيه والمساميه يتطلب بناء موديل جيولوجي كخطوه اساسية ومهمه لوضع خطط واختيار ستراتيجيات ملائمه لتطوير هذا النوع المهم من المكامن والحصول على اعلى نسبة استخلاص للنفط منها. طبيعة هذه المكامن من

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*Email: naghamjasim288@yahoo.com

حيث قلة نفاذيتها ومساميتها وتركيبها المعقد وغير المتجانس جعل من بناء موديل جيولوجي لها يمثل تحدي
كبير, في هذا البحث تم تطبيق نموذج جيولوجي ثلاثي الابعاد لمكمن كلسي عراقي يمثل مكمن قليل النفاذيه
غير تقليدي وتم عرض اكثر النقاط التي تؤدي الى عدم الدقه في بناء الموديل مثل دقة حساب حد القطع لقيم
النفاذيه والمساميه والتي تؤثر بشكل مباشر على حساب سمك الطبقه المنتجه في حسابات المحتوى النفطي
الاولي داخل المكمن اضافه الى صعوبة التعامل مع البيانات المدخله لبناء الموديل لهذه المكامن المعقده وغير
المتجانسه.

1. Introduction

Prediction of future reservoir performance needs accurate construction of 3-D static models for reliable evaluation of the reservoir to achieve efficient management. Accurate characterization of the formation is the main step in building a static model. Distinguishing formation's net to gross ratios of pore and grain geometry and size reflects reservoir complex structure and aids in the accurate construction of the geological model [1]. Apaydin et al.[2] proposed critical parameters in tight reservoir modeling, which include sand body geometry, water saturation permeability, and hydraulic fracturing. Fine gridding and upscaling also have direct effects on the results of static model [3]. Understanding tight reservoir heterogeneities and avoiding mistakes in the main input data (porosity, permeability, and saturation) allows better construction and visualization of 3-D static models [4]. Abd El-Aziz et al.[5] proposed several recommendations to develop a 3-D model for a high heterogeneous limestone reservoir by improving reservoir layering through seismic data interpretation. Hajizadeh et al.[6] proposed a method to be applied to high heterogeneous tight reservoirs by dividing the reservoir to a proper rock typing based on hydraulic flow unit method to accurately recognize between different geological rock types and net to gross ratio. Dealing with tight reservoir properties is a real challenge in static and dynamic model building. These properties are represented by the ultralow permeability, nano pore throat size, high initial reservoir pressure, and increasing effective stress during reservoir depletion. A general workflow to model a complex tight carbonate reservoir is given by Gomes et al.[7], Bovan et al.[8], Darhim and Ibrahim [9], Kevin et al.[10]. The details of geological and structural information necessary to introduce a dynamic model are mentioned in the following paragraphs.

2. Geological Background

Sadi/Tanuma reservoir was discovered in 1976 and located in Halfaya oil field southern east Iraq. A shallow water carbonates deposit was developed in this field during early to late Cretaceous and also during Oligocene to early Miocene. This effective water development was supported by the location of Halfaya field in the west of Persian Gulf Basin and to the east of Arabic Continental Shield. In general, Halfaya field was deposited in a mid-outer shelf of a carbonate open platform. Within the regional geology, Sadi and Tanuma reservoirs are in the same sedimentary cycle where they developed in the environments of ramp platform, with a tested formation to be oil-bearing. Sadi formation is mainly deposited on a NW-SW stretching sub-basin. The average thickness of Sadi formation is from 120m to 130m. It is subdivided into 2 layers: Sadi- A and Sadi- B. Sadi-B includes B1, B2 and B3, which are distributed continuously in the contact area, and is an oil-bearing layer. Vertically, Sadi-B3 has 4 sublayers according to the variation in lithology, electricity and petrophysical properties, namely Sadi-B3-U1, Sadi-B3-U2, Sadi- B3-U3 and Sadi-B3-U4. Tanuma formation is mainly 13-18m thick. The evaluation indicates that the thickness values of each layer are about 51 m for Sadi-A, 28 m for Sadi-B1, 30 m for Sadi-B2 , 20 m for Sadi-B3, and about 13m for Tanuma reservoir [11]. The lithology of Sadi-B and Tanuma formations was examined based on the cores and thin sections from the one cored wells. Rock quality varies vertically in these two formations. Sadi-B1 and Sadi-B2 are relatively tight but their cores still show oil stain. Cores in Sadi B3 have good oil stain and consist of enlarged pore spaces. Cores from the upper interval of Tanuma also show good oil stain. A continuous marl layer with a thickness of 2-6 m exists between Sadi-B3 and the underlain Tanuma reservoir, which can serve as a barrier. Sadi-A is a medium grey, soluble calcareous shale. Sadi-B1 mainly consists of bioturbated wackestone, while Sadi- B2 comprises primarily bioturbated packstone and pelagic foram chondrites, which are either dolomitized or pyrite cemented. Sadi-B3 developed shale containing smectitic, pyritic, oolitic, and skeletal intraclastic packstone. Echinoderms, pebbles, oolitic and dark grain (pyritic) packstone, and chondrite can also be

found in Sadi-B3. Scanning electron microscope (SEM) and thin section (TS) images provide geological description for each section of Sadi reservoir, as shown in Figure-1 [12].
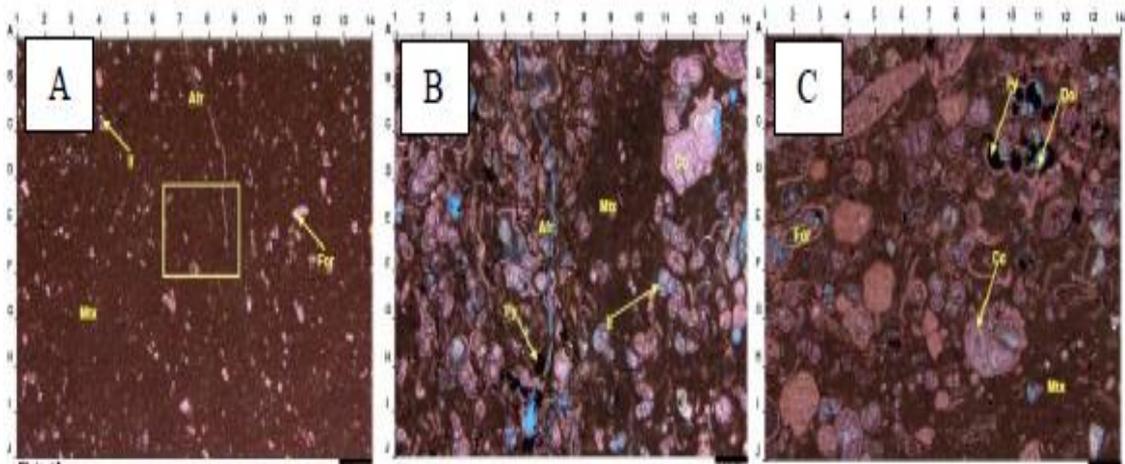
Figure 1-Lithofacies of Sadi-B1 (A), Sadi-B2 (B), and Sadi B3 (C) from TS and SEM photos.

3. Integration of Static Geomodel

Prediction of future reservoir performance requires accurate construction of 3-D static model for reliable evaluation of the reservoir to achieve efficient reservoir management. Accurate formation characterization is achieved through structure detection, which is the main step in building a static model. Ensuring the accuracy of the detection of petrophysical properties is the first important step in constructing static models. This step needs to calibrate petrophysical properties data with core data to build static model, as will be discussed in the following section. Also, it is essential to obtain accurate cutoff values for these petrophysical properties in order to calculate accurate net to gross thickness and, hence, reach an accurate estimation of initial oil in place.

3.1   Evaluation of Petrophysical Properties of Sadi/Tanuma Reservoir

Evaluation of the studied tight reservoir was conducted using core samples measurement of both porosity and permeability. Twenty seven porosity and permeability measurements were performed for twenty seven core samples taken from three cored wells in the field. These measurements were taken at ambient conditions for different depths of the reservoirs to reflect their petropysical properties. In addition, these measured data were used to validate log derived data, which were calculated using conventional (resistivity and density) logs. Porosity raw data were collected from log interpretation results available for 17 wells passing through the studied formation [13].

Porosity log calculation was achieved by field operator, based on density log interpretation. The resulted porosity values were corrected to reflect hydrocarbon effect and clay content. Clay content was generally estimated from gamma ray log results by radioactive rock content. The available porosity raw data was plotted with the measured data to evaluate their consistency after the core data were depth-shifted to match the log results data.

Water saturation was given by a field operator and estimated from the calculated porosity and resistivity log using Archie equation [13]. The empirical parameters in this equation (m and n) are set as 2.15, whereas a is equal to 1. The obtained log-derived water saturation data should be validated with Dean-Stark water saturation measurements.

As known, the well logging techniques cannot directly measure permeability. The most reliable permeability values may be obtained from core analysis. Therefore, the permeability measurement was provided by the field operator, using the established porosity- permeability relationship from core data. This method can give a reasonable result for most sandstone and carbonate reservoirs.

These log derived parameters (Φ, k, and Sw) were validated with core measured values after the core data were depth-shifted to match the resulted log data. The validation was conducted for the three cored wells. Thus, the calculated porosity from density log, in addition to permeability established from the relation between core permeability and porosity, and water saturation log derived from Archie equation can be used as input data in reservoir evaluation using Petrel software with an acceptable accuracy for all layers in Sadi formation in Halfaya oil field. Figure-2 illustrate the relation between both measured and log derived data of porosity, permeability, and saturation of as an example

for one cored well. The resulted porosity, permeability and saturation are generally matched well with the core data.

Core data showed that Sadi-B1 porosity values ranged from 8.07% to 26.1%, averaging 14.6%, while permeability ranged from 0.01mD to 1.31mD, averaging 0.08mD. Porosity values of Sadi-B2 ranged from 8.1% to 32.42%, averaging 17.53%, whereas those of permeability ranged from 0.01mD to 2.22mD, averaging 0.175mD. Sadi-B3 showed average porosity of 11.07% and average permeability of 0.56mD. The results suggest that porosity and permeability values of Sadi-B1 are lower than those of Sadi-B2. In addition, porosity of Sadi-B3 is lower than that of Sadi-B2, but its permeability is much higher. Sadi-B3-U3 has the highest permeability among Sadi-B3 layer units. The resulted porosity and permeability data are generally well consistent with those of the core.
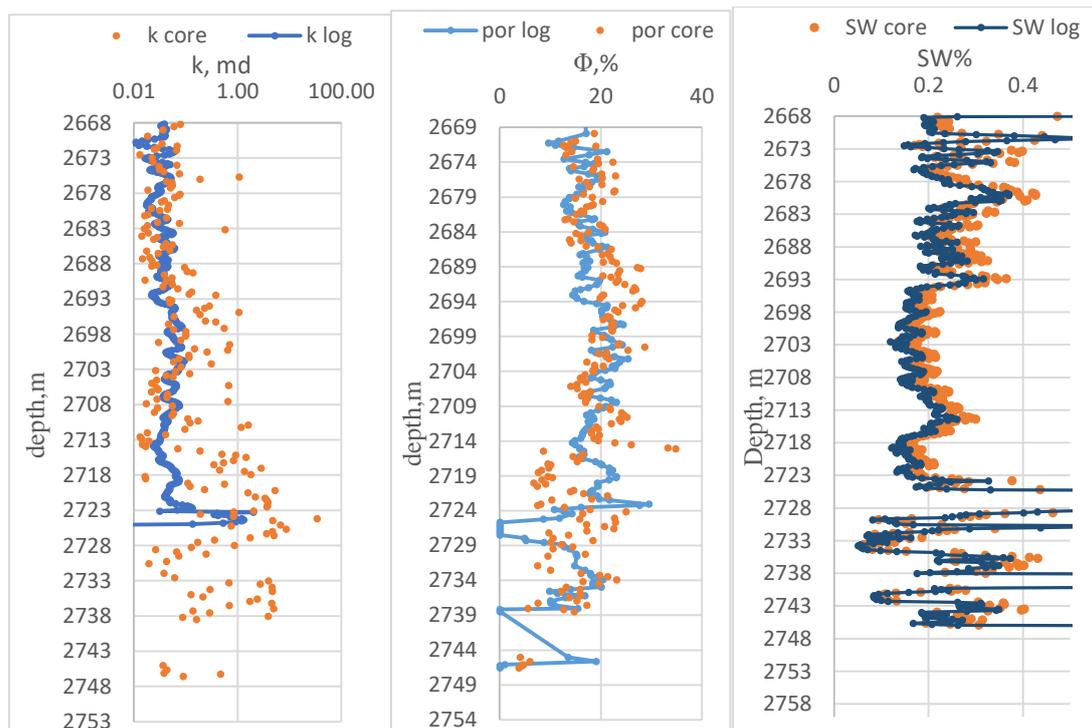
Figure 2-The relation between measured and log values of porosity, permeability, and saturation for one cored well as an example

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3.2 Determination of Petrophysical Properties Cut-off Values

Cut-off porosity, permeability, and saturation values define zones with moveable hydrocarbon storage. These cutoff values are important to calculate the net to gross thickness ratio for each well depth, which is a very important parameter in calculating reservoir's initial oil in place. However, the objective of detecting these values is to eliminate those rock volumes that do not contribute significantly to the reservoir evaluation.

These cutoff values were detected in this research for each layer of Sadi reservoir due to the difference in petrophysical properties of each layer. Gong *et al.*[14] a throat radius value of less than 0.015 μm for complex carbonate tight reservoir, causing the maximum Hg pressure to be increase sharply. As a result, the cutoff of this radius is used to find permeability cutoff. For Sadi tight reservoir, mercury injection capillary pressure (MICP) is used to find permeability cutoff value by plotting mercury injection capillary pressure versus pore throat radius. This plot showed a pore throat radius of 0.015 μm which caused a sharp increase in capillary pressure for Sadi-B1 and Sadi-B2 reservoir, as shown in Figure-3. Therefore, the estimated permeability cutoff value corresponding to that radius is equal to 0.01 md. For Sadi-B3 layer, the pore throat radius (0.005 μm), causing the sharply increasing Hg pressure, is higher than the detected value in the other two layers, which results in an increase in permeability cutoff for Sadi-B3 layer to 0.015md.

This permeability cutoff value is utilized to find porosity cutoff values. The general method to estimate these values is by drawing core data of logarithmic permeability and linear porosity[15]. The

cut-off values were determined using the measured data of porosity and permeability of the twenty seven core samples at ambient conditions, as shown in Figure-4.

Water saturation cutoff values can be detected by plotting well log derived porosity versus water saturation, as shown in Figure-5. Intersecting the above mentioned porosity cutoff value with the curve passing through the data point provides water saturation cutoff value [15]. Through the comprehensive study of Figures-(5-4) through (5-6), it was found that a value of 11 % is recommended to be the porosity cutoff (porosity ≥ 11%) for Sadi-B1 and B2, while 0.01 md is that for permeability cutoff (permeability ≥ 0.01 md). However, porosity cutoff detection was difficult for Sadi-B3 due to high data scattering resulted from high layer heterogeneity. A value of 0.015 md is recommended for permeability cutoff to this layer. Water saturation cutoff was estimated to be 48% (water saturation ≤ 48%), whereas the shale volume cutoff was ≤ 35%.
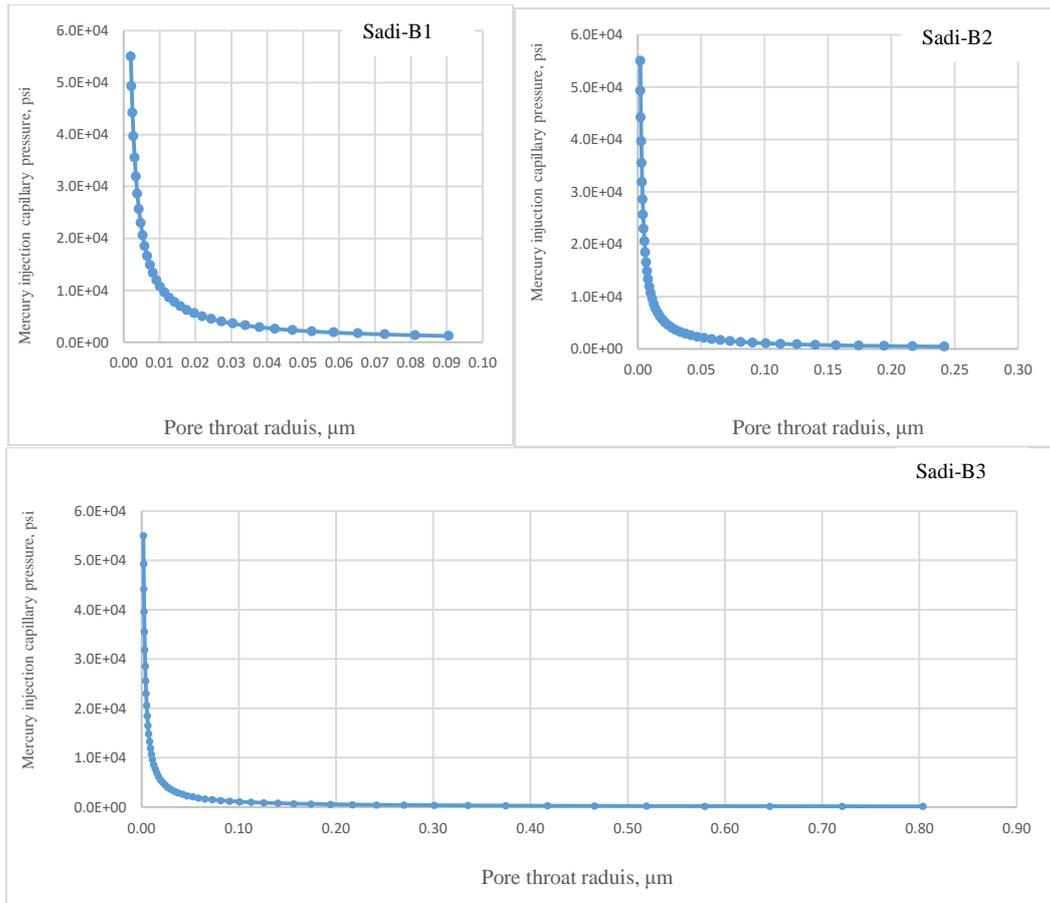
Figure 3-Permeability cut-off estimation in Sadi reservoir using MICP data.
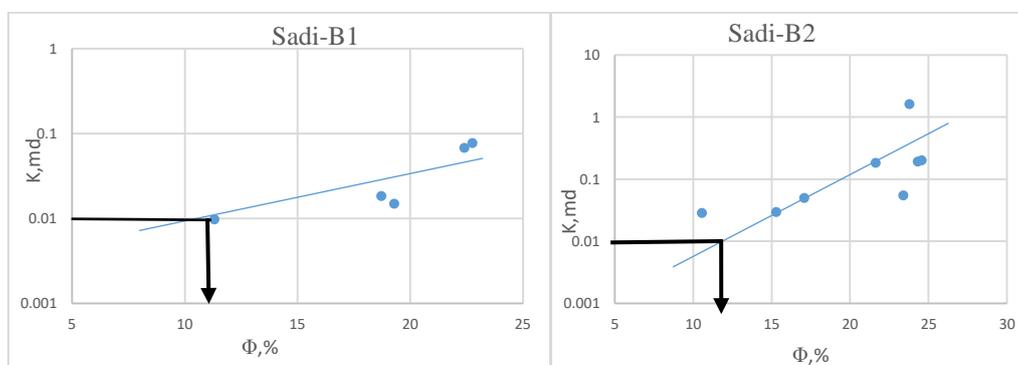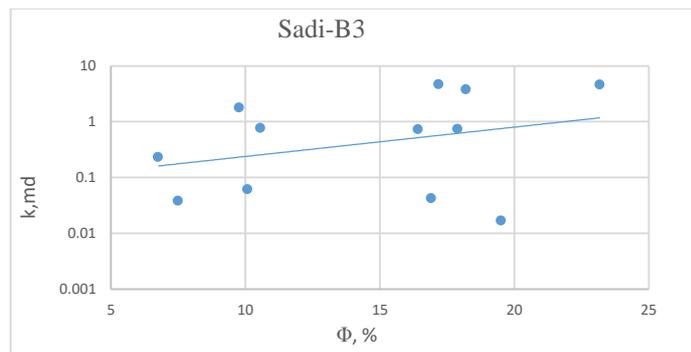
Figure 4-Porosity cut-off estimation in Sadi reservoir.
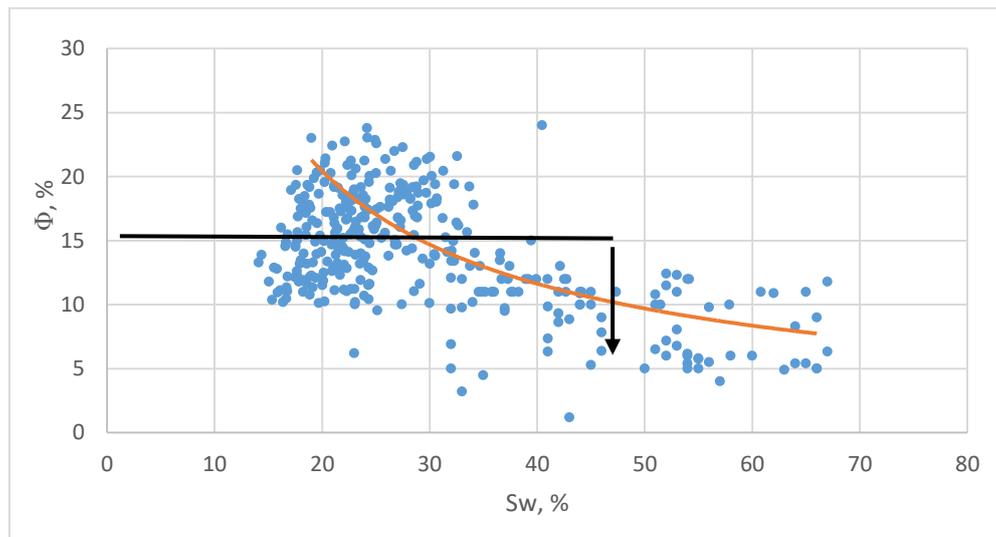
Figure 5-Saturation cut-off estimation in Sadi reservoir.

3.3 Net to Gross Thickness

Net to gross thickness is an important input data in reservoir modeling. In relation to formation's evaluation, this parameter is used to separate between formation's rocks that are useful for hydrocarbon production and those that are not. Net pay thickness calculation is an important step in building a static model, since it is excluding low hydrocarbon storage and low flow capacity rock intervals from the volumetric calculation of initial oil in place. Thus, the effective intervals entered to IOIP calculation will be of high oil storage and productive. Net pay is also a basic step in the evaluation of reservoir favorable area for each layer in Sadi/Tanuma reservoir. This parameter is calculated in the present study using Interactive Petrophysics "IP v.3.5" software for each log reading interval along the loged 17 wells. The input data necessary for the calculation of net to gross thickness are well porosity, permeability, and saturation, as well as their cutoffs limit values.

4. Structural and Geological Model

Distinguishing formation's pore and grain geometry and size reflects the complex structure of the reservoir and aids in accurately constructing geological models. The conclusions obtained from studying the reservoir core samples, in terms of pore size and geometry from MICP test in addition to TS and SEM image, will aid to identify reservoir layering and horizon. Sadi and Tanuma reservoirs are in the same sedimentary cycle. Sadi formation is mainly deposited on a NW-SW stretching anticline, covering 462 km^2 areas. The thickness of Sadi formation ranged from 120 m to 130 m. Obtaining accurate petrophysical properties and using accurate zone tops is the first step in constructing structural models. Wells cross section was carried out to examine zones' tops in the constructing model. Data used in the construction of structural models mainly include surface maps of reservoir units and wells' tops of each layer. 2-D geological top surface map of Sadi-B were obtained depending on 3-D seismic data [14] . Top surface maps of other units are generated based on Sadi-B top surface map, due to absence of other layer maps. In addition to surface maps, data from 24 vertical

and deviated wells' tops for all layers of the studied reservoir were entered to Petrel software to generate the accurate structural shape of Sadi/Tanuma reservoir.

4.1 Geological Model Gridding

To describe the quality and heterogeneity of the studied reservoir, it is essential to distribute the evaluation of petrophysical properties all over the reservoir. Therefore, a high resolution 3-D grid system was built depending on a structural model to achieve vertical and lateral petrophysical properties distribution along the discrete reservoir grids. The static model was built to contain a 342*156*91 grid to describe the large area of the studied reservoir and determmines the total Sadi/Tanuma reservoir thickness. The total number of grid cells were 4,855,032 grid, while grid dimensions were 75 m in both X and Y directions and about 1 m thickness in Z direction.

4.2 Reservoir Horizons and Layering

After identifying Sadi reservoir units based on lithological description and petrophysical properties evaluation of core samples. Wells cross section was carried out using Petrel software for the interpretation of loaded petrophysical properties, detection of the lateral variation of the studied thin and heterogeneous zones, and adjusting the layers to the constructing model. The examined petrophysical data were used as input data into Petrel to build a static model for reservoir's quality estimation. The well-to-well cross plots of these input data were used to define the stratigraphic horizons bounding the main stratigraphic sequence of the studied reservoir based on the variation in petrophysical properties. The next step was identifying structural reservoir horizons. Generally, Sadi/Tanuma structural model was divided into five main horizons and four zones, which are Sadi-B1, Sadi-B2, Sadi-B3, Tanuma, and Khasib. All the horizons were created depending on the geological surface map of Sadi-B, due to the lack in the received data. Therefore, well tops data derived based on petrophysical core data and lithological description were used, in addition to surface maps, to generate reservoir zones. Finally, the 4 zones were divided into 91 layers; 28 layers for Sadi-B1, 30 for Sadi-B2, 20 for Sadi-B3, and 13 layer for Tanuma, each with 1 m thickness. Figure-6 shows reservoir horizons and layering.
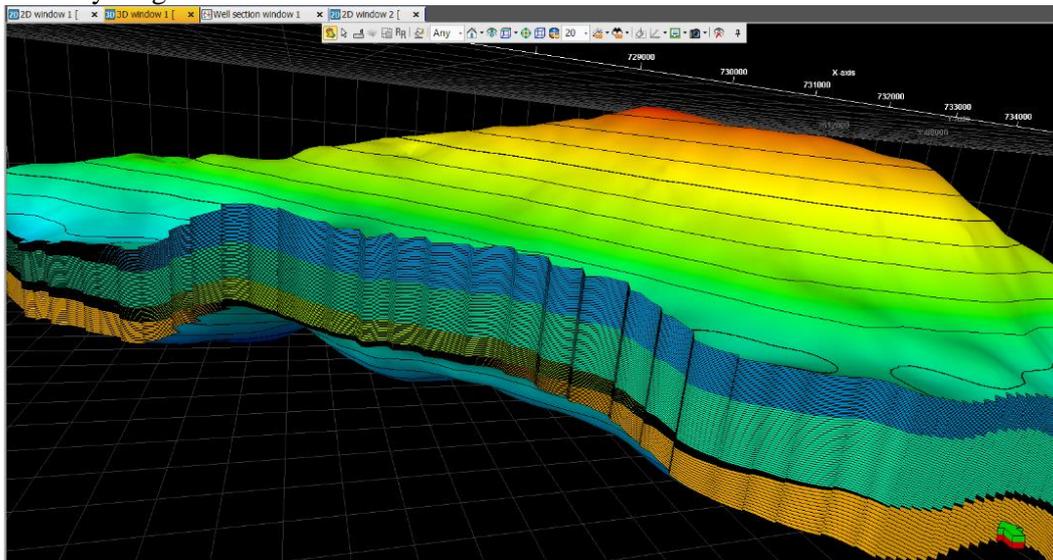
Figure 6-3-D static model describing Sadi/Tanuma reservoir layers

4.3 Petrophysical Properties Model

A stochastic technique was applied for the distribution of horizontal and vertical petrophysical properties along the discrete reservoir grids model. Over this model, the entered log data (porosity, permeability, water saturation, and net to gross ratio) were distributed using sequential Gaussian simulation algorithm to conduct the petrophysical model. Figures-(7 to 9) explain the output permeability, porosity and saturation models for each layer of Sadi and Tanuma reservoirs. Also, the Net pay model, which is a basic step in the evaluation of the reservoir favorable area for each layer in Sadi/Tanuma reservoir, is illustrated in Figure-10.
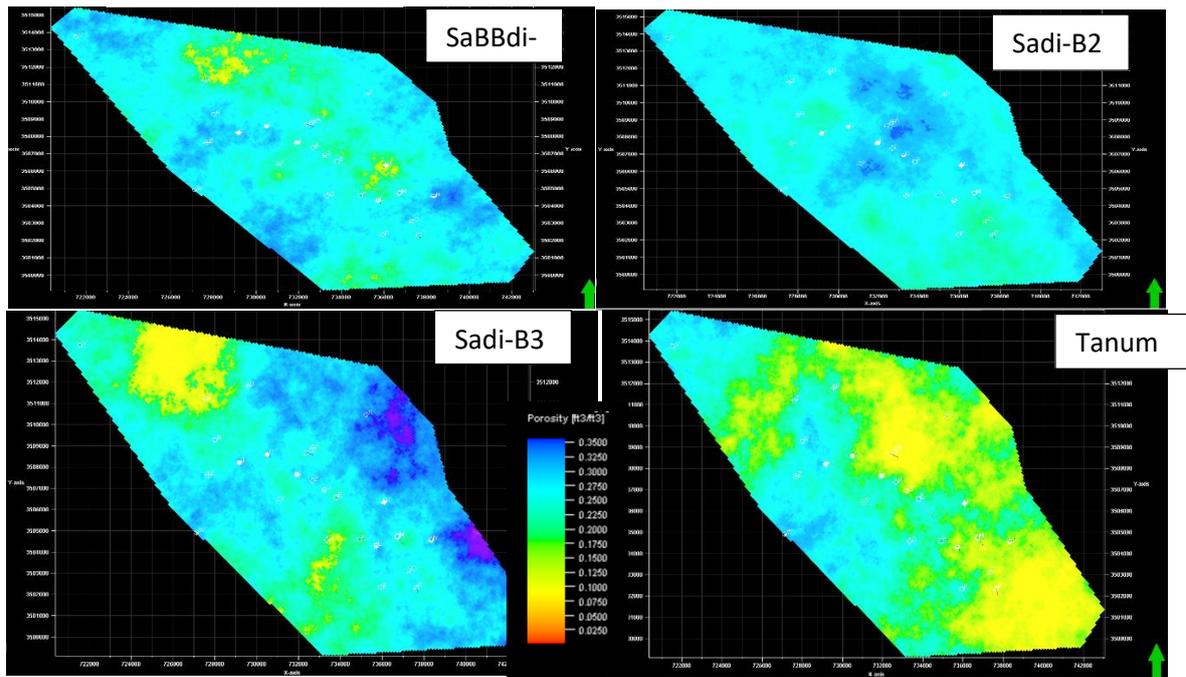
Figure 7-Porosity model for Sadi-B1, Sadi-B2, Sadi-B3, and Tanuma layers.
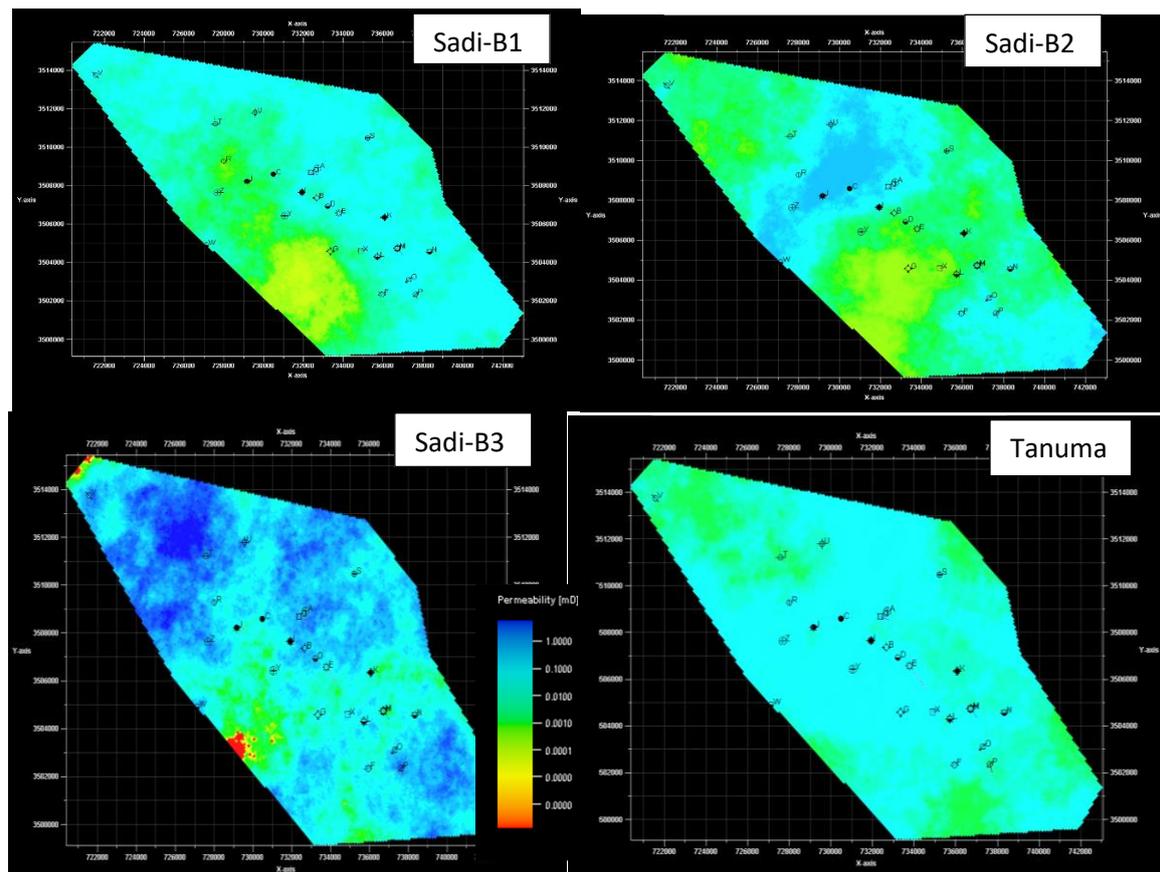
Figure 8-Permeability model for Sadi-B, Sadi-B2, Sadi-B3, and Tanuma layers.
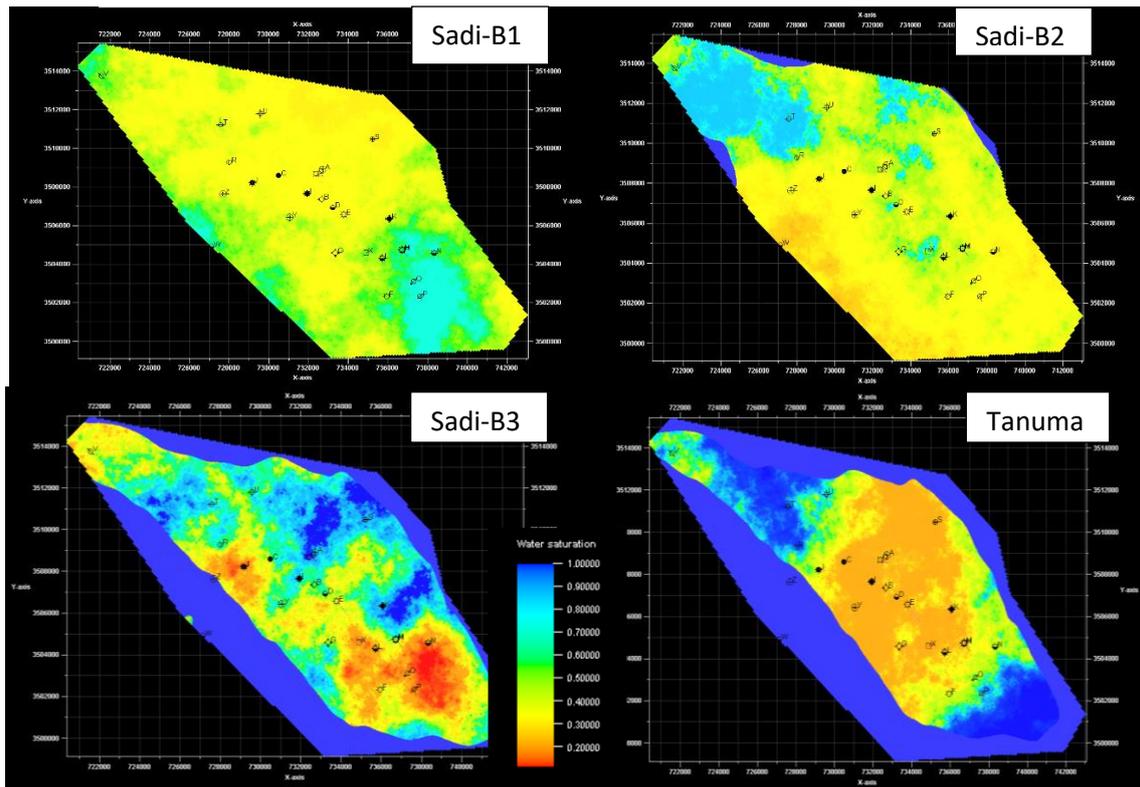
Figure 9-Saturation model for Sadi-B1, Sadi-B2, Sadi-B3, and Tanuma layers
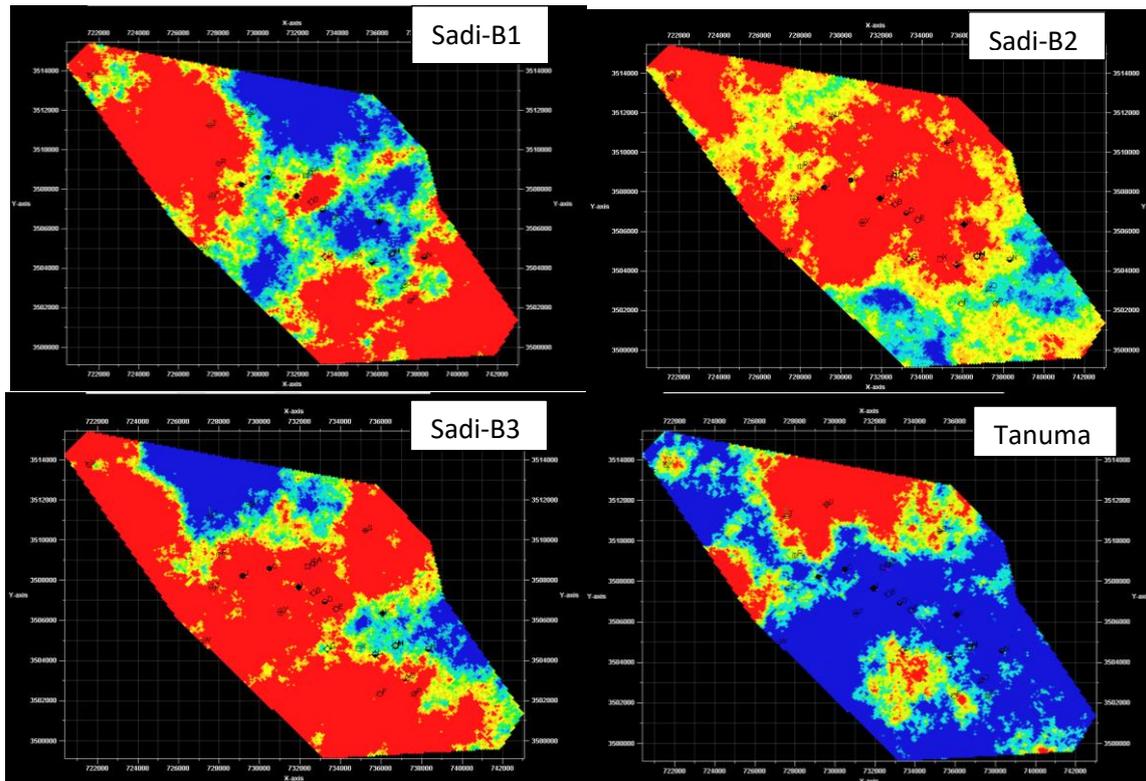
Figure 10-Net pay model for Sadi-B1, Sadi-B2, Sadi-B3, and Tanuma layers

5. Reservoir Dynamic Model

After building a static model, it is required to include many parameters to the model. These parameters are related to fluid flow in the reservoir model. However, it is first necessary to modify the model size and properties (model upscaling) to be appropriate to represent dynamic flow in the

reservoir. Describing the details of the underground geological reservoir required a very fine scale geological model. But due to the limitation of computer resources, time, and size, it is essential to upscale the fine grid model to a coarse grid model that can be used to represent dynamic fluid flow in the reservoir. The upscaling process includes both grid size (structural upscaling) and properties.

First of all, the static model in the present study was of about five million grids representing Sadi/Tanuma reservoir. The upscaling procedure was applied by reducing the model grids to reach 1,036,152, by dividing the model to 162*82*78 grid, with grid dimensions of 150 m in both X and Y directions and 1 m thickness in Z direction. Arithmetic average weighting method was applied in the current model to upscale reservoir properties. In this process, the arithmetic mean method was used to upscale net to gross ratio. Arithmetic mean weighted by the NGT method was used to upscale both porosity and water saturation. For permeability upscaling, the harmonic weighted method by net to gross thickness is applied.

The resulted coarse grid model, after the upscaling process, must be validating. The best validation approach is to compare the estimated IOIP after running the new coarse grid model with the initial fine grid model. The fine grid model indicated an oil in place value of 4092 MM STB, while the up-scaled coarse model indicated a decrease of 2.2 % of this initial value (3873 MM STB). This difference between the two fine and coarse grid models is due to the excluded grid cells because of properties weighting methods and reducing modeling layers.

5.1. Dynamic Model Construction

As discussed previously during the description of the core and FMI images, no naturally fractures are present in Sadi reservoir. Therefore, a single porosity model was selected. Depending on PVT analysis reports, Sadi was found to be an undersaturated reservoir and, hence, the black oil-single porosity model was generated. Building a dynamic flow model need fluid and rock-fluid properties to be defined in the model.

Reservoir fluid properties were obtained from PVT test of samples taken from two depths in Sadi-B reservoir as a function of pressure. These data are taken from two samples in Sadi-B reservoir. No difference was indicated from the PVT data of the two samples and, therefore, the reservoir fluid properties suggested the presence of one region in the constructing model. These PVT data included solution gas-oil ratio (Rs), fluid viscosities, and formation volume factors for three phases (oil, gas and water). Chemical analysis was performed for one water sample from Sadi reservoir, showing a water formation volume factor of 1.018 bbl/STB, water compressibility of $2.62*10^{-6}$ 1/psi, and water viscosity of 0.44 cp. In the dynamic model, rock-fluid data imply properties related to phase saturation, such as relative permeability and capillary pressure data.

5.2. Dynamic Model Initialization

The initial Sadi reservoir conditions (reference pressure and depth, phase contact depth, bubble pressure, and datum depth) need to be supplied to the dynamic model, in addition to the prementioned rock-fluid properties. According to the fact that there is one oil water contact depth for Sadi reservoir, the current dynamic model was conducted on the basis of one region. Gravity-capillarity equilibrium was used as a method to calculate all grid block pressures and water saturations.

After loading all required data to the dynamic flow model, it is necessary to run the generated dynamic model in order to obtain its initial results of IOIP, calculated based on initial water saturation, and validate the resulted oil volume with that calculated using the static model. The resulted IOIP value by using the dynamic model was 0.638 MMM m3 (4012.3 MM STB) which was comparable to that reached by using the static method (3873 MM STB), after model upscaling.

5.3. History Matching

The dynamic flow model should be calibrated through history matching in order to utilize the model for the forecasting of production performance, based on good history matching results with past reservoir production. History matching process was conducted for each production well individually and for all field production data. Matching was conducted in the current study for oil production only, since there is no significant amount of water production from the observed production file. Matching was also conducted for reservoir pressure and well flowing pressure due to available production data.

5.3.1 Production History Matching

Calibration of the constructed dynamic model through history matching was conducted in this study through the existing producing wells. The history of the total production of the five existing wells was matched. For the producer interest, it was necessary to adjust the most uncertain and

effective parameters on such heterogeneous tight reservoir to obtain good match between observed data and simulation results. Generally, for the tight reservoir, the most valuable parameter affecting fluid movement was reservoir permeability. There were two uncertainty factors in reservoir permeability; The first factor is the input permeability data to the constructing model were derived from core data correlating of porosity and permeability, which absolutely causes an error of inaccurate percentage. The second factor is the relation between horizontal and vertical permeability input in the dynamic model. For such ultralow permeability reservoir, vertical fluid movement is controlled by the vertical to horizontal permeability ratio, which was assumed to be kv/kh=0.1. Figure-11 illustrates the results of oil production matching for each well and the field production matching with the observed production data.
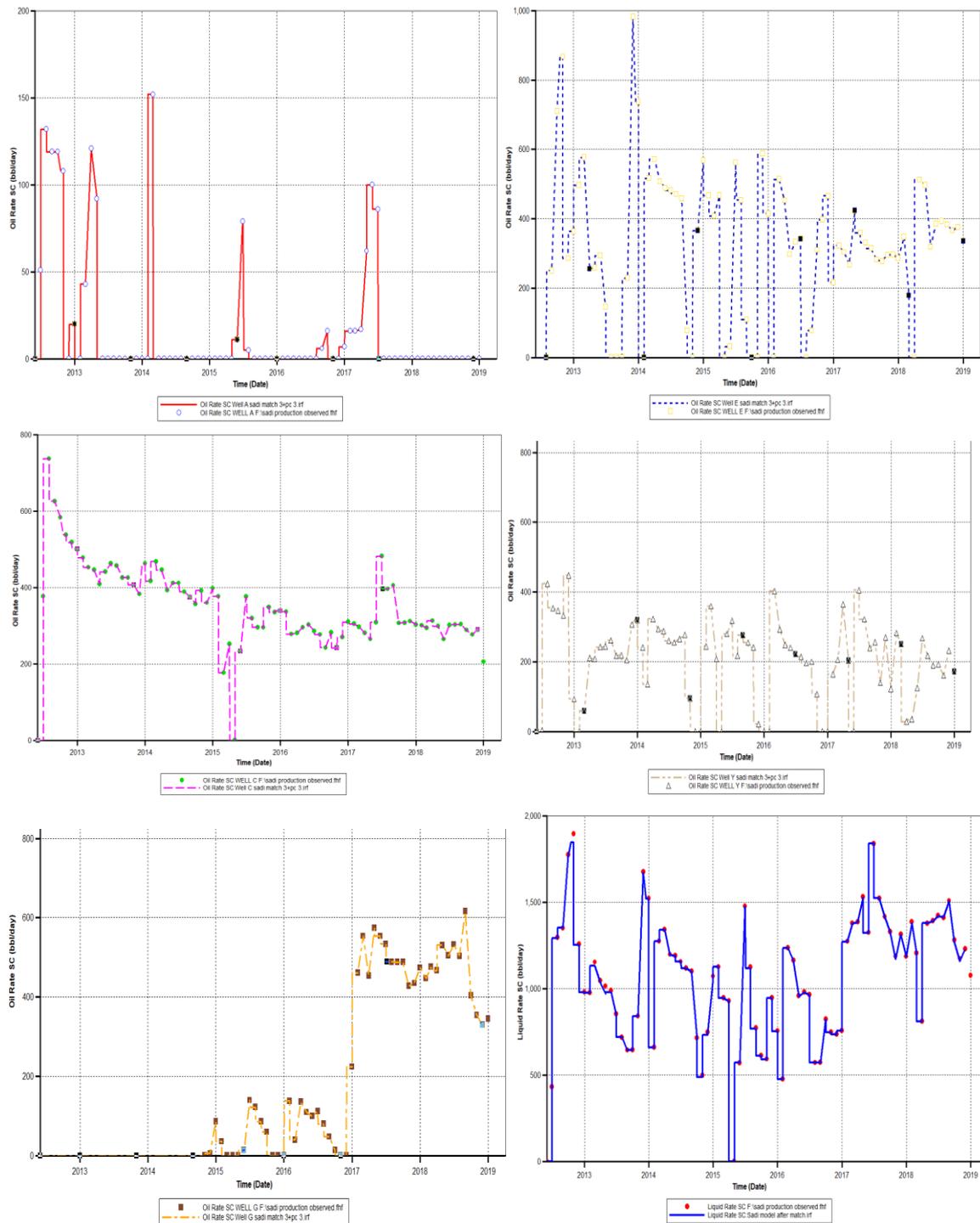
Figure 11-Field and well by well oil rate history matching.

5.3.2   Pressure History Matching

Pressure matching was conducted in the present work depending on available data of average reservoir pressure and well bottom hole pressure (BHP). These observed data should be corrected to Sadi reservoir datum depth before comparing it with pressure results from the dynamic simulation model. The matching was also achieved for individual wells and average field results. Modular Formation Dynamics Tester (MDT) pressure data were used to match average reservoir pressure results, as illustrated in Figure-12.

MDT test results indicated obviously low pressure depletion in Sadi reservoir due to its ultralow petrophysical properties. Simulation results indicated 135 psi reservoir pressure depletion within the simulation history period. The average trend of the reservoir pressure depletion obtained by the simulation dynamic model had good match with some points of MDT data.
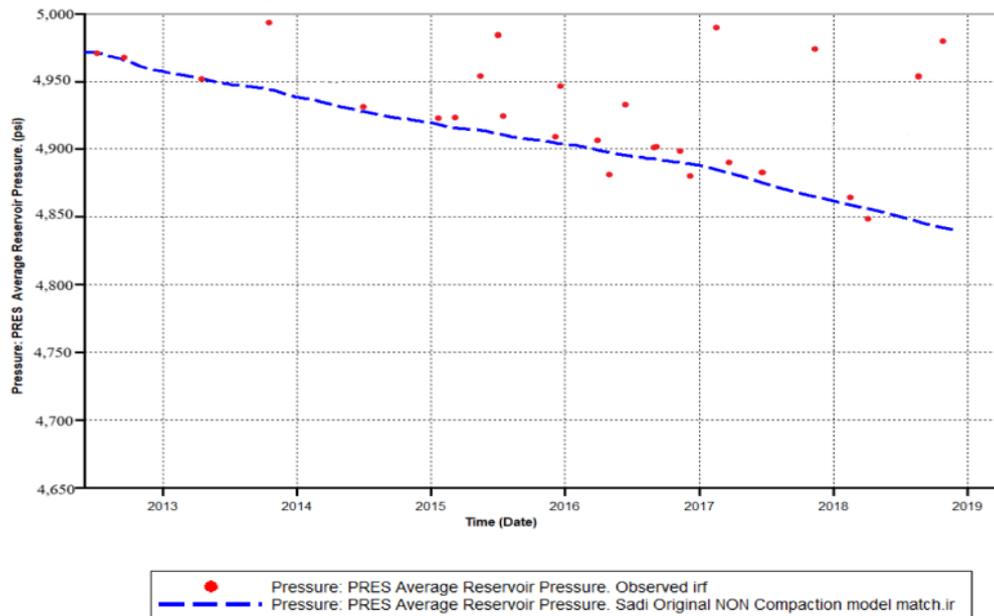
Figure 12-Average reservoir pressure history matching

The two wells, B and C, subjected to shut-in period, were used to obtain static pressure history matching. For such tight reservoir, the shut-in period must be adequately long in order to obtain correct and representative static pressure results; inadequate or short shut-in period leads to poor matching between the simulation results and observed data. The obtained results of static pressure history matching for the two wells are displayed in Figure-13.

Data of BHP recorded from the simulation results and the observed data of history matching are illustrated in Figure-14. The available observed data were limited and, thus, insufficient to determine the matching degree.
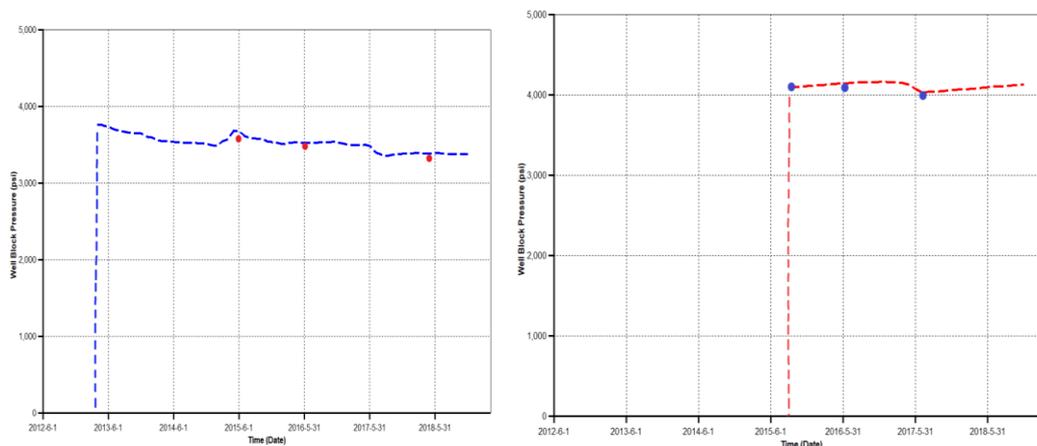
Figure 13-Static pressure history matching for wells B and C.
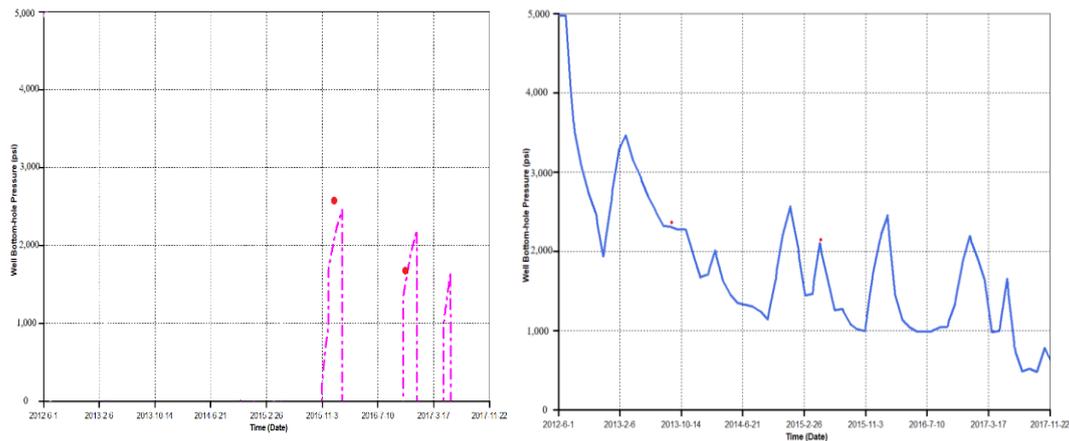
Figure 14-BHP history matching for wells B and C.

5. Model Results and Discussion

Reservoir quality (RQ) could be estimated in terms of best reservoir petrophysical properties and reserve estimation through the use of the static model. The 3-D porosity model map indicated a good porosity distribution in Sadi-B2 layer among the other Sadi/Tanuma layers, with an average value of (17%), especially on the crest of the reservoir structure. This value tends to increase toward the south east of the reservoir. This indicates high storage capacity of this layer. Low porosity values were indicated in Sadi-B1 layer (13%) and Sadi-B3 layer (12%). A very low porosity was found in Tanuma reservoir, reaching a maximum a value 0f 7%. The 3-D permeability model map indicates a good permeability region in the crest and the south west region of the reservoir in Sadi-B3 layer, reaching 3.6 md, as compared to other layers (0.5md in Sadi-B1and 0.4 md in Tanuma layers). For Sadi-B2 layer, the permeability reached 1.4 md, implying a good ability to transmit fluid within this layer. High water saturation regions appeared in Sadi-B1, Sadi-B3, and Tanuma layers, especially in the north eastern region of the reservoir, with values reaching 80%. A low water saturation region was found in Sadi-B2 layer. Porosity and permeability maps show the difficulties in using petrophysical properties in detecting favorable areas for future development plans. Areas of high porosity and low permeability can identify non-connected vugs, whereas areas of low porosity and high permeability may identify fractures.

According to the above mentioned petrophysical model results, it was difficult to detect the best area or region in Sadi/Tanuma tight reservoir. Therefore, using the net to gross 3-D map was the most useful approach in that case, since it excludes low permeability and high water saturation areas from each layer. The 3-D net to gross map revealed that Sadi-B2 and Sadi-B3 layers are of the best quality and the red regions in these layers are the most favorable to drill producing wells with a net to gross ratio reach to unity. The reservoir's simulation 3-D static model was used to estimate the initial hydrocarbon pore volume and, consequently, IOIP for each layer in Sadi/Tanuma reservoirs on the basis of the petrophysical model of oil/ water contact. The total estimated IOIP for the entire Sadi/Tanuma reservoir was 4092 MM STB, including 1448 MM STB in Sadi-B1 layer, which represents 29.37% of the total IOIP in Sadi reservoir. This is because of low porosity of this layer. IOIP was 2021 MM STB in Sadi-B2 layer, which holds the largest reserve of Sadi reservoir (58% of total IOIP). This is absolutely related to good porosity distribution within the layer. For Sadi-B3 layer, the IOIP was 495 MM STB, which represents only 13% of the total IOIP in Sadi reservoir. The IOIP in in Tanuma reservoir was 128 MM STB.

Conclusions

The 3-D static model provided a comprehensive complete evaluation of hydrocarbon reserve in the studied reservoir. The main conclusions of this study are:

• The evaluation of the formation through core samples measurement of petrophyical properties, in addition to the study of TS and SEM images, provide a good tool to correct data used in building a useful static model as a basic step for future studies.

• The petrophysical properties model provides better understanding of reservoir texture and heterogeneity.

- Care should be taken when determining the cutoff values of such heterogeneous reservoir.
- Layer Sadi-B3 has the best petrophysical properties among Sadi reservoir layers, while layer Sadi-B2 has the largest reserve in the entire Sadi reservoir.
- The porosity increases from the crest toward north east of the reservoir.
- Good permeable zones contrast in the crest toward south west of the reservoir.

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