Dynamic model of Tertiary reservoir in Khabaz Oil field

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Abstract. This study deals with building a reservoir model for Tertiary reservoir in Khabaz oil field and calculate oil and gas in place by volumetric method using Petrel RE software and by Dynamic method through material balance by using MBAL software ,testing the reservoir dynamic model through history match over 26 years, and predicted (4) case of reservoir and well performance over 29 years start at the end of history match (1/1/2016 ) until (1/1/2045) by natural depletion for case-1 Do nothing (current producing wells) , Case-2 Base case (work over non-producing wells) case-4 new wells (drill 6 new wells) and add water injection for case-3 (drill 7 new water injector wells).

1-Introduction
Khabaz Field is located in the North East of Iraq at approximately 12 km North West of Kirkuk city. Discovered in 1955, the first exploration well (Kz-1) was drilled on April/1976, the structure consists of an elongated asymmetrical anticline, 15 km length and 5 km width, with a NW-SE axis and faulted mainly on its West flank. It lies between Jambur and Bai Hassan structures and South West of the Baba dome (Kirkuk Field). Being more deeply buried than the Jambur and Bai Hassan fields by respectively 600 and 1000 m, Tertiary series are not outcropping and unlike its neighbours, the Khabaz anticline cannot be detected from the surface5.

The field is consist of 2 main carbonate reservoirs: -
1-Tertiary Reservoir.
2-Cretaceous reservoir which consist of two reservoirs:-
A-Upper Qamchuqa Reservoir (Mauddud).
B-Lower Qamchuqa Reservoir (Shuaiba).

Figure 1. Khabaz Field location
Since the discovery Kz-01 well, 20 wells were drilled on the Khabaz oil tertiary reservoir and the oil production started in 1993-94 with 13 oil producers on Tertiary interval. At the end of 2016, about 89.8 MMSTB were produced representing less than 7.89% of the overall present reservoir accumulation. The total field oil production reaches approximately 30000 STB/D in 2000, but dramatically dropped down since 2004. Nearly half of the producing wells are now shut down due to well plugging by asphaltene, gas / water break through or even blow-out.

The Tertiary carbonate formations 150 m thick Top reservoir 1794.5 MBSL Saturated oil 36° API with CO2, no H2S, the GOC around 1925 MBSL and the WOC around 2050 MBSL at least the top part (JERIBE) of the reservoir is fractured.

The Reservoir production is characterized by good productivities due to the fracturing, early water and gas break-through and problems linked to asphalting precipitation.

Figure 2. History Production profile for the Reservoir

2- Literature Review
A Reservoir Simulator is a computer generated model that aims to represent the full geological extent and structure of a reservoir. The reservoir simulator gives the reservoir engineer the ability to study and analyze the performance of the reservoir under various operating conditions in order to adopt an efficient and maximum profit-driven development strategy for producing hydrocarbons from the reservoir. Petrel RE is the pre and post processor of Eclipse reservoir simulation interface that is well known in the Oil and Gas Industry. With Petrel RE a user is able to develop reservoir simulation cases that aid in studying and analyzing the performance of reservoirs under various operating conditions to facilitate final decision making for reservoir management.

3- Layering- Reservoir model Grid
The reservoir model layering derives from the geological model. The layering and the horizontal gridding have been defined to allow a good description of the vertical and horizontal flux with a reasonable number of cells to allow an acceptable simulation time. Grid mesh/175 x 75 (100m x 100m), Layering/ 19 layers, Facies/ (dolomite, dolomitic limestone, limestone), the total grid contains / (211584) cells 210238 of which are active in the model, the NTG model, it was calculated in the geological model with (0.06) md as cut off permeability, and (45%) was determined as a cut off for V Clay, where the (NTG) calculated using the formula below:

\[
NTG=\begin{cases} 
0 & \text{if } VCL \leq 0.45, \\
0.06 & \text{if } PHIE \geq 0.06, \\
0 & \text{otherwise} 
\end{cases} 
\]

The Geological model divided the reservoir rocks into three types (DOLOMITE), (DOLOMITIC LIMESTONE) and (LIMESTONE).
4-Petrophysic properties
The petrophysical parameters (porosity - permeability - Net to gross) used in the ECLIPSE reservoir model are the Those parameters were exported from the PETREL geological model. The permeability are derived from the plugs permeability/porosity plots, they only reflect the matrix characteristics and thus do not take into account the fracturing of the rock.

5-Buildup Pressures Analysis:
The permeability depended in the geological model represents the permeability of the matrix neither fractures. And because some of the wells in the tertiary reservoir are produced at good rates, have a medium productivity index (P.I), the permeability obtained from their completion tests and mud loss data in the production formations all of that indicate to fractures.

The permeability of the model has been increased in order to allow the wells to produce the rates required by the production history. It is believed that the increase of permeability between the geological model (from Phi K correlations) and permeability's issued from testing reflects the importance of the fracturing in the drainage area of the wells. The adjustment of the permeability has also allowed (combined to adjustments on other parameters) the match of the static pressures and GOR.

In order to stay in a realistic range, this increase of permeability has been based on observed data (permeability derived from well tests). A complete re-interpretation of the available pressure build-up data has been made, 16 well pressure build up were re-interpreted over the 20 wells producing this reservoir using Kappa software (Saphir) for the purpose of obtaining the total permeability of the rocks.

Figure 3. Pressure Transit Analysis Log-log plot:dp and dp'(psi) vs dt(hr) for Kz-10

Most of the build-up were stopped before the end of the well bore storage period leading to poor estimation of the K: very short time for build-up on. The flow rates were only estimated from the pressure drop measured on the flare line (in the build-up interpretation, the K is directly proportional to the average rate). Therefore the resulting K cannot be considered as a 100% reliable data but as an approximation. (Table 1) includes the total permeability values obtained from the analysis process.
Table 1. Total permeability values obtained from the analysis process

| WELL  | Permeability Well Test (md) | WELL  | Permeability Well Test (md) |
|-------|-----------------------------|-------|-----------------------------|
| KZ-03 | 14.3                        | KZ-25 | 314                         |
| KZ-08 | 15                          | KZ-26 | 132                         |
| KZ-09 | 104                         | KZ-27 | 33.5                        |
| KZ-10 | 133                         | KZ-32 | 120                         |
| KZ-15 | 50                          | KZ-33 | 55                          |
| KZ-17 | 235                         | KZ-34 | 6.4                         |
| KZ-19 | 90                          | KZ-37 | 16.6                        |
| KZ-22 | 64                          |       |                             |

6-Special core analyses:

The data of capillary pressure and relative permeability entered into the SCAL software to perform quality control (such as curve smoothing), grouping the data according to lithological parameters or porous unit and transform the laboratory data into rock curves suitable for input to the simulator.

6.1 Capillary pressure data:

The data available from the Centrifuge and Restored State experiments were depended on 85 samples obtained from some of wells of formations (Jeribe, Anah, Anah/Azqand and Azqand). The data were converted from laboratory conditions to reservoir conditions then normalized by using J-Function as shown below:

Figure 4. J-Function Curves
The curves were classified into three groups based on the initial water saturation, which was consistent with the number of rock types that were approved in the construction of the geological model.

1- **DOLOMITE FACIES** which have high permeability, with an initial water saturation 15%.
2- **DOLOMITIC LIMESTONE FACIES**, which are medium permeability, with an initial water saturation ranging from 15 to 35%.
3- **LIMESTONE FACIES** characterized by its low permeability, with an initial water saturation ranging from 35 to 65%.

Then each group have been averaged as shown in the figure below.

![Average J-Function Curves](image1)

**Figure 5.** Average J-Function Curves

![Water-Oil Relative permeability curve for all samples](image2)

**Figure 6.** Water-Oil Relative permeability curve for all samples
6.2 Relative permeability data Water-Oil (k_{rw-kro}): -
The relative permeability calculations of the water / oil system were based on 17 samples data, as shown in the figure below from water flooding experiments, the samples were classified into groups according to reservoir rock types based on the previous method in capillary pressure calculations. each groups normalization, averaged, and De-normalization to extract the final curves for each group, as shown in the figure below, where the program calculates the modified properties of Sw, Krw, Kro.

![Figure 7. Average water-Oil Relative permeability curves](image)

6.3 Relative permeability Gas-oil (k_{rg-kro}): -
The relative permeability calculations of the gas / oil system were based on 11 samples data as shown in the figure below, from Gas flooding experiments.

![Figure 8. Gas-Oil Relative permeability curve for all samples](image)
The samples classified into three groups according to reservoir rock types based on the previous method in capillary pressure calculations and relative permeability of water-oil, each groups Normalization, averaged and De-normalization to extract the final curves for each formation, as shown in the figure below, where the program calculates the modified properties of Sg, Krog, Kr.

![Figure 9. Average water-Oil Relative permeability curves](image)

Tables below represent the final results of these the end point curves for the three rock types which were exported to the Petrel RE software.

| FACIES        | SWI | SOL | SGC | KRW max | KRO max | KRG max |
|---------------|-----|-----|-----|---------|---------|---------|
| DOLOMITE      | 0.15| 0.29| 0.01| 0.17    | 0.89    | 0.1     |
| DOLOMETIC LIMESTONE | 0.33| 0.25| 0.05| 0.14    | 0.85    | 0.91    |
| LIMESTONE     | 0.65| 0.19| 0.07| 0.06    | 0.8     | 0.25    |

7-Fluid Modelling Black oil PVT.
Podbielinak analysis data from Kz-18 table (2) are used to build a pvt model and applied to the whole field by matching them with lab data using regression to obtain the best parameters for the equation of state (Peng Robesion), Then black oil PVT table have been derived and exported to (Eclipse, Prosper, Saphir and MBAL) softwares.
Table 3. Podbielinak analysis data from Kz-18

| Well | KZ-18 2nd |
|------|-----------|
| Report date | 1989 |
| Weight % | Mole % |
| Methane | 9.09 | 49.61 |
| Ethane | 2.84 | 8.14 |
| Carbon Dioxide | 1.99 | 3.94 |
| Hydrogen Sulphide | - | nil |
| Propane | 2.44 | 4.81 |
| I-Butane | 0.5 | 0.79 |
| n-Butane | 0.9 | 1.31 |
| I-Pentane | 0.24 | 0.26 |
| n-Pentane | 0.23 | 0.26 |
| Hexanes+ | 81.8 | 20.88 |
| Total | 100 | 100 |

S.G of c6++ @ 60/60: 0.8354
Mwc6++: 232

First separation stage 203 psi 104°F Second separation stage 58 psi 104 °F and Storage tank 14.5 psi 60 °F representing the existing installation process. The main parameters for the reservoir fluid are listed below:

Table 4. Main Oil parameters for the reservoir fluid

| Parameter | Value |
|-----------|-------|
| GOR SCF/STB | 1065 |
| Bo (BBL/STB) | 1.63 |
| API | 38.2 |
| Oil Viscosity @ Psat. (cp) | 0.77 |

8-Well modelling

The typical well for Tertiary reservoir is KZ-25. IPR established using last test with available GOR on KZ-25 in August 2002. VLP have been delivered to Eclpise. Oil flow rate in case of blow out when = 8000 STB/D. Absolut opening flow (AOF) = 9800 STB/D.
9. MATERIAL BALANCE

9.1 Material Balance Theory
Schillthuis (1936) first presented a method of reservoir estimation using the material balance. Material balance is a volumetric balance which states that since the volume of a reservoir (as defined by its initial limits) is constant, the cumulative observed production, expressed as an underground withdrawal, must equal the expansion of fluids in the reservoir resulting from finite pressure drop which is the governing principle for the MBAL software i.e. Underground withdrawal (rb) = Expansion of oil (rb) + originally dissolved gas cap (rb) + reduction in HC pore volume (HCPV) due to connate water expansion (rb) 7

9.2 The MBAL Software Tool
A classic material balance study was conducted to estimate the initial hydrocarbons in-place. The tank model was built using Petroleum Experts Integrated Production Modelling IPM-MBAL software and calibrated by history matching using production data, reservoir pressure reservoir rock data, and reservoir fluid data.

9.3 Data Requirements and Input
The following data are required for Material Balance Analysis using MBAL software:
1- PVT Data
2- Initial Reservoir Pressure
3- Reservoir Average Pressure History
4- Production History
5- All Available Reservoir and Aquifer Parameters

(Table 5) illustrates the data that have been used in the material balance equation.
Table 5. data used in the material balance equation

|                          | TERTIARY |
|--------------------------|----------|
| Reservoir                |          |
| Res. Temp. F             | 170      |
| Initial Pressure psig @GOC| 3273     |
| Porosity Fraction        | 0.15     |
| Connate. Water Saturation Fraction | 0.3     |
| Initial Gas cap volume Factor | 0.238    |
| Rock Compressibility 1/Psi | 0.238E-6 |
| Water Influx (BBL/PSIG/DAY) | 49.5     |

Black oil PVT table has been used that derived from equation of state depend on Podbielinak analysis data for Kz-18. Preparation of data and consistency checks were performed on the production history, average reservoir pressures, reservoir and aquifer data. The History Matching Process begins when there is consistency in the data inputted.

9.4 History-Matching

History matching involves a trial and error approach to provide a best fit dimensional level. It comprises the functions of the graphical method, the analytical method and simulation tests. History matching is used to determine and identify sources of reservoir energy and their magnitude, the value of OOIP, OGIP, aquifer type and strength etc. History matching in MBE is the most effective way to determine the aquifer model that best fits the observed data. Comparison between the observed data and the calculated data on a zero-

An iterative non-linear regression is used to automatically find the best mathematical fit for a given model, a simulation of production can be run to check the validity of the result of the above two techniques as shown in (figure 12).

Figure 12. Reservoir history matching
9.4.1 Analytical Method.
The analytical method allows for regression on all reservoir model parameters. Regression is used to adjust the reservoir model to minimize the difference between the observed/measured and the model production. It is used to assess the effects of varying parameters such as formation compressibility that cannot easily be assessed using graphical methods. The quality of the regression match is expressed as the standard deviation between model and measured values. The analytical plot was regressed to compute the oil in place, and the aquifer diffusivity as shown in figure below.

9.4.2 Graphical Method
The first step taken was to plot (F-We)/Et versus F the withdrawal) known as Campbell’s plot with no aquifer defined initially. If there is no other source of reservoir energy other than the total fluid expansion Et, then this Campbell’s plot will be a horizontal straight line with a Y axis intercept equal to the original oil in place (OOIP). Any “turn-up” in the plot (i.e deviation from the theoretical horizontal straight line) indicates another source of energy present (due to a source (injector) or an aquifer influx). Sensitivities were conducted using various aquifer models, the best technical case estimate of the initial oil in-place was 850 MSTBO as in (Figure 11).
9.5 Energy plot
The plot describes the prevalent energy system present in the reservoir; water influx, pore volume compressibility. Fluid expansion, ingestions e.t.c. It describes the fractional contributions of these energy systems present in the reservoir and the most prominent at various dates. The figure below illustrates the drive mechanisms for the reservoir.

10- Reservoir dynamic simulation
The tertiary reservoir model has been developed with the petrel RE version 2016. The model is based on the Dynamic Synthesis and the geological PETREL model, the purpose of the Model is to design a redevelopment plan. The model represents the Tertiary carbonate reservoirs with reservoir fluids are saturated oil, and initial gas cap. The production started in 1993. A total of 20 vertical wells were drilled in the reservoir.
Figure 16.

11- INITIALIZATION PARAMETER & OOIP / OGIP
The oil in place was determined by the volumetric method by using data generated from geological and petro physical evaluation (areal extent, formation sand thickness, porosity and the saturation e.t.c) and computing the initial oil in place from the general formula. The governing equation for the volumetric estimation of oil in place is given as:

\[ N = 7758 \text{ Ah} \left(1 - \text{swc}\right)/\text{Boi} \]

\[ N = \text{STOIIP}, \text{ Ah} = \text{Bulk(rock)volume, } = \text{porosity(Fraction)} \]
\[ , \text{swc} = \text{connate water saturation(Fraction)}, \text{Boi} = \text{Formation volume factor dimensionless.} \]

(Table 6) contain the parameter used in the initialization.

| Parameter                          | Value       |
|------------------------------------|-------------|
| Initial pressure @ datum depth (psi) | 3330        |
| Datum depth (MBSL)                 | 1990        |
| Reservoir Temperature (F) @datum depth | 170        |
| Reservoir Temperature (F) @GOC     | 166         |
| saturation pressure @ GOC (PSI)    | 3273        |
| Saturation Pressure @ reservoirs Temperature (Psi) | 3282 |
| GOC (MBSL)                         | 1925        |
| OWC (MBSL)                         | 2050        |
| BO (BBL/STB)                       | 1.636       |
| BG (CF/SCF)                        | 0.0049      |
| Oil Viscosity C.P                  | 0.79        |
| GOR (SCF/STB)                      | 1060        |
(Table 7) summarizes the estimation of the oil and gas volume by ECLIPSE initialization.

**Table 7.** Estimation of the oil and gas volume by initialization the model

| Zones            | STOOP STB 6810 | OGIP SCF 9810 |
|------------------|----------------|---------------|
| Jr-1             | 8              | 8             |
| Jr-2             | 6              | 13            |
| Jr-3             | 43             | 45            |
| Anah             | 12             | 19            |
| Anah/Azkand      | 45             | 41            |
| Az-1             | 94             | 89            |
| Az-2             | 248            | 179           |
| Az-3             | 372            | 92            |
| Azkand/Ibrahim   | 225            | 3             |
| **Total**        | **1053**       | **489**       |

**12-History matching**

**12.1- Model status before matching**

On the first run performed before history matching, three main problems were encountered: The permeability issued from the geological model was too small for the wells to reach the observed rates, most wells did not respect the history oil rate required due to a poor productivity. The GOR was not correct. The gas production was generally too low. Gas break through were not represented correctly. The water cut was generally too high, therefore to reduce the water cut, two region of oil water contact have been used 2065 MBSL for North east region and 2050 MBSL for south west region, the initial oil in place depending on new contact level was 1138 MM STB and initial gas in place was 489 MMM SCF.

**12.2- Monitoring - Production data**

The production history has been matched until 1/1/2017. Modification made on position of the OWC contact, and the transmissibility. Monthly oil well production rates for the period 1/1/1990 to 31/12/2016, well shut in dates file and causes for shut-in well test data including oil rate, GOR and WCUT, manifold pressure, well head pressure, type of production (tubing or tubing + annulus) static pressure data issued from pressure build-up, as no production profile for total gas and water rate is available, the model could not be constrained with a reservoir rate (oil + water + gas rate at down hole condition) as it is normal practice for history matching, it was constrained only with the oil rate. The water-cut and the GOR were matched to the observed well test data.

**12.3- Static pressure matching**

There was no need for increasing / decreasing the aquifer size in the model nor activating analytical aquifers to match the depletion. There was no attempt to match the pressure observed during the production period, because there was no guaranty on the reliability of those measurements (correct stabilization or extrapolation). Matching was more emphasized on pressure points recorded during long shut in periods.
12.4- Well Head Flowing Pressure matching.
Pressure drop calculations were produced with the PROSPER software on well KZ-25. It was developed for the prediction runs after matching where the production can be constrained by a minimum well head pressure. They represent only the production through tubing, the production through annulus was not considered. The VFP was used to match the well P.I in the late period of the history (100% production though tubing). The matching of the surface flowing pressure was only possible when the gas rates were correctly matched (GOR close to Rs). On high GOR wells the quality of the GOR match does not allow the WHP to be matched correctly. P.I adjustments made in the model for WHP matching:

12.5- GOR matching
Very high increases of GOR have been observed on some wells, while on the other wells the GOR stayed close to the Rs. Those GOR increases were interpreted as fingering of gas from the gas cap, therefore it was tried to adjust the GOC position and locally the permeability field for matching. On KZ-19, due to the low position of the perforations, the breakthrough of gas observed from 2001 cannot be reproduced by the model unless a strong connection to the gas cap. The horizontal anisotropy. The permeability in the vertical direction was increased to improve the communication with the gas cap. The global horizontal permeability was kept: vertical permeability equal to 0.05 of horizontal permeability.

12.6- Water Cut matching
The match was mainly realised by adjustment of the WOC depth on the two previously defined zones. The Kro/Krw favourable to oil was selected in order to minimise the change on WOC depth and OOIP. In the north east zone the WOC was lowered from 2050 MBSL to 2065 MBSL. In the South west zone the WOC was 2050 MBSL. A good match was obtained for most of wells.

13- Development Strategy
Four development cases have been simulated for reservoir and well performance over 29 years start at the end of history match (1/1/2016) until (1/1/2045), the natural depletion for Do nothing case (current producing wells), Base case (work over non-producing wells), add water injection wells for water injection case (drill 7 new water injector wells) and Additional drilling of vertical wells is proposed to extend the duration of the production plateau at maximum production capacity (15000 STB/D) for final case (drill 6 new wells) with the existing wells assuming that basic remedial works are made.

The manifold is repaired and group control for oil production of 15000 STB/D, and gas rate 35 MMSCF/D. Gas compression operational on the two stages of separation. The wells are controlled by the manifold outlet pressure (minimum 217 psi), the pressure drop, tables used no Water Cut limit set in the model. The wells stop when they lose their productivity at minimum manifold pressure. The well GOR is controlled by cut-back the liquid rate 20% for GOR in excess of 3000 SCF/STB. No gas flaring nor re-injection.

13.1- Do Nothing Case: -
The DO-NOTHING run is designed as a reference case to evaluate the effect of new investments. The number of producing wells is (13), (Table 8) show the well flow rate.

| wells | Kz-2 | Kz-3 | Kz-5 | Kz-10 | Kz-20 | Kz-22 | Kz-25 | Kz-27 | Kz-28 | Kz-32 | Kz-34 | Kz-37 | Kz-41 |
|-------|------|------|------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| Flow rate | STB/D | 850  | 1100 | 400   | 700   | 2100  | 1000  | 3850  | 700   | 350   | 1100  | 500   | 950   | 700   |
The plateau at 12750000 STB/D lasts for 1 year, cumulative oil production was 180 MMSTB, RF equal to 10% water cut equal to 19% and reservoir pressure drop equal to 640 psi the, as shown in figure below. Maximum gas rate is reached on year two; the production declines rapidly due to the loss of productivity caused by
- Water breakthrough
- Drop of static pressure.
- Liquid rate cut back due to gas arrivals.

![Figure 17. Production prediction profile for Do-Nothing case](image)

13.2- Base case: -
The base case run has been built to evaluate the possible profiles with the same hypothesis of the DONOTHING and with additional production wells were work over in order to maintain the production plateau for (6) years at full capacity (15000 STB/D) as long as possible, the number of producing wells is (20). (Table 9) show the date of putting the additional wells to the work.

![Figure 18. Production prediction profile for Base Case](image)
Table 9. Additional wells time schedule

| wells      | kz-8 | kz-15 | kz-18 | kz-26 | kz-33 | kz-31 | kz-42 |
|------------|------|-------|-------|-------|-------|-------|-------|
| Flow Rate, B/D | 500  | 1300  | 1500  | 500   | 750   | 500   | 500   |
| Date of Production | 2019/1/01 | 2019/1/01 | 2019/1/01 | 2019/1/01 | 2019/1/01 | 2019/1/01 | 2019/1/01 |

The plateau at 150000 STB, cumulative oil production 208 MMSTB, RF equal to 18.8% water cut equal to 21% and reservoir pressure drop equal to 730 psi as shown in figure below.

13.3- Water Injection: -
The plateau was for (6) years at 150000 STB, cumulative oil production 205 MMSTB, RF equal to 18% water cut equal to 30% and reservoir pressure drop equal to 430 psi as shown in figure below. The number of producing wells is (20) with (8) water injection wells as shown in figure below.

Figure 19. Production prediction profile for Water Injection Case
13.4. Drill New Wells
The final selected design includes: 26 production wells, 6 of which are new wells drilled the model predicts 14 years plateau at 15000 (STB/D) and cumulative oil production 233 MMSTB in 2045. The expected final recovery is 20%, water cut equal to 18% and the total reservoir pressure drop equal to 800 psi as shown in figure below.

Figure 20. Contour map for top of Jeribe formation with new injection wells location Case 3

Figure 21. Production prediction profile for Drill New Wells Case
14. Material Balance vs. Simulation Average Pressure

This subsection compares the average reservoir pressure versus time profile computed from ECLIPSE and MBAL models against the measured pressure at datum depth (1990 mBSL) calculated from pressure measurement surveys for wells (kz-8, kz-9, kz15 and kz-30) as shown in figure below. The average pressure calculations for MBAL model was based on yearly flow rates.

The MBAL results reflect the theory underlined this model, such as, for example any pressure change is instantaneous and uniform throughout the tank. This implies that the MBAL reservoir pressure depletion associated with fluid production dropped faster compared to ECLIPSE one. The most noticeable features are:
1. The calculated reservoir pressure MBAL and ECLIPSE simulator matched perfectly after 01/2009, the reason is the pressure measurement from kz-30 which is observation wells represent stabilized static reservoir pressure, before that the discrepancy has started between the ECLIPSE and MBAL because the pressure measurement depend on wells kz-8, kz-9 and kz15 were are producing wells, the shut in time was not sufficient to reach the static reservoir pressure

2. Comparably, the two calculated pressure curves from ECLIPSE and MBAL, they have the same trend.

15-Conclusions: -
1-Initial Oil in Place (1138 × 106) STB while the Initial Gas in Place reached (489 × 109) SCF, Compared with the calculated from the geological model (937 × 106) STB of oil and (610 × 109) SCF. 
2-The Initial Oil in Place calculated by material balance Eq. about (900 ×10^6) STB, which is less than the value calculated by the volumetric method in the reservoir model.
3-The volumetric method estimates the STOIIP based on its static nature and net pay basis by utilizing petro physical and geological properties obtained from static model. With the knowledge of the area and the sand thickness generated from Petrel software, which takes into account the net-to– gross thickness, porosity (effective), the estimate is supposed to be same with that obtained from the MBAL. The difference observed from the estimate (about 286MMSTB) suggests the possibility of a fault which MBAL is not seeing and was not accounted for in the estimate with MBAL tool as it assumes the reservoir to be a tank.
4-Good history matching of pressure achieved in most wells, which have measurements of bottom hole pressure except for some wells and this is due to the incomplete bottom hole build up pressure.
5-Average pressure calculated at the datum level from the model was compared with the measured reservoir pressures at the same level and found they are taking same behaviour.
6-Fourth case forecast (Drill new wells) which is recommended case showed the possibility of sustaining the production of the Tertiary reservoir at a rate of (15000) STB/D for a period of 14 years, assuming that the gas / oil ratio is allowed to rise to 3000 SCF/STB and the lowest pressure on the head of the well (350) psi through (26) producing wells, With RF (20%) with cumulative oil production of (233 × 106) STB at the end of 2044.

Recommendations: -
Having concluded on results gotten, the following recommendations for application towards enhancing the estimates gotten from reservoirs for project planning and development.
1- Wells Production tests had been stopped since 2004, and production rates for wells estimated from empirical correlation from completions tests, last GOR measured for wells were in 2002, Accurate value for oil rate and producing GOR important to perform good history match.
2- Laboratory tests need on core samples focus on (Wettability Restoration) to reflect the case of the correct original wettability of reservoir rocks.
3- Very useful to do a few experiments depended on Steady State method so that a set of integration relative permeability data can be achieved in terms of the endings and curves.

Nomenclatures
Bg: Gas formation Volume Factor
Bo: Oil formation Volume Factor
BSL: Below Sea Level
OOIP: Original Oil in Place
OGIP: Original Gas in Place
GOC: Gas Oil Contact  
GWC: Gas Water Contact  
Krg: Relative Permeability gas  
Kro: Relative Permeability oil  
Krw: Relative Permeability water  
SWC: Connate water saturation  
SOR: Residual oil saturation  
SGC: Critical gas saturation  
MBAL: Material Balance  
N: Stock Tank Oil in Place  
PVT: Pressure, volume, temperature.

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