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Modelling Well Performance in Niger Delta Reservoir using Tuned Vertical Lift Performance (VLP) Correlation

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ABSTRACT

Well performance modelling is an intrinsic part of petroleum engineering study. It is a combination of the produced fluid PVT model, the reservoir IPR model and the VLP model. It involves modelling the pressure losses encountered by the reservoir fluid as it flows from the bottomhole to the surface. Many investigators have developed different correlations to model these pressure losses but none has been found to be the most accurate because fluid flow in the tubing is usually multiphase and very complex. In this work multiphase flow correlations were modified by tuning to fit the measured downhole pressure and rate from the production test using prosper in order to model the performance of the well under study. Thus, results from production tests are required to tune the correlation to match the observed behaviour. Results showed that the well performance is dependent on the reservoir pressure, tubing head pressure (THP), tubing size and water cut. From the case study, it was observed that the well will not flow if left at its present condition (250psig THP, 30%water cut, 2.875" tubing size) at reservoir pressures below 2900psig. Reducing the THP (to about 200psig) as well as the tubing size results in increase in production.

Keywords: VLP, PVT, THP, AKUB, GLR, PROSPER

I. INTRODUCTION

Hydrocarbon accumulations are usually found thousands of feet beneath the earth surface. This means that a connection has to be made between the surface and the subsurface reservoir to permit the production of the accumulated hydrocarbons. This connection is the well. Thus, the need to analyze and predict the performance of the well cannot be over emphasized. Well performance is the measure of the ability of the well to produce the reservoir fluid related to the well's anticipated productive capacity, pressure drop or flow rate (Karikari, 2010)). Therefore, well performance analysis involves establishing a relationship between tubular size, wellhead and bottom-hole pressure, fluid properties, and fluid production rate including the reservoir deliverability (Ahmed, 2010). The investigation of pressure drop in oil and gas wells is a very important aspect of petroleum engineering because it acts as a guide for cost effective well design, well completions and production optimization (Fossmark, 2011). The pressure drop is encountered as the fluid flow from the bottom hole through the tubing/casing to the surface. This results from friction between the fluid and the walls of the tubing, restrictions in the tubing, gravitational and viscous forces. A good well performance evaluation should include the well and its fluid model in the form of the PVT model of the fluid produced through it, the inflow performance relationship model and the vertical lift performance model (Ahmed, 2010). The PVT model is important because produced fluid usually has varying properties at different pressure and temperature. This approach is applied for proper prediction of the flow conditions in the tubing since pressure and temperature changes are unavoidable in vertical upwards fluid flow (Petroleum Experts, 2010). Flow up the tubing will usually be multiphase. Gas and liquid tend to separate and will normally not travel with the same velocities. Calculation of pressure drop is therefore very complex and challenging (Time, 2009). However, accurate prediction of pressure drop in oil and gas wells is desirable to forecast well deliverability and to optimize depletion. Thus, many investigators proposed different multiphase flow correlations but none of them have been proven to give good results for all conditions that may occur when producing hydrocarbons (Pucknell *et al.*, 1993; Fossmark, 2011). The approach has been to analyze all available correlations to determine the one that best matched the test data and thus use it to model the flow (Brill and Mukherjee, 1999). However, it is worthy to note that these correlations are empirical meaning that their application is limited to the conditions of which they are based (Pucknell *et al.*, 1993; Fossmark, 2011). The approach utilized in study is to modify the correlations by tuning in Prosper, thereby making the correlations more accurate. The tuned correlations were then utilized for predicting the future performance of the well.

II. Methodology

In this work, the following approach was applied to model the behaviour of the well under study: Data collection, Fluid PVT modeling, Equipment data input, Generation of well IPR using the data provided, VLP/IPR Matching, calculations and sensitivity analysis.

Overview of the Well used for the Study

AKUB Well 221 is a well drilled into reservoir AKUB in the Niger Delta, South-South Nigeria. The well was put on stream on December, 1965 and produced at an average rate of 2600BPD with 0% water cut. Its production rated decreased to an average of 2100BPD with 30% water cut by July, 1971. PVT Laboratory analysis carried out on the produced fluid showed that it has a bubble point pressure of 1983psia and solution GOR at this pressure is 688scf/STB. However, the reservoir was initially at the pressure of 5867psia at a temperature of 181ºF when the well started production. Table 3.1 shows the PVT data. Also, production test conducted on the well on 12/09/1971 gave the following result:

- THT and THP: 108ºF and 250psig
- Gauge depth and pressure: 8630ft and 2996psig
- Liquid rate, GOR and water cut: 2400BPD, 688scf/STB and 30%
- Reservoir pressure: 3050psig

Table 3.1: The Reservoir Fluid PVT Data

Pressure (psia)	GOR (scf/STB)	B_o (rb/STB)	μ_o (cp)
5015	688	1.407	0.52
4015	688	1.419	0.47
3015	688	1.434	0.45
2515	688	1.441	0.42
2015	688	1.449	0.4
1983	688	1.450	0.38
1715	600	1.416	0.42
1415	508	1.377	0.46
1115	419	1.338	0.51
815	334	1.302	0.56
515	248	1.259	0.61
215	140	1.203	0.73

Data Collection

The following data were used for the modeling: (i) the produced fluid PVT data obtained from the PVT analysis of the fluid. (ii) Well status data which is obtained from the well status diagram. It shows the various equipment and gadgets installed in the well, the depth that they were placed and their properties. This includes the tubing type and size, (tubing diameters used –1", 1 ½", 2 3/8", 2 7/8", 3 ½"), casing type and size and perforation depth. (iii) well deviation data which is obtained from well deviation survey. (iv) production test data from the well showing the flow rate, tubing head temperature (THT), tubing head pressure (THP), water cut, gas oil ratio (GOR) and the reservoir pressure at the time of the test. (v) Other required data are gas liquid ratio, GLR – 500 scf/stb, reservoir depth and reservoir properties: permeability, skin, area, pay thickness, initial reservoir pressure and temperature.

Fluid PVT Modeling

PROSPER was used to model the reservoir fluid. This is done by matching the PVT data obtained from laboratory analysis to the available correlations. The match is performed through nonlinear regression, adjusting the correlations to best fit laboratory measured PVT data. It applies a multiplier (parameter 1) and a shift (parameter 2) to each of the correlations. The correlation that best matched the fluid is one which required the least correction. The standard deviation represents the overall closeness of the fit. The lower the standard deviation, the better the fit.

Equipment Data Input

This is made up of: (i) Deviation Survey data: measured depth, (MD) and true vertical depth, (TVD). These data were inputted and prosper automatically calculates the cumulative displacement and the angle of the well. (ii) Down-hole equipment data: this includes data on the size and type of all fittings and equipment the reservoir fluid flows through from the bottomhole up to the well head. (iii) Geothermal gradient data: this shows the temperature values with depth. (iv) Average heat capacities: the default value for average heat capacities specified in PROSPER was used. Note that surface equipment data was not used in this analysis because the analysis did not consider the effect of surface equipment on the well performance. Figure 1 shows the well schematic developed by PROSPER from the inputted values.

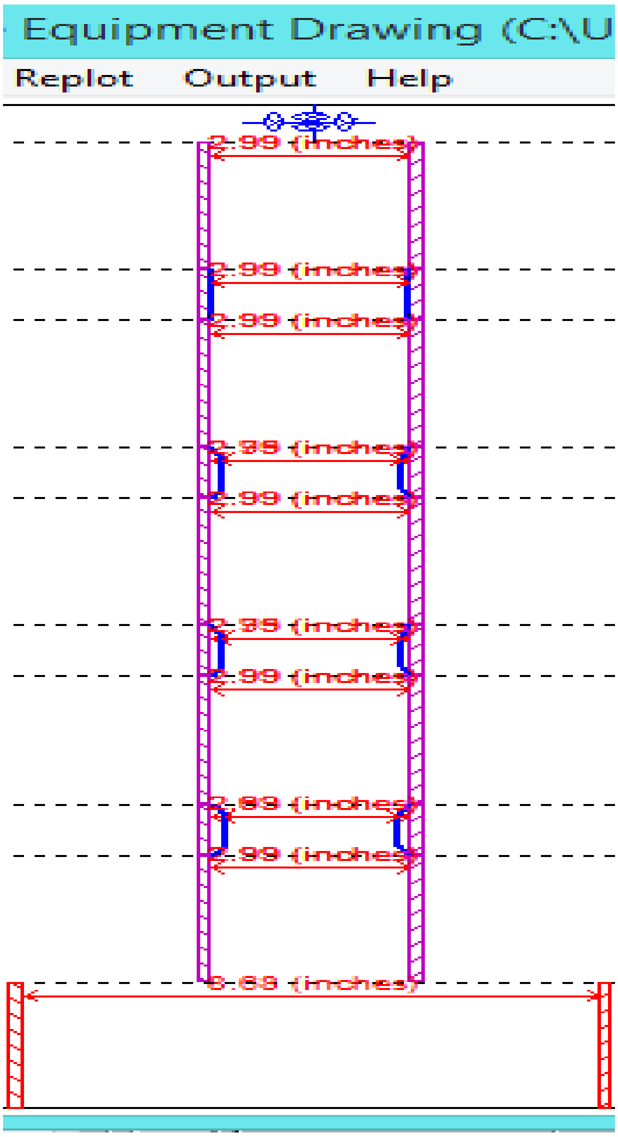


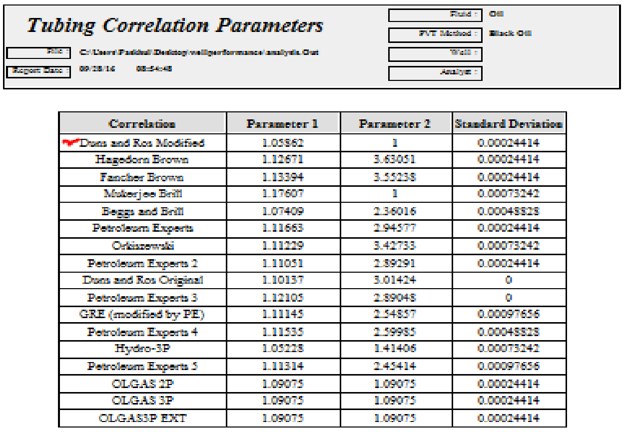
Figure 1: Schematics Representation of the Well Completion Designs

Generation of Well Inflow Performance Relationship (IPR)

PROSPER was used to select the model to generate the IPR of the well. In this work, Darcy's model was selected because the reservoir is undersaturated. Vertical Lift Performance (VLP) curves were also generated with Prosper, and the intersection between them reported as production rates.

Correlations Modification to Match Measured Reservoir Pressures

Here, the multiphase flow correlations were modified by tuning to fit the measured downhole pressure and rate from the production test. Prosper was employed for tuning the correlations (VLP matching). A matched VLP enables the generated IPR to be matched to the measured downhole pressure and rate. PROSPER does this match by performing a nonlinear regression whereby the error between the measured and calculated pressures (using a correlation) are determined. Thus, the gravity and friction terms of the pressure loss equation are adjusted until the calculated and measured pressures agree within 1psi or are terminated after 50 iterations. Parameter 1 and parameter 2 are the multiplier for the gravity term and friction term of the pressure loss equation respectively and should be within $\pm$10% from unity (1) if the data are consistent, that is, it should be between 0.9 and 1.1. Figures 2 is the report from the VLP match showing the Modified Duns and Ross correlation that best matched the test data.



Tubing Correlation Parameters

Fluid : Oil
PVT Method : Black Oil
Well :
Analyst :

Correlation	Parameter 1	Parameter 2	Standard Deviation
Duns and Ros Modified	1.05862	1	0.00024414
Hagedorn Brown	1.12671	3.63051	0.00024414
Fancher Brown	1.13394	3.55238	0.00024414
Mukerjee Brill	1.17607	1	0.00073242
Beggs and Brill	1.07409	2.36016	0.00048828
Petroleum Experts	1.11663	2.94577	0.00024414
Orkiszewski	1.11229	3.42733	0.00073242
Petroleum Experts 2	1.11051	2.89291	0.00024414
Duns and Ros Original	1.10137	3.01424	0
Petroleum Experts 3	1.12105	2.89048	0
GRE (modified by PE)	1.11145	2.54857	0.00097656
Petroleum Experts 4	1.11535	2.59985	0.00048828
Hydro-3P	1.05228	1.41406	0.00073242
Petroleum Experts 5	1.11314	2.45414	0.00097656
OLGAS 2P	1.09075	1.09075	0.00024414
OLGAS 3P	1.09075	1.09075	0.00024414
OLGAS3P EXT	1.09075	1.09075	0.00024414

Figure 2: The VLP Match Report

Well Performance Curve and Sensitivity Analysis

Here, the well performance curve is generated. A well performance curve is the plot of flow rate versus wellhead pressure at a given reservoir pressure. This shows the wellhead pressure at which the well will not flow. It is anticipated that the reservoir pressure will drop further from the present as production continues. In this work, the well performance curve is generated at five various reservoir pressures between 2800psig and 3000psig. Sensitivity analysis is then performed to see the effect of varying tubing sizes on the well performance curve. The size or diameter of the production tubing can play an important role in the effectiveness with which a well can produce liquid (Lea *et al.*, 2008).

III. RESULTS AND DISCUSSIONS

Figure 3 shows that at reservoir pressures below 2900psig at the present production condition (no artificial lift, tubing diameter of 2.375inches, THP of 250psig and 30% water cut), the well will not be able to lift the reservoir fluids to surface. Thus, decrease in the reservoir pressure reduces the well performance.

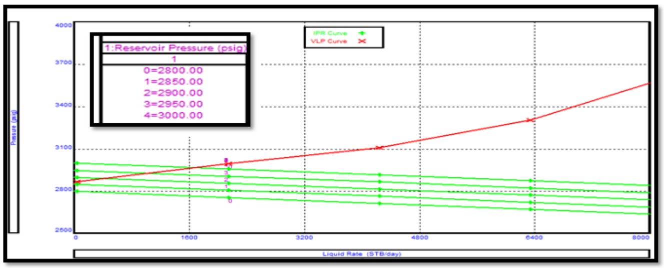


Figure 3: IPR/VLP Plot at various Reservoir Pressures and at the Present Production condition

Change in Tubing Head Pressure (THP)

The well will be able to lift the fluid when the reservoir pressure is below 2900psig if the THP is reduced to 200psig and below. However, at THP above 300psig, the well will not produce even when the reservoir pressure is at 3000psig (Figure 4). Figure 5 shows the effect of THP on the liquid rate. It can be seen that decrease in the THP results in increase in flow rate and better well performance.

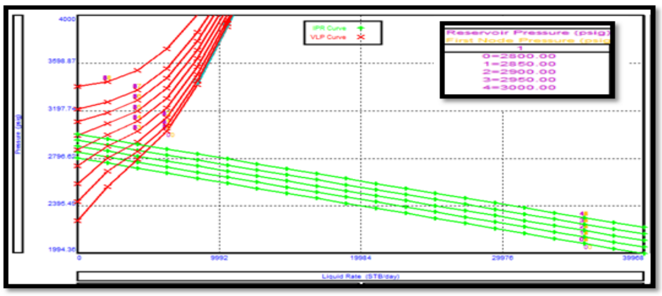


Figure 4: VLP/IPR Plot at varying Reservoir Pressure and THP

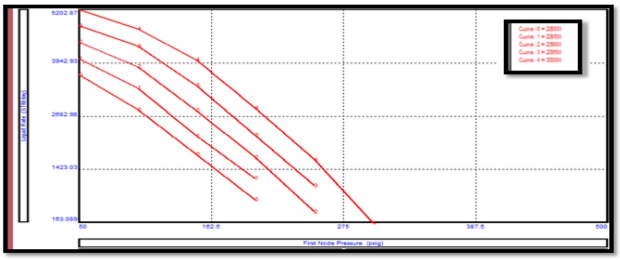


Figure 5: Plot of Liquid rate versus tubing head pressure at various Reservoir Pressures

Production of Water

Increase in water cut results in increase in the bottomhole pressure because water is much denser than oil. From Figure 6, it can be seen that at water cut of above 35%, the well will not lift the fluid even at reservoir pressure of 3000psig. It can also be observed form Figure 7, that increase in the production of water leads to drop in the liquid rate. The only way to obtain a high production rate of a well is to increase production pressure drawdown by reducing the bottomhole pressure with artificial lift methods (Boyun *et al.*, 2007; Karikari, 2010).

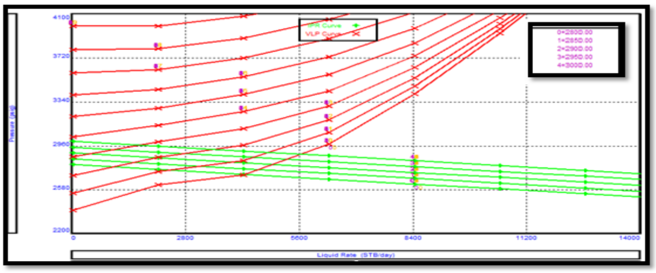


Figure 6: VLP/IPR Plot at varying Reservoir Pressure and Water Cut

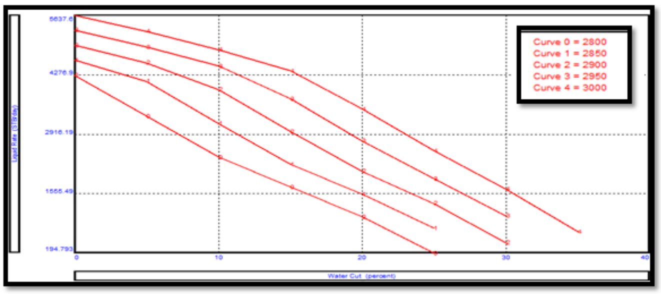


Figure 7: Plot of Liquid rate versus water cut at various reservoir pressures

Sensitivity Analysis

By varying the tubing size from 1inch to 3.5inches, it was observed from Figure 9 that:

- At reservoir pressure of 2800psig the well could not flow with tubing sizes above 1".

- At reservoir pressure of 2850psig, the well could not flow with tubing size above 1.5inches.

This shows that as the reservoir pressure drops, smaller tubing size will be required to lift the reservoir fluid. This is in agreement with the position of Lea *et al*., 2008, that, smaller tubing sizes have higher frictional losses and higher gas velocities which provide better transport for the produced fluids. At lower flow rates, there is dominance of the effect of gravity is. This effect however, is observed at almost a common bottom-hole flowing pressure point, (about 1600 psi) for the three larger tubing strings. This shows that the gravity effect is the same irrespective of the selected tubing size. It is also observed that increase in tubing size generally results in increase in liquid rate only if the reservoir pressure is high enough.

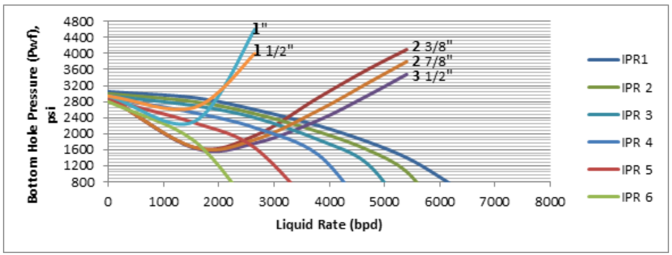


Figure 9: Plot of IPR with various Tubing Sizes

IV. CONCLUSION

A well performance model is a combination of the produced fluid PVT model, the Reservoir IPR model and the VLP model. The performance of a well is affected by the reservoir pressure, the tubing size, tubing head pressure and the water cut. As the reservoir pressure drops, the well's ability to lift the reservoir fluid (well performance) also drops. Thus, smaller tubing size will be required to lift the reservoir fluid. At reservoir pressure below 2900psig, the well could not lift the reservoir fluid at the present conditions (250psig THP, 30%water cut, 2.375" tubing size). Decreasing the THP increases the well performance. At THP above 300psig the well could not flow even when the reservoir pressure was at 3000psig. Increase in the tubing size resulted in increase in flow rate at high reservoir pressure. However, there are limitations as the reservoir pressure drops. Increase in water cut also decreased the performance of the well. At water cuts above 35% the well could not flow even at 3000psig.

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