Analysis of the impact of reservoir fluids invasion on well performance and productivity

Precious Chisom Jumbo-Egwurugwu[1]; Franklin Okoro[2]; Obo-Obaa Elera Njiran[3]
[1,3] University of Port Harcort
[2] CleanScript Group

Abstract: **This paper assessed the impact of fluid invasion on well performance and productivity. OLGA simulation of fluid invasion into the well was done to generate data points for modelling the effect of fluid invasion on well performance and productivity. From the simulations, about 32 data points were generated which were exported to excel and was analyzed using data analysis toolpak. The outcome of the analysis generated a multi variate correlation which equated well performance in terms of volume flow rate to independent variables including the tubing total fluid content in the well. The trend volumetric plots from OLGA were used to indicate the onset of fluid invasion into the well and for this study, the critical volume flow prior to the onset of fluid invasion was 450,000 sm^3/day and this occurred after about 38 hours of flow. The implication of this is that, below this rate, the well is underperforming due to fluid invasion and the continuous experience of fluid invasion will later cause a total formation damage, and when this occurs, the production is completely interrupted. The correlation revealed that the relationship between fluid content in the wellbore and the well productivity is inverse. That is, a decrease in fluid content in the wellbore results to an increase in the well productivity. With this correlation, at any point in time t, the well productivity can be predicted and from the value of the volume flow rate of the well, it can be confirmed if the wellbore is underperforming due to fluid invasion or not. The correlation was validated using statistical analysis by assessing the R square, P, Significance F values and the trend plots of the predicted volume flow rates and actual volume flow rates. These tests confirmed that the correlation is statistically significant.**

Keywords: **Fluids' invasion; Well performance; Well productivity; OLGA; Reservoir.**

I. INTRODUCTION

During well construction, drilling fluids are used to control the borehole pressure, to reduce the temperature of the drill bits and to circulate the drilled cuttings out of the boreholes. Drilling fluids need to be carefully designed so that they can have certain density and viscosity to maintain the wellbore stability and lift the cuttings (Xiaoyan, 2011). To obtain the required viscosity and density, various solid particles are added to drilling fluids. Besides these solids, drilling fluids also contain cuttings which are generated during the drilling process. Because of the pressure difference between the wellbore and the formation, drilling fluids flow into the permeable formation (Fakoya and Ahmed, 2018). Consequently, the suspended particles in the fluids penetrate into the formation matrix under the action of the hydrodynamic drag forces exerted by the fluids, and then are gradually deposited on the formation grain faces drilling particles penetrate into the formation matrix and are deposited in the near wellbore region (Elkatatny *et al*., 2016). The invaded particles reduce the porosity of the formation, impair the formation permeability, and thus adversely affect the productivity of the well (Adam, 2017).

Invasion of solids fluid and formation that can lead to particle plugging or fine migration is also another serious concern of formation damage. The measure of formation damage is called "skin" (Omotara *et al*., 2015). The formation damage obviously reduces well deliverability, drainage efficiency and ultimate recovery (Elkatatny *et al*., 2013) (see Figure A). These parameters are key factors to determine the reservoir performance and field development, production test, pressure build-up test or drawdown test indicates formation damage (Okotie *et al*., 2015). Thus, this paper analyzed how the invasion of fluids into reservoir affects well performance and productivity.

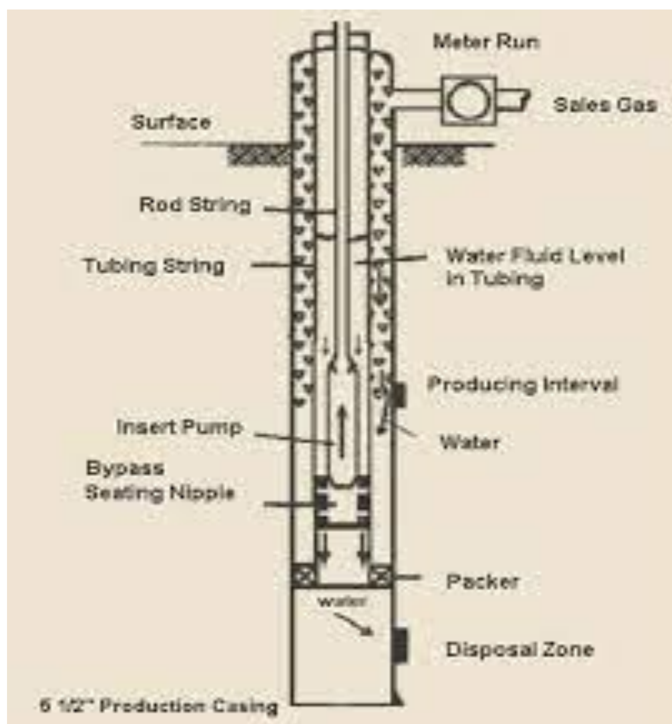

Figure A: Schematic of Fluid Invasion problem in a well (Lea & Nickens, 2004).

II. METHODOLOGY

OLGA is a dynamic, transient multiphase simulator for flow of oil, natural gas and water in the same pipeline, a process known as multiphase flow. OLGA stands for "oil and gas simulator". The main issue with multiphase fluid transport is the formation of slugs in the offtake lines, which results to huge problems at the first stage separators on the platforms. OLGA simulation software makes it possible to estimate the fluid flow and safely bring the flow to the receiving destination on a platform through the pipes. The OLGA dynamic multiphase flow simulator models transient flow behavior, providing valuable insights through the entire production system—from reservoir pore to process facility—to help maximize production potential. Operational changes, such as shutdowns and startups, are inherently transient. By predicting time-varying changes in operations— as well as flow rates, fluid compositions, temperature, and solids deposition—the OLGA simulator provides an added dimension to steady-state analyses. Dynamic simulation is essential in deep water developments, but is also used extensively offshore and onshore to investigate transient behavior in pipelines and wellbores.

In this paper, OLGA was used to simulate the invasion of fluid and the effect of this invasion on the performance and productivity of the well was determined. Data from a deviated gas well was used to carry out the simulation in order to generate a trend and profile data. The data points generated from the simulation done by OLGA were exported to Excel and further used to develop correlation which analyzed the effect of the fluid invasion on well performance using data analysis toolpak of Microsoft Excel. A comparison between the result gotten from the OLGA and the outcome of the correlation is made in order to validate the developed correlation for its applicability.

In this paper, a deviated gas well was used.

III. SIMULATION DATA

Table 1: The Well Profile

MD (m)	TVD (m)	Inclination (°)	Azimuth (°)	North (m)	East (m)	Horizontal distance (m)
0	0	3.35029	0	0.00	0.00	0.00
275	274.53	11.5421	0	16.0711	0.00	16.0711
500	494.98	22.7057	0	61.091	0.00	61.091
700	679.48	33.0495	0	138.2904	0.00	138.2904
900	847.12	41.8366	0	247.363	0.00	247.363
1100	996.13	41.7155	0	380.7648	0.00	380.7648
3000	2414.4	0	0	1645.0868	0.00	1645.0868

Table 2: The Casing Profile

Casing type	Size (“)	Top MD (m)	Bottom MD (m)
Conductor	20	0	100
Intermediate	13.375	0	1095
Production	9.63	0	2700
Liner	7.625	2500	3000

Table 3: Tubing Profile

Tubing Length (m)	Tubing Size (“)	Inner Diameter (m)	Outer Diameter (m)	Density (kg/m^3)	Heat Capacity (J/kg-C)	Conductivity (W/M-C)
2500	7	0.163982	0.1778	7840	500	48

Table 4: Equipment

Equipment type	Inner diameter (m)	Equilibrium model
Valve	0.0889	FROZEN

Table 5: Ambient temperature

TVD (m)	Ambient temperature (°C)
0	15
2414.4	100

Table 6: Air Velocity

TVD (m)	Velocity (m/s)
0	4
0	4

Table 7: Formation

Bottom MD (m)	Formation type	Conductivity (W/M-C)	Density (Kg/M^3)	Heat Capacity (J/Kg-C)
3000	Rock	2	2500	1000

Table 8: Fluid outside production tubing

Bottom MD (m)	Fluid name	Conductivity (W/M-C)	Density (Kg/M^3)	Heat Capacity (J/Kg-C)	Viscosity (Cp)
2500	Nitrogen (P = 50 psia)	0.009153	3.58	1047	0.1903
2500	Water	0.6	1.193	4184	1.676

Table 9: Reservoir

Depth (m)	Time (s)	PR (bara)	TR (^oC)	Inflow Temperature option
3000	0	40	100	Isothermal
	172800	30	100	

Table 10: Tubing top boundary conditions

Node type	Time (s)	Pressure (bara)	Temperature (^oC)	Gas Fraction (-)
Pressure	0	20	15	1

Table 11: Discretization

Bottom Depth (m)	Minimum pipe length (m)	Maximum section length (m)	Minimum sections per pipe
3000	20	100	2

The profile and trend data points were exported to excel to develop correlation that analyses the effect of fluid invasion on well performance and productivity using data analysis toolpak of Microsoft Excel via the regression analysis option.

Excel produces the summary output (rounded to 3 decimal places) as shown in the next section. The closer to 1 of the R Square value, the better the regression line fits the data. To confirm if the results are reliable (statistically significant), the value of the Significance F must be less than 0.05. If Significance F is greater than 0.05, it is an indication to stop utilizing the set of independent variables. At which point, the user must delete a variable with a high P-value (greater than 0.05) and rerun the regression until Significance F drops below 0.05. Most or all P-vales should be below 0.05.

The residuals reveal how far or how close the actual data points (for this study, the data points from OLGA) are from the predicted data points (data points predicted using the developed correlations). The actual and predicted data points were plotted in order to check how close they are to each other. The closer the fit, the more reliable the developed correlation is. This is another way to validate the developed correlation for its applicability.

IV.RESULTS AND DISCUSSION

In this study, custom plot of temporal variation of gas-volume flowrate at standard conditions at the wellhead location was done to predict the onset of fluid invasion and determine its effect on the volumetric flow rate (see Fig. 1).

From Fig. 1, it can be clearly seen that the gas flowrate decline curve was steady from 780,000 sm3/day to 450,000 sm^3/day. At this flow rate of 450,000 sm^3/day, there was an appearance of a curvature on the gas flowrate trend. This curvature appeared at ‘t’ of about 137,000 seconds.

The appearance of curvature on the gas flow rate trend below 450,000 sm^3/day and at‘t’ approximately 137,000 seconds is taken as the onset of fluid invasion. The flow rate short of curvature is retrieved as the critical flow rate prior to the fluid invasion, and from Fig. 1, the critical volumetric flow rate before the onset of fluid invasion for this present study is 450,000 sm^3/day. The plot of temporal variation of gas-volume flowrate (Fig. 1) for this study indicates that fluid invasion started after about 38 hours of normal flow.

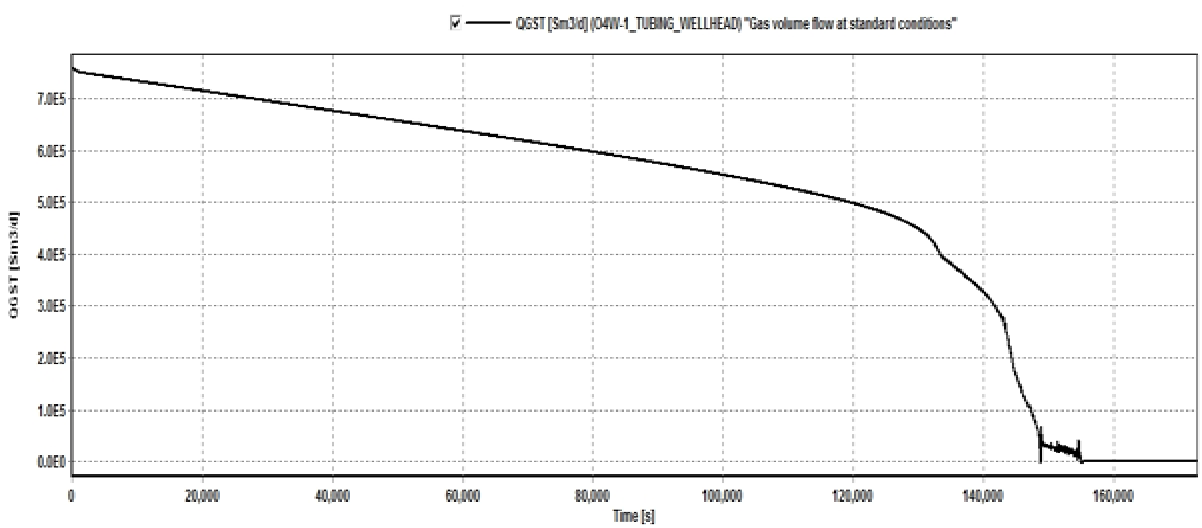

Figure 1: Plot of temporal variation of gas-volume flow rate at standard conditions.

The custom plot of fluid content in the wellbore was also generated to compare the fluid content trend (see Fig. 2) to that of gas decline curve (Fig. 1) in order to validate the prediction of the onset of fluid invasion made with the gas volume flow rate trend.

From Fig. 2, it can be clearly seen that the trend for fluid content plot was steady till about t = 136,800 secs. Just slightly above this time, there was appearance of curvature on the fluid content trend indicating increase in the fluid content in the well. The plot shows that the fluid content in the wellbore increases as the well loads up at about 38 hours. This was exactly the same time when the curvature appeared on the gas volume flow rate trend. The two plots (Figs. 1 and 2) have now confirmed that the onset of fluid invasion in the wellbore occurred after 38 hours and the critical gas flow rate is 450,000 sm^3/day.

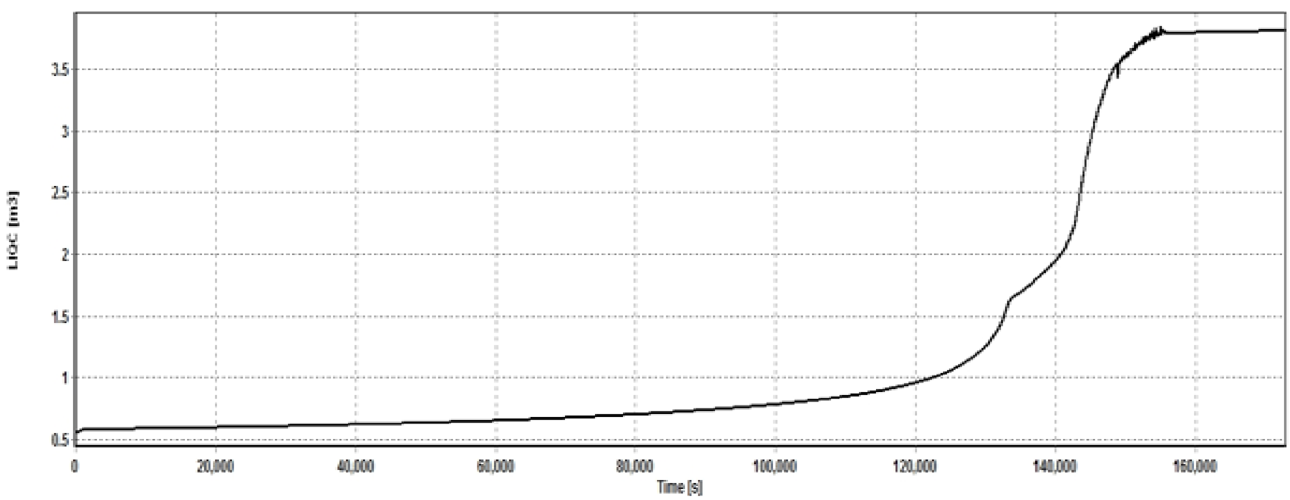

Figure 2: Plot of Fluid Content in the wellbore.

Under the ‘Equipment’ impact section of the OLGA well-editor environment, an observation point to plot variables at the wellhead to observe temporal variations in the standard volumetric flow rate of gas, oil and water was added. The plot trend of that of gas rate is Fig. 1. That of oil and water are shown in Figs. 3 and 4. The fluid outside the production casing for this study were Nitrogen, water, and drilling fluids (all referred to as fluid).

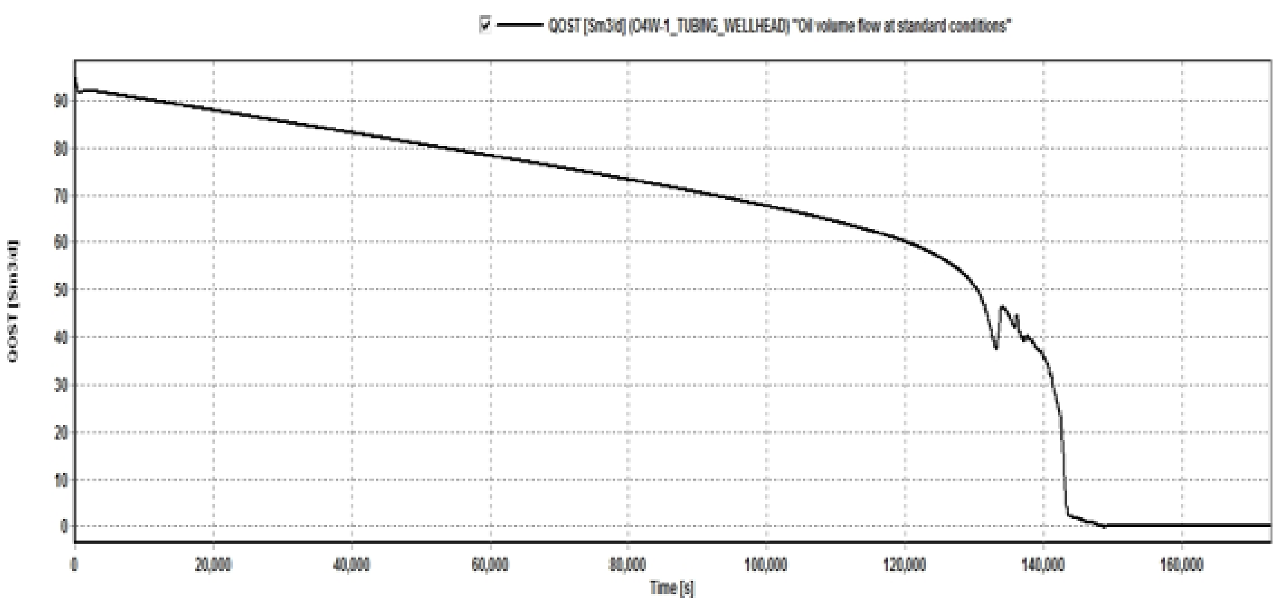

Figure 3: Plot of temporal variation of oil volumetric flowrates at standard conditions.

From Fig. 3, it is evident that the trend is same as the volumetric gas flow rate. The oil rate trend also experienced a curvature after 126,000 seconds, also indicating the onset of fluid invasion in the wellbore. This happened at oil volumetric flow rate of 55sm^3/day.

Fig. 4 shows a steady trend of water volumetric flow rate until at flow rate of about 5.8sm^3/day and after 120,000 seconds of flow, at which point a curvature appeared on the trend. This sudden curvature on the trend is similar to that of gas and oil volumetric flow rate trends and could also be taken as a sign of increased fluid content in the wellbore.

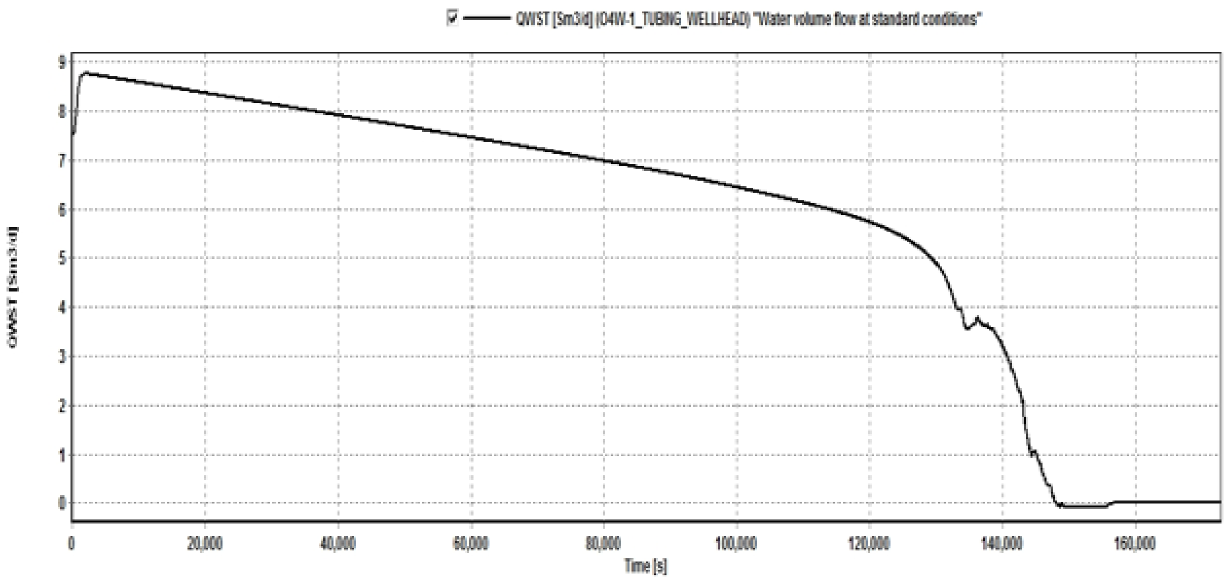

Figure 4: Plot of temporal variation of water volumetric flowrate at standard conditions

Development of a model/correlation for predicting and assessing the effect of fluid invasion on well performance and productivity

The profile and trend data results from OLGA simulations are provided in the Appendix. OLGA simulation generated 31 data points which were exported to Excel for data analysis.

Equation 1 is a simple linear multivariate correlation developed in this study using Microsoft Excel Data Analysis ToolPak. It is a correlation for the prediction of critical well flow rate, below this rate implies that the well is being invaded by unwanted fluids and is underperforming.

$$
\begin{aligned}
&Q_g(m^3/d\,) \\
&= 3.9\ x\ 10^7 - 1.03\ x\ 10^5 LIQ_c(m^3) + 2356\ Q_{WST}\left(\frac{m^3}{d}\right) \\
&- 32.4\ t(s) \\
&- 1.11\ x\ 10^6 P_T(bara)
\end{aligned} \tag{1}
$$

Where Q_g is the gas volume flow,

LiQc is the tubing total fluid content,

Qwst is the tubing water volume flow

t is time, and

P_T is the tubing pressure.

From Equation 1, the relationship between fluid content in the wellbore and the well productivity is inverse. That is, a decrease in fluid content in the wellbore results to an increase in the well productivity. Having predicted the critical volume rate prior to the onset of fluid invasion into the wellbore from OLGA trend plots, Equation 1 can be utilized to know the maximum allowable fluid content in the well in order to ensure that the well volume rate does not go below the critical rate. The implication of this is that, if the fluid invasion is not predicted and stopped, it could get to a time when the formation will get damaged and production gets completely interrupted. Therefore, at any point in time t, the well productivity can be predicted and from the value of the volume flow rate of the well, it can be confirmed if the wellbore is underperforming due to fluid invasion or not.

To verify the reliability of the volume flow model (Equation 1), the R square, Significance F value, and the P values are assessed and the plot of the actual volume flow data points (from OLGA) and the predicted volume flow data points (using the model) was carried out. The closer to 1 of the R square value, the better the regression line fits the actual data. If the value of the Significance F is less than 0.05 and most of P-values are below 0.05, then the developed model is highly reliable.

From Table 12, R Square equals approximately 1, which is a perfect fit. This implies that over 99% of the variations in the well volume flow is influenced by the independent parameters: Tubing pressure, time, Tubing water volume flow, and tubing total fluid content. From table 12 also, the Significance F is 4.26×10^{-6} and all the P-values are also way below 0.05. Therefore, from these three criteria, Equation 1 is very reliable for the prediction of fluid invasion and the assessment of well performance.

In developing the well performance assessment correlation (i.e., Equation 1), the values under the 'coefficient' columns in Table 12 were utilized. From Table 12, the intercept value was approximately 3.9×10^{7}, the coefficient of the tubing total fluid content was approximately -1.03×10^{5}, the coefficient of the tubing water volume flow was approximately 2356, the coefficient of time was -32.4 and the coefficient of the tubing pressure was approximately -1.11×10^{6}.

Arranging these coefficients and putting them in the form of a linear regression equation

'$Y=Ax_1+Bx_2+C$' resulted to Equation 1.

Table 12: Summary Output for the Analysis of Well Performance Due to Fluid Invasion

Regression Statistics					
Multiple R	0.999988939				
R Square	0.999977877				
Adjusted R Square	0.999974474				
Standard Error	538.5247466				
Observations	31				
ANOVA					
	df	*SS*	*MS*	*F*	*Significance F*
Regression	4	3.4083E+11	8.5208E+10	293810.2	4.25597E-60
Residual	26	7540231.471	290008.903		
Total	30	3.40838E+11			
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*
Intercept	38932309.18	326935.2376	119.082634	4.01E-37	38260284.17
LIQC TUBING Total fluid content in branch[m3]	-102901.2537	6770.071992	-15.199433	1.89E-14	-116817.3359
QWST_TUBING_Water volume flow at standard conditions [Sm^3/d]	2355.944475	210.7819989	11.1771617	1.99E-11	1922.675871
TIME[s]	-32.42474542	0.260378747	-124.52916	1.26E-37	-32.9599616
PT_TUBING_Pressure[bara]	-1107196.517	9298.946192	-119.06688	4.02E-37	-1126310.775

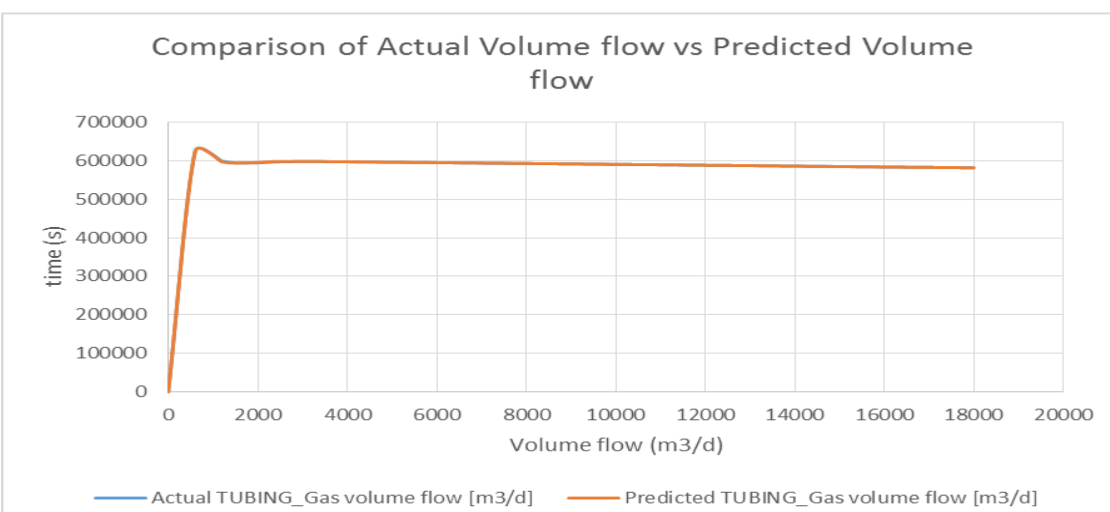

Figure 5: Trend plots of actual and predicted well volume flow

From Fig. 5, it can be seen that the curve for the predicted well volume flow, completely superimposed that of the actual well volume flow curve. This implies a high accuracy and reliability of the developed correlation in predicting fluid invasion and assessing the impact on well performance as both curves are perfect fit. Therefore, when conducting experiments, carrying out simulations or the deployment of other predictive techniques becomes unviable or uneconomical, Equation 1 can reliably be used as a tool to accurately predict the onset of fluid invasion into the well and to assess the performance of the well as a result of the fluid invasion

V. CONCLUSIONS

In this paper, the trend volumetric plots from OLGA were used to indicate the onset of fluid invasion into the well and for this study, the critical volume flow prior to the onset of fluid invasion was 450,000 sm^3/day and this occurred after about 38 hours of flow. The implication of this is that, below this rate, the well is underperforming due to fluid invasion and the continuous experience of fluid invasion will later cause a total formation damage, and when this occurs, the production is completely interrupted. The correlation developed in this paper can be reliably used for the prediction of critical well flow rate, and below this rate implies that the well is being invaded by unwanted fluids and is underperforming. The correlation revealed that the relationship between fluid content in the wellbore and the well productivity is inverse. That is, a decrease in fluid content in the wellbore results to an increase in the well productivity. With this correlation, at any point in time t, the well productivity can be predicted and from the value of the volume flow rate of the well, it can be confirmed if the wellbore is underperforming due to fluid invasion or not. The correlation was validated using statistical analysis by assessing the R square, P, Significance F values and the trend plots of the predicted volume flow rates and actual volume flow rates. These tests confirmed that the correlation is statistically significant. Therefore, when conducting experiments, carrying out simulations or the deployment of other predictive techniques becomes unviable or uneconomical, the correlation can reliably be used as a tool to accurately predict the onset of fluid invasion into the well and to assess the performance of the well as a result of the fluid invasion.

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APPENDICES

Appendix A: OLGA simulation steps

The steps for this simulation were as follow:

1. Launch the OLGA simulator, go to file, choose well and select gas-well fluid invasion.
2. When the gas well fluid invasion comes up on the screen, click on the well editor and select the 'info' tab on the info page, supply the field information, the well information, the author's name, other relevant information and other the options select the steady state calculations to enable the steady state pre-processing calculations in OLGA by initializing the well-bore.
3. The next section is 'PROFILE'. On the profile page, supply the well survey in terms of MD-TVD. Select onshore, that is, a land well as the well head type (see Table 1).
4. Go to the 'Casing' section and supply the casing schematics data, including the data for a conductor, intermediate casing, production casing and liner. The schematics data must be such that all the casing type must be cemented to the top (see Table 2).
5. Go to the 'Tubing' section and supply the tubing type, the tubing stack depth, tubing size and the tubing length (see Table 3).
6. Go to the 'Equipment' section, a fully-opened wellhead choke of 3.5in (0.0889m) inner diameter is added, an observation point to plot variables at the wellhead to observe temporal variations in the standard volumetric flowrate of gas, oil, water and the liquid phase is also added. FROZEN equilibrium model is also chosen in this section (see Table 4).
7. Go to the 'Ambient' impact section, specify the geothermal gradient, the flowrate outside the production tubing to account for heat transfer through the Annulus between the tubing and the production casing (see Table 5).
8. Go to the 'Fluid' impact section. Specify the PVT look out table, also specify the perforation interval and the inflow performance relationship. Forchheimer inflow performance model with pre-calculated B and C (linear and non-linear part of the productivity index respectively) coefficients is the chosen model.
9. Go to the 'Boundary Condition (BC)' section. The tubing outlet boundary pressure in this case is the choke downstream pressure and it has to be specified. No initial conditions are needed as the steady state calculation option was selected on the info page (see Table 10).
10. Go to the 'Output' section. Under the output, the list of profiles and output variables are available by default.
11. Go to the 'Discretization' section. In this section, the discretization parameters to define the well flow path into pipes and sections are specified (see Table 11).
    a. After the 11th step, all the impact sections on the OLGA well-editor are now complete.
12. Now switch to the standard OLGA GUI to specify the integration parameters as well as the trending profile plotting frequencies.
13. After specifying the integration parameters and the plotting frequencies, come back to the OLGA well-editor and run the case in batch mode.
14. After the run is finished, go to custom plot and plot the temporal variation of gas-volume flow rate at standard conditions at the wellhead location.

Appendix B: Excel regression analysis steps

The steps for the data (regression) analysis

1. On the Data tab, in the Analysis group, click Data Analysis.
2. Select Regression and click OK.
3. Select the Y Range. This is the predictor variable (also called dependent variable).

4. Select the X Range. These are the explanatory variables (also called independent variables). These columns must be adjacent to each other.
5. Check Labels.
6. Click in the Output Range box
7. Check Residuals.
8. Click OK (Seref *et al*., 2007).