



## **Reservoir Model and Production Strategy of Mishrif Reservoir-Nasryia Oil Field Southern Iraq**

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### **1- Abstract:**

Nasryia oil field is located about 38 Km to the north-west of Nasryia city. The field was discovered in 1975 after doing seismic by Iraqi national oil company. Mishrif formation is a carbonate rock (Limestone and Dolomite) and its thickness reach to 170m. The main reservoir is the lower Mishrif (MB) layer which has medium permeability (3.5-100) md and good porosity (10-25) %.

Form well logging interpretation, it has been confirmed the rock type of Mishrif formation as carbonate rock. A ten meter shale layer is separating the MA from MB layer. Environmental corrections had been applied on well logs to use the corrected one in the analysis. The combination of Neutron-Density porosity has been chosen for interpretation as it is close to core porosity. Archie equation had been used to calculate water saturation using corrected porosity from shale effect and Archie parameters which are determined using Picket plot.

Using core analysis with log data lead to establish equations to estimate permeability and porosity for non-cored wells. Water saturation form Archie was used to determine the oil-water contact which is very important in oil in place calculation. PVT software was used to choose the best fit PVT correlation that describes reservoir PVT properties which will be used in reservoir and well modeling.

Numerical software was used to generate reservoir model using all geological and petrophysical properties. Using production data to do history matching and determine the aquifer affect as weak water drive. Reservoir model calculate 6.9 MMMSTB of oil as

initial oil in place, this value is very close to that measured by Chevron study on same reservoir which was 7.1 MMMSTB. [1]

Field production strategy had been applied to predict the reservoir behavior and production rate for 34 years. The development strategy used water injection to support reservoir pressure and to improve oil recovery. The result shows that the reservoir has the ability to produce oil at apparently stable rate equal to 85 Kbb/d, also the recovery factor is about 14%.

### موديل مكمني و خطة انتاج مستقبلية لمكمن المشرف-حقل الناصرية النفطي جنوب العراق

#### الخلاصة:

يقع حقل الناصرية النفطي الى 38 كيلومتر شمال غرب مدينة الناصرية. تم اكتشاف الحقل سنة 1975 بواسطة المسح الزلزالي من قبل شركة النفط الوطنية العراقية. طبقة المشرف تتكون من صخور كلسية و بسمك حوالي 170 متر. المكمن الرئيسي لطبقة المشرف هو تكوين المشرف الاسفل ذي المواصفات المعتدلة كالنفاذية تتراوح (3-100) ملي دارسي و المسامية (10-25)%.

من تفسير مجسات الابار تم التوصل الى نفس نوعية الصخور لمكمن المشرف و المستحصل من اللباب الصخري و هي عبارة عن صخور كلسية. من خلال التفسير تم تاكيد وجود طبقة سجل بسمك 10 متر تفصل المشرف الاعلى MA عن المشرف الاسفل MB. للحصول على قراءات صحيحة للمجسات تم تطبيق التصحيحات الخاصة بحالة البئر و الضغط و الحرارة و نوع طين الحفر. اختيار النفاذية المستحصلة من معدل النفاذية من جهاز الكثافة و جهاز النيوترون بالحسابات بسبب تقاربها مع قيم النفاذية المستحصلة من اللباب الصخري. حساب التشبع المائي باستخدام معادلة ارجي و التي تعتمد على النفاذية المصححة من كميات السجيل و متغيرات ارجي التي تم استحصالها بواسطة طريقة رسم بكيت (Picket plot).

ان استخدام المسامية و النفاذية المستحصلة من اللباب قاد للحصول على علاقات يمكن من خلالها الوصول الى قيم المسامية و النفاذية للابار التي لا تمتلك لباب صخري. تم استخدام التشبع المائي المستحصل من معادلة ارجي لغرض تحديد عمق تماس النفط مع الماء نظرا لاهمية هذا العمق في تحديد كمية الاحتياطي النفطي. استخدم برنامج خاص لمواصفات الموائع بالاعتماد على القياسات المختبرية لبعض الابار لغرض الوصول الى علاقات عامة تصف هذه المواصفات للمكمن لغرض استعمالها في الموديل المكمني وتصميم الابار.

تم استخدام برنامج محاكي (Rubis) لغرض عمل موديل مكمني باستعمال البيانات الجيولوجيا و البتروفيزيائية. بواسطة البيانات الانتاجية للحقل تم الوصول الى التمثيل الاقرب للحقيقي في سلوك المكمن اثناء الانتاج و الذي اثبت وجود مستودع مائي ضعيف. قدر الاحتياطي النفطي بحوالي 6.9 مليار برميل و الذي يكون قريباً للتقديرات

المستحصلة من الدراسات السابقة للحقل كما في دراسة شركة شفرن حيث كان احتياطي النفط المحسوب 7.1 مليار برميل.

تم تطبيق استراتيجية انتاج و التنبؤ بظروف المكنن و مقدار الانتاج الكلي للحقل لمدة 34 سنة. استخدم طريقة حقن الماء للحفاظ على ضغط المكنن عند مستويات تمكن المكنن من الانتاج و لزيادة عامل الاستخلاص النفطي. اظهرت النتائج امكانية المكنن للانتاج بصورة مستقرة نسبيا عند معدل انتاج 85 الف برميل/يوم و بمعامل استخلاص يصل الى 14%.

## **2- Introduction:**

Geological Model “Static Modeling” is the first and the most important stage in the reservoir modeling process. In this step the model will be created to meet all structural, stratigraphically and petrophysical features.

The data from seismic, drilled well formation tops, well logging and cores are used to define the reservoir tops, thickness, porosity, water saturation and net to gross maps. As there is more and more data, the model structural and stratigraphically maps will be more accurate and as a result the model will be highly effective especially on original oil in place (OOIP) calculations.

The model should be fed with the required data to build the Dynamic Model with the dynamic data such as Pressure-Volume-Temperature (PVT) properties, special core analysis (SCAL), production data and pressure. At the end, the model will be initialized to calculate OOIP and if it is accepted, the model will be simulated for a certain time as a history match with actual production data to approve the dynamic performance of the model is true as actual reservoir. [2]

## **3- Area of Study:**

Nassriya oil field is located about 38km in the North-West of Nassriya city. The field is discovered in 1975 after applying seismic technology by Iraqi National Oil Company. The field dimensions are about 34 Km long and 13 Km width in the direction of North-West to South-East, the trap is anticline. [3]

Lower Mishrif is considering as the main pay zone due to its good rock properties such as:

1. Good porosity: (9-24) % for MB1 and (21-26.2) % for MB2 according to core analysis and well logs measurement.

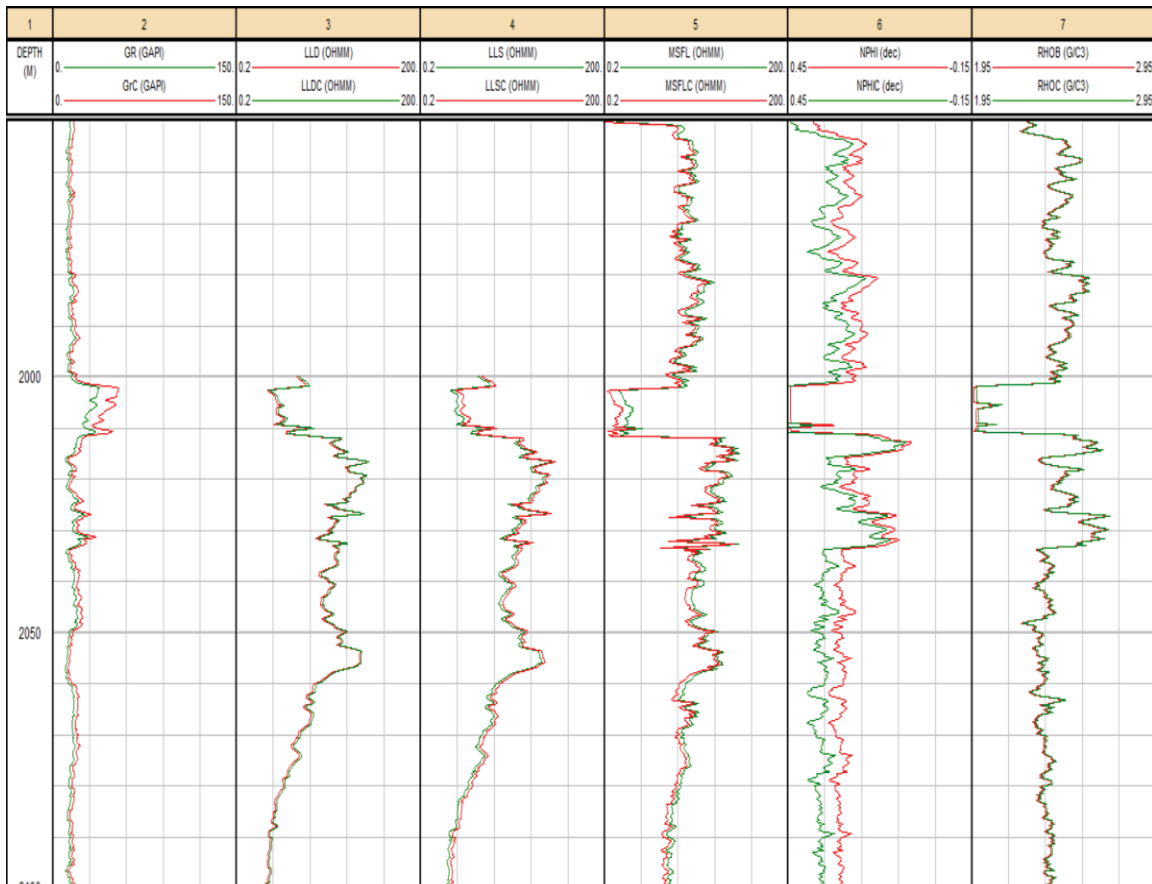
2. Medium permeability: (3.5-100) md for both MB1 and MB2 according to core analysis and mathematical correlations.

**4- Well logging Interpretation:**

Well logging software (Interactive Petrophysics V3.5) was used to analysis the well logs for ten wells available in this study.

**i. Environmental corrections of Well Logs**

Schlumberger Environmental Corrections had been applied for used well logs as most of these well logs had been recorded by Schlumberger Co. Figure (1) is the environmental corrections for well NS-1. The temperature curve is created using temperature gradient method. [4] & [5]



**Fig. (1) NS-1 Logs Environmental Corrections.**

**ii. Determination of formation Water Resistivity**

From water sampling laboratory report, the concentration of pure NaCl in well NS-2 is 190788 ppm, so this NaCl value will be used as a fixed salinity for all Mishrif reservoirs. Equation (1) is used to calculate  $R_w$  @ 75°F which equal to 0.0455 ohm meter using NaCl in ppm. then, it is corrected to the bottom hole temperature by using equation (2). Table (1) presents  $R_w$  values for all the studied wells. [6]

$$R_{w75} = \frac{1}{2.74 \times 10^{-4} \times CP^{0.955}} + 0.0123 \dots\dots\dots(1)$$

$$R_{wf_m} = R_{w75} * \frac{81.77}{T_f + 6.77} \dots\dots\dots(2)$$

Where,

$R_{w75}$  : Resistivity of Formation water at surface temperature 75°F, Ω.m

$R_{wf_m}$  : Resistivity of Formation water @ reservoir temperature, Ω.m

CP: Saturation of NaCl, ppm.

**Table (1)  $R_w$  and  $R_{mf}$  at a given temperature.**

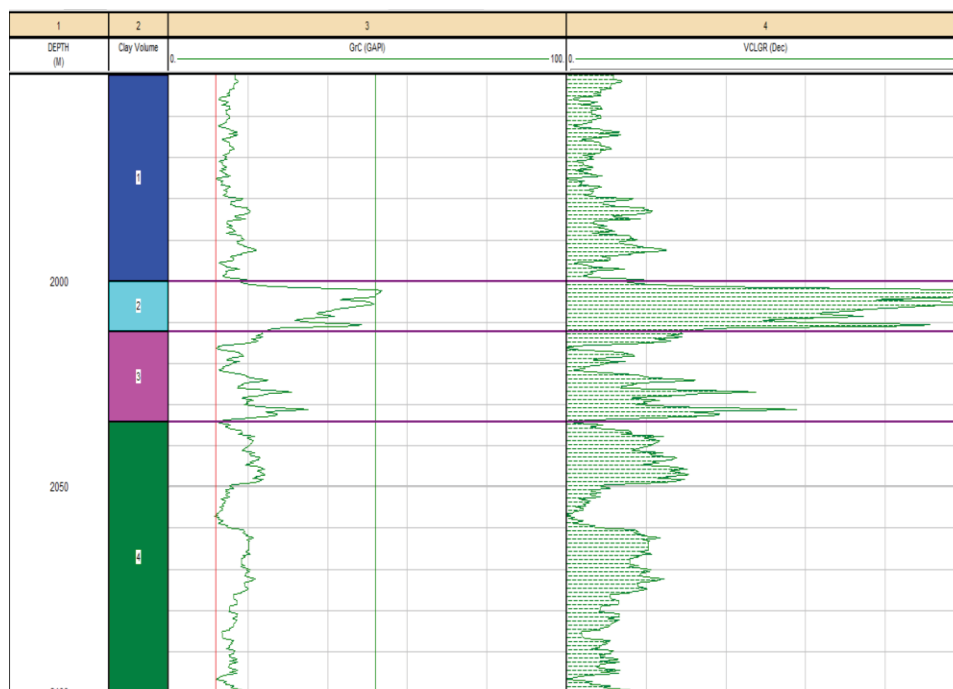
Well No.	$R_w$ @ BHT °F	$R_{mf}$ @ given Temp. °F
1	0.02 @ 185°F	0.202 @ 56°F
2	0.0195 @ 190°F	0.199 @ 75°F
3	0.0205 @ 175°F	0.282 @ 60°F
4	0.022 @ 160°F	0.269 @ 70°F
5	0.020 @ 165°F	0.58 @ 64°F
6	0.026 @ 140°F	0.83 @ 71°F
9	0.022 @ 160°F	0.202 @ 56°F
18	0.022 @ 160°F	0.58 @ 64°F
19	0.022 @ 160°F	0.202 @ 56°F
23	0.022 @ 160°F	0.282 @ 60°F

**iii. Shale volume Estimation**

As the shale rock is pours but it has no permeability so it will not consider as reservoir and because of that shale volume should be eliminate from total volume and reservoir thickness

calculation. There is more than one method to eliminate shale volume from porosity calculation but the most used one is Gamma Ray method which will be used in this study. [7]

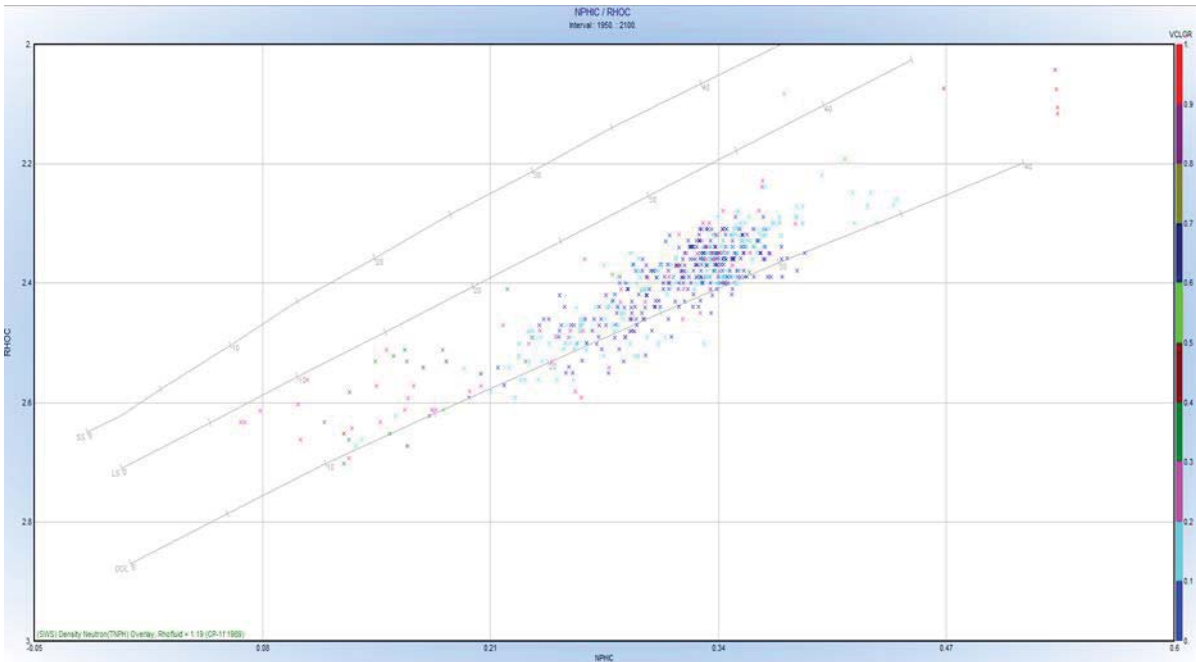
Figure (2) shows the shale volume in well NS-1. It is clear that there is a shale layer reaching up to (10) m that separates the MA unit from MB unit of Mishrif Formation in Nasiriya oil field.



**Fig. (2) NS-1 Shale Volume Calculation.**

#### **iv. Lithology Identification**

Neutron-density cross plot is used for lithology evaluation. The cross plots for studied wells show that most of points located between Limestone and Dolomite lines. This approved as core data that Mishrif formation is a carbonate reservoir mixture of limestone and dolomite as shown in Figure (3).



**Fig. (3) NS-1 Lithology Identification Plot**

**v. Porosity Estimation**

It is the most important reservoir properties which reflect the reservoir storage capacity and has direct effect on recovery factor. To get the actual effected porosity from the total measured porosity. There are many corrections but the most important is correct the porosity to shale volume effect using neutron porosity and density porosity as shown in equations (3) and (4) [7].

$$\phi_t = \frac{\phi_N + \phi_D}{2} \dots \dots \dots (3)$$

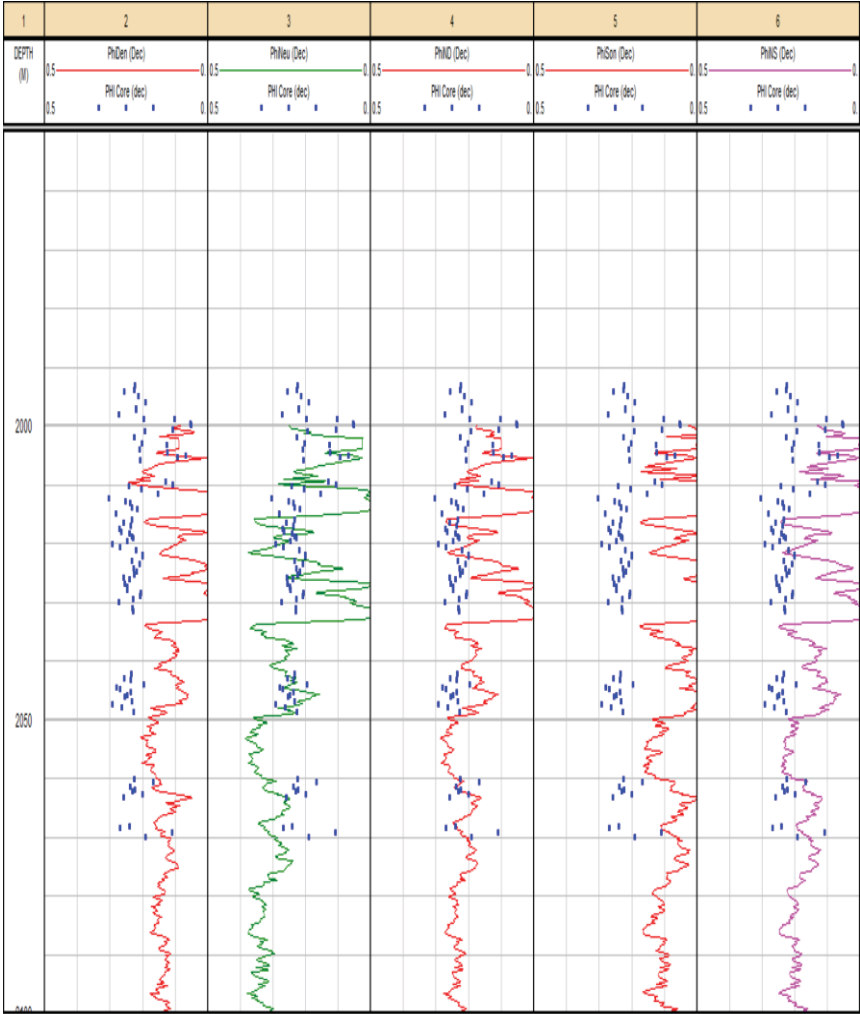
$$\phi_e = \phi_t * (1 - V_{sh}) \dots \dots \dots (4)$$

Where:

- $\phi_t$ : Total Porosity, %.
- $\phi_e$ : Effective Porosity, %
- $\phi_N$ : Neutron Porosity, %.
- $\phi_D$ : Density Porosity, %.

The measured porosity from well logging such as sonic log, density log, neutron log and neutron-density averaging log are compared with the core porosity values for cored wells.

The neutron-density porosity gives closest values with the core porosity for most of studied wells among other derived porosities as shown in Figure (4). The calculated (N-D) porosity is then applied to determine the total and effective porosity which is used to calculate reservoir net pay thickness after corrects it for shale effect by using equations (3 and 4).



**Fig. (4) NS-1 Porosity Logs with Porosity Core.**

**vi. Estimation of Archie’s Parameters for Sw Calculation**

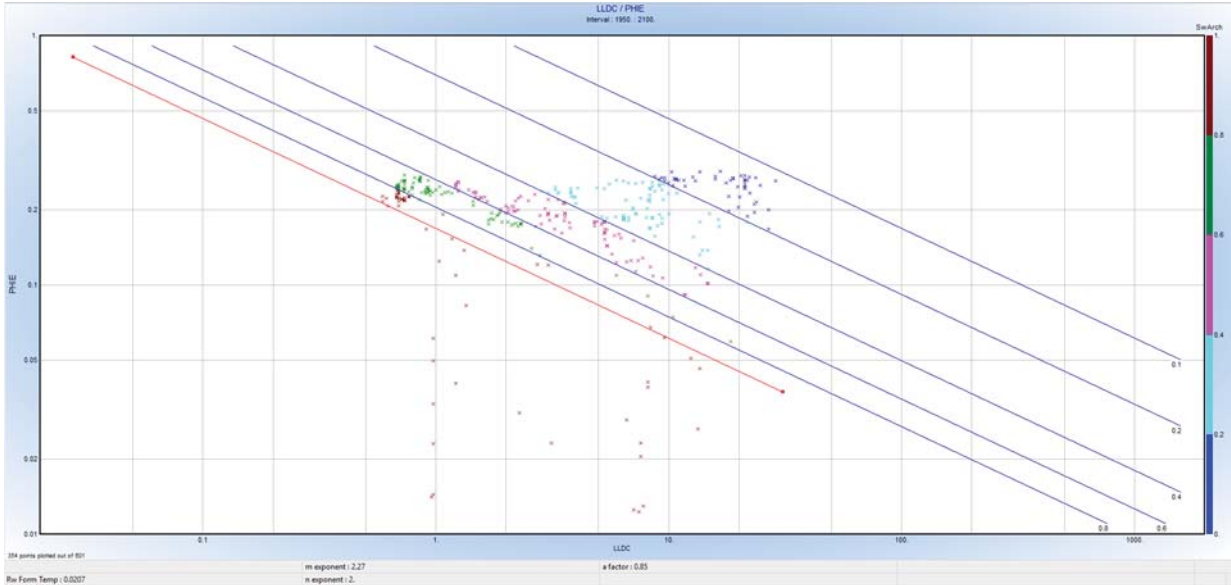
Saturation of water in the reservoir could be determined using Archie’s equation (5). As rock parameters depend on carbonate properties of the rock and heterogeneities of carbonate reservoir, the applying of the equation will be relatively hard. It had been noticed that the saturation of water is more effecting on Archie’s parameter than the resistivity (Rt & Rw) [8].



$$S_w^n = \frac{a}{\phi^m} * \frac{R_w}{R_t} \dots\dots\dots(5)$$

Pickett’s method is used to determine Archie’s. Figure (5) represent Pickett’s plot method and Table (2) shows Archie’s parameters for all the studied wells.

As Mishrif reservoir is a carbonate (Limestone and Dolomite), so **a** and **n** parameter will be used to be 0.85 and 2 respectively while **m** parameter is normally from 1.8 to 2.5 depending on connected which is normally found in carbonate rock [9].



**Fig. (5) NS-1 Picket Plot.**

**Table (2) Archie’s Parameters.**

Well No.	a	m	n
NS-1	0.85	2.27	2
NS-2	----	----	----
NS-3	0.85	2.17	2
NS-4	0.85	2.12	2
NS-5	0.85	2.27	2
NS-6	0.85	1.82	2
NS-9	0.85	2.14	2
NS-18	0.85	2.24	2
NS-19	0.85	2.19	2
NS-23	0.85	2.26	2

**vii. Fluid Analysis**

To calculate water saturation in Mishrif reservoir / Nassriya Oil Field, Archie equation (5) had been used in un-invaded zone by it OOIP could be determine. Another important parameter is  $S_{xo}$ , calculated by equation (6), is used to calculate movable hydrocarbon.

$$S_w^n = \frac{a}{\phi^m} * \frac{R_w}{R_t} \dots\dots\dots(5)$$

$$S_{xo}^n = \frac{a}{\phi^m} * \frac{R_{mf}}{R_{xo}} \dots\dots\dots(6)$$

Estimation of flushed zone water saturation and then determine the ratio  $S_w/S_{xo}$  is very useful to identify movable hydrocarbon. No moveable hydrocarbon indication when  $S_w/S_{xo}$  equal to 1. An indication of movable hydrocarbon in place could be shown when  $S_w/S_{xo}$  is equal or less than 0.7 [10].

**viii. Bulk Volume Analysis**

The volume of rock porous media which filled with water is known as water bulk volume. The hydrocarbon bulk volume is the porous volume filled with hydrocarbon [4]

$$BVW = S_w * \phi_e \dots\dots\dots(7)$$

$$BVWS_{xo} = S_{xo} * \phi_e \dots\dots\dots(8)$$

The movable hydrocarbon bulk volume as:

$$BV_{mo} = (S_{xo} - S_w) * \phi_e \dots\dots\dots(9)$$

The final set of evaluated logs interpretation such as saturation, porosity, fluid and matrix evaluation tracks are known as computer processed interpretation (CPI). CPI results of the studied formation indicate that the most of the movable hydrocarbon is located in the MB1 unit and in the upper part of MB2 unit. MA unit is almost water zone. A thick shale unit (about 10 m) separates the two main units MA &MB. Figure (6) represent (CPI) for the well NS-9.

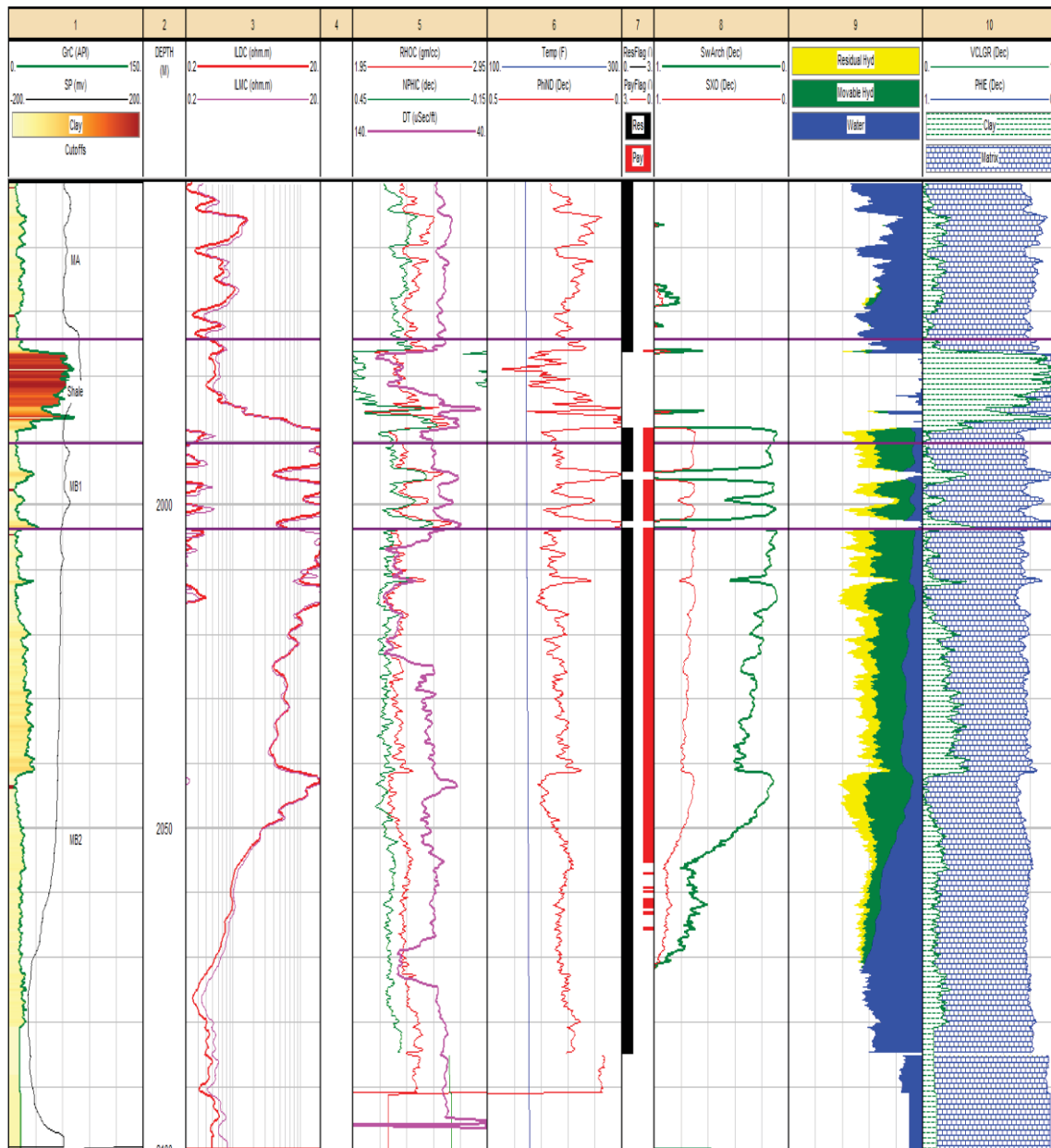


Fig. (6) NS-9 CPI Plot.

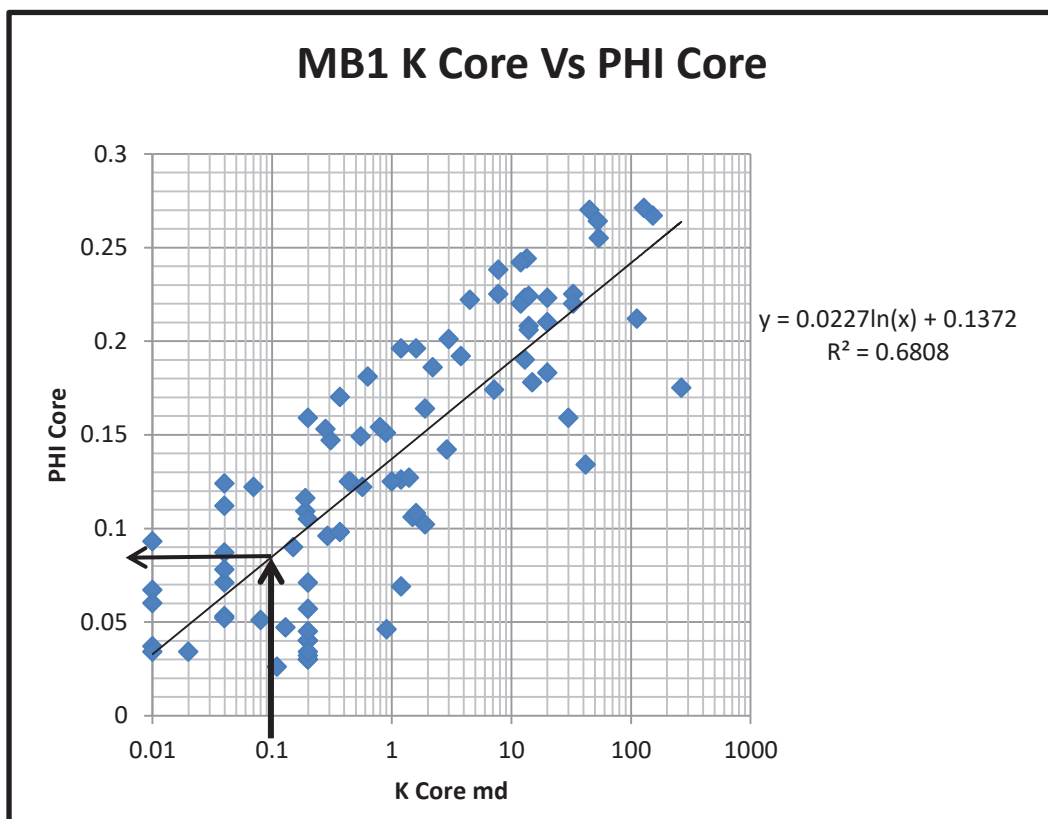
**5- Permeability Estimation:**

The accurate procedure to measure the permeability is Lab measurement by using cores from drilled wells. It was found that no all drilled wells are cored due to high cost so correlations depended on porosity measurement from wire line is used to find permeability for non-cored wells.

In this study there are only three cored well which are NS-1, NS-2 and NS-3. For each layer of MB1 and MB2 drawing of core porosity on linear scale with core permeability in Log scale is established to first find the cut-off for porosity when permeability equal to 0.1md and second to find a relationship between porosity and permeability for each layer as shown in Figures (7) and (8).

Porosity cut off for MB1 equal to 8.5% and for MB2 equal to 10%. An average cut-off equal to 9% porosity unit was used in CPI to determine reservoir net pay thicknesses.

Another required approach is to find relationship between porosity from cores and porosity from log as shown in Figures (9) and (10). This correlation is used to convert the log porosity of non-cored wells to its equivalent of porosity core then it used to find permeability as explain previously.



**Fig. (7) MB1 Core Permeability Vs Core Porosity.**

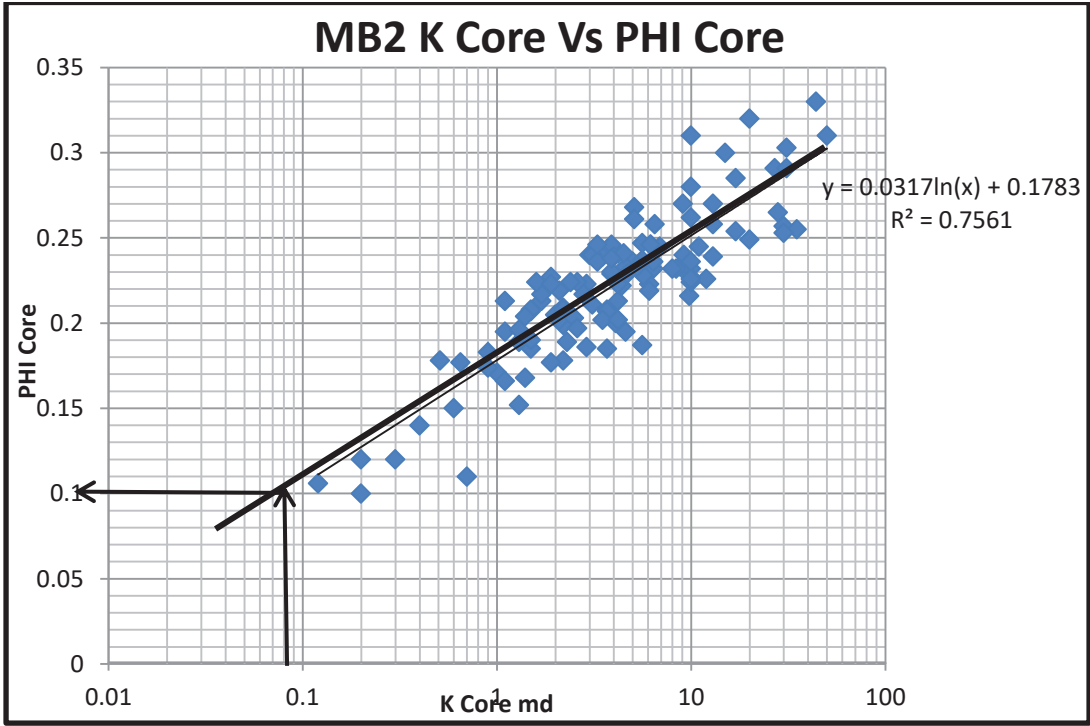


Fig. (8) MB2 Core Permeability Vs Core Porosity.

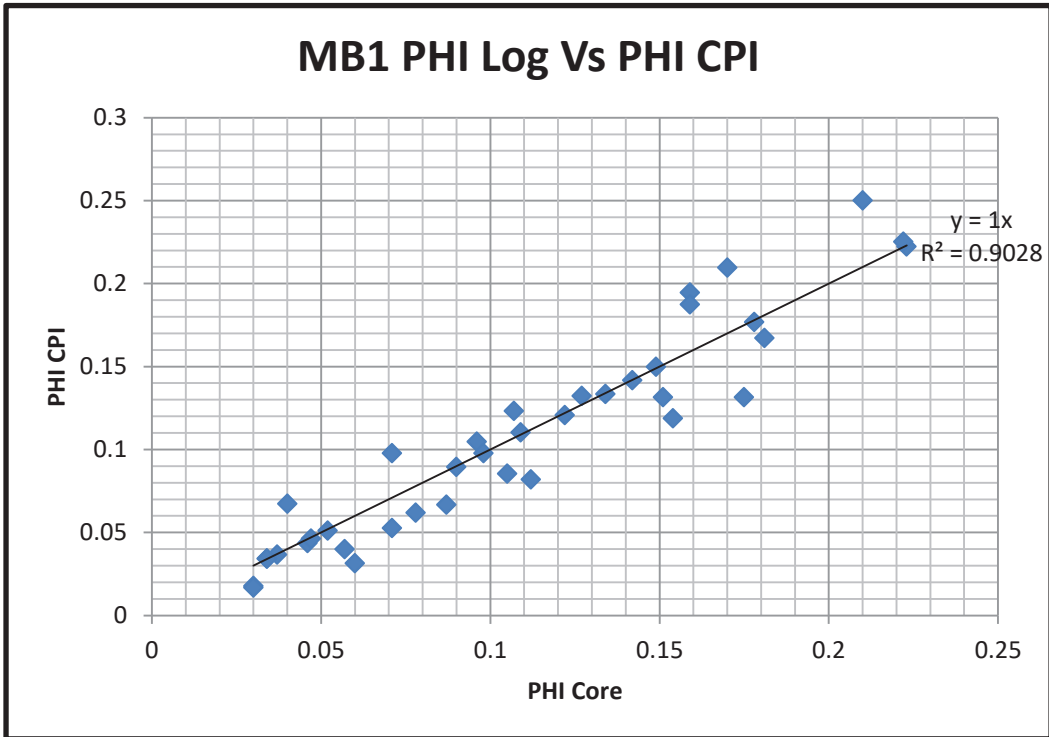


Fig. (9) MB1 Core Porosity Vs Log Porosity.

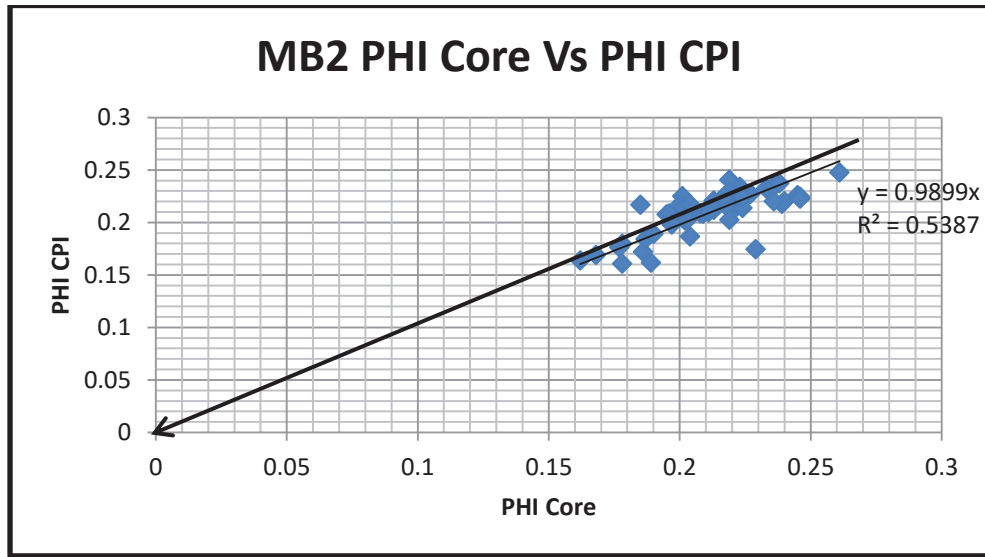


Fig. (10) MB2 Core Porosity Vs Log Porosity.

**6- Oil Water Contact and Water Saturation Cut off:**

OWC depth is very effective parameter on calculation of original oil in place. The water saturation which is determined from well logging for each well had been drawn with depth and an average depth 2070m was chosen to be used in reservoir model as shown in Figure (11).

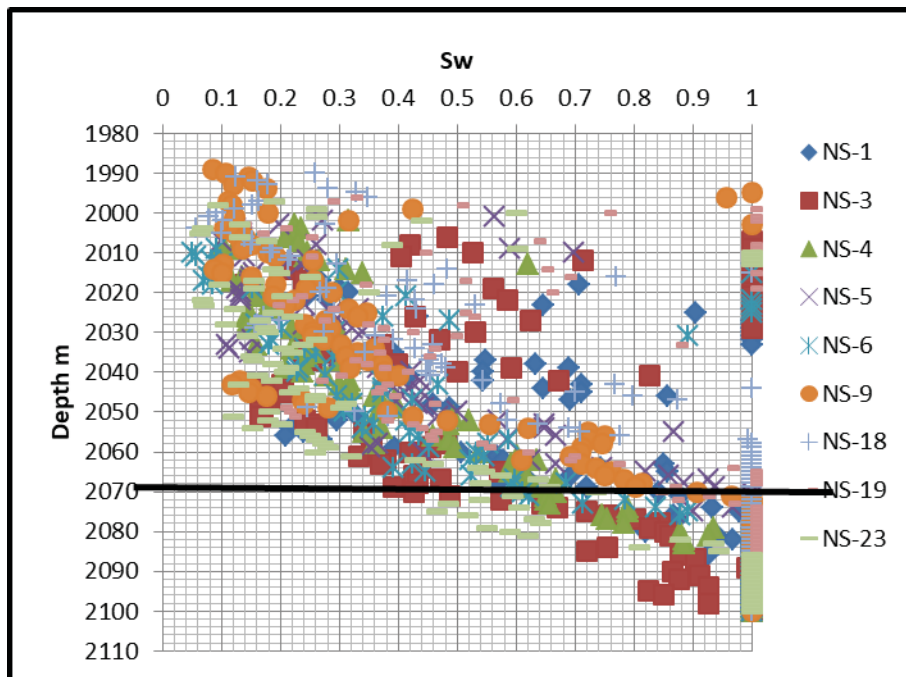
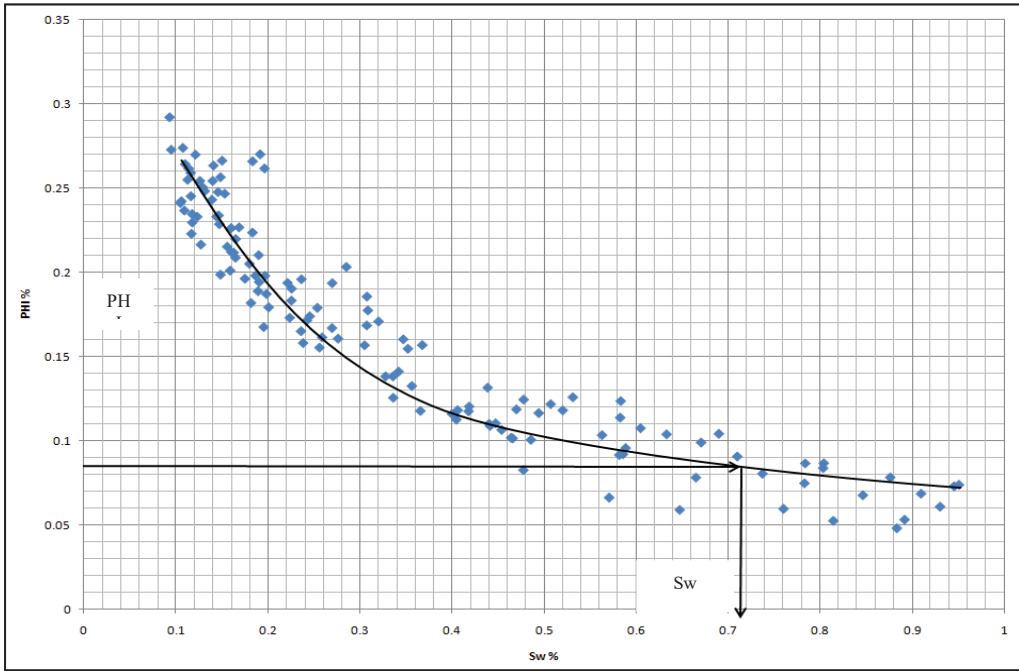
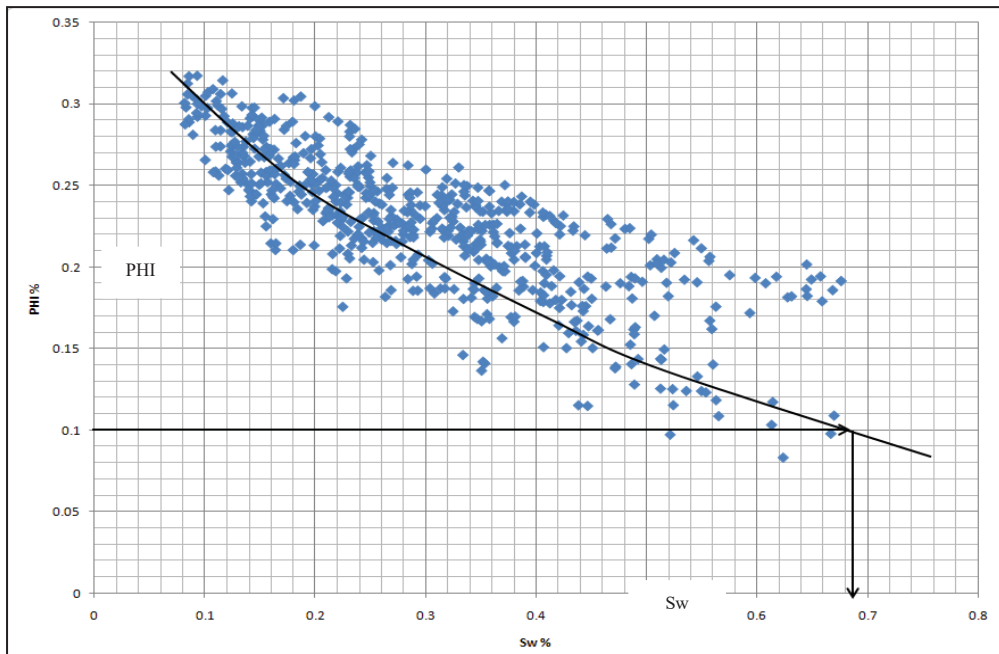


Fig. (11) Depth Vs Water Saturation.

To find water saturation cut off, a plot between porosity and water saturation is used and depending on porosity cut off, the value of water saturation cut off could be found. Figure (12) shows water saturation cut off of MB1 layer which is about 0.71 %.



**Fig. (12) MB1 Log Porosity Vs Water Saturation.**



**Fig. (13) MB2 Log Porosity Vs Water Saturation.**

Figure (13) shows water saturation cut off of MB2 layer which is about 0.68 %.

In CPI an average value of 70% water saturation was used as cut-off for both MB1 and MB2 layers to calculate net pay thickness.

Table (3) contains well No. of layers thicknesses, average porosity, average permeability and net to gross for each MB1 and MB2 layer.

**Table (3) Wells Information.**

Well No.	MB1				MB2			
	Thickness m	Av. PHI	Av. K md	N/G	Thickness m	Av. PHI	Av.K md	N/G
1	22	0.23	74.46	0.406	76	0.276	23.894	0.442
3	24.5	0.155	2.191	0.357	70	0.215	3.418	0.603
4	15.5	0.188	9.382	0.983	89.5	0.241	7.83	0.684
5	24	0.242	101.37	0.979	76	0.229	5.347	0.502
6	18	0.201	16.64	0.808	85	0.18	1.123	0.589
9	13	0.211	25.855	0.807	80	0.243	8.18	0.562
18	27	0.208	22.65	0.929	73	0.219	3.889	0.41
19	23	0.143	1.291	0.49	74	0.19	1.54	0.518
23	24	0.204	18.992	0.822	78	0.235	6.48	0.745

### **7- PVT Properties:**

PVT reports of four wells are available on this study. A PVT software (PVTp) was used to get all required PVT properties using the best correlation which matching the actual PVT from reports. Second step is to calculate wells' PVT properties at one reference temperature equal to 75 °C as shown in Table (4). Then an average of the PVT properties was used in reservoir model and well model.

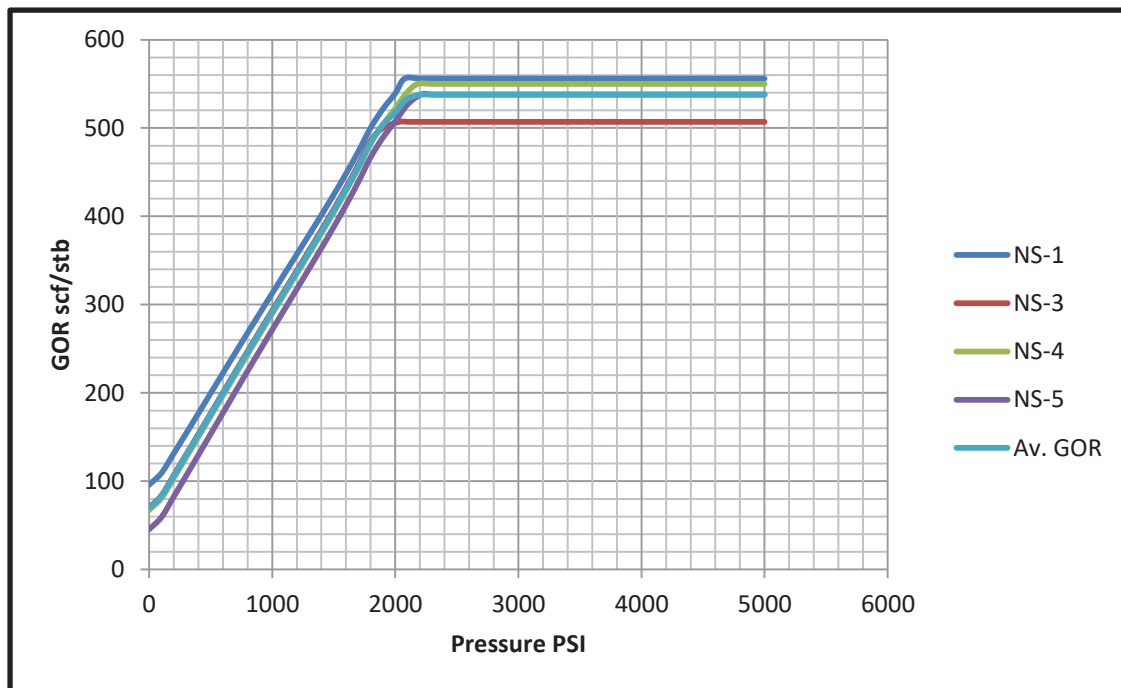


**Table (4) Wells PVT Correlation Matched.**

Well No.	Pb, Rs and Bo	Viscosity
1	Laster	Petrosky
3	Laster	Beggs
4	Laster	Petrosky
5	Laster	Petrosky

Laster and Petrosky correlations had been used to define Field PVT average properties as it describe PVT properties of the most of wells.

The following figures show the wells and average PVT properties.

**Fig. (14) GOR of Mishrif Reservoir.**

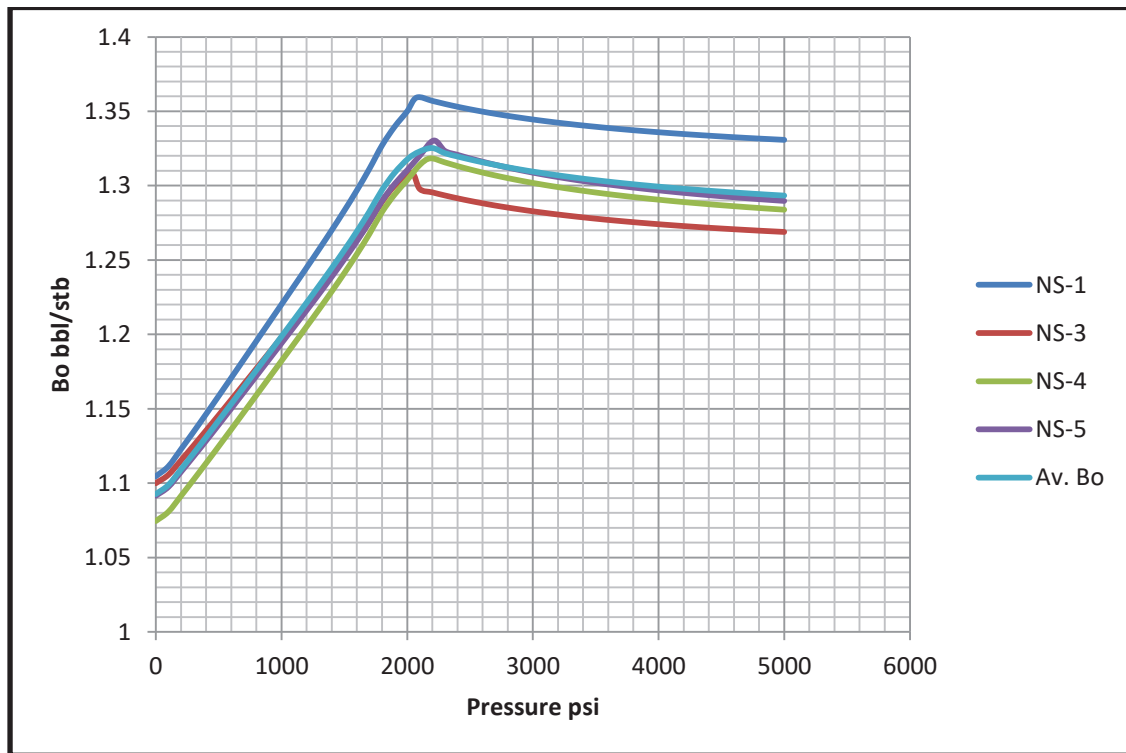


Figure (15) Bo of Mishrif Reservoir.

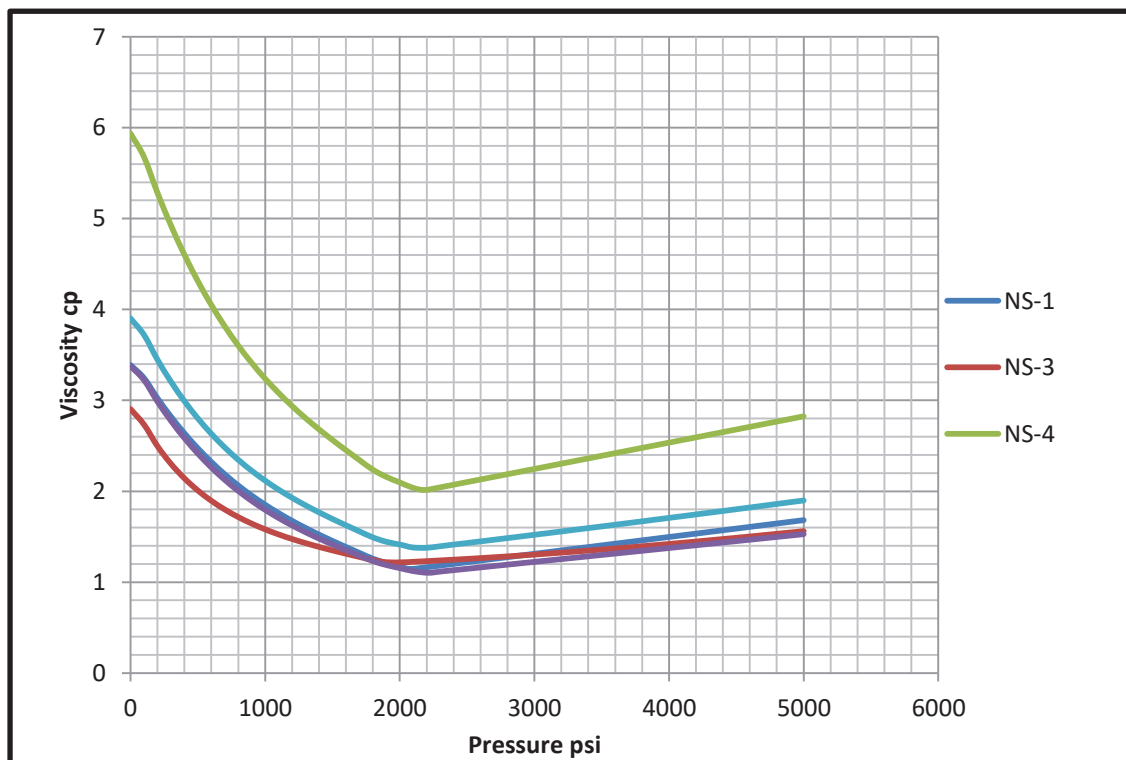


Fig. (16) Oil Viscosity of Mishrif Reservoir.

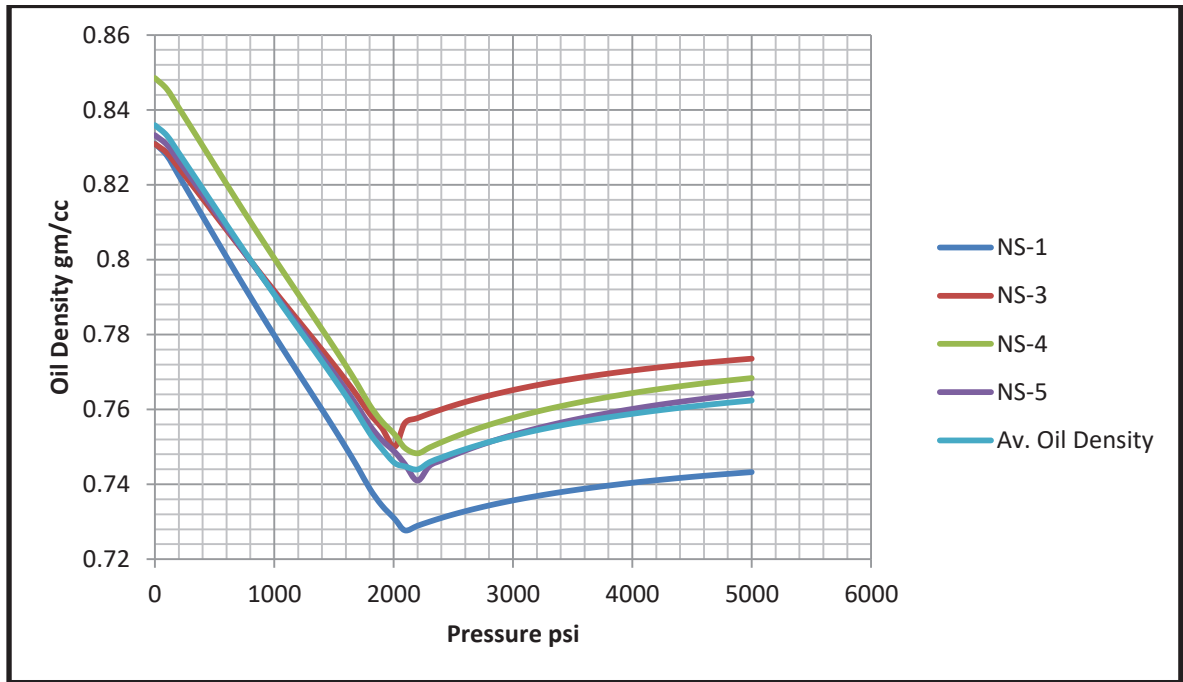


Fig. (17) Oil Density of Mishrif Reservoir.

**8- Capillary Pressure, Relative Permeability and Rock Compressibility:**

Special core analysis is taken from a previews study. Figure (18) reflects relationship between Sw and Kro, Krw and Pc. Rock compressibility is equal to  $4.5 \times 10^{-5} \text{ bar}^{-1}$  at a reference pressure of 252 bar. [3]

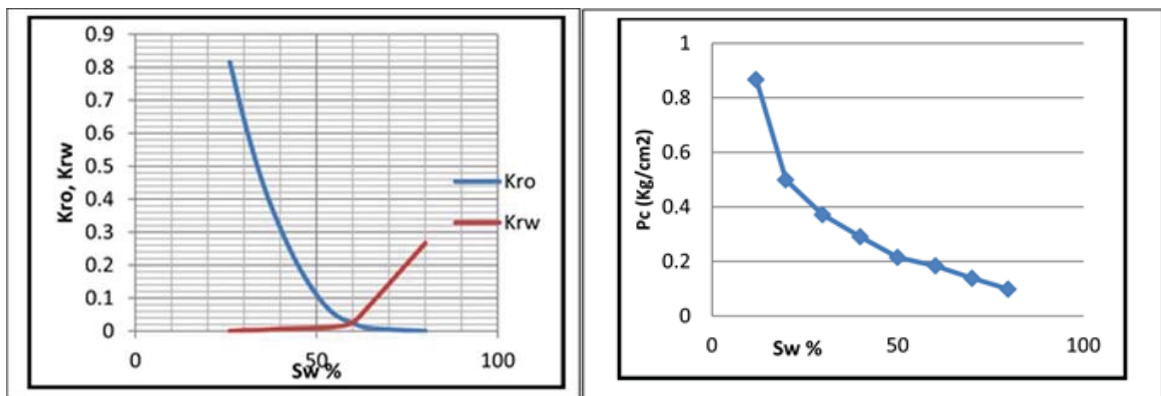


Fig. (18) Sw vs. Pc and Sw vs. Kro, Krw plots.

### **9- Reservoir Physical Model:**

Geological Model “Static Modeling” is the first and the most important stage in the reservoir modeling process. In this step the model will be created to meet all structural, stratigraphically and petrophysical features.

The data from seismic, drilled well formation tops, well logging and cores are used to define the reservoir tops, thickness, porosity, water saturation and net to gross maps. As more input data are used, the structural model and stratigraphical maps will be more accurate and it will be highly effective on model results especially on original oil in place (OOIP).

Permeability maps will be depending on both actual permeability from core data and correlations which are mainly based on log porosity for wells.

After that, the model will be fed with the dynamic measurements like PVT properties, special laboratory core analysis reports (SCAL), Production data, Pressure values and relative permeability.

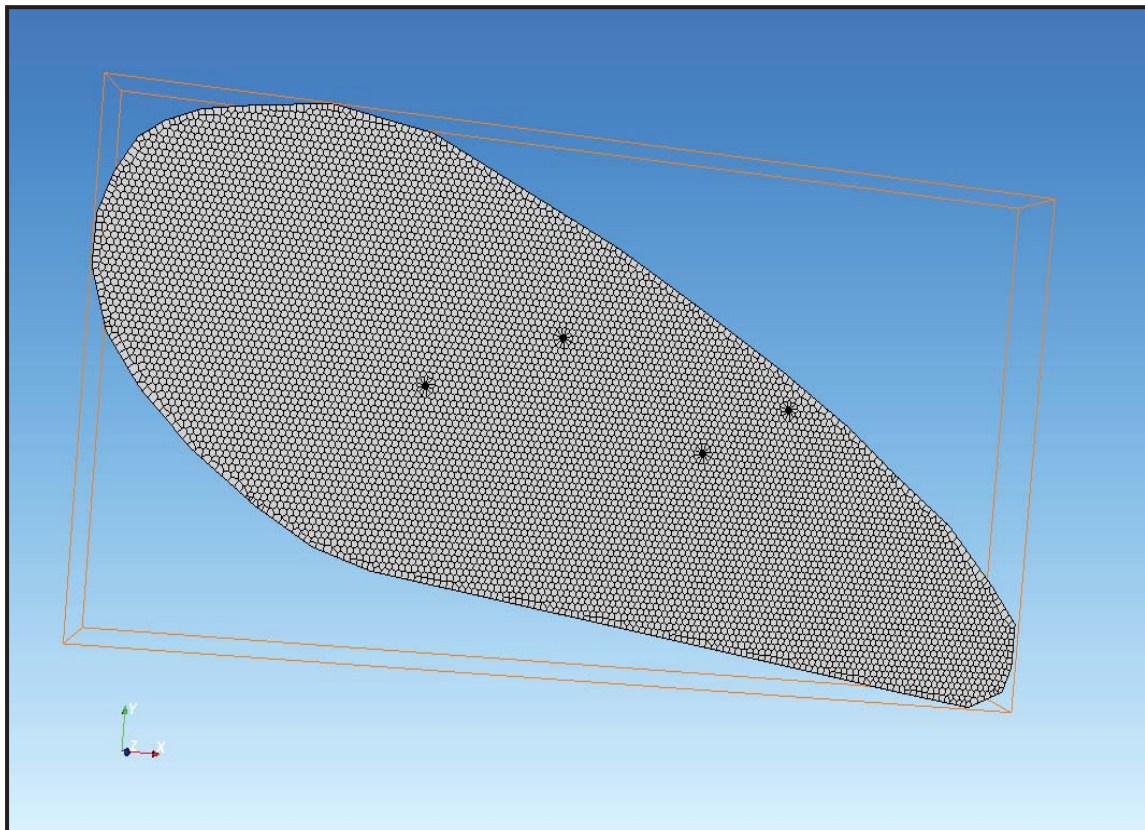
At the end, the model will be initialized to calculate OOIP and if it is accepted, the model will be run for a certain time as a history match with actual production data to approve the dynamic performance of the model is true as actual reservoir.

Reservoir simulator (Rubis-KAPPA Workstation 5.20) was used to create reservoir model (static and dynamic) after fed it with all required data.

By using MB1 layer of Mishrif reservoir the extensions of the field was known and then the boundary of the field was established as non-flow boundary from all directions. After many time of choosing different scenarios to fit the history match, the bottom boundary condition set to has small aquifer and its volume equal to the volume of the reservoir. The aquifer model was chosen to be as numerical aquifer.

### **10- Reservoir Grid System:**

Hexagonal cell with optimal well up scaling were used to define grid system for the reservoir in this study. The Hexagonal cell is more accurate than square or rectangular cell which they have six connections with surrounding cells. On the other hand, the Hexagonal cell has eight connections with the surrounding cells which increase the accuracy of pressure drop and fluid movement prediction. The disadvantage of using Hexagonal cell is that the software needs more time and high computer efficiency for reservoir performance prediction. The total cells which had been used in the simulator model are about 200,000 cells, 27 cells in Z-direction and 7400 cells in X-Y directions. Figures (19) and (20) show the grid system of reservoir model.

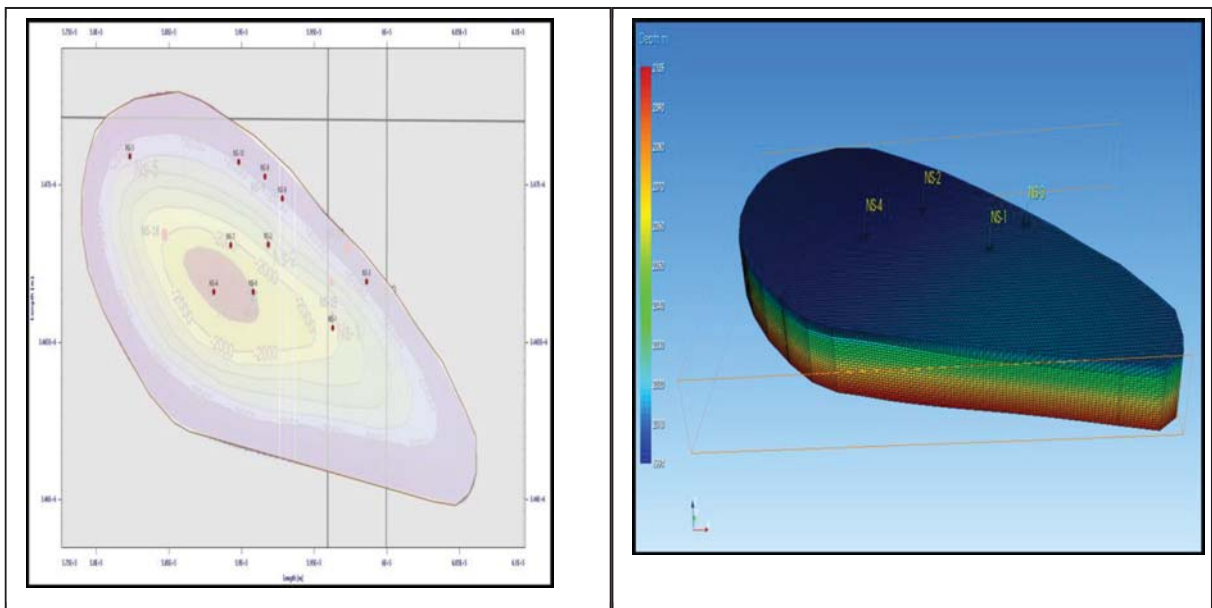


**Fig. (19) Reservoir model grid system**



**Fig. (20) Reservoir model grids shape**

Figure (21) shows MB1 top map and Mishrif reservoir grid system.



**Fig (21) MB1 top map and Mishrif reservoir grid system**

By using the data from well cores, well loges and CPI interpretation the simulator software is able to generate maps for Porosity Figure (22), Permeability Figure (23) and Net to Gross Figure (24).

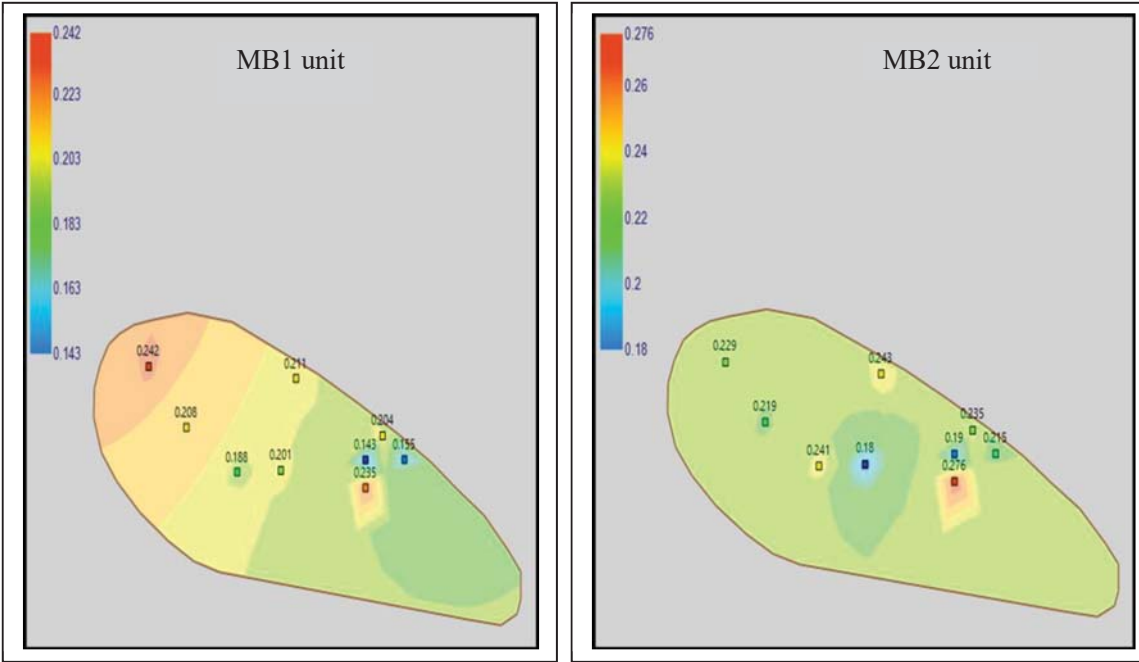


Fig. (22) Porosity maps

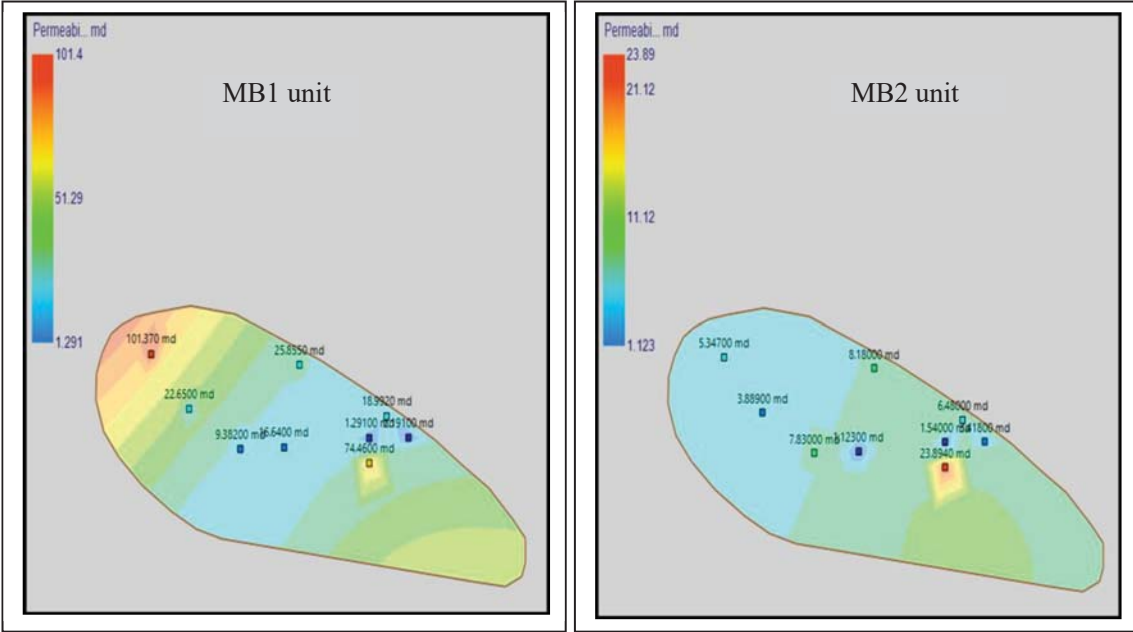
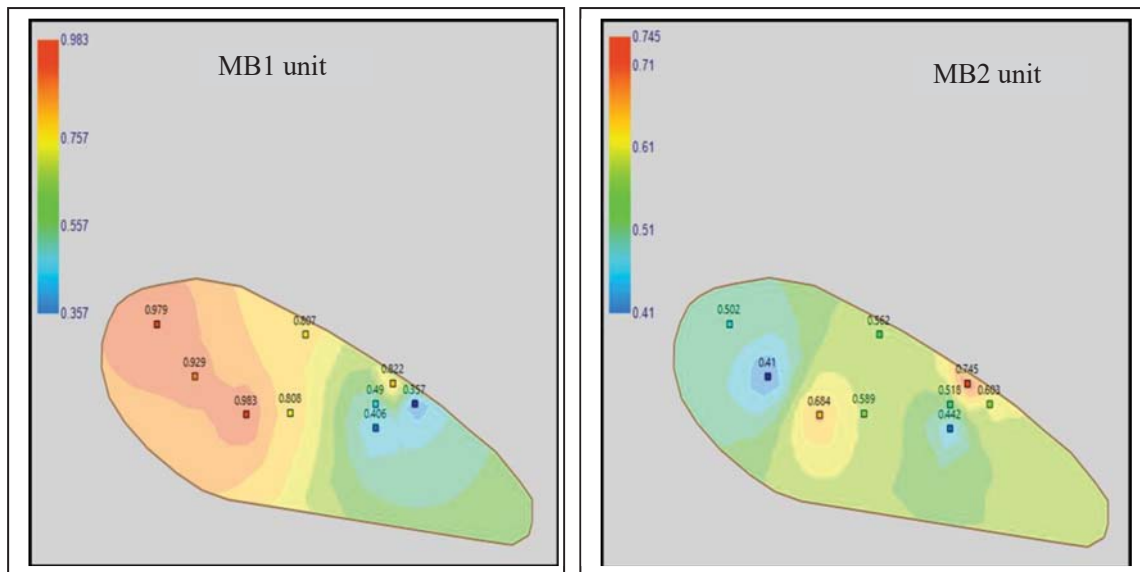


Fig. (23) Permeability maps



**Fig. (24) Net to Gross Maps**

**11- Initialization and History Matching:**

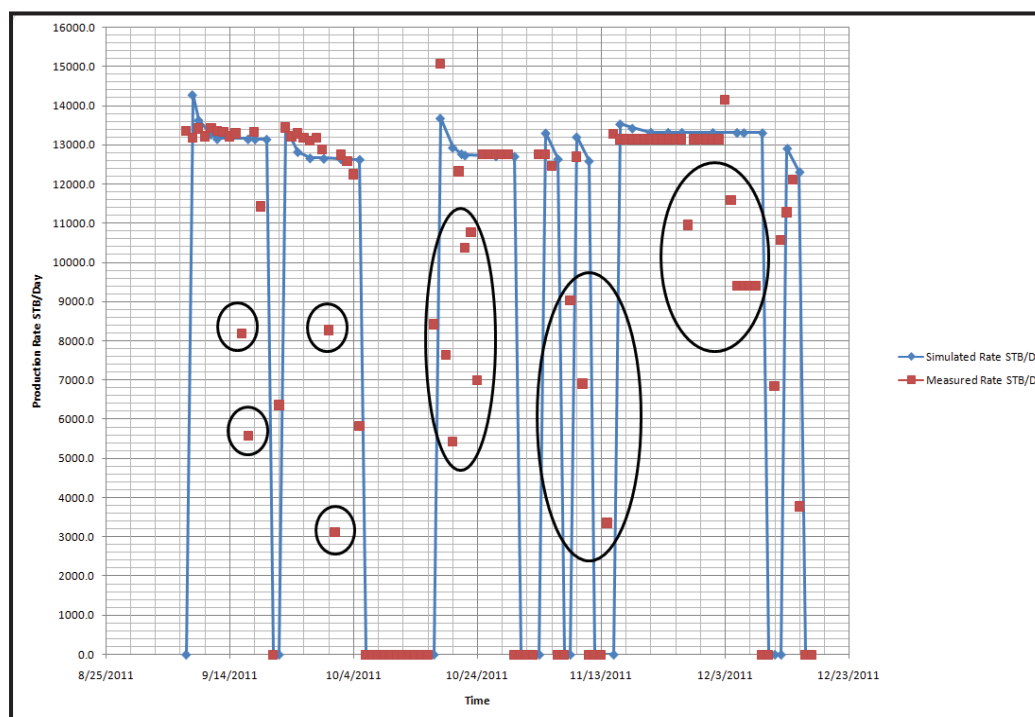
Reservoir model initialization required to be fed with the required data such as PVT, Pc, Free Water Level FWL (2070m) and reference pressure (3700 psi) and Temp (75°C) at datum level of 3040m as presented in Table (5).

**Table (5) Reservoir Initialization Results.**

Saturated Oil with Water	
PV	17175.4 MMbbl
GIIP	3712.7 bscf
OIIP	6913 MMSTB
WIIP	8196 MMSTB

For history matching, another data are required such as relative permeability, rock compressibility, absolute permeability and porosity. Also the vertical permeability was assumed to be 0.1 from horizontal permeability. The history matching was split into two stages; the first one was for production data (field production rate) as these data was available for the period 07/09/2011 to 16/12/2011 as shown in Figure (25).



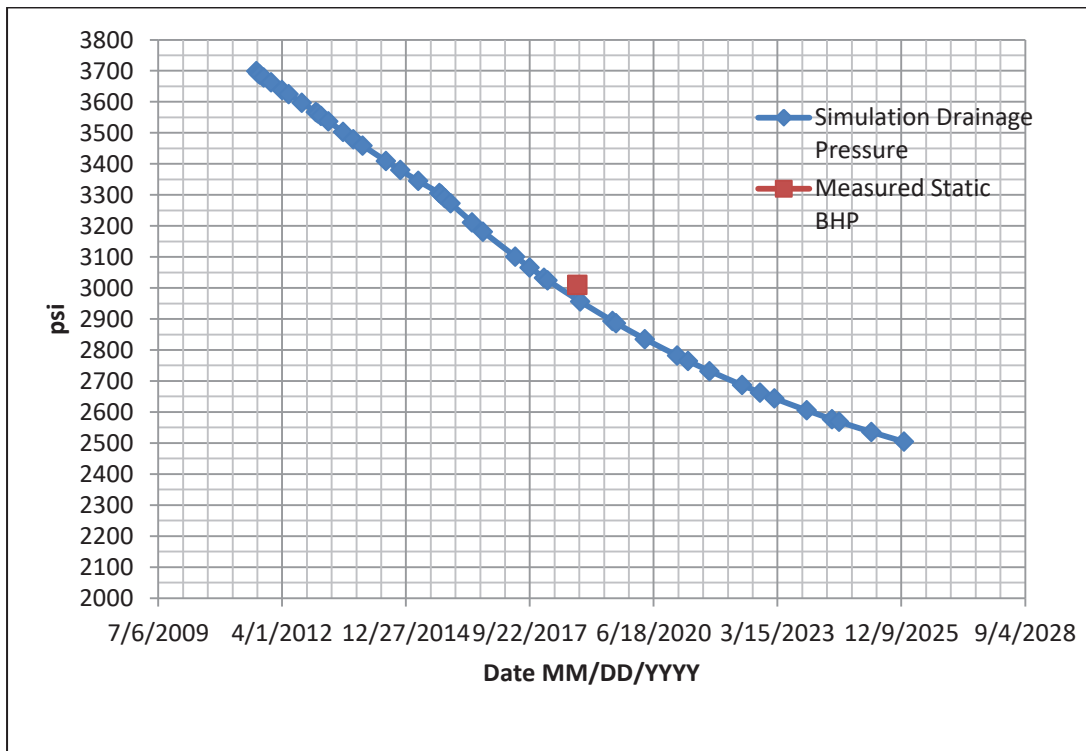


**Figure (25) History Match Plot.**

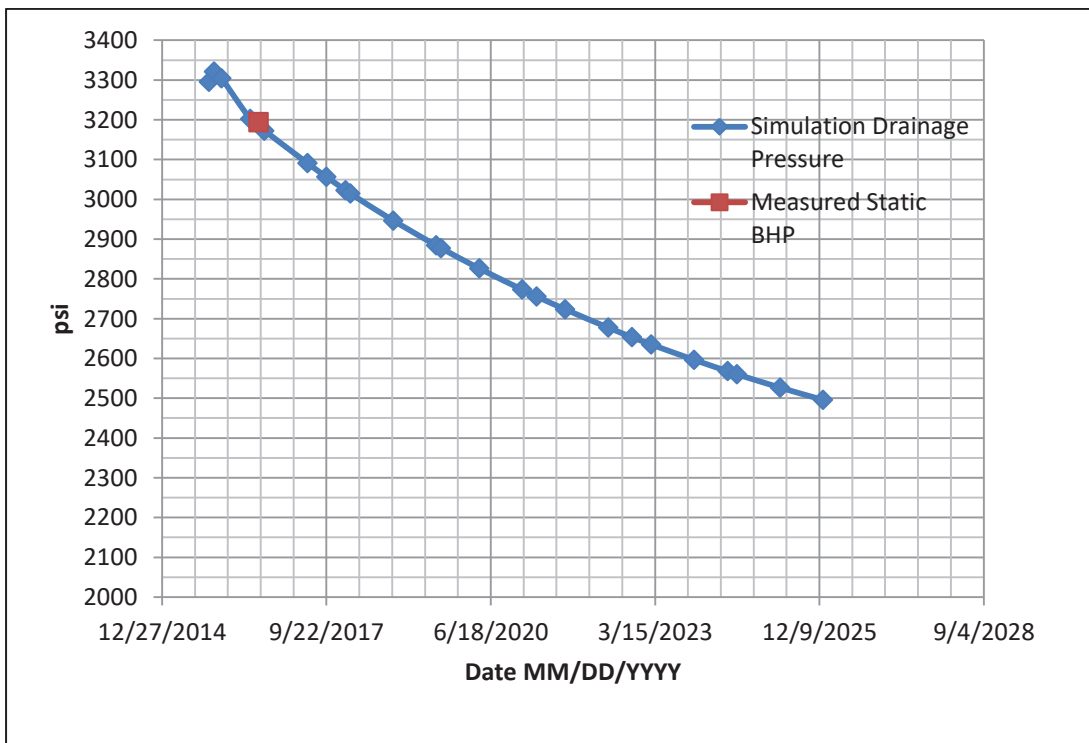
The second step of history match was for static bottom hole pressure measured for the wells. Figures (26) and (27) show the static bottom hole pressure measured at a certain date with simulator results.

After many run and modification on reservoir permeability, the history matching of production rate reach to accepted values and has minimum difference between the actual (measured) data and simulated data for a reservoir model. The production history match was accepted and could be dependable as shown in Figure (25). In Figure (25), the points in black circle represents a measured data in which the production rate was measured less than 24 hr, so that the rate is less than expected.

The pressure history matching results show that pressure data from simulator are very close to measured data and this with production data confirm that the reservoir model is near to actual reservoir behavior.



**Fig. (26) Well NS-8 static BHP matching**



**Fig. (27) Well NS-15 static BHP matching**

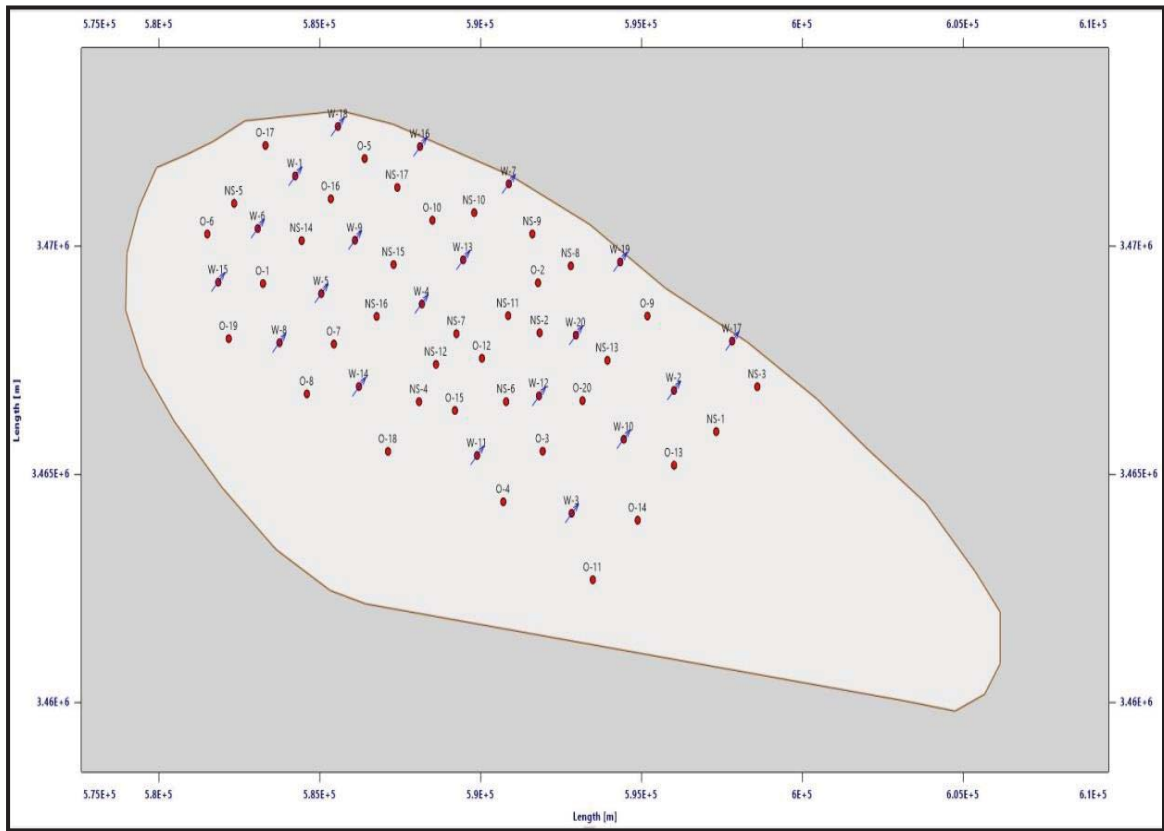
## **12- Reservoir development strategy:**

Production strategy will use a production rate value equal to 85 Kbb/d to evaluate field performance and to monitor production stabilization to the end of prediction period. As it was clear from the history matching, there is weak aquifer supporting the reservoir, so that water injection was used to support field pressure.

Seventeen wells were initially drilled until 2015, then twenty well will be added (four wells each year), therefore the total producing wells will be thirty seven wells at the end of prediction period 2045 (34 years). The operation constrains was to produce oil with minimum wellhead pressure (WHP) of 400 psi, Pwf to be above bubble point pressure and 50% water cut. The perforation interval of existing wells are as mentioned in final well reports while the new suggested wells, are perforated in the middle of the MB1 layer and in the top part of MB2 layer to be far from OWC.

Twenty injector wells will be added to the field started from 2015 (four wells added each year). The injection strategy was to be as line drive with the maximum injection rate and maximum bottom hole pressure equal to 10k BPD and 4500 psi respectively as the fracture pressure of Mishrif formation equal to 5000 psi. The water injection had been designed to inject water in oil zone through the middle of MB1 unit and the top part of MB2 unit.

The new drilled wells are located to cover reservoir area with about 400 meter drainage area radius for each oil producer well (about 800 meter distance from well to another) and to allow a line drive injection between oil producers and water injector wells. Figure (28) shows the locations of proposal wells.



**Fig. (28) Locations of proposal wells**

The strategy results are field maximum production rate reached up to 85 Kbb/d in 2020, then the production rate get stable for about ten years after that it started to decrease till the end of the period to amount of 65 kBPd. The water cut percent increase gradually until it reached at the end of the prediction to 33%. Field cumulative oil, cumulative water injected and recovery factor are 930 MMSTB, 1124 MMSTB and 13.5% respectively. Reservoir pressure was stable as the injection rate and production rate are nearly stable as shown in Figure (29).

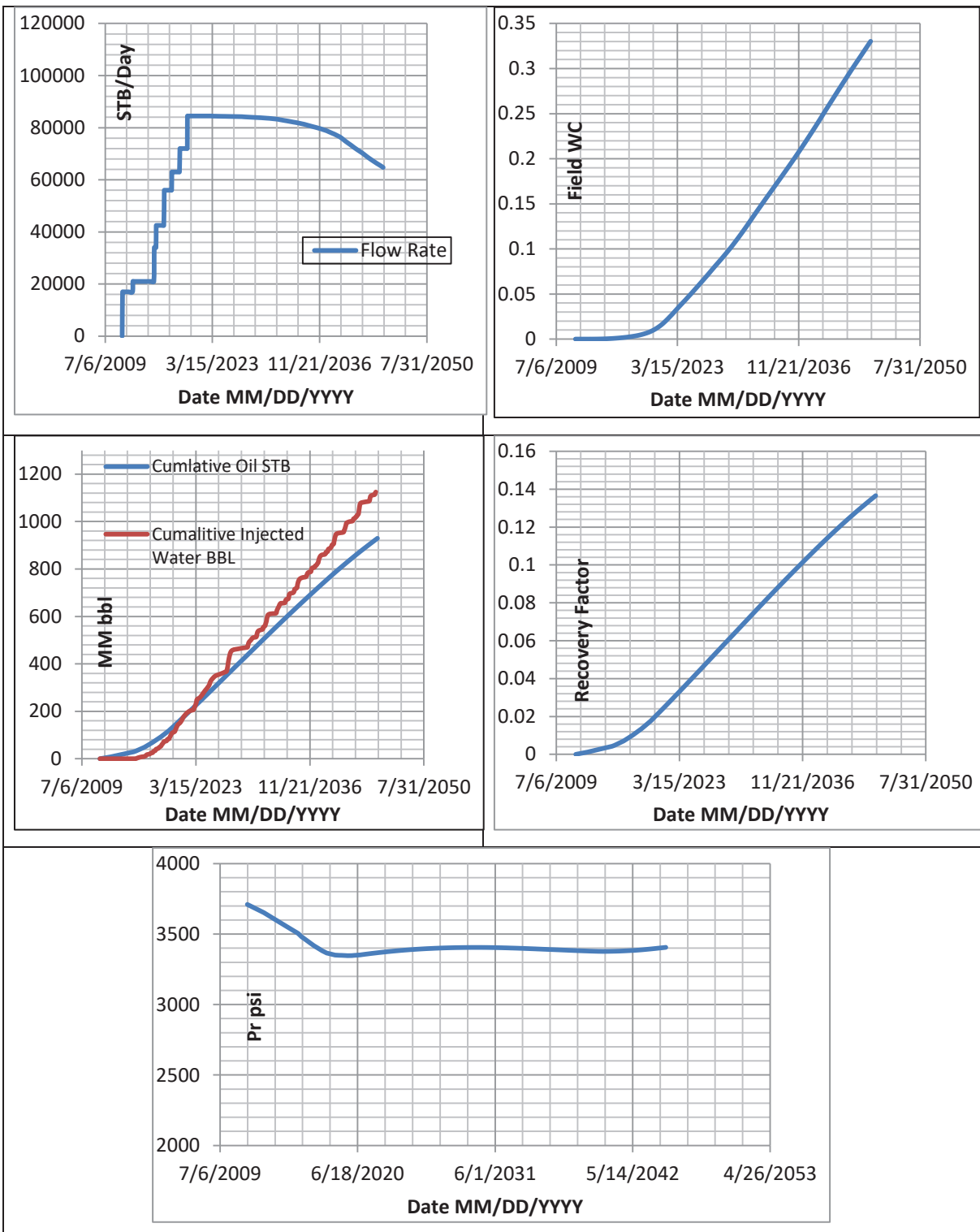


Fig. (29) Strategy results

**Conclusion:**

1. From Figure (3), the Density-Neutron plot approved that Mishrif reservoir is a carbonate rock as the points fall between Limestone-Dolomite lines.
2. CPI shows a shale layer about 10 meter thickness is separating the MA layer from the main reservoir layer MB. Corrected porosity from shale effect is used in Archie equation to calculate saturations.
3. Reservoir quality (porosity, permeability and net to gross) is getting better toward the west of the field and this is mentioned also before the previous studies [3].
4. The calculated OOIP from simulator is 6.9 MMSTB is very close to that calculated one from the previews study (Chevron study on 2007) which was about 7.1 MMSTB. [1]
5. The comparison between static bottom hole pressure and the simulation pressure shows that the values are very close to each other, increase the certainty of the model and approve that the reservoir model is close to represent the actual reservoir.
6. Water flooding improves field production for two reasons, first it support reservoir pressure and second it push the oil toward production wells.
7. Recovery factor consider low due to few production wells and with respect to large amount of oil reserve.
8. The production rate was stable for 10 years as the wells production rates were in optimum rate range then the production rate decreased due to increase in water cut because of water injection.

**Nomenclature:**

GOR	Gas-Oil Ratio	scf/STB
Rw	Water Resistivity	ohm
Rt	Formation Resistivity	ohm
Sw	Water Saturation	%
SXO	Invaded Water Saturation	%
Kro	Oil Relative Permeability	Dimensionless
Krw	Water Relative Permeability	Dimensionless
Pc	Capillary Pressure	psi
WC	Water Cut	%
Pr	Reservoir Pressure	psi
GR	Gamma Ray	API degree
P	Pressure	psi
Pb	Bubble Point Pressure	psi
K	Permeability	md
Bo	Oil Formation Volume Factor	BBL/STB

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