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Decline Curve Analysis of Continuous Injection Gas Lifted Wells

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Abstract
Decline Curve Analysis is one of the established techniques for reservoir performance evaluation and estimation of developed reserves. While it has been well utilized for natural drive production, there have been challenges in accurate evaluation of gas lifted wells because of additional energy that supplements the natural which changes future production rate of the reservoir and distorts the reservoir's production decline trend. For continuous gas lifted wells, several attempts have been made to model production rates, but none have been found to be simple or accurate. In this article the principle of superposition has been applied such that the production rate of a well at a time, t after gas-lift has been introduced would be the sum of the flow rate due to the natural flow and gas-lift induced flow rate. Four actual well production data sets obtained from the SPE Data Repository and from reservoirs in literature from Niger Delta were used to assess the model. The analysis done included cases with and without gas lift and statistical analysis was done to evaluate the error margin. The equation derived is a mathematical model in which the traditional Arps' exponential model accounts for the natural flow and a power law model accounts for the gas-lift induced flow expressed as:

$$q_t = q_{inf}[e^{-Dt} + \beta t^{-\lambda D}]$$

The model proposed showed that 0.48MMstb, 0.31MMstb, 8.75MMstb, and 1.23MMstb respectively would be produced when gas-lift is introduced as opposed to 0.26MMstb, 0.16MMstb, 7.96MMstb, and 1.10MMstb without gas-lift respectively, from well 1 to 4. The model also predicted future rates that were similar to the actual field data with correlation coefficient of 0.884, 0.806, 0.917, and 0.874 respectively. This statistical result indicates the effectiveness of the model in predicting the production decline rate of gas-lifted wells.

Keywords: *Decline curve analysis, Developed reserves, Production rate, Gas lift, Arps' exponential model.*

1.0 Introduction

Petroleum engineers constantly have the task of forecasting a producing well's future life in a reservoir and also estimating the expected recoverable amount from oil and/or gas reserves. This is because oil and gas production passes through various stages with time which can be described by an idealized production curve as shown in figure 1.[1]

Estimating the recoverable reserves of reservoirs is essential to form reservoir management policy formulation and practices and petroleum economics. Because of its importance, various methods have been observed to help industry experts predict a geological well's future life. These methods include the pressure transient analysis, decline curve analysis, material balance, volumetric calculations and many others. [2,3,4]

Decline Curve Analysis (DCA) is one of the common methods used in predicting the future production of well. DCA is an empirical method that requires no knowledge of the reservoir properties/parameters. The Decline Curve technique assumes that the past production trend of a well with its controlling factors will continue in the future. This analysis involves fitting a decline curve to the observed production data, and then extrapolating that curve to predict future production rates. By using the production history of a well acquired over a series of months or years, DCA can be utilized to forecast the future production and estimate ultimate recovery effectively since it makes use of the curve fitting of the well's past performance. [5,6,7]

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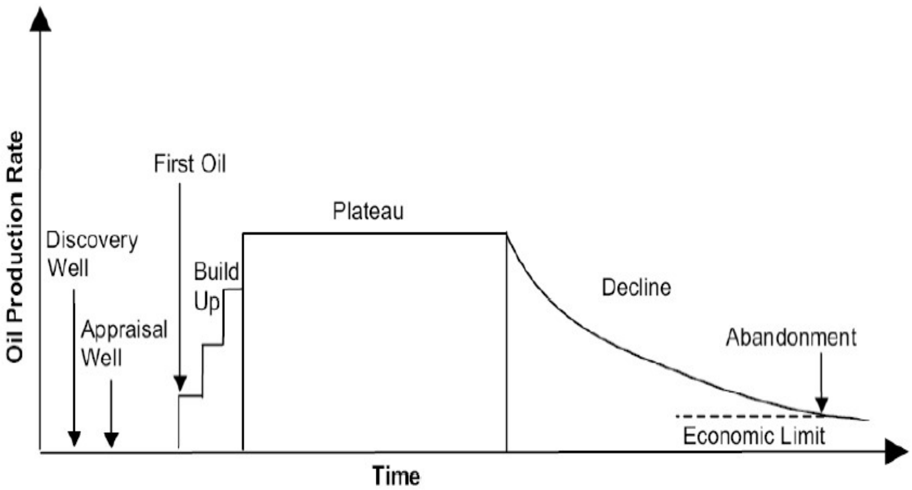

Figure 1: An idealized production curve illustrating the various stages of maturity (Source: Robelius, 2007)

The most common types of decline curves that are utilized frequently are: Production rate vs. Time (i.e q vs. t), Cumulative Production vs. Time (i.e Q vs t), and Production rate vs. Cumulative production (i.e q vs. Q). [5,8]

Decline curve analysis is commonly performed using a well production-rate data because well production rate data is the most easily accessible data of a producing well. These data are commonly available in formal reports on a daily or monthly basis, but they are rarely evaluated on this basis.

The first model that was developed to predict the future performance of a well using its past performance was developed by [5]. According to Arps, the decline curve of a well can be characterized by its:

1. Initial production rate or production rate at a specific time
2. Curvature of decline
3. and Decline rate

The Arps general decline curve equation is stated as:

$$q_t = \frac{\mathrm{q_i}}{(1 + \mathrm{bDit})^{\frac{1}{b}}} \quad (1)$$

where; q_t = production rate of the well at time; q_i = initial production rate of the well b = Arps decline curve exponent/ loss ratio;D_i = initial nominal decline rate, t = time

The nominal decline rate, D, is simply the rate of change of the natural logarithm of the production rate with respect to time. It can be expressed as:

$$D = -\frac{\mathrm{d(lnq)}}{dt} = -\frac{1}{q}\frac{dq}{dt} \quad (2)$$

The minus sign is added to this Equation 2 because dq and dt have opposite signs and it is more convenient to compute the decline rate when it is positive.

Depending on the decline exponent (b) value, there are three types of decline curves. When b=0, exponential, b=1 harmonic and 0<b<1, hyperbolic decline.[5]

The exponential decline curve is the simplest and the most widely used in the industry because most wells typically have a constant decline rate during their production life and will only deviate slightly from this trend towards the end of its producing life.[9]

But, the main theoretical assumptions for these equations are that the well operates in a boundary-dominated flow condition such that the bottom-hole flowing pressure, skin factor, drainage radius, and productivity index are constant. Thus, the application of the Arps model has its limitations, such as assuming a constant decline rate and not accounting for changes in reservoir and well conditions, yet it remains a valuable tool for predicting the future life of a well and estimating its ultimate recovery. [5,10,11]

Gas Lift decline models

Accurate production forecasting can aid in the optimization of gas-lift design and operation, the reduction of operational costs, the improvement of reservoir management, and the enhancement of economic evaluation. [6,12,13,14]. As a result, decline curve analysis, particularly the exponential decline model, has emerged as a valuable tool for projecting the future life of gas-lifted wells due to its simplicity and accuracy as seen in [2]. Despite its importance, limited research has been conducted on its application for gas-lifted wells.

This study attempts to address this research gap and provide a better understanding of the future production behavior of gas-lifted wells subjected to continuous gas lift, using a superposed exponential and power law decline model. Furthermore, the findings of the study would lead to advances in the technical understanding of gas-lifted wells and decline curve analysis methodologies.

2.0 Methodology

This study proposes a mathematical model that can predict the future production life of a gas-lifted well by using the principle of superposition to combine the Arps' exponential decline model and the power law equation [9].

2.1 Model derivation

2.1.1 Production rate at time, t

By applying the principle of superposition, the total flow rate at time t after gas lift has been introduced into an oil reservoir would be the sum of the natural flow rate and the gas lift induced flow rate. This can be expressed mathematically as:

$$q_t = q_{nf}(t) + q_{gif}(t) \tag{3}$$

The flow rate of the natural flow will simply be expressed using the Arps' exponential decline model, which is stated below;

$$q_{nf} = q_{inf}e^{-Dt} \tag{4}$$

To get the expression for the gas-lift induced flow, we would assume that the injected gas induces a non-linear flow. In 1918, [15] proposed a plot of a logarithmic rate term against the logarithm of time. This was based on the assumption that the decline curve of a producing well is hyperbolic

But, when gas lift is introduced to a reservoir system, the gas flow rate of the well may increase rapidly as the pressure gradient is established and the reservoir fluids begin to flow. As the injected gas continues to flow and the fluid production increases, there can be a decrease in the gas flow rate over time. This means that we can describe the flow of gas-lift induced flow to be hyperbolic and won't experience an exponential decay. This study suggests the use of power law equation proposed by [15,16] that can perfectly account for the production lift due to gas lift and can be expressed using this equation;

$$y = cx^n \tag{5}$$

During the gas-lifted production, a gas lift rate, α, introduced affects the performance of the well. By writing equation 5 in terms of the initial gas lift production rate, time and the gas lift rate we get;

$$q_{glf} = q_{iglf}t^{-\propto} \tag{6}$$

where q_{iogl} is the maximum oil flow rate got from when gas lift is introduced to the well before the well starts declining.

The gas lift rate can be expressed in terms of the decline rate. The gas lift rate slows down the decline rate of the well by a parameter, λ, increasing the production rate of the well. We introduce λ as the ratio of the gas lift rate to the decline rate of the well. By making the gas lift rate subject of formula, we can express this mathematically as:

$$\propto = \lambda D \tag{7}$$

By substituting equation 7 into equation 4, we get;

$$q_{glf} = q_{iglf}t^{-\lambda D} \tag{8}$$

By using the principle of superposition [2,17] to combine the Arps' exponential decline model and the power law equation, a mathematical model can be developed that can predict the future producing life of a gas-lifted well. This model can account for both the early life before gas lift was introduced and the later life of the well after gas lift is introduced. The Arp's exponential model will describe the early production life of the well, while the

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proposed equation got from the principle of superposition [2,17] will describe the later production life of the well after gas lift has been introduced.
By inputting equation 4 and 6 into equation 3, we get this expression;

$$q_t = q_{inf}e^{-Dt} + q_{iglf}t^{-\lambda D} \tag{9}$$

Gas lift has a significant effect on the natural flow of a well such that the production rate of the well increases significantly. We define a parameter, β, as the ratio of the production rate of the gas-lift induced flow to the natural flow of the well at any time. This is expressed mathematically as:

$$\beta = \frac{q_{glf}}{q_{nf}} \tag{10}$$

By making this ratio to be at the initial time of both the gas-lift induced rate and the natural flow rate, we can make the initial gas-lift induced production rate the subject of formula in equation 10. By doing this we get this expression,

$$q_{iglf} = \beta q_{inf} \tag{11}$$

Substituting equation 9 into equation 7, we get;

$$q_t = q_{inf}e^{-Dt} + \beta q_{inf}t^{-\lambda D} \tag{12}$$

By simplifying and factorizing the common factor in equation 12, we can reduce the equation to;

$$q_t = q_{inf}[e^{-Dt} + \beta t^{-\lambda D}] \tag{13}$$

From the equation 13, we can deduce that the equation in the bracket accounts for the gas lift effect in the well such that if no gas lift is introduced the equation would represent a well producing at natural flow.

2.2 Boundary Conditions

1. If no gas lift is introduced in the well, λ= 1 and β=0 (as q_{iglf} would be equal to 0. This reduces equation 13 to equation 4 which accounts for the well production for natural flow only.
2. The initial gas-lift production rate is the maximum/optimum attainable flow rate that can be achieved when gas lift is introduced into the reservoir. This means rising production rates before attainment of the maximum rate are not considered in equation 13 It only considers the period of declining flow rate after gas-lift has been introduced.

Equation 13 which is a Combination Log model represents an exponential decline curve model that can be used to predict the future production rate of a gas-lifted well.

2.3 Cumulative Production at time t

The cumulative production of an oil reservoir is simply expressed as the integral of the production rate with respect to time. This can be mathematically expressed as;

$$Q_t = \int_0^t \mathrm{q(t)}\ \mathrm{dt} \tag{14}$$

By substituting equation 12 into equation 14, we get;

$$Q_t = \int_0^t q_{inf}e^{-Dt}dt + \int_0^t \beta q_{inf}t^{-\lambda D}dt \tag{15}$$

Integrating equation 15 with respect to time and evaluating the definite integrals yields;

$$Q_t = \left[\frac{-q_{inf}e^{-Dt}}{D} + \frac{\beta q_{inf}t^{-\lambda D}}{1-\lambda D}\right] - [\frac{-q_{inf}}{D}] \tag{16}$$

Simplifying equation 16 yields;

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$$Q_t = [\frac{-q_{inf}e^{-Dt}(1-\lambda D)+D\beta q_{inf}t^{-\lambda D}+q_{\mathrm{inf}}(1-\lambda D)}{D(1-\lambda D)}] \quad (17)$$

Let,
$$q'_{inf} = q_{\mathrm{inf}}(1 - \lambda D) \quad (18)$$
and
$$q'_t = q_{inf}e^{-Dt}(1 - \lambda D) - D\beta q_{inf}t^{-\lambda D} \quad (19)$$

By substituting equation 18 and 19 into equation 17, we get;

$$Q_t = [\frac{q'_{inf} - q'_t}{D(1-\lambda D)}] \quad (20)$$

Equation 20 represents the model for finding the cumulative production of a gas lifted reservoir.

2.4 Model Verification

The production data obtained were smoothed out by removing the outliers to establish a consistent trend. The following steps highlight how to apply this DCA model using production data from gas-lifted wells thereby validating the model:

1. Using excel, the production data was reviewed to remove the outliers to establish a consistent trend.
2. The smoothed production history was divided into two sets for each well. The first set contains the production rate of the well during the natural flow. The production rate will be plotted against time on a semi-log graph to obtain the decline rate constant during the natural flow regime. The intercept of the graph will be the initial production rate during natural flow and the slope will be the decline constant.
3. By assuming a β and α (i.e the gas-lift injection rate) value, the predicted rate using the proposed gas-lift model is compared against the production rate at the second set to show what the production rate would look like with and without gas-lift. The parameters which will be obtained from the first production data will be inputted into equation 13 and extrapolated to the time of interest.
4. Calibrated parameters such as the R^2 value will be used to check the curve-fit accuracy. Better accuracy can be deduced if the R^2 value is close to 1.
5. The EUR-Expected Ultimate Recovery for each time period was calculated.

The time it takes for the oil reservoir in each time period (i.e with gas-lift and without gas-lift) to reach the economic limit and the percentage increase in developed reserves was calculated.[2]

3.0 Results and Discussion

The model which was derived using the principle of superposition consists of two parts which accounts for the period of natural flow and gas lift flow. As shown in equation 13, the model is mathematically expressed as;

$$q_t = q_{inf}[e^{-Dt} + \beta t^{-\lambda D}]$$

This model was created such that when no gas lift is introduced into the reservoir $\lambda = 1$ and $\beta = 0$ which reduces the equation to equation 4 which accounts for the period of natural flow only.

Four actual reservoir data sets from both used to verify the accuracy of the model. This verification included cases with and without gas lift to further check how this model can be used.

3.1 Case Study 1: Eagle Field

The first case is the dataset of a gas-lifted well of well number 4 producing from Eagle Ford formation in Eagle field. This data was got from the SPE Data Repository.[19]

The production data was divided into three set. The first set of the production data consists of the first 10 months. Plots of production rate against time using this data was plotted using the available data on a semi-log data as shown in figure 1 to obtain D and the intercept, which is the $q_{inf.}$. From the graph as shown in figure 2, the following data was obtained; $D = 0.137$; $q_{inf} = 1249 bopd$

The second set of the production data (the next 10 months) shows the period which gas injection was introduced to the well. By plotting production rate against time on a Semi-log paper, the maximum gas lift production rate, which is the intercept, and the gas injection rate can be read as show in figure 3.

From figure 3, we can deduce;
$\alpha = 0.40\ MMScf$; $q_{iglf} = 698.6 bopd$

Using the parameters obtained from figure 1 and 2, we can obtain λ and β. Therefore;

$\lambda = 2.92;\ \beta = 0.56$

By substituting the above parameters into equation 13, we can get the production rate at any specific time of interest keeping in mind the boundary condition. The superposed rate time curve is extrapolated to the time of interest (which is the same time period as the third set of the production data) to obtain the production rate at that time. This is shown in figure 3. The R^2 value was obtained from figure 4 and it was shown to be equal to 0.884.

A comparison graph was plotted to show how the rate time curve of the actual flow rate, the predicted flow rate using the proposed model, and the predicted flow rate assuming gas lift was not introduced into the well deviate from in each other. This is shown in figure 5.

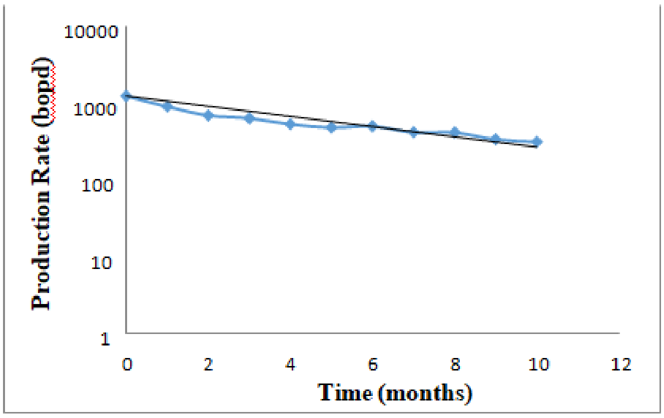

Figure 2: Production rate against time during natural flow

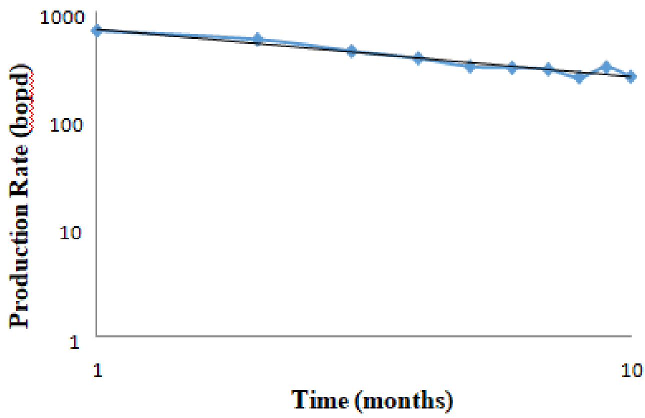

Figure 3: Gas-lift induced plot for finding maximum gas-lift induced rate

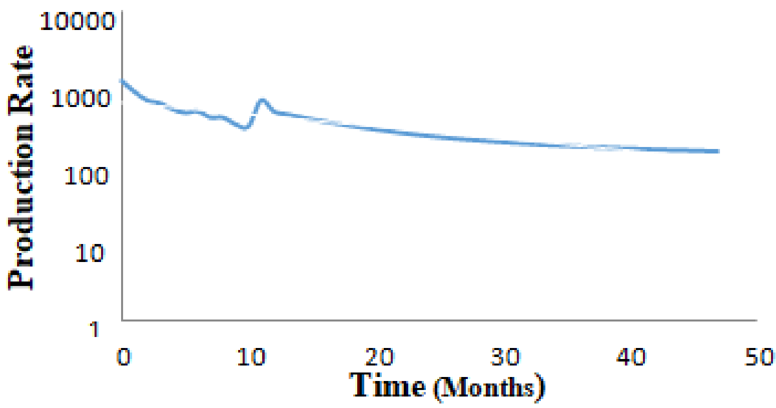

Figure 4: Plot of the future production using the model

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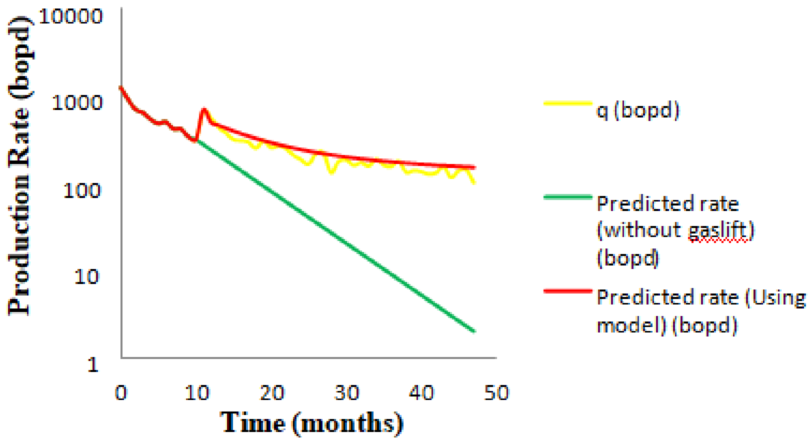

Figure 5: Comparison of the natural rate flow and gas-lift induced flow

3.2 Case Study 2: Osprey Field

The second case is the dataset of a gas-lifted well of well Number 1 producing from Eagle Ford formation in Osprey field. This data was got from the SPE Data Repository.[20]

The production data was divided into three sets. The first set of the production data consists of the first 10 months. Plots of production rate against time using this data was plotted using the available data on a semi-log data as shown in figure 5 to obtain D and the intercept, which is the q_{inf}. From the graph as shown in figure 6, the following data was obtained;

$$D = 0.13;\ q_{inf} = 728 bopd$$

The second set of the production data (the next 10 months) shows the period which gas injection was introduced to the well. By plotting production rate against time on a Semi-log paper, the maximum gas lift production rate, which is the intercept, and the gas injection rate can be read as shown in figure 7.

From figure 7, we can deduce;

$$\alpha = 0.40 MMScf;\ q_{iglf} = 557.2 bopd$$

Using the parameters obtained from figure 5 and 6, we can obtain λ and β. Therefore;

$$\lambda = 3.08;\ \beta = 0.77$$

By substituting the above parameters into equation 13, we can get the production rate at any specific time of interest keeping in mind the boundary condition. The superposed rate time curve is extrapolated to the time of interest (which is the same time period as the third set of the production data) to obtain the production rate at that time. This is shown in figure 7. The R^2 value was obtained from figure 8 and it was shown to be equal to 0.806. A comparison graph was plotted to show how the rate time curve of the actual flow rate, the predicted flow rate using the proposed model, and the predicted flow rate assuming gas lift was not introduced into the well deviate from in each other. This is shown in figure 9.

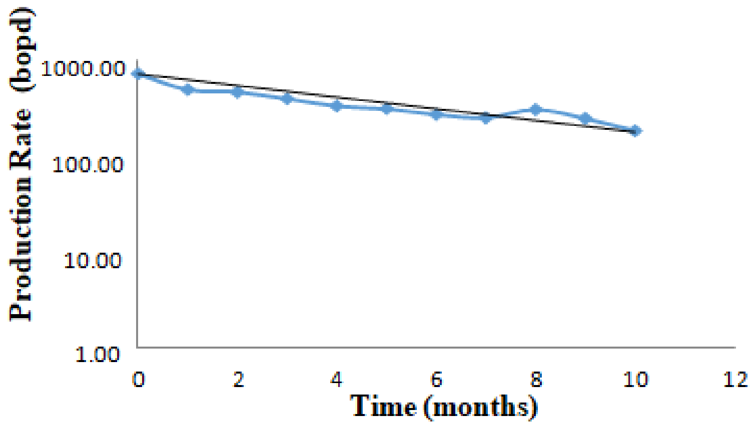

Figure 6: Plot of production rate against time during natural flow

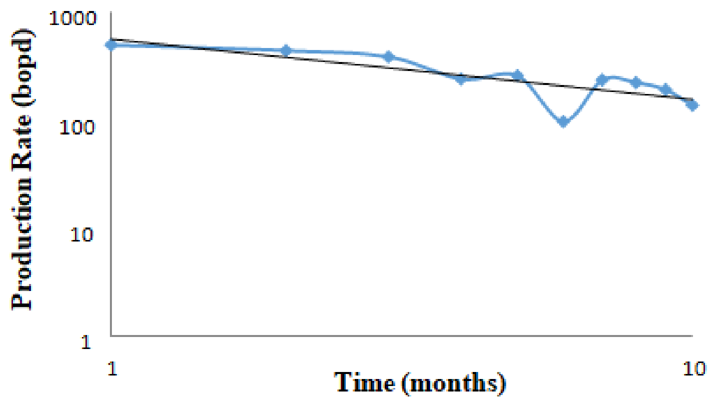

Figure 7: Gas-lift induced plot for finding the maximum gas-lift induced rate

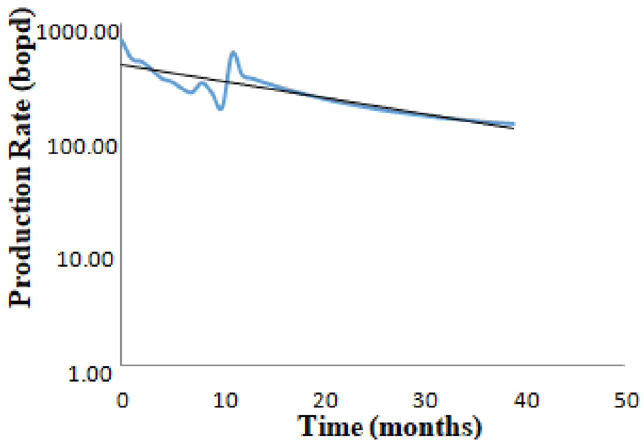

Figure 8: Plot of the future production rate using the model

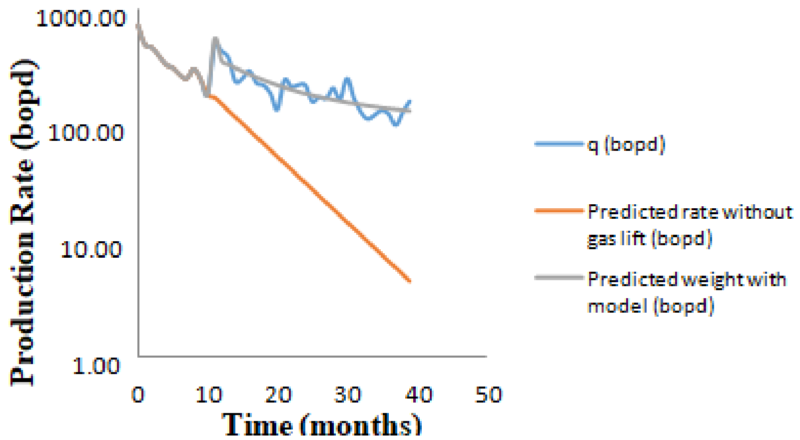

Figure 9 Comparison of natural flow and gas-lift induced flow

3.3 Case Study 3: Reservoir A

The third case is a dataset from reservoir A located in Southeast, Nigeria, summarized by [3]. The production data ranges from year 1999 to 2009 and we will be using the mathematical model to predict the future production life of the well up to 2025 assuming gas-lift was introduced to the well in 2010.

Plots of production rate against time using this data was plotted using the available data on a semi-log data as shown in figure 10 to obtain D and the intercept, which is the q_{inf}. From the graph as shown in figure 10, the following data was obtained;

$D = 0.0877$;$q_{inf} = 2398 stb/d$

As this well was not gas-lifted, we would be assuming a gas injection rate and the ratio of the production rate during natural flow and gas-lift. We assume that the gas injection volume that can yield the maximum production rate is 0.25MMScf, such that the production rate of the reservoir increases by 0.1. Mathematically, we express this statement as:

$\alpha = 0.40MMScf; \beta = 0.1$

By substituting the above parameters into equation 13, we can get the production rate at any specific time of interest keeping in mind the boundary condition. The superposed rate time curve is extrapolated to the time of interest to obtain the production rate at that time. This is shown in figure 10. The R^2 value was obtained from figure 11 and it was shown to be equal to 0.917.
A comparison graph was plotted to show how the rate time curve of the predicted flow rate using the proposed model and the predicted flow rate assuming gas-lift was not introduced into the well deviate from in each other. This is shown in figure 12.

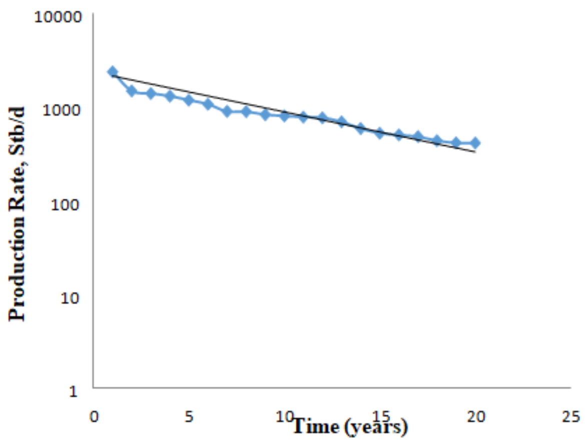

Figure 10 Plot of production rate against during natural flow

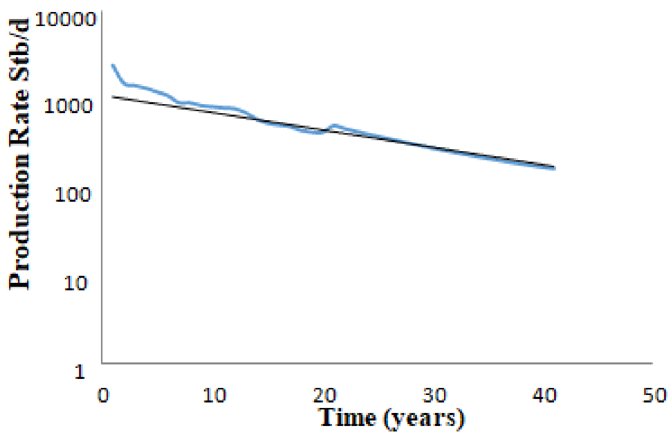

Figure 11: Plot of the future production time rate using the model

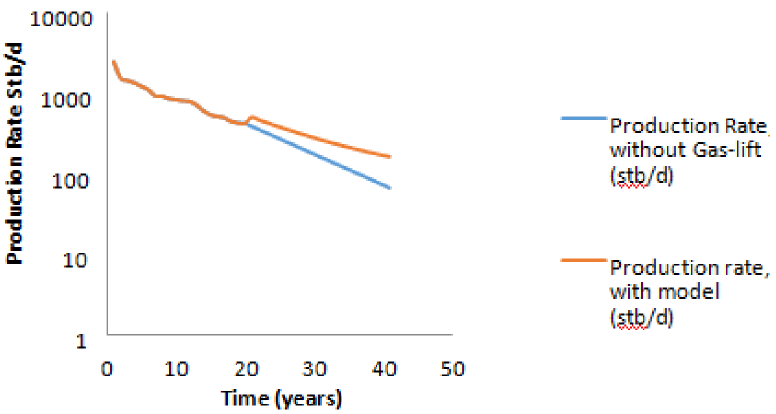

Figure 12 Comparison of the natural flow and the gas-lift induced flow

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3.4 Case Study 4: Well A-1

The fourth case is a dataset from well A -1 obtained from a field in the Niger Delta region, Nigeria, summarized by [2]. From the paper, we can deduce that gas-lift was introduced into the well at month 25.
Plots of production rate against time using this data was plotted using the available data from the first 19 months on a semi-log data as shown in figure 13 to obtain D and the intercept, which is the $q_{inf.}$. From the graph as shown in figure 13, the following data was obtained;

$D = 0.042; q_{inf} = 1801 stb/d$

From the paper, the gas injection volume that can yield the maximum production rate is stated as 0.0861MMScf, such that the production rate of the reservoir increases by 0.2 when gas lift is introduced. Mathematically, we express this statement as:

$\alpha = 0.0861 MMScf; \beta = 0.2$

By substituting the above parameters into equation 13, we can get the production rate at any specific time of interest keeping in mind the boundary condition. The superposed rate time curve is extrapolated to the time of interest to obtain the production rate at that time. This is shown in figure 14.
Figure 15 is a comparative plot showing how the rate time curve of the predicted flow rate using the proposed model and the predicted flow rate assuming gas-lift was not introduced into the well. The R^2 value was obtained from figure 15 and it was shown to be equal to 0.874 for the predicted gas lift and actual gas lift production data.

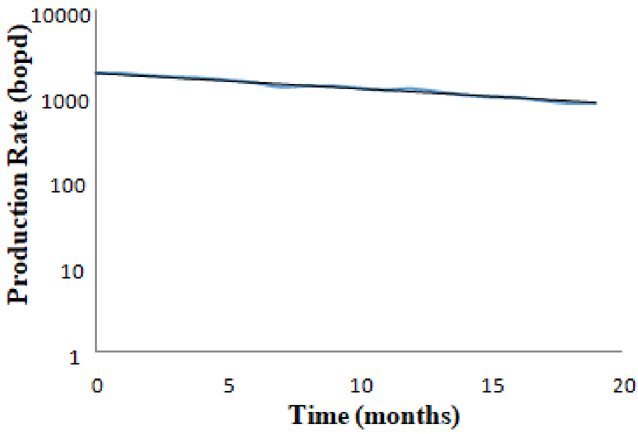

Figure 13: Plot of production rate against time during natural flow

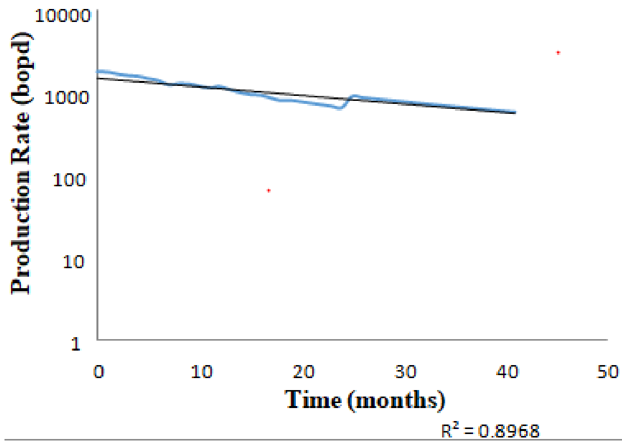

Figure 14: Plot of the future production rate using the model

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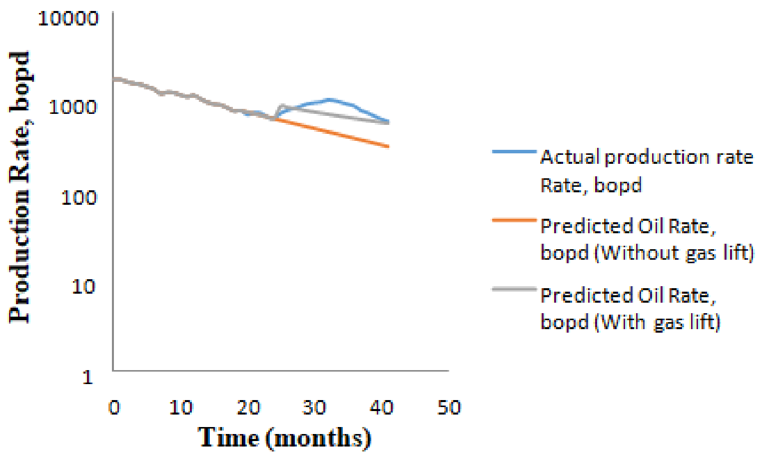

Figure 15 Comparison of the natural flow and gas-lift induced flow

3.5 Discussion of results

Field data from the four fields helped validate the effectiveness of the proposed empirical model. Generally, based on the proposed model, the production rates after gas lift was introduced to the well declines more slowly when compared to the natural flow as seen in figure 15. It can also be seen that the sum of the natural flow and the gas-lift induced flow gives the total flow rate at time, t after gas-lift has been introduced to the well. An economic limit of 100bopd was used during the course of this study.

By applying the proposed model to the Eagle field, we find that the cumulative production of the well during the period of flow increased by 0.22MMstb when gas-lift was applied to the reservoir, which indicates an 85% increase in developed reserve. The time to reach economic limit, $t_{ec,}$ also increased from 18.5 months during natural flow to 129 months when gas-lift was applied. Comparison of the production rate of the proposed model to that of the actual field data showed a relative error of 0.07 and a correlation coefficient of 0.884. This error can be as a result of other reservoir and operational condition not accounted for in the model.

In the Osprey field, the cumulative production of the well during the period of flow increased by 0.15MMstb when gas-lift was applied to the reservoir and an 89% increase in developed reserve. The $t_{ec,}$ also increased from 15.5 months during natural flow to 74 months when gas-lift was applied. Comparing the production rate from the proposed model to that of the actual field data, a relative error of 0.01 and a correlation coefficient of 0.806 was observed. This error difference can be as a result of other reservoir and operational condition not accounted for in the model.

In the case of Reservoir A, the cumulative production also increased by 0.78MMstb when gas-lift was applied to the reservoir, resulting in a 9.8% increase in developed reserves. The $t_{ec,}$ also increased from 36.2 months during natural flow to 59 months. A correlation coefficient of 0.917 was obtained when comparing the production rate from the proposed model to that of the actual field data. This indicates the accuracy of the model in predicting the future production rate of gas-lifted wells.

For Well A -1, the cumulative production of the well during the period of flow increased by 0.13MMstb as a result of gas-lift. This is a 12.4% increase in developed reserve. The $t_{ec,}$ also increased from 69 months during natural flow to 150 months. When comparing the production rate from the proposed model to the actual field data, a relative error of 0.06 was observed and a correlation coefficient of 0.874. This error difference can be as a result of other reservoir and operational condition not accounted for in the model.

Summary of the results obtained from applying the model on the different fields is displayed in Table 1.

Table 1: Result obtained from different fields

Well Name	Period of flow	q_{ec} (bopd)	t_{limit} (months)	Q_t (MMstb)	% Increase in developed reserves
Eagle field	Natural	100	18.5	0.26	85
	Gas lift	100	129	0.48	
Osprey field	Natural	100	15.5	0.16	89
	Gas lift	100	74	0.31	
Reservoir A	Natural	100	36.2	7.96	9.8
	Gas lift	100	59	8.74	
Well A-1	Natural	100	69	1.1	12.4
	Gas lift	100	150	1.23	

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3.6 Performance Indicators

To evaluate the performance of the new model in predicting the future forecasting life of gas-lifted wells, statistical indicators such as the coefficient of correlation (R^2), Mean Absolute Percent Error (MAPE), and Root Mean Square Error (RMSE) are compared with that of the model proposed by [2].
As seen in table 2, the new model shows the better prediction with RMSE, MAPE, and relative error value. This is because the power law model better approximates the gas lift induced flow than the exponential or Arp's model used by [2] .

Table 2: Comparison between the new model and Daniel and Isehunwa model

Well Name	Model Type	R^2	RMSE	MAPE	Er
Eagle field	Daniel and Isehunwa (2009)	0.992	142.2	61.2	0.39
	New Model	0.884	34.6	13.3	0.07
Osprey field	Daniel and Isehunwa (2009)	0.981	137.35	57.1	0.43
	New Model	0.806	35.33	11.9	0.01
Reservoir A	Daniel and Isehunwa (2009)	0.993	-	-	-
	New Model	0.917	-	-	-
Well A-1	Daniel and Isehunwa (2009)	0.996	261.5	18.11	0.15
	New Model	0.874	125.6	7.76	0.06

4.0 Conclusion

This study used a superposed model that accounts for the production rate during natural flow and continuous gas-lift induced flow to predict the future production rate at time, t, after gas-lift has been introduced into the well. Based on the analysis performed, the study concluded that;

i. The Arps exponential decline model is inadequate for predicting accurately the future production rate of a gas-lifted rate as it depends on the past performance of the well whereas, gas-lift distorts the well's production trend.
ii. The principle of superposition can be used to derive an empirical model which is made up of the Arps exponential decline model for the natural flow period and the power law model proposed by Lewis and Beal for the gas-lift induced flow period
iii. When the superposed equation was applied to field cases, the resulting production rates coincides with the actual field data with a little error difference ranging from 0.01 to 0.07 which can be as a result of other reservoir conditions not accounted for in the model. The correlation coefficient ranged from 0.874 to 0.996 which shows very high accuracy of the model for prediction of flow rates.

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