IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG)
e-ISSN: 2321–0990, p-ISSN: 2321–0982.Volume 8, Issue 3 Ser. I (May–June 2020), PP 18-28
www.iosrjournals.org

Optimization of Production in Alwyn-North Field through Well Placement Modelling

Igben Enohor Ngozi[1,2], Lawrence C. Edomwonyi-Otu*[3], Godwill Peprah[2].
[1]*Institute of Petroleum Engineering, Heriot Watt University, Edinburgh, United Kingdom*
[2]*Department of Oil and Gas Engineering, All Nations University College, Koforidua, Ghana*
[3]*Department of Chemical and Petroleum Engineering, Delta State University, Abraka, Nigeria.*

Abstract: *This study presents the findings on how production optimization in Alwyn-North Field can be enhanced by well placement modeling. To carry out this research, knowledge of Stanford Geomodeling Software®(SGeMs), MATLAB® and Eclipse 100® were employed. For this work, great caution is taken in the modeling phase as well locations will beproposed based on this. The 3D reservoir geologic model is built based on the data from the seismic surveys and analysis from nearby wellsusing MATLAB®. The model shows the pressure zones, structural traps and nine (9) possible productionwell placement locations for vertical wells. Eclipse100® reservoir simulator aided the simulation of the field oil efficiency, gas production rate, oil production rate, cumulative production rate, water cut and active drive mechanisms. The presence and the absence of an infinite aquifer were taken into consideration for each simulation. From the simulation, after a period of 3,300 days considering the primary recovery mechanism, producer wells 3 and 4 proved more promising. This showed a cumulative oil production of 0.77 x* 10^6 m^3 *and 1.84 x* 10^6 m^3*, recovery factor of 19.3% and 8%, and solution gas and water as driving force, respectively. It is recommended, that in the absence of an aquifer the drilling should be in the region favourable for well 3, while in the presence of an aquifer, the well should be drilled in the region favourable for well 4. The novelty of this work is that it provides solution to the adverse effect, well placement and drive mechanisms have on production in the field scale. This work reveals the huge risk involved operationally if any wrong decisions are made.*

Keywords*: Reservoir, Drilling, Geomodeling, Safety, Well placement, Simulation.*

Date of Submission: 27-04-2020 Date of Acceptance: 10-05-2020

I. Introduction

In oil recovery, to avoid expense on drilling dry holes, the use of reservoir simulators has been very useful and promising. Reservoir simulation involves construction and operation of a mathematical model which mimics the behavior of an actual reservoir with the objective of predicting future reservoir performance (Al-Yousef, 2013). Similar models have been developed for transportation of crude mixtures from production wells and across the oil & gas industries as well as other chemical related industries (Edomwonyi-Otu and Angeli, 2015, 2019; Edomwonyi-Out et al 2015). The main purpose ofthe simulationcarried out here, is to provide an information database that can help the oil companies to position and manage wells and well trajectories to maximize the oil and gas recovery (Lie, 2014). Moreover,the economy ofmost oil producing countries relies on money made from oil and their products. Hence, the relevance of this work, is that it serves as a guidance on how production can be optimized by well placement. It is important to note that during the early stages of optimizing field development, well placement is very demanding because the available data is not sufficient to pin-point the exact locations suitable for economic recovery (Kheireddine et al 2018). The data gotten at the early stages are minimal and prone to errors,but long-term decisions have to be made reliant on this information. (Peprah and Waburoko, 2016). Well placement is dependent on the reservoir and fluid properties which can be gotten in real time, well test analysis, and surface equipment specifications, as well as economic parameters (Bourgeois et al 2006; Pouladi et al 2018). Likewise, optimum reservoir performance is dependent on the well locations. Therefore, determining the well locations requires the use of most reliable techniques to avoid excess drilling costs, and drilling impenetrable areas (Jesmani et al, 2016). This will alleviate the problems associated with placement of oil and gas wells in the initial stages of field development. Furthermore, the use of intuitive judgement alone in determining well locations is not appropriate. This is because aside the non-linear correlation, reservoir engineering and geological variables affecting reservoir performance are also time and process dependent (Ahmed and McKinney, 2005). Hence, there is the need to run simulations for an objective well-placement location considering key production variables. Development strategies and well placement may significantly depend on field geology, maturity of the depletion stage, technological factor, drive resources and other parameters. (Badru, 2003) Using a mathematical model for optimization does not account for certain physical occurrences that take place within the reservoir and would affect any conclusions made solely from this (Yakovlev et al, 2019). Therefore, embedding feasible and practical constraints into this process as it involves including relevant reservoir engineering knowledge into the solution (Jesmani et al, 2016; Yakovlev et al, 2019). The SGeMs uses an algorithm to get a global solution that optimizes the drilling location by narrowing the data sequentially(Ilsik et al, 2018). Before strategies for the development and management of petroleum fields, it is important to account for any limitations with the intended model and optimization approach to be used. Reservoir Management begins with exploration leading to discovery followed by appraisal of the reservoir, development of the field under primary and secondary means, improved oil recovery, enhanced oil recovery and finally to abandonment (Akpan, 2012). Accordingly, this study aimed at determining the well placement location for optimum oil and gas production in Alwyn-North Brent East reservoir from nine wells. This is achieved by simulating the field oil production, water production, and gas production with and without an aquifer using Eclipse. Since it is the initial development stage, the active drive mechanism in the reservoir is facilitated the choice of well location with maximum oil and gas recovery efficiency. This study utilized the MATLAB Reservoir Simulation Toolbox (MRST) and Schlumberger Eclipse 100 simulator in modelling the reservoir and simulating different production scenarios respectively.

II. Methodology

STUDY AREA

The Alwyn-North Field was discovered in 1974 in the South Eastern part of the East Shetland Basin in the UK North Sea. It's location relative to other fields is shown in Figure 1. The Alwyn field lays respectively 4 and 10 km south of Strathspey and Brent field, 7 km east of Ninian field, and 10 km north of Dunbar field. The water depth is around 126m and the field is operated by Total E&P. The field data simulated here is gotten from the UKCS Block 3/9 and extends northward into the Block 3/4 (See Figure 1).A dynamic flow simulation is carried out on an oil field with MRST to determine the best location to drill a well on the field. Running sensitivities on two possible scenarios and predicting production for primary recovery. During primary recovery the natural energy of the reservoir is used to transport hydrocarbons towards and out of the production wells. The earliest possible determination of the drive mechanism is a primary goal in the early life of the reservoir, as its knowledge can greatly improve the management and recovery of reserves from the reservoir in its middle and later life (Glover, 2012). Figure 2 is a flow chart that shows the step by step process carried out in this study.

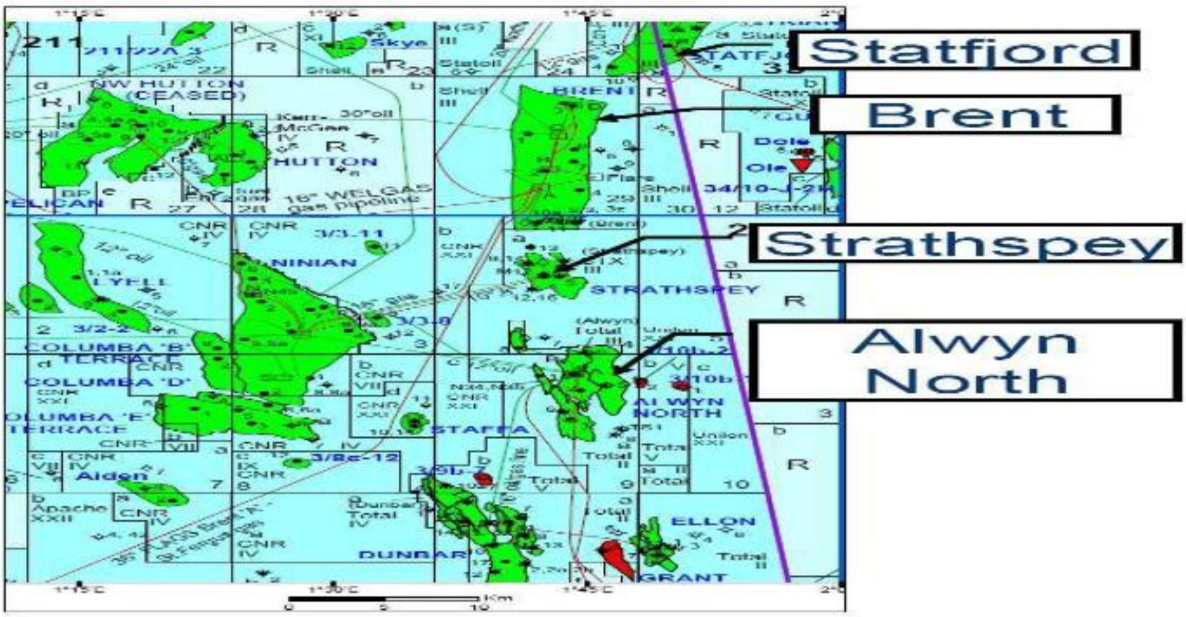

Figure 1: Alwyn North Oil Field (Nwosu, 2015)

The reservoir in the field has an anticlinal structure, which is not symmetrical at both ends. In each assumption, 9 cases were simulated. The nine cases are the possible well locations on the field gotten from the SGeMS tool. This tool works based on kriging technique. In Figure 4, the SGeMS tool which works on Kriging principle shows the possible producer and injector wells. It gives a total of nine producer wells which in turn narrows down the large reservoir portion to nine possible locations. It shows the wells with no dynamic (pressure, temperature and saturation) or static (porosity and permeability) parameters description. The anticline nature of the reservoir also affects the position of the wells and it can be seen that most of the wells are positioned at top or flanks of the structure.

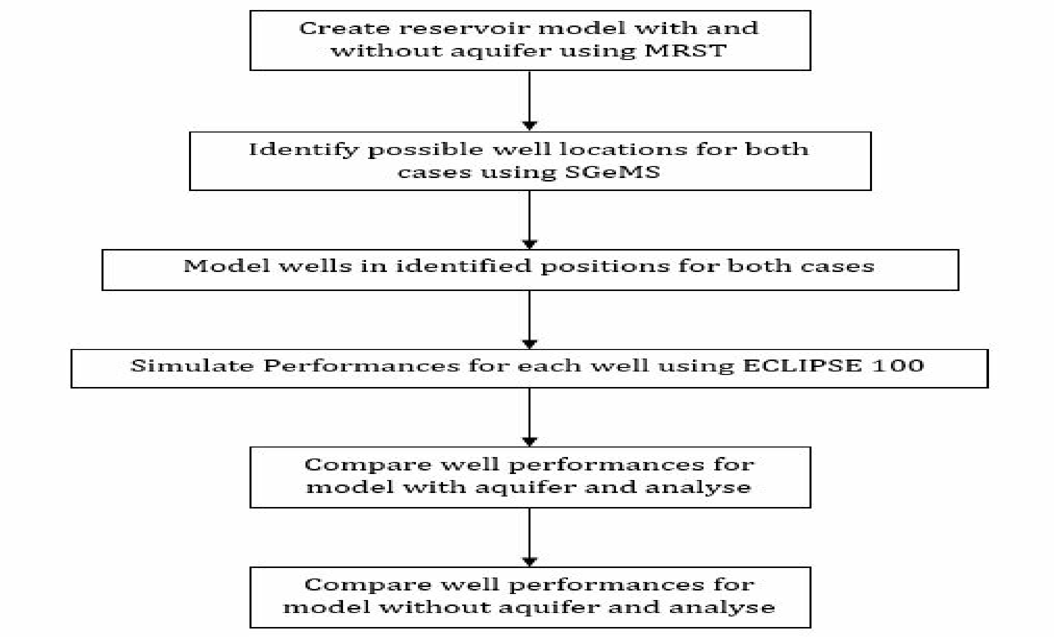

Figure 2: Flow chart indicating the step by step process carried out

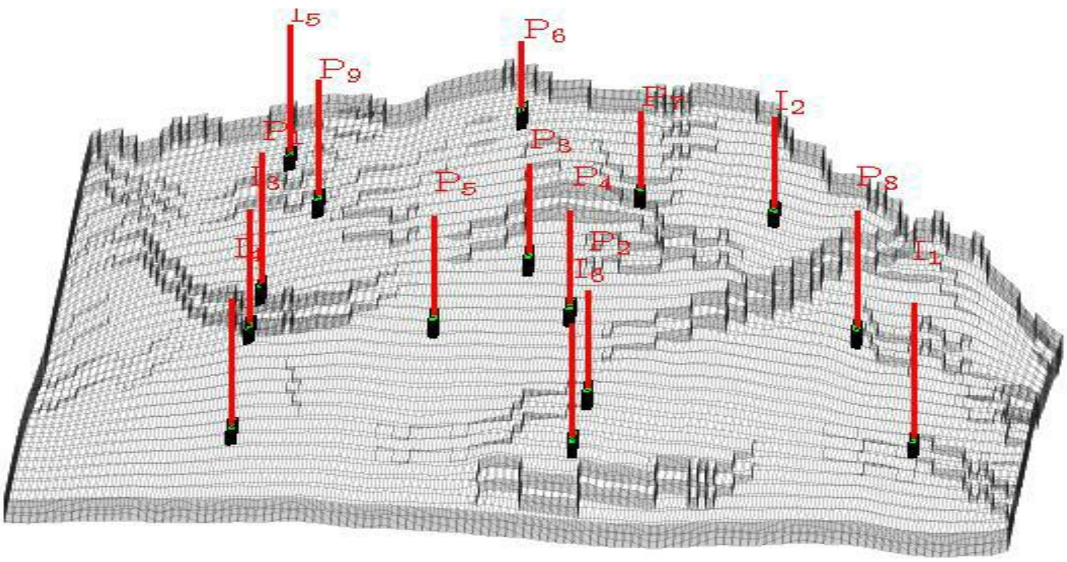

Figure 3: Possible Producer and Injector wells.

Table 1 shows data is used to simulate the model with the two cases with and without an aquifer. This data was acquired from resource personnel in the department of oil and gas engineering, All Nations University College, Ghana.

Table 1:Alwyn-North reservoir data

Parameters	**Value**	**Units**
Reference pressure	260	Bar
Water FVF at Pref	1.01	$\frac{rm^3}{sm^3}$
Water compressibility	4.4E-5	1/bar
Water viscosity at Pref	0.4	cP
Oil density	825.8	kg/sm^3
Water density	1025	kg/sm^3
Gas density	0.982	kg/sm^3
Oil relative permeability, k_{ro}	0.0265	Dimensionless

Oil formation volume factor, β_o	1.63	rb/stb
Oil viscosity, μ_o	0.27	cP
Average reservoir thickness	70	Ft
Total oil in place	2,493,078,669	MMStb
Solution oil-gas ratio, R_s	195.8	$\frac{Sm^3}{rm^3}$

Original Oil in Place Calculation

$$N_p = \frac{7758 * A * h * \emptyset * s_o}{\beta_o}$$

Oil Recovery Efficiency Calculation

RE = $\frac{Initial\ \ oil\ in\ place\ - Residual\ \ oil}{Initial\ \ oil\ in\ place} X\ 100\%$ 2 Where: RE = Recovery Efficiency

Table 2: Live oil PVT table

Solution gas ratio, Rs (scf/stb)	PSAT (psia)	Oil formation volume factor, Bo (stb/day)	Viscosity of oil (cP)
0	1.0	1.010	2.87
14.8	25.0	1.048	2.50
28.9	50.0	1.078	2.24
42.9	80.0	1.121	1.96
61.0	110.0	1.170	1.72
78.0	140.0	1.226	1.53
102.3	170.0	1.291	1.36
124.7	200.0	1.362	1.22
140.0	220.0	1.411	1.15
162.0	240.0	1.405	1.16
184.6	260.0	1.403	1.17
206.4	300.0	1.398	1.18
227.0	350.0	1.388	1.22

Table 3: Dissolved gas PVT table

Pressure (psia)	BG (ft^3/scf)	Viscosity of Gas (cP)
1.0	1.243	0.0121
25.0	0.0497	0.0131
50.0	0.0249	0.0136
80.0	0.0155	0.0145
110.0	0.0113	0.0158
140.0	0.0089	0.0172
170.0	0.0073	0.0189
200.0	0.0062	0.0207
220.0	0.0057	0.0220

Table 4: Formation water PVT table

PRES (psia)	BW (stb/rb)	Water Compressibilty (psi^{-1})	Viscosity of Water (cP)
260.0	1.0100	4.4E-5	0.4

Table 5: Water-Oil relative permeability table

Water saturation	Water relative permeabilty	Water-oil relative permeability	Water-oil capilary pressure, (psig)
0.22	0.0000	0.8000	0.600
0.25	0.0002	0.6835	0.390
0.30	0.0022	0.5143	0.210
0.35	0.0074	0.3742	0.124
0.40	0.0168	0.2609	0.079
0.45	0.0310	0.1721	0.053
0.50	0.0507	0.1052	0.037
0.55	0.0765	0.0576	0.027
0.60	0.1088	0.0265	0.020
0.65	0.1482	0.0089	0.015
0.70	0.1951	0.0014	0.0122
0.75	0.2500	0.0000	0.009
1.00	1.0000	0.0000	0.000

Table 6: Gas-Oil relative permeability table

Gas saturation	Gas relative permeability	Gas-oil relative permeability	Gas-oil capillary pressure,

			(psig)
0.00	0.0000	0.8000	0.000
0.05	0.0144	0.6722	0.000
0.1	0.0408	0.5556	0.001
0.15	0.0750	0.4500	0.002
0.20	0.155	0.3556	0.004
0.25	0.1614	0.2722	0.007
0.30	0.2121	0.2000	0.012
0.35	0.2673	1389	0.020
0.40	0.3266	0.0889	0.029
0.45	0.3897	0.0500	0.042
0.50	0.4564	0.0222	0.058
0.55	0.5266	0.0056	0.077
0.60	0.6000	0.000	0.100

III. Results

The reservoir initial pressure distribution measured in bars is shown in Figure 4. The numeric pressure values with the colour coding are represented with the vertical column above. The bluish to reddish regions indicates low to high pressure zones respectively.

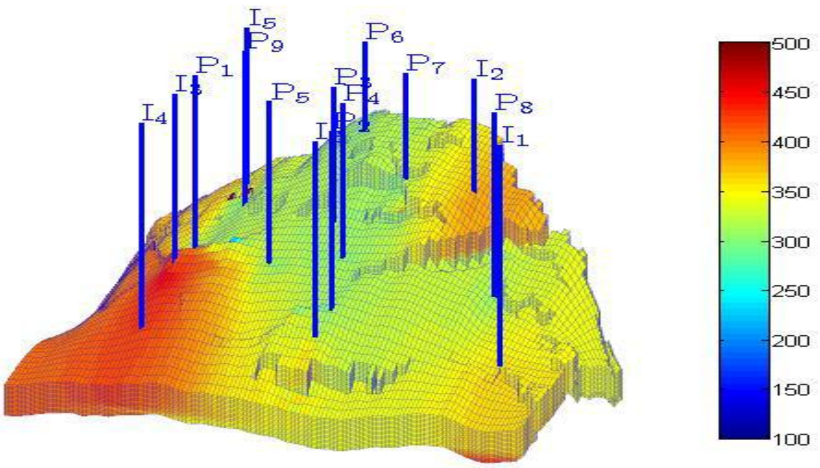

Figure 4: Geologic model showing initial pressure distribution measured in bar

Flow Simulation Results without Aquifer

An aquifer is an underground layer of permeable rock, sediment (usually sand or gravel), or soil that yields water. The pore spaces in aquifers are filled with water and are interconnected, so that water flows through them. In this case scenario, simulation is performed without including the presence of any aquifer. From Figure 5, the total oil reserve is 9,260,000 sm^3. Well 3 had the lowest residual oil volume of 8,500,000sm^3, followed by wells 2, 4, 8, 1, 7, 9, 5 and 6 respectively at the end of 3,300 days. Wells 3, 2, 4 and 8 were more promising than the others.

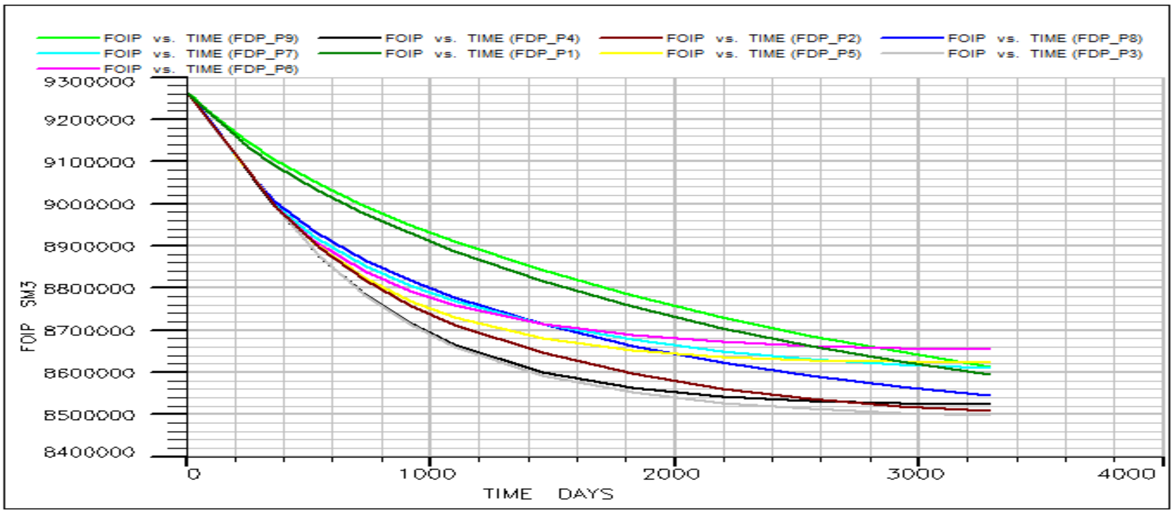

Figure 5: A plot showing field oil in place, before, during and after production

The results achieved in Figure 6 shows well 3 had the highest oil production total of about 770,000 sm^3. Followed by wells 2, 4 and 8, while well 6 had the lowest yield of about 610,000 sm^3.

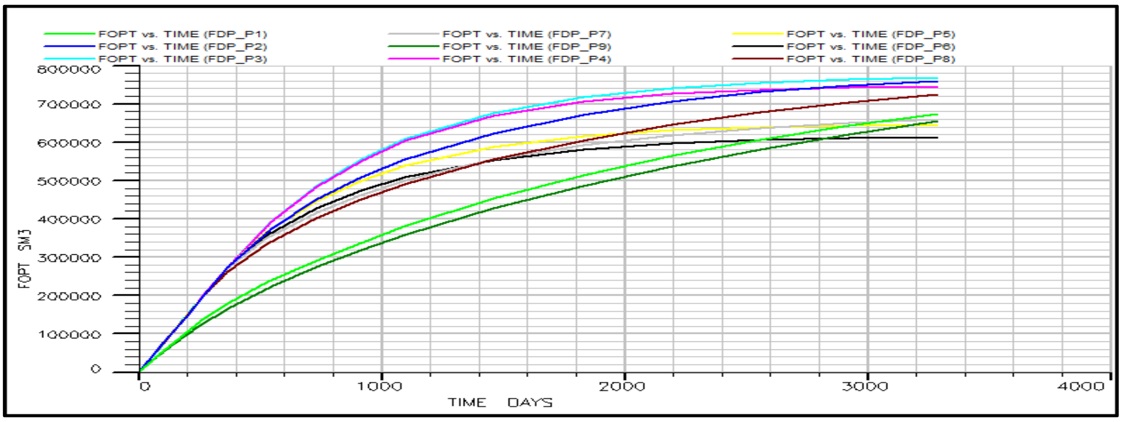

Figure 6: Graph showing cumulative oil production without aquifer for all the 9 wells.

From the Figure 7, the production of gas favours well 4, 3 and 5. This is as a result of the position of the wells in relation to the field geometry (anticlinal) and gravity contrast between the different fluids.

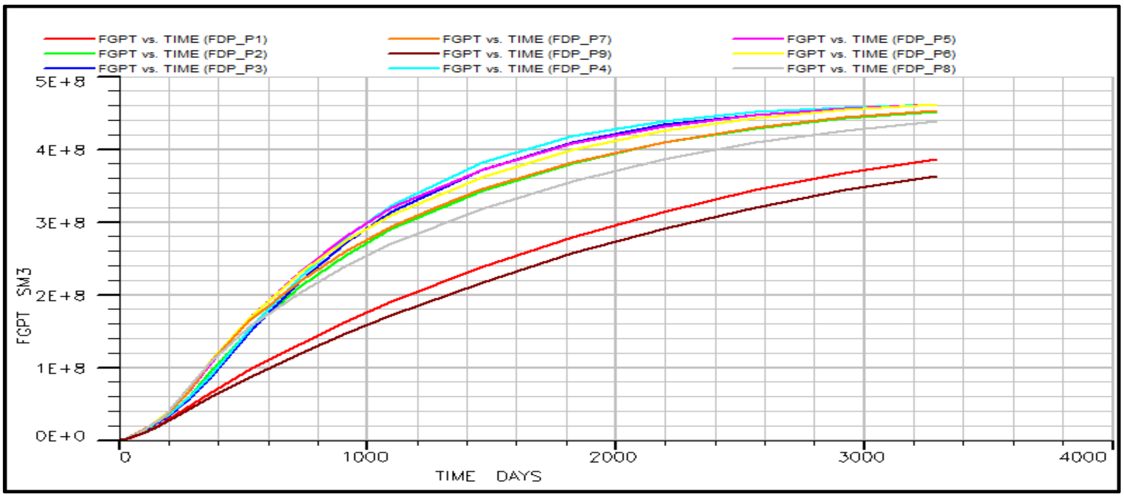

Figure 7: Graph showing cumulative gas production without aquifer for all the 9 wells

From Figure 8, well 1 and 9 produce some amount of water even when the simulation is done without aquifer. This is due to the fact that these wells are located at the flank of the anticline, close to the oil water contact (OWC).

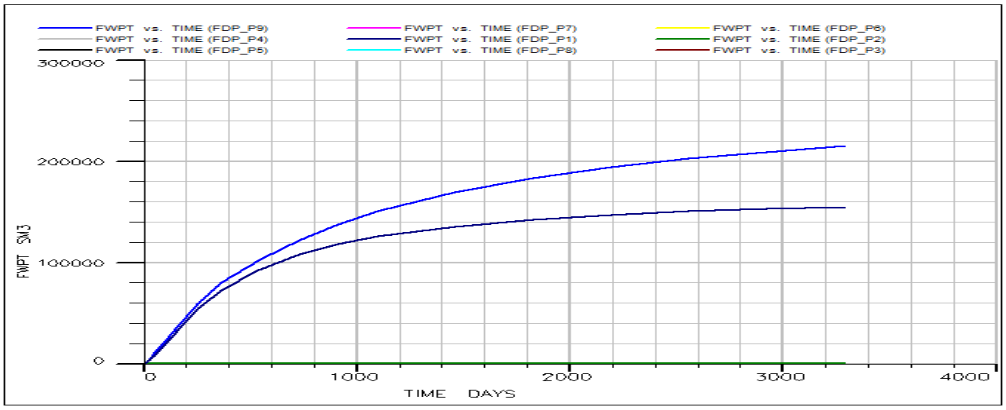

Figure 8: Graph showing cumulative water production without aquifer for all the 9 wells

Major Drive Mechanisms Analysis For Well 3 Without Aquifer

From the Figure 9, the major drive mechanism without aquifer is fluid expansion (solution gas drive) as confirmed from the previous plot of FOTP versus time.It shows the four major primary drive mechanisms contributing to the production of oil in well 3.

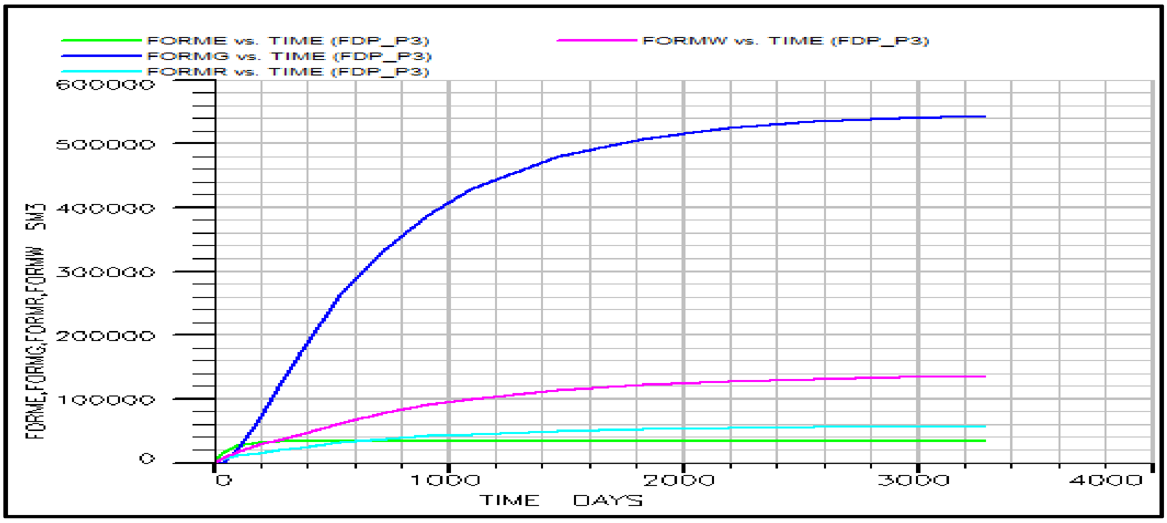

Figure 9: Graph showing the four major drive mechanisms contributing to the production of oil in well 3

Flow Simulation Results with Aquifer

Cumulative Oil Production per Wells with Aquifer

From the Figure 10, it is observed that with an aquifer, well 4 gives the highest oil production, followed by well 3, unlike the case without aquifer. From the simulation, it is evident that the main drive mechanism is water drive with a slight support from solution gas drive.

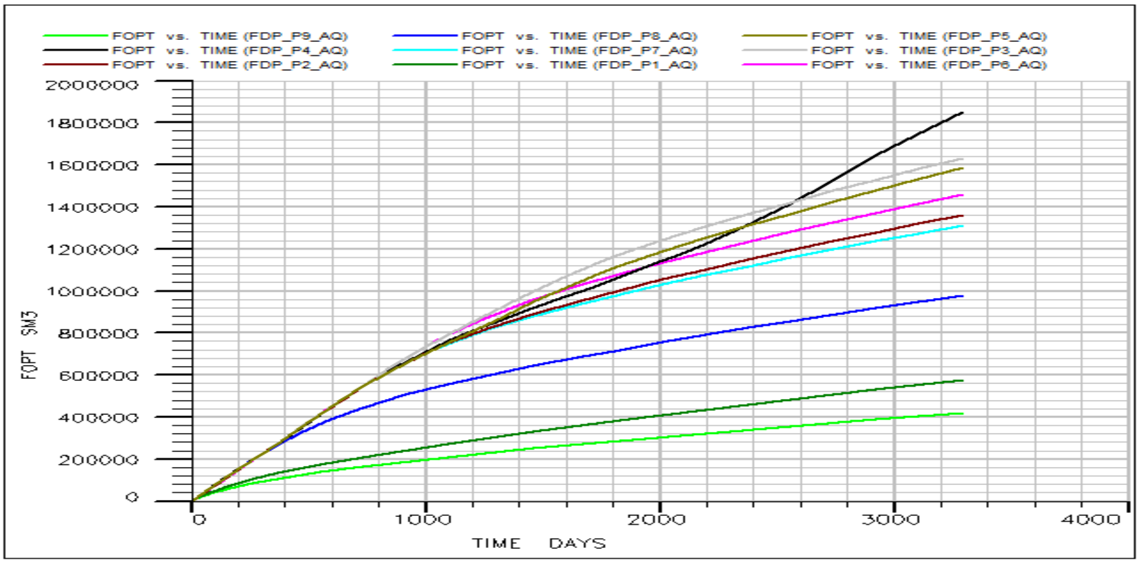

Figure 10: Plot cumulative oil production per wells with aquifer

From Figure 11, there is a decrease in the field oil in place after production commenced. This plot shows the field oil before, during and after production.

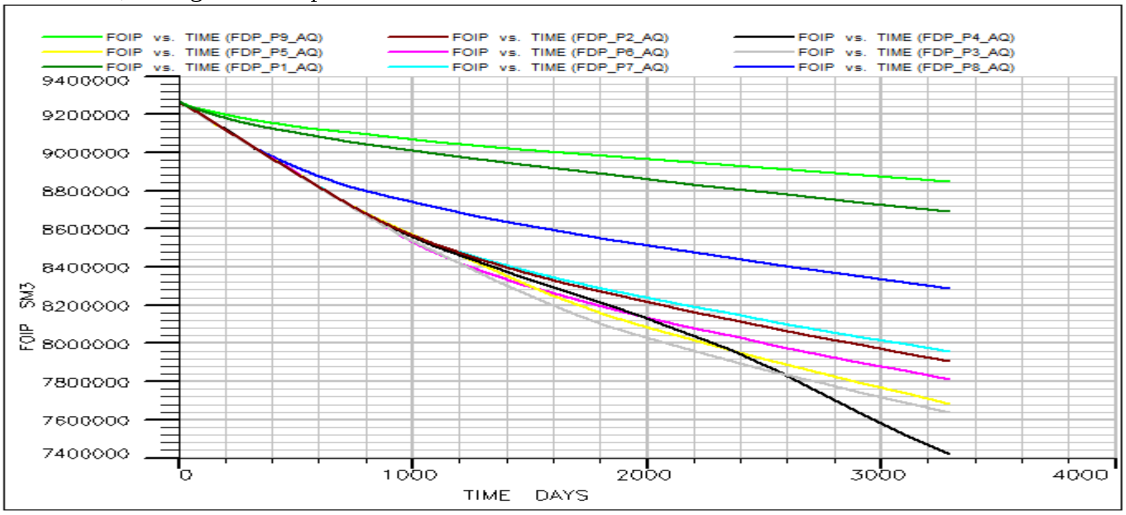

Figure 11: A plot showing field oil in place, before, during and after production

From Figure 12, the highest production of gas favours well 4, followed by 3 and 5. This is as a result of the position of the wells in relation to the field geometry (anticline) and gravity contrast between the different fluids.

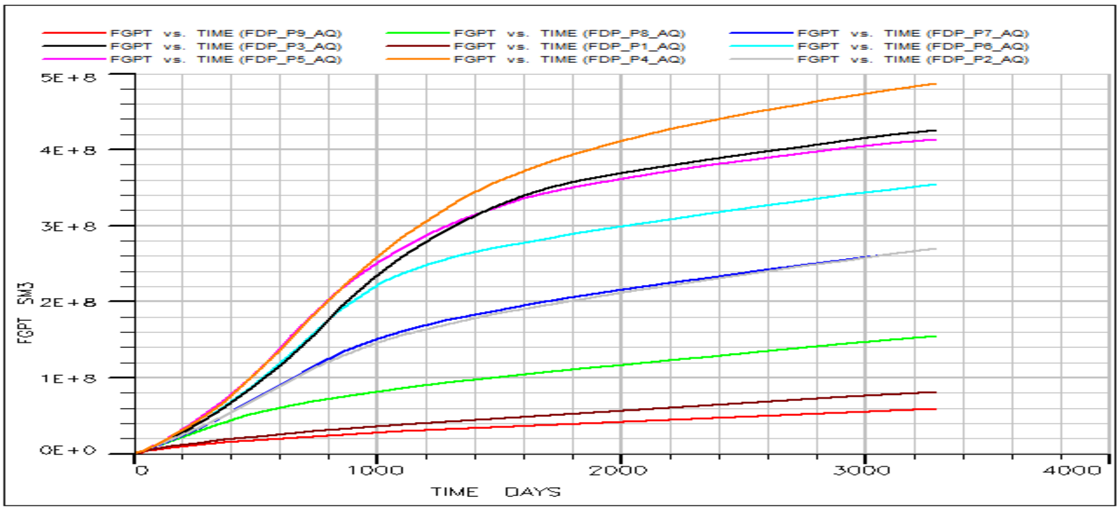

Figure 12: Plot showing gas production from the nine (9) wells

Water Production

From Figure 13, it is observed that all the wells are producing significant amount of water with the exception of well 4 due to its location in the field. Well 1 and 9 produce the highest since they are located at the flank of the anticline, close to the oil water contact (OWC).

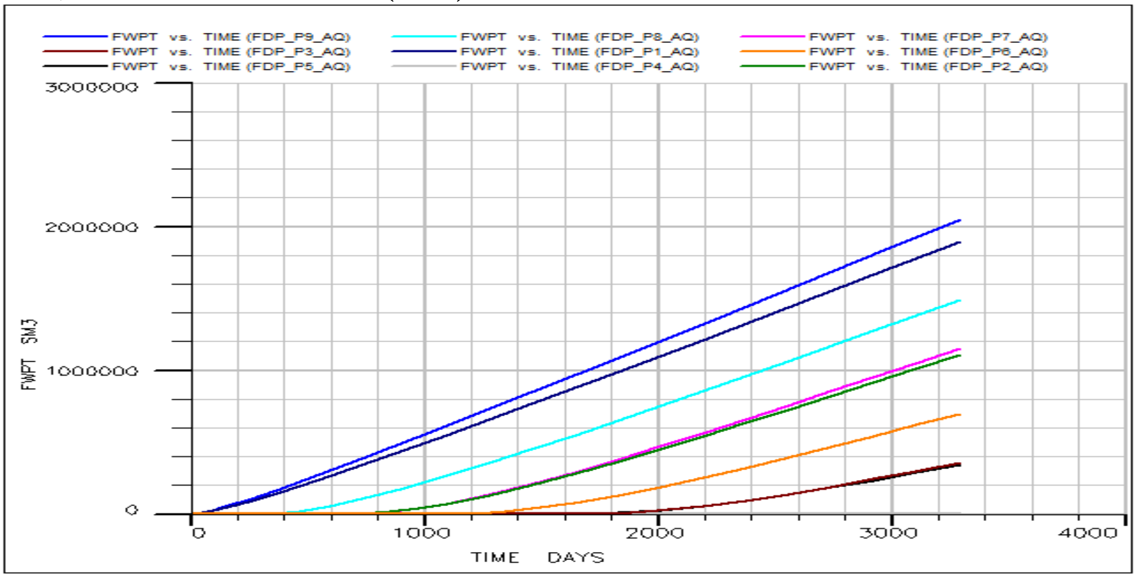

Figure 13: Plot showing water production from the nine (9) wells

Major Drive Mechanisms Analysis per Well with Aquifer for Well 2, 3 and 4

From Figure 14, the major drive mechanism is water drive, unlike in the case without aquifer where solution gas is the main drive mechanism.

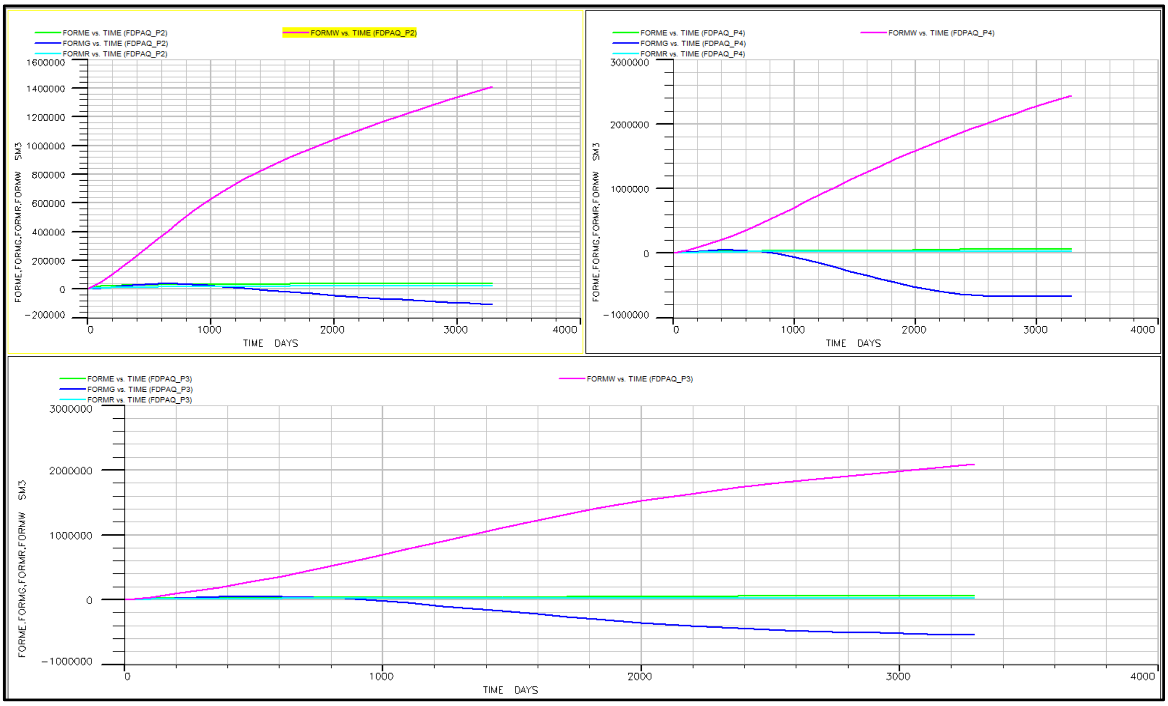

Figure 14: Plot showing the major drive mechanisms per well with aquifer

Oil Recovery Analysis

Oil recovery analysis for well 3 (aquifer present) and well 4 (aquifer absent), shows the difference in oil recovery for both case scenarios. For the presence of an aquifer, well 4 had oil recovery efficiency of 19.3% and in the absence of an aquifer, well 3 had a low oil recovery efficiency of 8%.

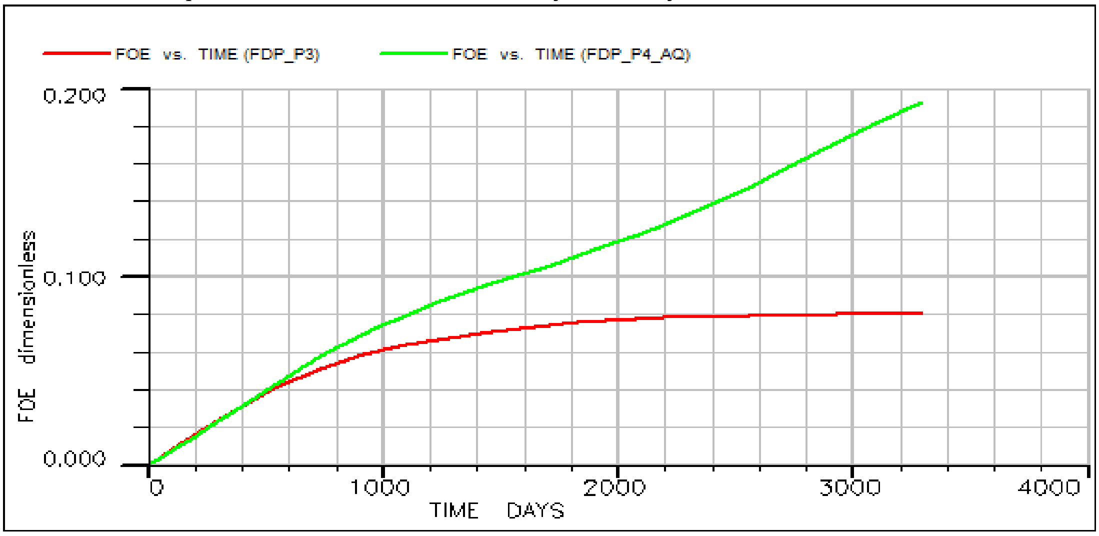

Figure 18: Oil recovery analysis per region for well 2, 3 and 4 without aquifer

The oil recovery analysis from the flow simulation indicates that well 4 and 3 had the highest oil recovery factor with and without an aquifer respectively. The best location for the major producers (3 and 4) is at the top of the anticline.

IV. Discussion

The simulation results for the case without anaquifer shows that at the end of 3,300 days, wells 3, 2, 4 and 8 were promising compared to the others. From the simulation, it is also evident that the main drive mechanism is solution gas drive, since there is no aquifer and gas cap. The solution gas drive is due to the released of gas from the oil. With a total oil reserve of 9,260,000 sm^3, well 3, had the highest oil production total of about 770,000 sm^3. Comparing the results obtained to the cases from Nwosu, U.D (2015) for the same field with varying data inputs such as the well location, where the natural depletion is simulated.This was based on the assumption of no aquifer support for 6 years and it yielded about 1,104,597sm^3 for an initial oil reserve of 35,681,991sm^3. They also had only 3 wells in that location based on the average well rate equation, implying that the wells chosen were not done considering the field's optimal production location. It is important to note that different optimization techniques can be bias based on the data used (Güyagüler, 2012). However, this work bridges the gap of depending on the proposed well rates method ofdetermining the number of wells within a field for optimum production. As it uses the kriging software to make the initial assumptions and tests the proposed locations to narrow the locations based on the wells with less water production and more oil production. As the reservoir has an anticline structure, it helps narrow the area of profitable recovery to the top region, just below the caprock.

V. Conclusion

Analysis on the well placement location considering the presence and absence of aquifer showed that producer wells 3 and 4 were more promising with cumulative oil production of 0.77E6 sm^3 where solution gas was the active drive mechanism and 1.84E6 sm^3 in the case where water drive was the active drive force in the reservoir respectively at the end of the simulation peiod 3300 days. Water production was a significant factor taken into consideration in this work to ascertain the decision on the best well location. In the absence of an aquifer well 3 produced no water due to its location at the top of the anticline, above the oil-water contact (OWC). This was not the case for well 4 in the presence of an aquifer, which had a water production of about 370,000 sm^3 water. This shows that in the absence of an aquifer, well 3 will produce at an optimum oil rate. Plausibly, the well should be drilled in the location, which is quite favourable for 3 with no aquifer and 4 in the case of an infinite aquifer with a recovery factor of 19.3% and 8% respectively.

References

[1]. Akpan, S. E. (2012) Well Placement for Maximum Production in the Norwegian Sea. Norwegian University of Science and Technology, Page 11, 17, 20.

[2]. Ahmed, T. and McKinney, P.D. (2005). Advanced Reservoir Engineering, Elsevier, Oxford. Eclipse Reference Manual, Page 120-123.

[3]. Al-Yousef, D. H. Y. (2013)Purpose of Reservoir Simulation. Kwame Nkrumah University of Science and Technology, Kumasi, Page 4.

[4]. Badru, O. (2003)Optimization Using the Quality Map Approach, Master's Thesis, Department of Petroleum Engineering Stanford University, U.S.A., Page 12-15

[5]. Bourgeois, D., Tribe, I.,Christensen, R.,Durbin, P., Kumar, S.,Skinner, G&Wharton, D. (2006) Improving Well Placement with Modeling while Drilling, Oilfield Review. 18. 20-29.

[6]. Edomwonyi-Otu, L.C. and Angeli, P. (2015) Pressure drop and holdup predictions in horizontal oil-water flows for curved and wavy interfaces, Chemical Engineering Research and Design, Elsevier, Volume 93,55–65. doi: 10.1016/j.cherd.2014.06.009.

[7]. Edomwonyi-Otu, L.C. and Angeli, P. (2019) Separated Oil-Water Flows with Drag Reducing Polymers Experimental Thermal and Fluid Science. Elsevier, Volume 102(September 2017), 467–478. doi: 10.1016/j.expthermflusci.2018.12.011.

[8]. Edomwonyi-Otu, L.C., Chinaud, M. and Angeli, P. (2015) Effect of Drag Reducing Polymer on Horizontal Liquid-Liquid Flows, Experimental Thermal and Fluid Science, Elsevier, Volume 64,164–174. doi: 10.1016/j.expthermflusci.2015.02.018.

[9]. Glover, P. (2012)Reservoir DriveMechanisms, Reservoir Engineering Lecture Notes, Petroleum Engineering and Geosciences Department. Chapter 3, Page 19-27.

[10]. Güyagüler, B. (2012) Optimization of Well Placement and Assessment of Uncertainty, PhD Thesis, Department of Petroleum Engineering, Stanford University, Page 36.

[11]. Ilsik, J., Seeun, O., Yumi, K., Changhyup, P &Hyunjeong, K. (2017) Well-placement Optimisation using Sequential Artficial Neural Networks, Energy Exploration & Exploitation, SAGE, Volume 36(3) 433-449.

[12]. Jesmani, M., Bellout, M.C., Hamea, R& Foss, B. (2016) Well Placement Optimization Subject to Realistic Field Development Constraints, Computational Geosciences. 2p.10.1007/s10596-016-9584-1.

[13]. Kheireddine, R., Nourddine, Z&Menad, N.A. (2018) Automated Optimization of Well Placement via Adaptive Space-Filling Surrogate Modelling and Evolutionary Algorithm, SPE Journal.

[14]. Lie, K. (2014)An Introduction to Reservoir Simulation Using MATLAB, User Guide for Matlab Reservoir Simulation Toolbox (MRST). SINTEF ICT, Page 110-111.

[15]. Nwosu, U.D. (2015)Dynamic Reservoir Simulation of Alwyn field using Eclipse, Dissertation. http://works.bepress.com/dixon_nwosu/1/. Page 28-33.

[16]. Pouladi, B., Sharifi, M., Akbari, M.R& Hosseini-Nasab, S.M., (2019) A New Numerical Well Testing Approach: Application to Characterization of Complex Fault Structures, Elsevier, Volume 5, Issue 3.

[17]. Peprah, G. and Waburoko, J. (2016). Application of 3D Reservoir Modeling on Zao 21 Oil Block of Zilatun Oil Field China. University of Geosciences, Wuhan, Hubei, China, Page 16.

[18]. Yakovlev, V.V., Kalugin, Y.I., Kalugin, Y.A&Stepova, N.G., (2019) Mathematical modelling of Enhanced Gas Production, Journal pf Petroleum Exploration and Production Technology 9, 561-571