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Evaluation of Key Parameters and Performance Indicators of A-05 Well in the Niger-Delta

*Nnaemeka Uwaezuoke, Kalu G. Oji, Ndubuisi U. Okereke, Lilian E. Ndoma-Egba, Chukwuebuka F. Dike**

Department of Petroleum Engineering, Federal University of Technology Owerri, Nigeria

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Abstract

This study focuses on the application of nodal analysis in evaluating the impact of water-cut, wellhead pressure (WHP) and gas oil ratio (GOR) on the production oil rate of well A-05, situated in the Niger Delta region. Leveraging available data encompassing well geometry, configuration, and well test results, the analytical software PROSPER was employed to calibrate and model the well's behavior. From the result of the study, a significant reduction in the oil production was observed with the increase in water cut with the well having a maximum economic water cut of 45%. It was observed that there is an increase in the oil rate with the decrease in WHP for a constant reservoir pressure. A decrease in the WHP from 415 psi to 100 psi extends the wells water cut economic limit to 70% keeping the well profitable for a longer period. Production rate was found to also increase with increasing GOR to 800 scf/stb while reducing WHP with increasing water cut which sees wells life extended while other artificial lift methods are being considered.

Keywords: *Production optimization; Nodal analysis; Production rate.*

1. Introduction

The demand for energy globally has grown exponentially over the years [1], and this has attracted keen interest from stakeholders within the oil and gas industry due to its close to 85% contribution to global energy [2]. At the early stages of oil and gas production, the reservoir is characterized by the presence of high pressure which allows crude oil, but continuous production reduces the natural pressure which significantly affects the profitability and hydrocarbon production potential of that field [3]. To address this challenge, engineers and scientists have turned to advanced reservoir management and production optimization strategies. Nodal analysis has emerged as a vital component of these strategies. Nodal analysis, borrowed from fluid dynamics and adapted to petroleum engineering, provides a systematic and comprehensive framework for assessing and optimizing the entire production system of an oil field. It takes into account various components, including the reservoir, wellbore, surface facilities, and pipelines, to create a holistic understanding of the production system's behavior. By examining this system as a whole, engineers gain insights into where pressure drops occur, how fluids move within the reservoir, and where intervention is needed to maximize oil recovery. The adoption of nodal analysis in the oil and gas industry has been facilitated by advancements in data acquisition, reservoir simulation, and computational tools. Modern software packages and modeling techniques allow engineers to create accurate representations of reservoir behavior and simulate various production scenarios, even in oil-rim reservoirs [4-5]. This computational power, combined with nodal analysis, has revolutionized the way oil reservoirs are managed. Production optimization implies striking a balance between the production deliverability of the wells and demand which aims at increasing the rate at which a well flows from the reservoir without restriction to the surface storage tank(s) [6]. Thus, production optimization through nodal analysis is a way of preparing a well for the production of oil/or gas from the reservoir to achieve the greatest possible efficiency. Beggs [7] stated that optimization is directly dependent on some functions. The functions may be a single variable or two or more variables (multivariate optimization). An optimization problem focuses on achieving the best design of a process or a product concerning a set of selected constraints or criteria, e.g., maximization of strength, productivity, efficiency etc. Often, engineers are required to identify certain suitable design solutions from which the best-suited solution needs to be chosen. It is regarded as a strategy to cause the best change in an inadequately appreciated situation within the accessible resources [8]. In a technological survey by Bieker *et al.* [9], real-time production optimization for oil and gas production systems was achieved through data collection, processing, and model updating. This optimization process facilitated both production and strategic planning.

Litvak & Angert [10] focused on field development optimization in large oil fields. They utilized a robust optimization procedure that combined a Genetic Algorithm, a global optimization method, with mixed-integer optimization techniques to achieve their goals. Stephenson *et al.* [11] conducted a case study on real-time fault detection for gas lift systems using intelligent algorithms. This innovative method allowed for continuous monitoring of wells employing continuous gas lift, particularly in developed onshore gas lift fields in the western United States. The IPR describes pressure drawdown as a function of production rate, where drawdown is defined as the difference between static and FBHP. The simplest approach to describe the inflow performance of oil wells is the use of the productivity index (PI) concept. The productivity index is a measure of the producing quality of strata within the drainage radius of a well [12]. Analysis of a Tubing performance or vertical lift performance (VLP) of a well is an important part of the well design. It allows selecting the well completion correctly corresponding to lifting methods and to evaluate well's performance. Accurate modeling of vertical lift performance is critical to predict a realistic production rate during the blow-down phase. The intersection of the inflow performance relationship curve and the vertical lift performance is called the operating point or working point (the point where the flow rate is optimum) If any change is made anywhere. Inflow or outflow then only that curve will be shifted and the other will be the same, intersection will be changed. For instance, if the tubing size increases which will give less pressure drop, the inflow curve will move.

In this study, the influence of critical parameters such as water cut, wellhead pressure (WHP) and gas oil ratio (GOR) on the oil production rate is analysed with the help of IPR curve and VLP curve using PROSPER software, employed for reservoir and production system analysis. The aim of this study is to obtain optimum conditions for maximum production by performing a sensitivity analysis on water cut, WHP and GOR to find their influence on oil production rate by carrying out a sensitivity analysis on this parameters.

2. Material and method

2.1. Material

The material utilized was for the well data and Integrated Production Modeling (IPM) package Prosper. The well data comprised of pressure-volume-temperature (PVT) data, the reservoir data and production data depicted in Table 1, and well completion profile shown in Figure 1. IPM Prosper is a software designed to aid production and reservoir engineers to forecast pipeline and tubing hydraulics and temperature with accuracy and speed. It is designed to assist development of consistent and reliable well models, with the potential to address aspects of PVT (fluid characterization), wellbore modeling, IPR (reservoir inflow) and VLP correlation (losses at the flow-line and tubing) [13].

2.2. Method

The simulation commenced with inputting fluid description (fluid and method), the well (flow type and well type) artificial lift type, calculation type approach, well completion (type and sand control) and reservoir information (inflow type and gas coning) on the system summary of the IPM Prosper simulator. Well data depicted in Table 1 was utilized for PVT Modelling and IPR Modelling. The well profile depicted in Figure 1 was utilized in filling up the downhole equipment, deviation survey and geothermal gradient. After the node pressure, gas oil ratio (GOR) and water-cut was utilized for VLP modelling before the VLP/IPR matching was conducted to determine the possible oil rate. Sensitivity Analysis with scenarios depicted in Tables 2, 3 and 4 was utilized using System (4 Variables) to derive the impact of wellhead pressure, water-cut and gas oil ratio (GOR) on the oil rate. Figure 2 depicted the diagrammatic representation of the simulation process.

Table 1. Well data.

Properties	Values	Properties	Values
Reservoir temperature	180 (°F)	Current pressure	3000 (psia)
Oil API gravity	40 (API)	Water salinity	200000 (ppm)
Gas relative density	0.80	Pressure on christmas tree	445 (psia)
GOR	550 (scf/stb)	PI or J (Well test)	12.4(stb/d/psi)
Pb	2044.7 (psia)	Water cut	30 (%)
Water viscosity	0.67 (cP)		

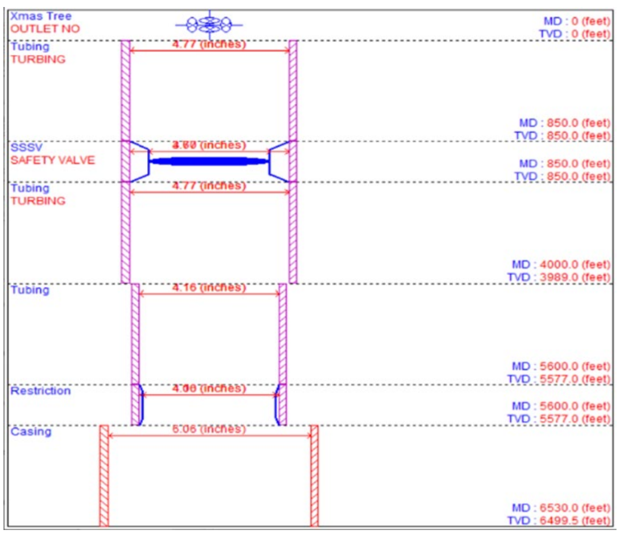

Figure 1. Schematics of down-hole completion with depth.

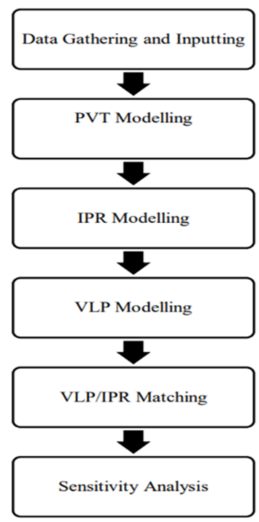

Figure 2. Research design.

Table 2. Effect of water-cut on oil rate for varying reservoir pressure.

Reservoir pressure	Water-cut (%)
3000	30, 35, 40, 45 and 50
2800	30, 35, 40, 45 and 50
2700	30, 35, 40, 45 and 50
2600	30, 35, 40, 45 and 50
2500	30, 35, 40, 45 and 50

Table 3. Effect of water-cut on rate for varying well-head pressure.

Well-head pressure	Water-cut (%)
100	30, 35, 40, 45, 50, 60, 70 and 80
200	30, 35, 40, 45, 50, 60, 70 and 80
300	30, 35, 40, 45, 50, 60, 70 and 80
415	30, 35, 40, 45, 50, 60, 70 and 80

Table 4. Effect of gas oil ratio (GOR) Oil rate for a constant reservoir pressure, varying water-cut and wellhead pressure (WHP).

GOR (scr/stb)	Well-head pressure	Water-cut (%)
550	100	30, 35, 40, 45, 50, 60, 70 and 80
	200	30, 35, 40, 45, 50, 60, 70 and 80
	300	30, 35, 40, 45, 50, 60, 70 and 80
	415	30, 35, 40, 45, 50, 60, 70 and 80
600	100	30, 35, 40, 45, 50, 60, 70 and 80
	200	30, 35, 40, 45, 50, 60, 70 and 80
	300	30, 35, 40, 45, 50, 60, 70 and 80
	415	30, 35, 40, 45, 50, 60, 70 and 80
700	100	30, 35, 40, 45, 50, 60, 70 and 80
	200	30, 35, 40, 45, 50, 60, 70 and 80
	300	30, 35, 40, 45, 50, 60, 70 and 80
	415	30, 35, 40, 45, 50, 60, 70 and 80
800	100	30, 35, 40, 45, 50, 60, 70 and 80
	200	30, 35, 40, 45, 50, 60, 70 and 80
	300	30, 35, 40, 45, 50, 60, 70 and 80
	415	30, 35, 40, 45, 50, 60, 70 and 80

3. Results and discussion

3.1. Base case

Figure 3 shows the plot of VLP vs IPR for base case. As shown from the result of VLP-IPR plot in Table 5, the well was observed to have recorded oil rate of 6004.3stb/d, water rate of 2573.3stb/d and gas rate of 3.302mmscf/d.

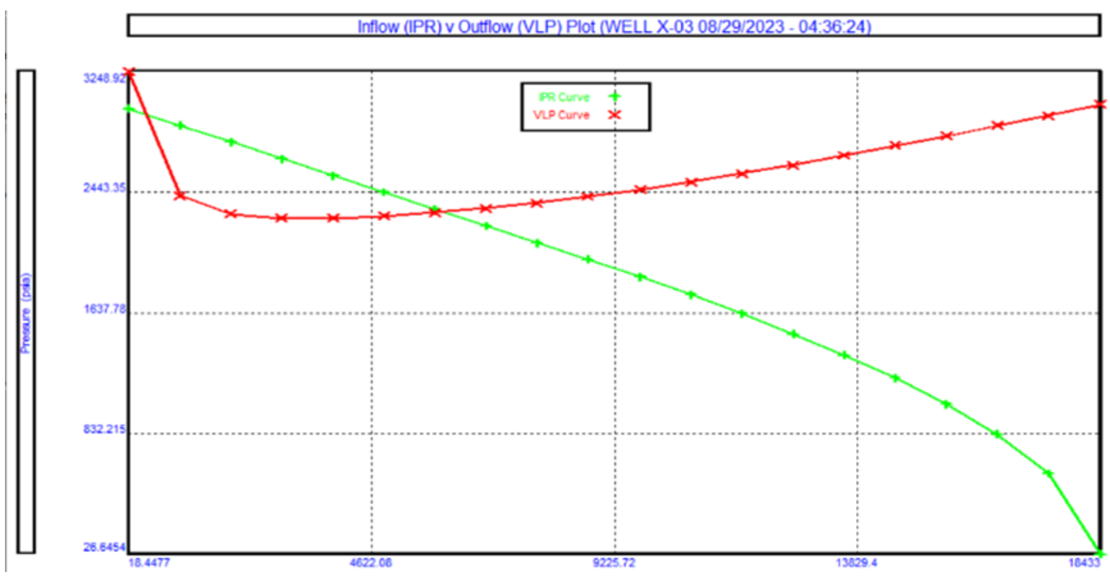

Figure 3 Present VLP matching IPR.

Table 5. Current well production capacity.

Liquid rate (stb/d)	Oil rate (stb/d)	Water-cut	Water rate (stb/d)	Gas rate (mmscf/d)	Solution node pressure
8577.6	6004.3	30	2573.3	3.302	2308.26

3.2. Impact of water-cut on oil rate at varying reservoir pressure

Figure 4 shows the impact of water-cut on oil rate at varying reservoir pressure. As shown from the result of VLP-IPR plot in Table 6, at 3000psig reservoir pressure the well was productive from 30% water-cut to 50% water-cut as it produced crude oil from 6004.3stb/d and

2340.2stb/d. At 2800psig reservoir pressure the well was productive from 30% water-cut to 45% water-cut as it produced crude oil from 4553.8stb/d and 1666.8stb/d. At 2700psig reservoir pressure, oil rate was recorded only at 30%-40% water-cut, at 2600psig reservoir pressure the well is only viable at 30% water-cut, while at 2500psig reservoir pressure the well is not productive. As observed from Figure 4 the simultaneous decrease in reservoir pressure and an increase in water cut is observed to eventually cause the well to stop producing oil. At this point, alternative recovery means (artificial lift) may be employed, if found to be economical and changes can be made on some or all of the good nodes if found to be economical and feasible.

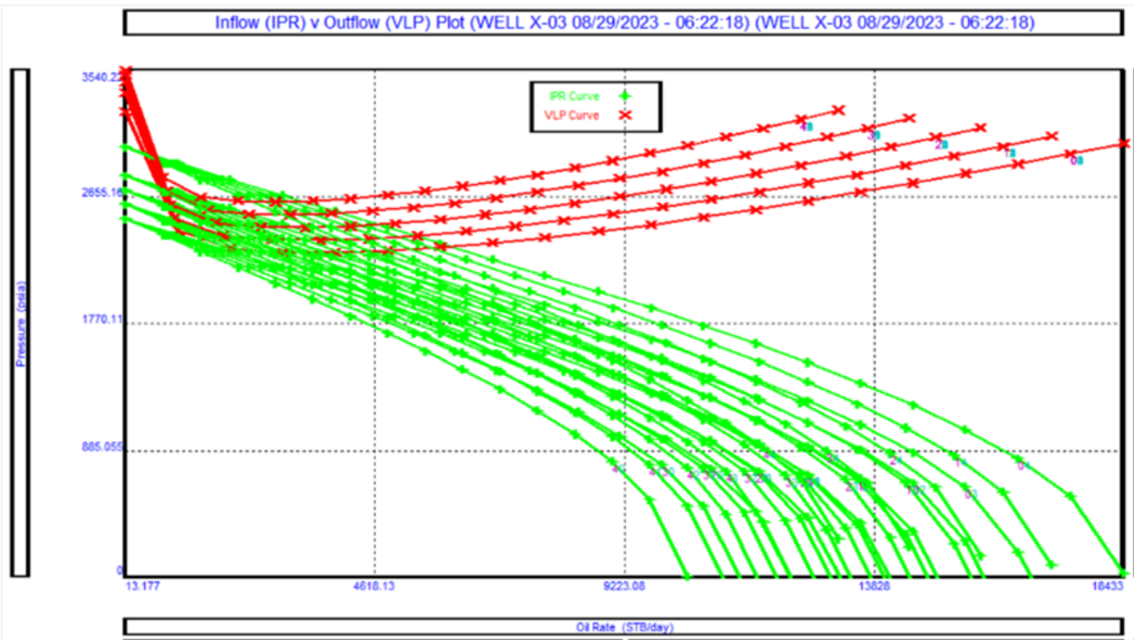

Figure 4. IPR and VLP plot water cut on oil rate for varying reservoir pressure.

Table 6. Impact of water-cut on oil rate at varying reservoir pressure.

Reservoir pressure (psig)	Water cut (%)				
	30	35	40	45	50
	Oil rate (STB/d)				
3000	6004.3	5041.5	4110.4	3212.8	2340.2
2800	4553.8	3618.3	2667.3	1666.8	0
2700	3760.1	2784.6	1720.2	0	0
2600	2855.4	0	0	0	0
2500	0	0	0	0	0

3.3. Impact of water-cut oil rate at varying well-head pressure

Figure 5 shows the impact of water-cut on oil rate at varying wellhead pressure. As shown from the result of VLP-IPR plot in Table 7, at 100psig wellhead pressure the well is viable up-to 80% water-cut, at 200psig wellhead pressure the well is viable up-to 70% water-cut at 300psig wellhead pressure the well is viable up-to 60% water-cut, while at 415psig wellhead pressure the well is viable up-to 50% water-cut. As observed in Table 7, the production rate reduces with increase in water-cut and increase in wellhead pressure.

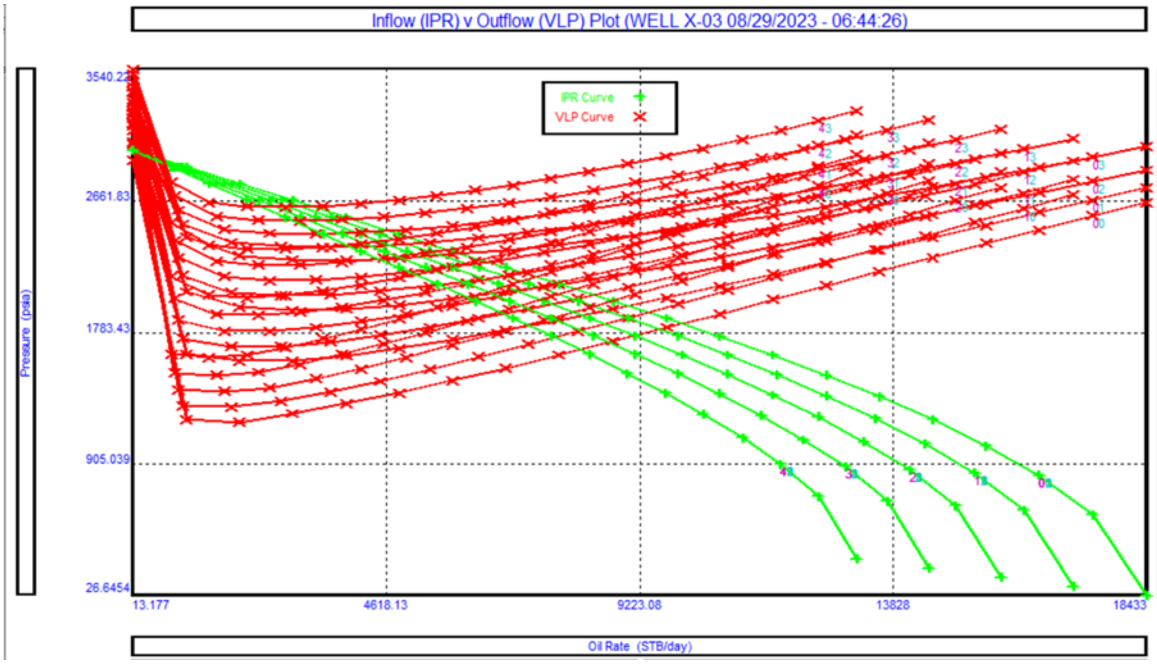

Figure 5. IPR and VLP plot water cut on oil rate for varying wellhead pressure.

Table 7. Impact of water-cut on oil rate at varying well-head pressure.

Well-head pressure (psig)	Water-cut (%)							
	30	35	40	45	50	60	70	80
	Oil rate (Stb/d)							
100	9992.4	9015.2	8030.3	6130.6	6016.7	4307.4	2522.9	1116.2
200	9013.5	8033.8	7046.7	6088.4	5153.1	3362.5	1695	0
300	7778	6782.4	5811.8	4851.2	3932.5	2195.4	0	0
415	6004.3	5041.3	4110.4	3212.8	2340.2	0	0	0

3.4. Impact of gas oil ratio (GOR) on oil rate for at varying water-cut and well-head pressure (WHP)

Figure 6 shows the impact of water-cut oil rate at varying gas oil ratio (GOR) and wellhead pressure (WHP). As shown from the result of VLP-IPR plot in Table 8, for 100psig wellhead pressure at 550scf/stb GOR oil rate reduced from 9992.4stb/d to 1116.2stb/d when water-cut increased from 30% to 80% respectively, at 600scf/stb GOR oil rate reduced from 10154.4stb/d to 1262.9tb/d when water-cut increased from 30% to 80% respectively, at 700scf/stb GOR oil rate reduced from 10231.3stb/d to 1510.5stb/d when water-cut increased from 30% to 80% respectively, while at 8000scf/stb GOR oil rate reduced from 10099.8stb/d to 1695.7stb/d when water-cut increased from 30% to 80% respectively. For 200psig well-head pressure at 550scf/stb GOR oil rate reduced from 9013.5stb/d to 1695stb/d when water-cut increased from 30% to 70% respectively, at 600scf/stb GOR oil rate reduced from 9292.8stb/d to 1953.7stb/d when water-cut increased from 30% to 70% respectively, at 700scf/stb GOR oil rate reduced from 9535.5stb/d to 822.5stb/d when water-cut increased from 30% to 80% respectively, while at 8000scf/stb GOR oil rate reduced from 9541.7stb/d to 1098.2stb/d when water-cut increased from 30% to 80% respectively. For 300psig well-head pressure at 550scf/stb GOR oil rate reduced from 7778stb/d to 2195.4stb/d when water-cut increased from 30% to 60% respectively, at 600scf/stb GOR oil rate reduced from 8199.7stb/d to 927.4stb/d when water-cut increased from 30% to 70% respectively, at 700scf/stb GOR oil rate reduced from 8675stb/d to 1507.4stb/d when water-cut increased from 30% to 70% respectively, while at 8000scf/stb GOR oil rate reduced from 8808.2stb/d to 1929.5stb/d when water-cut increased from 30% to 70% respectively. As observed in Table 8, increase in GOR yielded better oil rate at constant WHP and water-cut, but these rates starts to drastically with increase in WHP and water-cut.

Table 8. Oil rate at varying parameter ranges of water cut, GOR and WHP.

GOR (scf/stb)	Water cut (%)							
	30	35	40	45	50	60	70	80
	Oil Rate (Stb/d)							
WHP = 100 (psig)								
550	9992.4	9015.2	8030.3	7073.2	6130.6	4307.4	2622.9	1116.2
600	10154.4	9182.5	8234.4	7279	6350.7	4527.6	2808.1	1262.9
700	10231.3	9321.1	8415.7	7506.4	6610.2	4825.9	3102	1510.5
800	10099.8	9258.6	8413	7561.5	6704.9	4989.2	3297.3	1695.7
WHP = 200 (psig)								
550	9013.5	8033.6	7046.7	6088.4	5153.1	3362.5	1695	0
600	9292.8	8328.1	7363.8	6406.4	5472.9	3655.1	1953.7	0
700	9553.5	8634.4	7719.8	6810.5	5897.5	4110.9	2398.6	822.5
800	9541.7	8685.4	7827	6967.4	6105.4	4383.2	2695.1	1098.2
WHP = 300 (psig)								
550	7778	6782.4	5811.8	4851.2	3932.5	2195.4	0	0
600	8199.7	7225.1	6253.2	5299.7	4366.3	2572.6	927.4	0
700	8675	7748.2	6827.1	5911.2	4999.4	3202	1507.4	0
800	8808.2	7949.7	7086	6224	5357.7	3625.8	1929.5	0
WHP = 415 (psig)								
550	6004.3	5041.5	4110.4	3212.8	2340.2	0	0	0
600	6620.7	5633	4671.8	3753	2863	0	0	0
700	7431.6	6496.8	5557	4630.9	3712.1	1960.1	0	0
800	7787.6	6916.7	6047.2	5169.5	4286	2548	859.7	0

4. Conclusion

At declining pressure and increasing water-cut, oil production by natural method becomes impossible and required proper management and introduction of suitable artificial lift system. Wellhead pressure must be kept at the lowest point to ensure production of oil at higher water-cuts. At declining GOR, the wellhead pressure to ensure continuous oil production at increasing water-cuts.

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To whom correspondence should be addressed: Chukwuebuka F. Dike, Department of Petroleum Engineering, Federal University of Technology Owerri, Nigeria, E-mail: dike.chukwuebuka@futo.edu.ng
https://orcid.org/0009-0007-5688-5513