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Effect of Gas-Oil Ratio on Oil Production for a Niger Delta Well

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Authors' contributions

This work was carried out in collaboration among all authors. All authors read and approved the final manuscript.

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ABSTRACT

This study delves into the intricate relationship between gas-oil ratio (GOR) and oil production rate in a vertical well within the framework of reservoir engineering. The investigation employs advanced reservoir modeling techniques, drawing insights from Prosper software simulations and well data analysis. A comprehensive methodology involving PVT data, inflow performance relationship data, and sensitivity analysis guides the exploration of GOR's impact on oil rate. The selected well configuration, a vertical well, serves as the experimental canvas for this study. Through meticulous analysis of reservoir and well data, an Inflow Performance Relationship (IPR) curve emerges. This curve is developed using the Darcy reservoir model available within the Prosper software, reflecting the intricate interplay between fluid dynamics, pressure gradients, and production behavior. Further expanding the analysis, the study explores the IPR-Vertical Lift Performance (VLP) curve, spotlighting the well's behavior at a top node pressure of 250 psig. Subsequently, the study dives into the realm of sensitivity analysis, seeking to unravel the nuanced connection between oil rate, GOR, and well head pressure. The captivating findings are encapsulated, a visual testament to the

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intricate dance of fluid dynamics. The results paint a vivid picture of the GOR's role in oil rate modulation. The correlation between GOR and oil rate is revealed to be a delicate balance, illustrated by a crescendo and diminuendo as GOR rises beyond the bubble point. Above the bubble point, the gas's continuous expansion within the solution propels oil production. The study's intricate examination of well head pressure offers further illumination. The result further exposes the inverse relationship between well head pressure and oil production rate, as heightened well head pressure curtails pressure drawdown and subsequently reduces the amount of oil lifted to the surface. The study concluded that Oil production rate increases with increase in gas-oil ratio up to a maximum above which oil production starts decreasing. The decrease in oil production starts when gas is released from the oil. An increase in well head pressure led to a decrease in oil production. This is attributed to a decrease in pressure drawdown between the bottom of the well and the well head.

Keywords: IPR; VLP; GOR; PVT; oil production.

1. INTRODUCTION

The Gas-Oil Ratio (GOR), also referred to as the Gas-to-Oil Ratio, is a pivotal parameter in the field of reservoir engineering and hydrocarbon production. The GOR represents the volumetric ratio of gas to oil produced from a reservoir, offering insights into the fluid composition, reservoir dynamics, and recovery potential [1]. As the world's energy demands continue to grow, understanding the effect of GOR on reservoir behavior becomes paramount for efficient resource management and sustainable energy production. The concept of GOR traces its roots to the early days of the oil and gas industry, where empirical observations of gas and oil production rates led to the recognition of the GOR as a critical reservoir characteristic [2]. In the mid-20th century, researchers began to explore the fundamental principles governing the GOR's behavior and its impact on reservoir performance. Studies by [3] and [4] laid the foundation for understanding the interplay between gas and oil phases within a reservoir and the subsequent effects on fluid flow behavior.

Gas-Oil Ratio (GOR) is characterized as the volume of gas liberated from oil under standard conditions (60°F and 14.7 psi) [5]. In the context of production, Gas-Oil Ratio refers to the ratio of gas emerging from the solution to the volume of oil, a phenomenon resulting from pressure and temperature reductions to surface conditions. Solution Gas-Oil Ratio (also termed gas in solution), Rs, represents the gas dissolved in oil at any pressure and temperature when brought back to reservoir conditions [6]. In undersaturated reservoirs or when reservoir pressure exceeds the bubble point pressure, the Solution Gas-Oil Ratio remains constant. However, when reservoir pressure drops below the bubble point pressure, gas bubbles form a gas phase due to its mobility [7]. The Instantaneous Gas-Oil Ratio is defined as the produced GOR at any specific moment, representing the ratio of standard cubic feet of total gas produced to the stock tank barrels of oil produced at that same instant [8]. Tubing, a relatively small-diameter pipe in wells, functions as a conduit for oil and gas passage to the surface. API recognizes two tubing ranges: Range 1 (20-24 ft) and Range 2 (28-32 ft), with Range 2 being the common choice. Shorter tubing joints (pup joints) are also available in various lengths (2, 3, 4, 6, 8, 10, and 12 ft) with a tolerance of +3 inches [9]. API 5CT (2011) specifies the tubing's outside diameter (OD) ranging from 1.050 inches to 4-1/2 inches and the tubing inside diameter (ID) varying from 0.7421 inches to 3.9582 inches. [10] introduced the Inflow Performance Relationship (IPR) as a crucial tool for equipping and operating oil wells. IPR involves plotting flowing bottom-hole pressures against oil/gas production rates, revealing the relationship at different pressure values [11]. Essentially, IPR signifies the fluids a reservoir can deliver to the bottom-hole or the reservoir's flow rate to the wellbore. Conversely, Tubing Performance Curve (TPC) or Vertical Lift Performance (VLP), also known as outflow, denotes the fluids a well can deliver from bottom-hole to the surface at a specified well head pressure or the required bottom-hole pressure for each flow rate inside the tubing.

Advances in reservoir simulation techniques further facilitated a deeper comprehension of GOR-related phenomena. With the ability to model complex fluid interactions and predict reservoir behavior under various conditions, researchers and engineers gained valuable insights into the implications of different GOR values on recovery strategies and production dynamics [12]. The influence of GOR extends beyond reservoir engineering, permeating into fields such as enhanced oil recovery (EOR) and reservoir management. As highlighted by [13], the GOR not only affects primary and secondary recovery methods but also plays a role in determining the feasibility and success of tertiary recovery techniques, including gas injection and thermal methods.

Furthermore, the relationship between GOR and reservoir behavior is intricately tied to geological and fluid properties. For instance, reservoirs with a high GOR may possess a gas cap that impacts pressure distribution and fluid displacement [14]. On the other hand, reservoirs with a low GOR may exhibit challenges in fluid mobility and sweep efficiency due to the dominance of viscous forces [15]. As the industry continues to push the boundaries of exploration and production, understanding the effect of GOR becomes crucial for optimizing recovery strategies, minimizing environmental impact, and ensuring economic viability. This study aims to build upon the existing body of knowledge by comprehensively analyzing the influence of GOR on reservoir behavior, drawing from a range of case studies and simulation models.

2. METHODOLOGY

This study uses software and well data to meet the objectives of this study. Prosper software was used to model the well and carry out sensitivity analysis. The well is a cased production well with no artificial lift or sand control equipment installed.

2.1 Data Used

The PVT data for the reservoir is shown in Table 1. The data shown in Table 2 was used to develop the inflow performance relationship of the well. The tubing is set at 7800 ft while the production casing is set at 8000 ft.

This study employs a combination of software simulations and well data analysis to achieve its objectives. Prosper software is utilized for well modeling and sensitivity analysis, aiming to enhance the understanding of Gas-Oil Ratio (GOR) behavior within a cased production well. This section provides a comprehensive and detailed methodology outlining the approach taken in the study to achieve its objectives;

a. Design a vertical oil well model using prosper prosper software modeling

The Prosper software, a renowned industry-standard tool for well modeling and analysis, was employed to simulate the cased production well's behavior under various GOR conditions.

Table 1. PVT data for the reservoir

Parameter	**Value**
Solution Gas-Oil ratio	400 SCF/STB
Oil Gravity	30º API
Gas Gravity	0.75
Water Salinity	80000 ppm

Table 2. Data for generating inflow performance relationship

Reservoir Pressure	**4000 psi**
Reservoir Temperature	200ºF
Water cut	50 %
Gas-Oil Ratio	400 SCF/STB
Well head Pressure	250 psi
Reservoir Permeability	150 md
Reservoir Thickness	100 ft
Drainage Area	340 Acres
Dietz Shape Factor	31.6
Wellbore Radius	0.354 ft or 4.248 inches

2.2 Well Modeling

- **Input Parameters:** Utilizing the collected PVT data and inflow performance relationship data, the Prosper software was configured with relevant input parameters. This included incorporating fluid properties, reservoir pressure, temperature, tubing and casing specifications, and wellbore geometry.

- **GOR Variation:** The simulation involved modeling the well's behavior under different GOR scenarios. GOR values were varied to observe how they impact fluid flow, pressure dynamics, and recovery potential.

b. Conduct a sensitivity study in which gas-oil ratio is varied from 100 SCF/STB to 10000 SCF/STB

2.3 Study Approach

The study focuses on a cased production well with no artificial lift or sand control equipment. To investigate GORrelated behavior and its implications, the following steps were undertaken.

2.4 Data Collection

- **PVT Data:** The study obtained PVT (Pressure-Volume-Temperature) data for the reservoir, as shown in Table 1. These data include essential fluid properties such as oil and gas densities, viscosities, and bubble point pressures. PVT data form the basis for understanding fluid behavior and phase equilibrium variations.

- **Inflow Performance Relationship Data:** Table 2 provides the data used to develop the inflow performance relationship of the well. This dataset includes parameters related to the tubing and production casing, with tubing set at 7800 ft and production casing set at 8000 ft. These data are instrumental in understanding fluid inflow dynamics and their relationship with wellbore conditions.

2.5 Sensitivity Analysis

- **Objective:** Sensitivity analysis was conducted to evaluate the well's response to changes in GOR and other influencing factors. This provided insights into the relative significance of GOR in comparison to other parameters.

- **Parameters Varied:** During sensitivity analysis, various parameters were altered within their plausible ranges, such as reservoir pressure, fluid properties, and tubing-casing configuration. The software's output was analyzed to identify the extent of GOR's influence on the overall behavior of the well.

2.6 Data Analysis and Interpretation

- **Simulation Results:** The Prosper software generated simulation results based on the input parameters and GOR variations. These results included flow rates, pressure profiles, and fluid behavior patterns.

- **Interpretation:** The simulation results were meticulously analyzed to draw correlations between GOR values and their impact on the well's performance. Fluid mobility, pressure distribution, and recovery potential were assessed in light of varying GOR conditions.

3. RESULTS AND DISCUSSION

3.1 Results

Fig. 1 shows a diagrammatic representation of the down-hole architecture of the well being considered in this study. The Xmas tree is a depth of 0 ft implying that it is at the surface. The tubing with an ID of 3.99 inches was set at a depth of 7800 ft while the production casing with an ID of 8.3 inches was set at a depth of 8000 ft.

The data shown in Table 2 were entered into Prosper, and a Darcy Reservoir model selected to generate the Inflow performance relationship for the well. This is shown in Fig. 2. The absolute open flow potential, productivity index and skin for the well are 23498.7 STB/day, 10.03 STB/day/psi, and 2 respectively.

A sensitivity study was conducted in which GOR was varied between 100 SCF/STB and 5000 SCF/STB for different top node pressures (well head pressures) ranging from 50 psig and 1200 psig. The results are presented in Fig. 4.

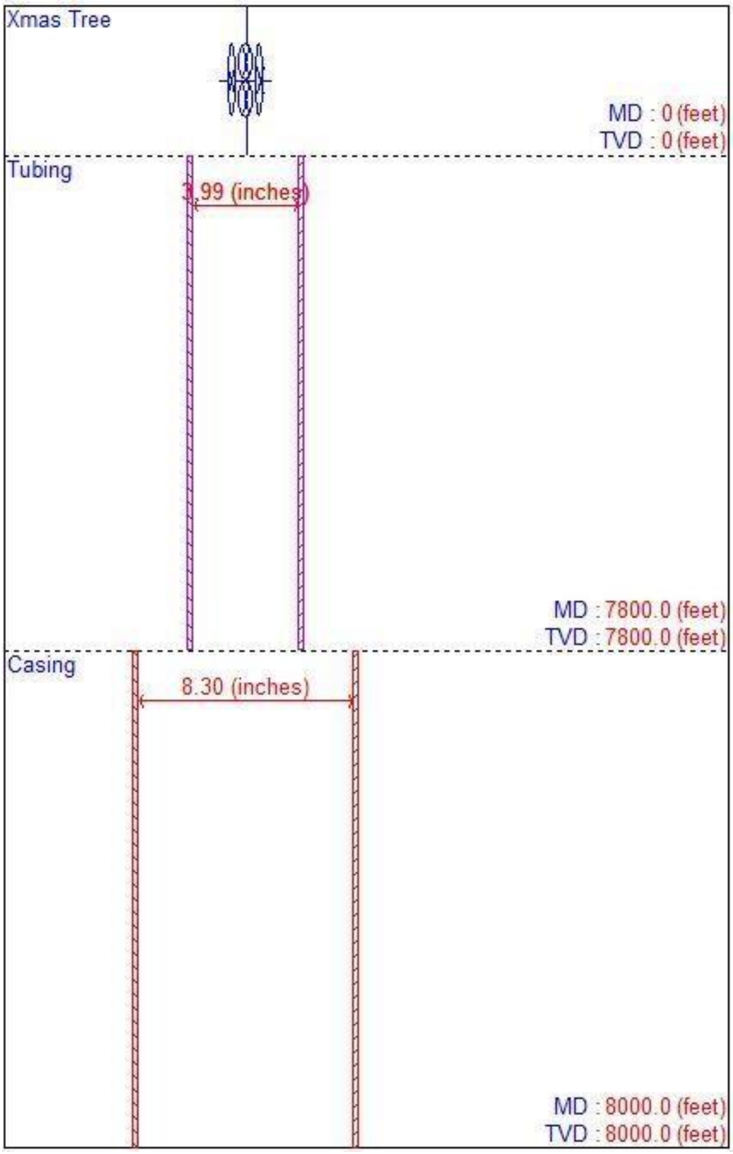


Fig. 1. Down-hole architecture of well

3.2 Discussion

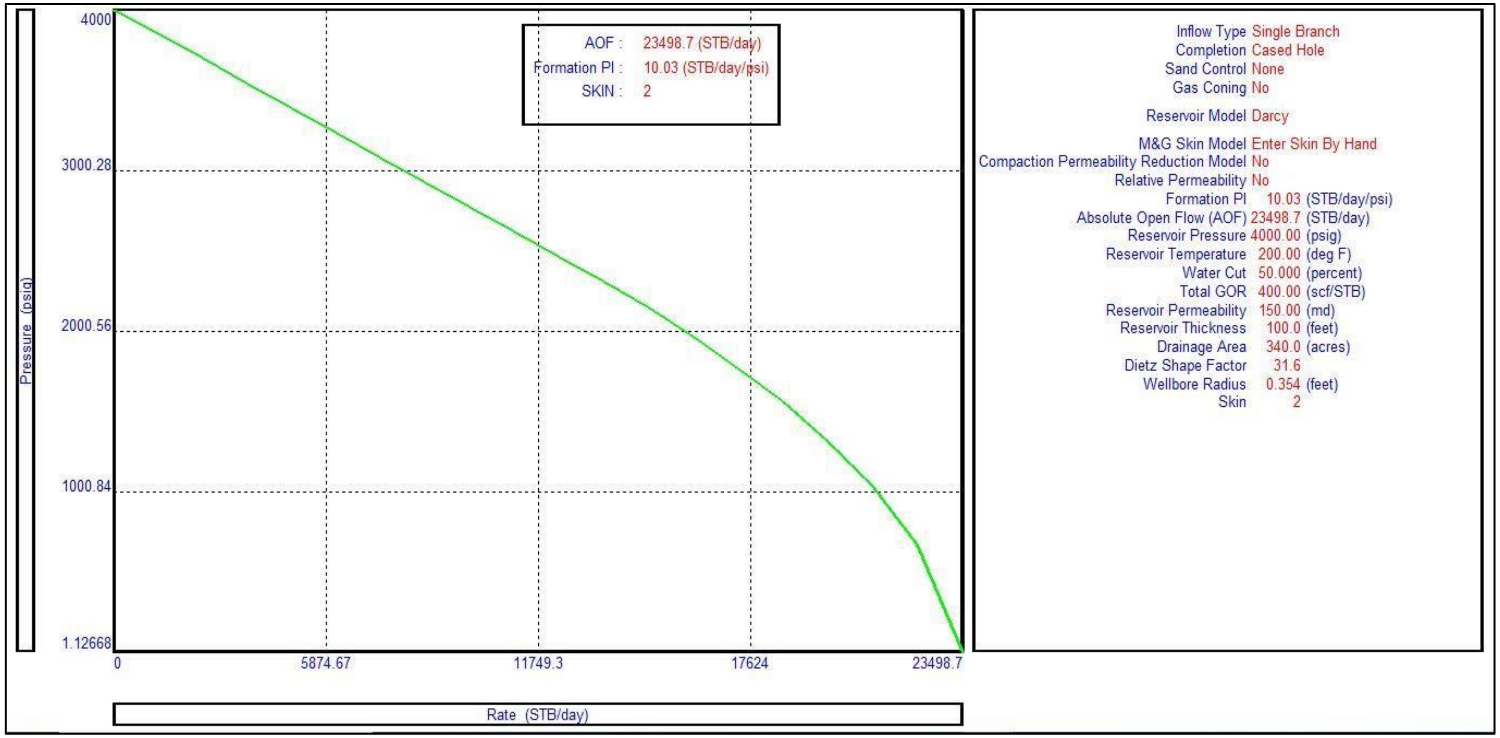
This section describes how the two specific objective of this research study was achieved;

a. Design a vertical oil well model using Prosper

The well presented in this study was used to investigate the effect of gas-oil ratio on oil rate. A vertical well was considered in this study as depicted in Fig. 1. Based on the data pertaining to the reservoir and well (Tables 1 and 2), the IPR curve shown in Fig. 2 was developed using the Darcy reservoir model found in Prosper software. Fig. 3 shows the IPR-VLP curve for the well at a top node pressure of 250 psig.

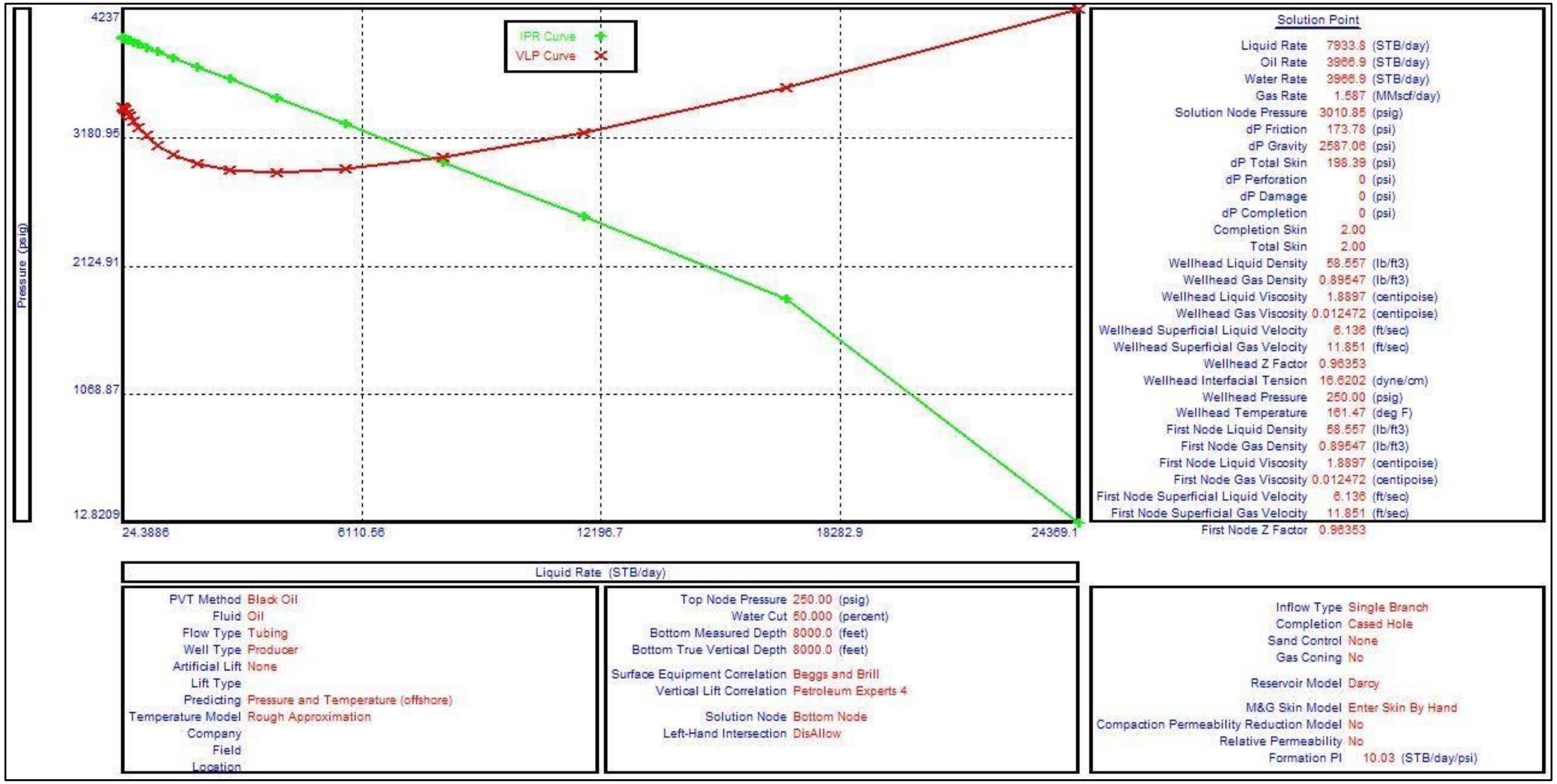
b. Conduct a sensitivity study in which gas-oil ratio is varied from 100 SCF/STB to 10000 SCF/STB

A further sensitivity study was conducted to investigate how oil rate varies with oil rate at different well head pressures. Results are presented in Fig. 4 which shows that for a given well head pressure, oil rate increases with increase in gas-oil ratio up to the gas-oil ratio at bubble point at which point oil rate starts to decrease. This is because above bubble point, the gas remains in solution which expands continuously and push the oil towards the production well. However, below bubble point pressure, gas is released from solution which causes the oil to shrink and hence oil production



Inflow Type	Single Branch
Completion	Cased Hole
Sand Control	None
Gas Coning	No
Reservoir Model	Darcy
M&G Skin Model	Enter Skin By Hand
Compaction Permeability Reduction Model	No
Relative Permeability	No
Formation PI	10.03 (STB/day/psi)
Absolute Open Flow (AOF)	23498.7 (STB/day)
Reservoir Pressure	4000.00 (psig)
Reservoir Temperature	200.00 (deg F)
Water Cut	50.000 (percent)
Total GOR	400.00 (scf/STB)
Reservoir Permeability	150.00 (md)
Reservoir Thickness	100.0 (feet)
Drainage Area	340.0 (acres)
Dietz Shape Factor	31.6
Wellbore Radius	0.354 (feet)
Skin	2

Fig. 2. IPR curve for the well



Solution Point

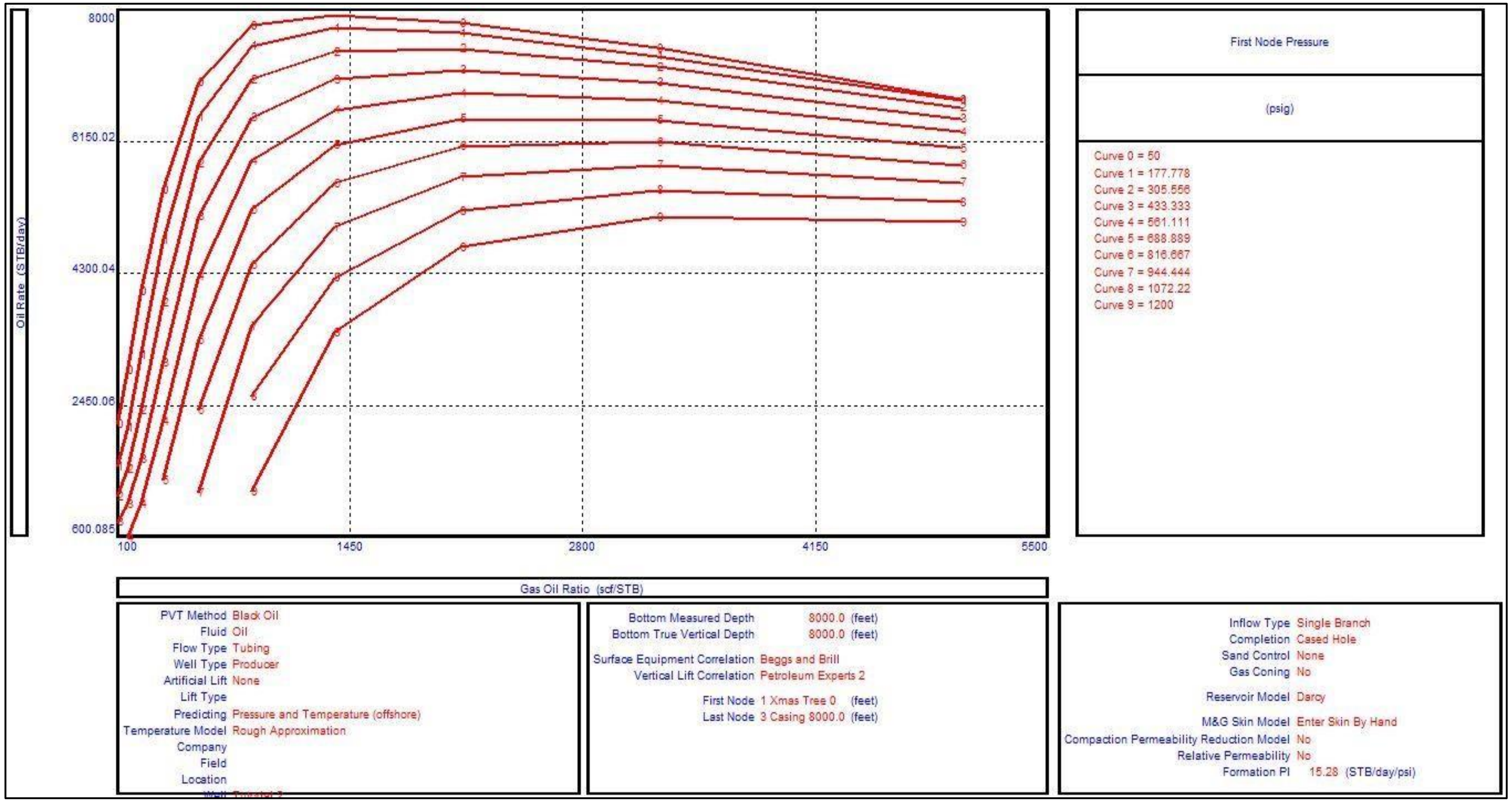
Liquid Rate 7933.8 (STB/day)
Oil Rate 3966.9 (STB/day)
Water Rate 3966.9 (STB/day)
Gas Rate 1.587 (MMscf/day)
Solution Node Pressure 3010.85 (psig)
dP Friction 173.78 (psi)
dP Gravity 2587.06 (psi)
dP Total Skin 198.39 (psi)
dP Perforation 0 (psi)
dP Damage 0 (psi)
dP Completion 0 (psi)
Completion Skin 2.00
Total Skin 2.00
Wellhead Liquid Density 58.557 (lb/ft3)
Wellhead Gas Density 0.89547 (lb/ft3)
Wellhead Liquid Viscosity 1.8897 (centipoise)
Wellhead Gas Viscosity 0.012472 (centipoise)
Wellhead Superficial Liquid Velocity 6.136 (ft/sec)
Wellhead Superficial Gas Velocity 11.851 (ft/sec)
Wellhead Z Factor 0.96353
Wellhead Interfacial Tension 16.6202 (dyne/cm)
Wellhead Pressure 250.00 (psig)
Wellhead Temperature 161.47 (deg F)
First Node Liquid Density 58.557 (lb/ft3)
First Node Gas Density 0.89547 (lb/ft3)
First Node Liquid Viscosity 1.8897 (centipoise)
First Node Gas Viscosity 0.012472 (centipoise)
First Node Superficial Liquid Velocity 6.136 (ft/sec)
First Node Superficial Gas Velocity 11.851 (ft/sec)
First Node Z Factor 0.96353

PVT Method Black Oil
Fluid Oil
Flow Type Tubing
Well Type Producer
Artificial Lift None
Lift Type
Predicting Pressure and Temperature (offshore)
Temperature Model Rough Approximation
Company
Field
Location

Top Node Pressure 250.00 (psig)
Water Cut 50.000 (percent)
Bottom Measured Depth 8000.0 (feet)
Bottom True Vertical Depth 8000.0 (feet)
Surface Equipment Correlation Beggs and Brill
Vertical Lift Correlation Petroleum Experts 4
Solution Node Bottom Node
Left-Hand Intersection DisAllow

Inflow Type Single Branch
Completion Cased Hole
Sand Control None
Gas Coning No
Reservoir Model Darcy
M&G Skin Model Enter Skin By Hand
Compaction Permeability Reduction Model No
Relative Permeability No
Formation PI 10.03 (STB/day/psi)

Fig. 3. IPR-VLP curve for the well at a GOR of 400scf/stb



Curve 0 = 50
Curve 1 = 177.778
Curve 2 = 305.556
Curve 3 = 433.333
Curve 4 = 561.111
Curve 5 = 688.889
Curve 6 = 816.667
Curve 7 = 944.444
Curve 8 = 1072.22
Curve 9 = 1200

PVT Method Black Oil
Fluid Oil
Flow Type Tubing
Well Type Producer
Artificial Lift None
Lift Type
Predicting Pressure and Temperature (offshore)
Temperature Model Rough Approximation
Company
Field
Location

Bottom Measured Depth 8000.0 (feet)
Bottom True Vertical Depth 8000.0 (feet)

Surface Equipment Correlation Beggs and Brill
Vertical Lift Correlation Petroleum Experts 2

First Node 1 Xmas Tree 0 (feet)
Last Node 3 Casing 8000.0 (feet)

Inflow Type Single Branch
Completion Cased Hole
Sand Control None
Gas Coning No

Reservoir Model Darcy

M&G Skin Model Enter Skin By Hand
Compaction Permeability Reduction Model No
Relative Permeability No
Formation PI 15.28 (STB/day/psi)

Fig. 4. Sensitivity analysis showing a variation of oil rate with gas-oil ratio at different well head pressures

reduces. With respect to the well head pressure, it can be seen from Fig. 4 that as the well head pressure increases, the oil production rate at each corresponding gas-oil ratio value decreases. This is because as the well head pressure increases, the pressure drawdown between the bottom of the well and the well head decreases causing the amount of oil lifted to the surface to decrease.

4. CONCLUSION AND RECOMMENDATION

4.1 Conclusion

The following conclusions can be drawn from the analysis conducted in this study

a. Oil production rate increases with increase in gas-oil ratio up to a maximum above which oil production starts decreasing. The decrease in oil production starts when gas is released from the oil.

b. An increase in well head pressure led to a decrease in oil production. This is attributed to a decrease in pressure drawdown between the bottom of the well and the well head.

4.2 Recommendation

a. It is advisable to ensure that the pressure in the reservoir remains above bubble point so that the amount of gas in the reservoir can be reduced which invariably increases oil production rate.

b. Determining an optimum well head pressure which result to an acceptable pressure drawdown between the bottom-hole and the well head.

COMPETING INTERESTS

Authors have declared that no competing interests exist.

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