Predicting Future Performance of a Field with Complex Reservoir Heterogeneities Undergoing Water Injection – a Case Study of a Niger-Delta Field

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Abstract
Structural heterogeneity is one of the critical factors that can strongly impact on the performance of a reservoir. A compartmentalized reservoir (A1) in a mature Niger-Delta field, having two blocks separated by a fault was shown from seismic mapping to be non-sealing. The initial pressure data obtained for both the East and West blocks through a Repeat Formation Test (RFT) were similar; suggesting that they were in hydraulic communication. After about 15 years of production from the West block, water injection was introduced, and this resulted in a successful pressure build-up and appreciable oil production in this block. RFT information, however, showed a larger pressure depletion than expected in the East block since there was no producing well in it. In this work, a highly cost-effective integrated approach, involving an analytical tool known as the multi-tank material balance (MBAL) model was used to effectively characterize the complex heterogeneous reservoir and revise the field development plan. The result derived from this study suggests that the multi-tank material balance method sufficiently characterizes this complex reservoir applying a degree of transmissibility of about 30%. This is further shown in the result section, where values of production parameters such as the average oil production rate, average water production rate, water cut and reservoir pressure closely match the current performance of the field.

Keywords: Complex reservoirs, heterogeneities, Niger-Delta, water injection

1.0 INTRODUCTION

Heterogeneities are formed when there is a discontinuity in the layers of the reservoir which may happen either during deposition of the sands or after the start of production while compartmentalization gives rise to regional patterns of variability in reservoir characteristics and production performance (Slatt and Galloway, 1992). Structural heterogeneity is a term used to describe the geological variations of a reservoir and how these variations affect the flow of fluids through it. It characterizes the quality of variation in rock properties with location in a reservoir. Practically, most reservoirs are geologically complex and heterogeneous and that greatly influences reservoir performance (Mahbub, 2012). These heterogeneities make petroleum system modelling, formation evaluation and reservoir simulation critical to maximizing production from such reservoirs.

Reservoir engineers are tasked with the responsibility of modelling a petroleum reservoir and its performance in order to make production forecasts. The success of any hydrocarbon exploration and exploitation program depends on the building of a reliable reservoir model. Inability to properly manage reservoir heterogeneities and uncertainties can lead to decreased production of fluids from the reservoir, incurring of high cost for remedial operations and a generally poor reservoir performance. Reservoir engineers have a wide range of tools and approaches that can be followed for reservoir simulation. The choice of the reservoir simulation approach is dependent on the complexity of the problem at hand, the amount of data available, and the objectives being pursued.

The material balance tool is one of the tools for estimating hydrocarbons originally in place in reservoirs. Others such as simple sector models and fine grid simulation models are also in use. A material balance (MBAL) tank model follows an analytical approach that renders an exact solution to an approximate problem. It involves some basic assumptions and was adopted for this study because of its simplicity of application when compared to other methods. It requires less computational cost, proves reliable in estimating in place volumes, and can capture and manage reservoir heterogeneities as shown in this study. However, it does not give a detailed discretization or distinctive property of every local part of the reservoir.

This paper analyses the result of history match, simulation, contacts validation and forecast done using the Multi-tank MBAL model. This involves using known attributes of reservoir geology, PVT properties and type of recovery process (aquifer drive, gas expansion) to construct diagnostic plots. Several similar methods that have been developed, such as the straight-line method by Havlena and Odeh (1963), apply the material balance equation (MBE) to various types of reservoirs.

An improvement on the MBAL is its use in a multi-tank material balance evaluation. It can be used for a reservoir which has over time sequestered into various blocks by a fault or for a reservoir having distinct geological units separated by intra reservoir shales. Due to complex faulting of the Niger-Delta, it becomes necessary to carry out multi-tank modelling as it gives a better-quality outlook of such reservoirs. The relevance of proper reservoir heterogeneity management cannot be over emphasized as it helps to properly understand the reservoir structure and is very useful in making relevant reservoir management decisions.
This paper shows how an integrated approach involving the Geologist, Petrophysicist and the Reservoir Engineer can result in significant cost saving, as well as how analytical methods can be used to effectively characterize a complex reservoir under water injection. Furthermore, the future performance of the case study reservoir based on proper history match and accurate future parameters is predicted with high accuracy.

2.0 RESERVOIR HETEROGENEITIES AND CHALLENGES

A reservoir, A1, in the southern part of Nigeria containing several communicating fault blocks and under water injection is used as a case study (Figure 1). Discovered in 1984, the reservoir is a low relief anticline reservoir with 4 fault blocks - A, B, C and D. The ‘A’ block has further been divided into East and West blocks as a result of an extending fault seen by the geological static model. Having similar reservoir properties such as initial water saturation, reservoir width and thickness, porosity and permeability with the western block, the eastern block was discovered at the same reservoir pressure as the western block before start of production suggesting hydraulic communication between both blocks. Information on the field is given in Table 1.

Production commenced in 2001 from the western block with the eastern block having no producing well. After a few years of production, a significant drop in reservoir pressure was observed in the West block due to weak aquifer strength. To arrest this pressure decline, powered water injection scheme into the western block of the reservoir commenced in April 2011. After four years of water injection, a substantial rise in reservoir pressure was observed (Figure 2) as confirmed from both static bottom hole pressure surveys and increase in field production.

With the successful implementation of pressure maintenance and oil being swept updip

structure as confirmed by history matched reservoir model, infill opportunities were identified in both the western and eastern blocks. To aid in well placement and to reduce uncertainties related to positions of current fluid contacts (water flood front and GOC), carbon-oxygen logging was attempted in strategically located wells to define the current GOC and OWC across the reservoir. Due to operational reasons, the C/O logging was aborted and instead pilot wells had to be drilled into the two blocks to acquire the data.

Pressure-depth data from RFT acquired while drilling the pilot hole was however surprising as reservoir pressure in the East block was found to be significantly depleted compared to the West block where the water injector was located. This result suggested a lag or no water injection support to the East block but also created an uncertainty on how the East block (updip of West block) was depleted as there is no producer drilled yet into it. Based on the initial understanding of the transmissibility of the fault separating the East and West blocks, it was expected that pressure in this East block would be similar to that of the western block. Reservoir pressure of 1142 psia was observed in the eastern block contrary to a pressure of 1752 psia seen in western block.

Table 1: Reservoir Properties

RESEVOIR PROPERTIES	WEST BLOCK	EAST BLOCK
Darcean sands reservoir with light oil (^{o}AP)	32	32
STOIIP (MMSTB)	42	14
Porosity (%)	27	27
Initial reservoir pressure (psia)	2380	2380
Current reservoir pressure (psia) as at July 2015	1752	1142
Current production (MMSTB) as at August 2015	1385	0
Depth of penetration ((ft tvd-ss)	6008	6210
Oil thickness (ft)	54	41

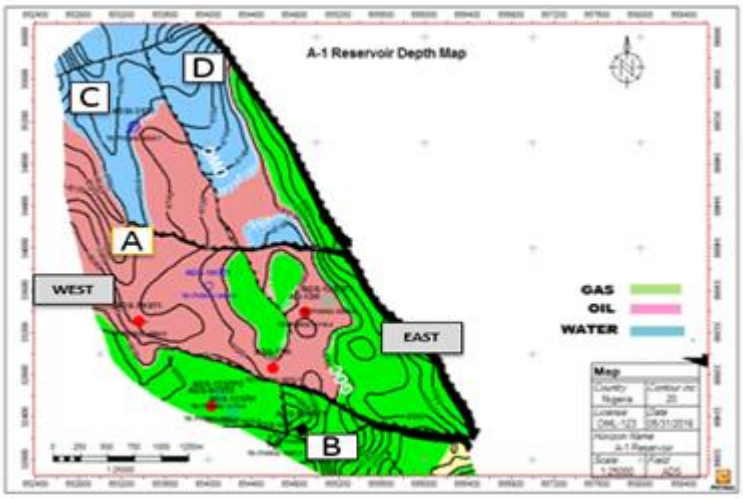


Figure 1: Geological map of the A1 reservoir

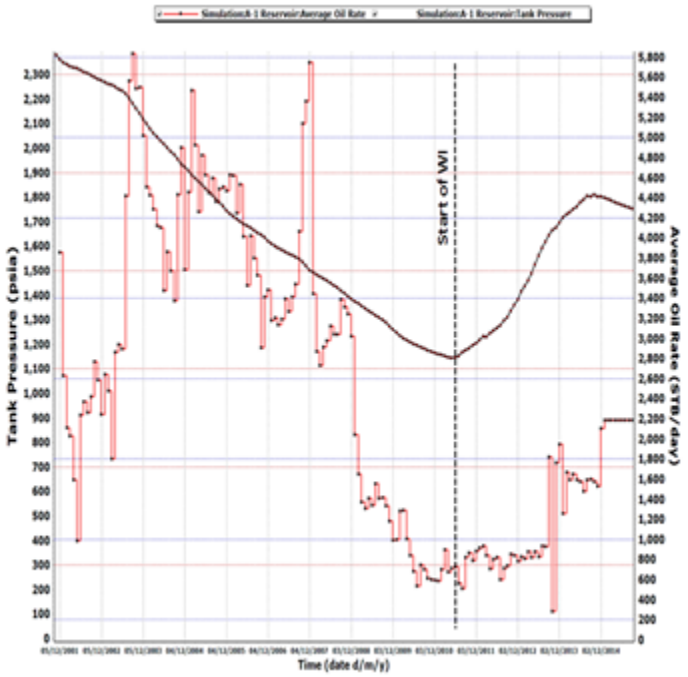


Figure 2: Pressure behaviour in A1 reservoir

In addition to pressure decline, lateral variation in sand quality between the two blocs was also confirmed. On the western side of the block, the reservoir sand was more massive and homogeneous while on the eastern side, the sand column got thinner, impaired by shaly intercalations and was less continuous. A zone referenced as a shaley area had been seen to have potential decrease in reservoir permeability. The result shows that a decrease in the sand quality in the eastern bloc of the reservoir tends to impair its response to water injection (Figure 3).

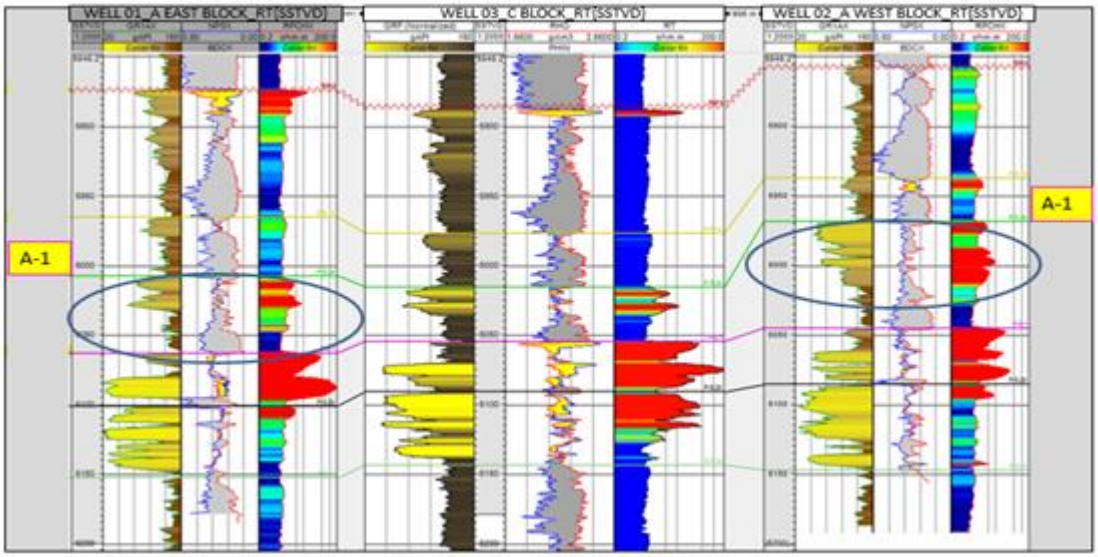


Figure 3: Stratigraphic cross section of the A1 reservoir

At a depth of 6200 ft-tvdss and current reservoir pressure of 1142 psia, the eastern block is under-pressured to warrant drilling an infill well as the reservoir pressure is not sufficient to overcome the hydrostatic head of the formation to enhance fluid flow to the surface. Hence, the need to accurately understand the reason for the difference in pressure between the two blocks, and have a model that is representative of the subsurface. It suffices to say that the

East block also contains its own reasonable unexplored Oil initially in-place (STOIIP) of about 14 MMSTB.

1.1 RESERVOIR MODELS

Some studies have been carried out, in recent times, to capture reservoir heterogeneities where they exist using various methodologies.

The ***Simple Sector Model*** is somewhat complex in that it recognizes different regions of the reservoir. It can therefore model a reservoir with different regional pressures. Its shortcomings, however, is that it may still be inadequate to answer detailed questions like where to locate an infill well in a mature field containing many injector/producer wells and whether or not the well should be vertical, inclined or horizontal.

The ***Fine Grid Model*** is a grid block model of a reservoir where each block typifies a local part of the reservoir within which the properties are uniform although they may change with time as production progresses. Blocks are generally linked to neighboring blocks so that fluid may flow in a block-to-block manner. It may contain sub-models which represent injection/producer wells. Its main limitation is the high computational cost required to discretize the reservoir into grids and the computational time taken (Slatt and Galloway, 1992).

Mogbolu et al (2015) built a ***Multi-Tank Material Balance (MBAL) Model*** as opposed to a single tank MBAL for a heterogeneous reservoir. The heterogeneities as seen in the reservoir they considered were classified into two cases (Case 1 and Case 2). Case 1 was modelled with a three-tank MBAL model while Case 2 was modelled with two-tank MBAL model. With these, they obtained better calibration of contact movement and forecast of existing and future opportunities in both cases. This method is employed in this work.

Heterogeneities have a considerable impact on the effectiveness of the displacement process and consequently, the recovery factor. These associated problems cannot be completely solved but their effects can be managed if known.

To properly manage reservoir heterogeneities, a holistic and integrated approach has to be taken to properly understand the reasons for the heterogeneities and to proffer a satisfactory solution to the problem. An integrated approach was adopted in this work and the result was quite effective in characterizing the heterogeneous reservoir.

2.0 METHODOLOGY

One of the fundamental principles employed in science and engineering is the law of conservation of matter. The application of this principle to hydrocarbon reservoirs, for the purpose of quantitative deductions and prediction, is referred to as *the material balance* (MBAL) *method of reservoir analysis* (Havalena and Odeh, 1963). The general form of the material balance equation is derived as a volume balance which equates the cumulative observed production, expressed as an underground withdrawal, to the expansion of the fluids in the reservoir resulting from a finite pressure drop (Dake, 1977).

The Underlying principle of the MBAL simulation procedure is derived from the general material balance equation. For this work, it relates the original oil, gas, and water in the reservoir to production volumes, current pressure conditions and fluid properties.

Mathematically, the material balance model for an initially saturated volatile and black-oil reservoir is expressed as:

$$\underbrace{G_{fgi}E_g}_{\text{free-gas expansion}} + \underbrace{N_{foi}E_o}_{\text{free-oil expansion}} + \underbrace{WE_w}_{\text{free-water expansion}} + \underbrace{V_{pi}E_f}_{\text{pore-volume contraction}} + \underbrace{W_e}_{\text{water influx}}$$

$$= \underbrace{(G_p - G_I)\left(\frac{B_g - B_o R_v}{1 - R_v R_s}\right)}_{\text{net gas withdrawal}} + \underbrace{N_p\left(\frac{B_o - B_g R_s}{1 - R_v R_s}\right)}_{\text{oil withdrawal}} + \underbrace{(W_p - W_I)B_w}_{\text{net water withdrawal}},$$

where:

- G_{fgi}, N_{foi}, and W are the initial free gas, oil, and water in place, respectively
- G_p, N_p, and W_p are the cumulative produced gas, oil, and water, respectively
- G_I and W_I are the cumulative injected gas and water respectively
- E_g, E_o, E_w, and E_f are the gas, oil, water, and rock (formation) expansivities

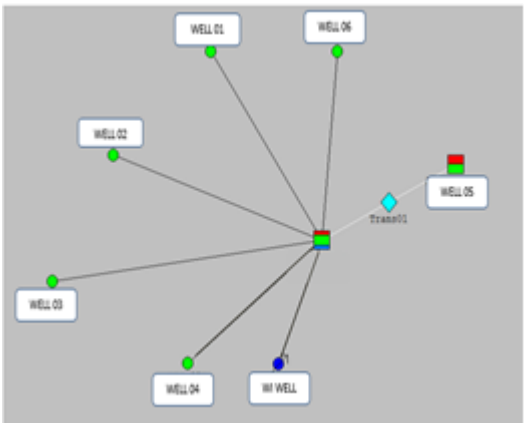
The material balance equation mainly assumes a *tank* behaviour at any given datum depth i.e. the reservoir is considered to have the same pressure and fluid properties at any location in the reservoir. This assumption is quite reasonable provided that production and static pressure measurements are obtained and remain the same. But in this case, the presence of an extending fault and the introduction of water injection as a form of pressure maintenance has divided the reservoir into two slightly difference blocks. Therefore, a two-tank model was built in this work which can adequately capture the presence of the fault, perform history matching and predict future performance of the reservoir. The results of history match, simulation, contacts validation and forecast are then analysed using the Multi-tank MBAL model.

The methodology adopted in carrying out this study is given in the following steps:

a) Data input and quality check
b) Fluid property modelling
c) History matching
d) Simulation and regression
e) Forecast

2.1 Data Input and Quality Check

The data input into the model includes production data, pressure history, PVT properties, relative permeability, aquifer and reservoir parameters. Production data was entered on a well by well basis for all the six (6) wells that have produced from the reservoir. Reservoir pressure was averaged before it was imported into MBAL. Hard pressure data were filtered to static pressures only and corrected to a datum of 6,200 ft-tvdss before imputing into the model. The uploaded data were used to initiate the MBAL model. In doing this a good understanding of the reservoir structure and aquifer strength is needed. A small pot aquifer was chosen for this case due to the small nature of the connected aquifer. The in situ GOR (GOR measured at down hole conditions) was calculated from the gas cap and oil column size converted to reservoir barrels condition. A two-tank model connected with a transmissibility barrier (Figure 4) was generated to capture the distinctive pressure signatures of the East and West blocs.



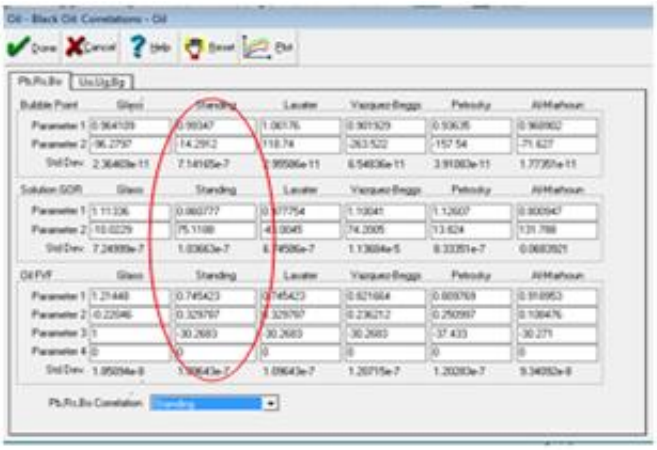


Figure 4: Subsurface representation of the two-tank model

2.2 Fluid Property Modeling

Properties of the reservoir fluid from PVT experiments were matched to the appropriate correlations. Tuned PVT correlations were used to match measured data using a non-linear regression technique. The KPIs from the tuning are; Parameter 1- as close to '1' as possible and Parameter 2 - as close to '0' as possible. A single representative correlation was used, as it gave the best match for P_b, R_s and B_o (with about the least standard deviation) while Beggs et al model was used to match the oil viscosity. Deviation was within a 10% acceptable limit for both Parameter 1 and Parameter 2 (Fig. 5).

3.0 History Matching (HM)

Pressure HM was carried out to tune the model parameters to match the observed pressure response from the reservoir. Fractional flow match model was built based on regression on relative permeability data for producing wells for the saturation history match. A good quality HM was obtained as shown in Figure 6 and can be used in simulation runs for the model.

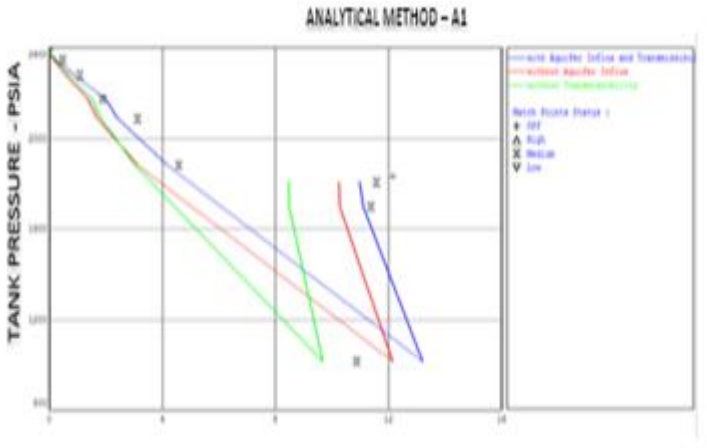


Figure 6: Pressure history match

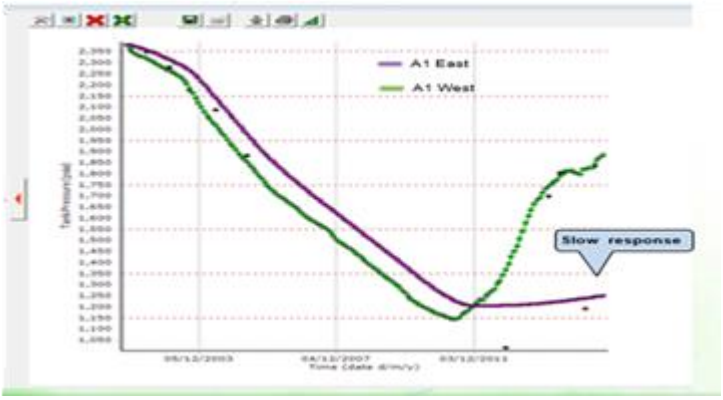


Figure 7: Graphical simulation for West and East blocks

4.0 RESULTS AND DISCUSSION

In this section, which comprises of simulation, regression, forecasting and analysis, we present and analyze the results obtained in this work.

4.1 Simulation and Regression

In this stage, simulation was carried out using our prepared multi-tank model and the results obtained were compared with the actual behavior of the reservoir by measuring the difference between the model and current reservoir performance. Regression involved stabilizing the history matched reservoir by selecting the most appropriate values for parameters such as reservoir width, gas cap size, aquifer size etc. by well-guided engineering judgment.

From the simulation results (figure 7), as pressure was increasing rapidly in the West block due to water injection (WI), a slow increase in reservoir pressure in the East block was observed due to the partial communication between these blocks in the oil leg. The slow response of the East block to WI may be attributed to the poor reservoir sand quality, position of the water injector and the very likelihood that the fault extends beyond the initial interpretation.

4.2 Forecast

Predictions were done using the production profile for each well and a cumulative of the various wells was calculated for the entire model (Figure 8). Well modelling was done by matching the individual well properties to the most recent well test. Sensitivities were run for water cut, top node pressure, GLR injected and GOR parameters and the corresponding Lift curves were generated and imported into MBAL.

a) Prediction started at the end of production (15/11/2015) and ended on 31/07/2022.
b) A maximum water injection rate of 9,000 stb/day and maximum water injection pressure of 1,300 psia were set as future production constraints.
c) For fractional flow, a Corey function based upon regression from saturation history matching was used for predictions rather than importing production history.
d) For future outflow performance relationship, tubing performance curves earlier generated were imported

4.3 Analysis of Result

a) The multi-tank material balance model was sufficient in characterizing the A1 reservoir
b) The presence of good quality sands in the West block explains the reason for its very rapid response to WI as seen in Figure 7.
c) The slow response of the East block to WI (Figure 6) may be attributed to the poor reservoir quality, position of the water injector and the very likelihood of the fault

extending beyond the initial interpretation.

d) The result obtained for tank pressure, average water, oil and liquid rates from the simulation model is a close replica of the current state of the reservoir (Figure 8, Table 2).

e) From the simulation result, some recommendations on how the East block can be re-pressurized can be deduced. Such as; waiting for a few years for the block to feel the impact of WI from the West block (since they are in partial transmissibility) or placing another injector well in a strategic location in the East block as a form of secondary recovery

Table 2: Simulation results for the West and East blocks

	History	Simulated	% Difference
Average oil rate (stb/day)	1612	1535.48	4.75
Recovery factor (%)	24	22	8.33
Reservoir pressure (psia)	1752	1681	4.05
Average water rate (stb/day)	351	323	7.98
Water cut (%)	17.38	17.38	0.00

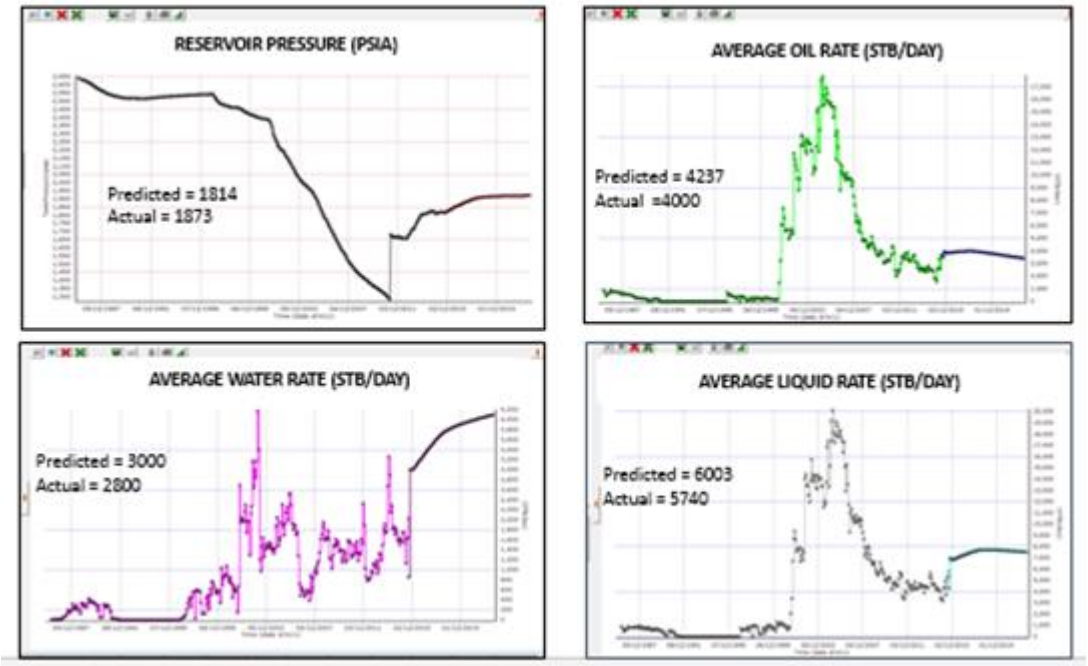


Figure 8: Forecast of the future behaviour of the A1 reservoir

5.0 CONCLUSION

The following conclusions can be drawn from this work.

a) Reservoir heterogeneity is a naturally occurring attribute of reservoirs based on their geological history.

b) In order to capture reservoir heterogeneities, a holistic and integrated approach has to be taken to properly understand the reasons for the heterogeneities and to proffer a satisfactory solution to the problems discerned.

c) From this study, it was shown how a proper understanding and analysis of the field has resulted in significant cost saving by evading the cost of drilling an offshore horizontal infill well into the low pressured East bloc.

d) A material balance (MBAL) model can be used to simulate the dynamic behaviour of a complex reservoir and account for its heterogeneities to a very reasonable extent.

e) The multi-tank model built for this study helped to further understand the dynamics of the reservoir by explaining the current position and nature of the fault.
f) The model has been used to make forecasts that would aid decision making such as where to place infill wells, and where to place injector wells for optimum oil recovery.
g) Continuous WI is encouraged for the East bloc to be re-pressurized over time.

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Abbreviations and Acronyms

Bo = Formation volume factor of oil
GLR = Gas liquid ratio
GOC=Gas oil contact
GOR = Gas oil ratio
HCIIP= Hydrocarbon initially in place
HM = History match
KPI = Key performance indicator
MBAL = Material balance
MBE= Material balance evaluation
OWC= Oil water contact
Pb = Bubble point pressure
PVT = Pressure, volume, temperature
RFT = Repeat formation tester
Rs = Solution gas oil ratio
STOIIP = Stock tank oil initially in place
Tvd-ss = true vertical depth subsea
WI = Water Injection