MOHAMMED RASHAD QADER PERFORMANCE ANALYSES TECHNIQUES TO OPTIMIZE AN OIL WELL IN NORTHERN IRAQ NEU 2019

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A THESIS SUBMITTED TO THE GRADUATE SCHOOL OF APPLIED SCIENCE OF NEAR EAST UNIVERSITY

By
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In Partial Fulfillment of the Requirements for the Degree of Masters of Science in Petroleum and Natural Gas Engineering

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Approval of Director of Graduate School of

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I hereby declare that all information in this document has been obtained and presented in accordance with academic rules and ethical conduct. I also declare that, as required by these rules and conduct, I have fully cited and referenced all material and results that are not original to this work.

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To my family...

ABSTRACT

Oil production is one of the most important areas in petroleum engineering. Optimum parameter values are determined in the production system and initialized by optimizing production to reduce operating costs under various technical and economic challenges and most importantly to maximize hydrocarbon production rate. The relationship between flowrate and pressure drop performance in reservoir is very important for production optimization in the field. Efforts have been made to optimize all levels of the industry, including exploration, development, production, and transportation; mathematical programming techniques have been applied for all of these processes in the petroleum industry. In order to show different ways of hydrocarbon production optimization, different approaches and technologies are used.

To reduce the uncertainty in a reservoir and also to determine fluid flow in porous media, as well as to make production forecasts, software program specialized in reservoir simulation has been developed. Material balance principles used in software programs were also introduced to simplify calculations. The optimization and estimation for production and controlling of wells have increased the reliability of digital oil fields in recent years which were allowed by the improvements in computer software program technologies.

The objective of this research is to make an optimization analyses for the production performance of the well through the intersection point between the inflow curve and the tubing lift curve; with regards to the pressure, flow rate, and other given variables in order to find the maximum oil production rate that could be achieved for the whole production system and to make some decisions for the optimization of well-A.

Vogel method has been used to construct inflow performance relationship (IPR) curve for the fluid flow inside the reservoir, Duns and Ros Original has been used to construct vertical lift performance (VLP).

Duns and Ros Modified used to predict the pressure losses throughout the tubing, the total pressure loss that has been calculated by this correlation method was 759.26 psi which was exactly the same as the actual data for well-A, and the same wellhead pressure as the actual given data which was 100 psi has been remained at the surface. 737.06 psi of the total loss was due to the gravity, 20.91

psi was caused by friction, and the rest of the pressure losses were due to acceleration which was 1.29 psi.

The intersection line was matched between both IPR and VLP curves with regards to the given data of well-A. The calculated bottom hole pressure was 857.75 psig, which was almost the same value with the measured data for well-A (859.27 psig), where there were only differences of 0.17565 percentage. The calculated liquid rate in the intersection point was 978.9 STB/day.

Results of the analyses showed that, in case of increased gas oil ratio (GOR), decreased wellhead pressure, and designed electrical submersible pump (ESP), a successful improvement might be achieved in the well performance for well-A. Also, it was found that the best tubing size was the original size. Decreasing in the reservoir pressure and increasing in the water cut percentage will lead to decreasing in the well performance. Therefore, all these aspects have been analyzed to maintain and improve the well performance for well-A.

Keywords**:** Optimization techniques; performance analyses; optimization model setup; correlations comparison; nodal analysis; software prediction

ÖZET

Petrol üretimi, petrol mühendisliğinde en önemli alanlardan biridir. Optimum parametre değerleri üretim sisteminde belirlenir ve çeşitli teknik ve ekonomik zorluklar altında işletme maliyetlerini azaltmak ve en önemlisi hidrokarbon üretim oranını en üst seviyeye çıkarmak için üretimi optimize ederek başlatılır. Rezervuardaki akış hızı ve basınç düşümü performansı arasındaki ilişki sahadaki üretim optimizasyonunun için çok önemlidir. Keşif, geliştirme, üretim ve ulaştırma dahil, endüstrinin tüm seviyelerini optimize etmek için adımlar atılmıştır; petrol endüstrisinde bu işlemlerin tümüne matematiksel programlama teknikleri uygulanmıştır. Hidrokarbon üretim optimizasyonunun farklı yollarını göstermek için, farklı yaklaşımlar ve teknolojiler kullanılır.

Bir rezervuardaki belirsizliği azaltmak ve ayrıca gözenekli ortamdaki sıvı akışını belirlemek ve ayrıca üretim tahminleri yapmak için rezervuar simülasyonunda uzmanlaşmış bir yazılım programı kullanılmıştır. Hesaplamaları kolaylaştırmak için yazılım programlarında kullanılan malzeme dengesi ilkeleri de tanıtıldı. Üretim için kuyu optimizasyonu ve kestirimi ve kuyuların kontrolü, son yıllarda bilgisayar yazılımı program teknolojilerindeki gelişmelerin sağladığı dijital petrol sahalarının güvenilirliğini arttırmıştır.

Vogel metodu rezervuar içinde akan akışkanlar için akış performansı ilişkisi (IPR) eğrisini oluşturmak için kullanılmıştır, Duns ve Ros Original Dikey Kaldırma Performansı (VLP) oluşturmak için kullanılmıştır.

Duns ve Ros Modified, tüp boyunca basınç kayıplarını, bu korelasyon yöntemiyle hesaplanan toplam basınç kaybını tahmin etmek için kullanılır. A kuyusundaki toplam basınç kaybı 759.26 psi olarak hesaplanmıştır ki bu değer gerçek değer ile birebir aynı değerdir. Aynı zamanda yüzeyde kalan basınç, kuyu başı basıncı olan 100 psi olarak hesaplanmıştır. Toplam kaybın 737.06 psi'si yoğunluk, 20.91 psi'si sürtünme ve geri kalanı basınç kaybı olan 1.29 psi ivme nedeniyle olmuştur.

Kesişim çizgisi, A kuyusu için verilen değerlerle ilgili olarak hem IPR hem de VLP eğrileri arasında eşleştirildi. Hesaplanan alt kuyu basıncı 857.75 psig'di, ki bu sadece 0.17565 yüzdelik farkların olduğu kuyu-A için ölçülen verilerle neredeyse aynı değerdi. Kesişim noktasında hesaplanan sıvı oranı 978.9 STB / gün idi.

Analiz sonuçlarına göre; Artan gaz petrol oranı (GOR) azaltılmış kuyu başı basıncı ve tasarlanmış elektrikli dalgıç pompa (ESP) olması durumunda, kuyu-A için kuyu performansında başarılı bir gelişme sağlanabilir. Ayrıca en iyi boru boyutunun orijinal boyut olduğu tespit edildi. Rezervuar basıncında düşüş ve su kesim oranındaki artış kuyu performansında düşüşe yol açacaktır. Bu nedenle, kuyu performansı korumak ve geliştirmek amacıyla tüm bu yönler A kuyusu için analiz edilmiştir.

Anahtar Kelimeler: Optimizasyon teknikleri; performans analizleri; optimizasyon modeli kurulumu; korelasyon karşılaştırması; düğüm analizi; yazılım tahmini

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LIST OF SYMBOLS AND ABBREVIATIONS

A: Cross-Sectional Area
AOF: Absolute Open Flow
Ap: Pipe Flow Area
API: American Petroleum Institute
BHP: Bottom Hole Pressure
Bo: Oil Formation Volume Factor
c: Isothermal Compressibility Coefficient
Cp: Specific Heat
CPR: Choke Performance Relationship
D: Diameter
ESP: Electrical Submersible Pump
GLR: Gas Liquid Ratio
GOR=Rs: Gas Oil Ratio
HL = y_L: Liquid Holdup
i: Location
ID: Inside Diameter
IPM: Integrated Production Modelling
IPR: Inflow Performance Relationship
k: Permeability
MD: Measured Depth
n: Exponent Depending on Well Characteristics
NPV: Net Present Value
OD: Outside Diameter
P: Pressure
Pb: Bubble Point Pressure
PI= J: Productivity Index
Pr: Reservoir Pressure
PVT: Pressure Volume Temperature

Pwf: Flowing Well Pressure

Pwfs: Sand Flowing Well Pressure

q: Volumetric Flowrate

SCSSV: Surface-Controlled Subsurface Safety Valve

SSV Subsurface Safety Valve

t: Time

TPR: Tubing Performance Relationship

TVD: True Vertical Depth

U: Average Velocity

V: Fluid Volume

v: Velocity

VLP: Vertical Life Performance

WMS: Well Monitoring Systems

WPR: Wellhead Performance Relationship

Δp: Pressure Drawdown

GREEK SYMBOLS

ρ: Fluid Density

υ: Apparent Velocity

μ: Viscosity

γ_g: Specific Gravity

CHAPTER 1

INTRODUCTION

Petroleum, literally means "rock oil" is the expression have been using to define the multitude of hydrocarbon-rich fluids gathered in underground reservoirs. Petroleum (as well as named crude oil) differs dramatically in flow properties, odor, and color that are reflecting its original diversity. (Speight, 2002). In all industrialized countries, the most significant natural source of energy is crude oil. There would be no such thing as modern civilization and its incredible achievements without crude oil. What makes it so significant in our daily lives is its wide range of uses. Beside fueling cars, aircraft etc., its products can be used to produce many types of chemical substances such as plastics, medicines, detergents, and many more (Tetoros, 2015).

Petroleum production is one of the key areas in petroleum engineering, it usually includes two different but closely linked general systems: a reservoir that is a porous medium with characteristics of flow and storage; and artificial systems that include a well, a bottom hole, well-head assemblies, surface complete set, separation, and storage. Production engineering is a section of petroleum industry which seeks to achieve maximum production cost-effectively, one or more wells may be involved (Economides et al., 1994). Over recent decades, the technique of predicting production and estimating maximum recovery in oil and gas reservoirs has stimulated many challenges among upstream engineers (Holdaway, 2014).

The analysis of the petroleum production system had yet to be known in the late 1800s until the early part of the 20th century. The idea of production optimization became a necessity when the first oil reservoirs began to suffer from drastic depletion. Due to the uncertainty and enormous risk of exploring new fields, the need to exhaust all options within the existing reservoirs became urgent (Tetoros, 2015).

To define various procedures in the petroleum industry, the term production optimization was used. The literature did not find a detailed definition of the term, the book by Beggs (2003) “Production Optimization Using NODAL Analysis” provides a system analysis approach called NODAL Analysis to evaluate the performance of production processes. However, total production system is analyzed as a whole unit, this method is used to independently evaluate components, pipeline with complex networks, pumps, compressors, and electrical circuits. Under any defined part of the network, areas of extreme flow resistance or pressure drop are recognized (Beggs, 2008).

Production optimization means determining and initiating the optimum parameter values in the production system to maximize the production rate of hydrocarbons or reduce operational costs under various technical and economic issues. Because a system could be described in different manner, it is possible to optimize production at different level stages like field level and platform / facility level. Some of the methods can be described in production optimization systems as: Naturally flowing well, gas lift facility, separator, gas-lifted well, sucker rod–pumped well, pipeline network. Therefore, different approaches and technologies are used in oil and gas production of upstream to give different ways of optimizing the production of hydrocarbons (Guo et al., 2017). Predicting the relationship between pressure drop and flow rate performance in the reservoir is very significant for production optimization in the field (Ba-Jaalah and Waly, 2015).

It is possible to forecast well production with the knowledge of Nodal analysis, which is, forecast production rate and also cumulative production for oil and gas, joint with information of oil and gas costs, it is possible to use the results of a production prediction for field economics analyses (Guo et al., 2017). Usually, oil industry engineers are looking to optimize production in three areas. From the perspective of reservoir engineering, a reservoir optimization techniques program has been developed with the aim of reducing the instability in a reservoir and predicting the flow of fluids in porous media as well as making production predictions. Computer programs that used material balance principles were also implemented to simplify calculations (Tetoros, 2015). Improvements in software programs and metering technologies allows the real-time monitoring, and controlling of wells have increased the reliability of digital oil fields in recent years (Ratcliff et al., 2013).

1.1 Production Optimization

Optimization means to have the most favorable result or the best available result under a given set of conditions or constraints, generally it can be the maximization or minimization of objective function subject to a set of constraints. Optimization in basic is a mathematical technique, which is generally used in engineering, science, economics, management science, mathematics, and so many other areas (Chowdhury, 2016). Furthermore, optimization is helpful in understanding and modeling physical phenomena and procedures, without using advanced optimization techniques, chemical and other production procedures would not be as effective as they are now. In brief, optimization is crucial if sustainable processes and production are to be achieved (Rangaiah, 2010). Literature is full of definition of optimization with varying degree of simplicity or complexity (Chowdhury, 2016).

A production engineer's function is to obtain the cost-effective maximization of oil and gas production, familiarization, and ability to understand of oil and gas production technologies are important for engineers. A full system for the production of oil or gas consisted mainly of a reservoir, well, flow line, pumps, separators, and pipelines for transportation. The reservoir provides the well-bore with crude oil or gas. The well creates a way to flow the production fluid from down of the hole to the ground and proposes a way to handle the rate of production of fluid. The flow-line pushes the fluid obtained to separators, the separators will eliminate water and gas from the crude oil, the transportation of gas and oil across pipelines to sales points will be done with pumps and compressors (Guo et al., 2007).

In the production phases and development of a petroleum project, a lot of design and operational choices have to be made, these will incorporate Adequate recovery methods, number of manufacturing and injection wells, area of wells, set up processing capacity, timing of drilling, storage and transportation services, injection and production rates, and decommissioning timing (Jahn et al., 2008). These options will all be made in order to maximize net present value (NPV) for the whole project. A real optimization problem experienced by a producer is deeply complicated (Jakobsson, 2012).

1.2 Optimization in the Petroleum Industry

Techniques for mathematical programming were applied in petroleum industry since the 1940s (Bodington and Baker, 1990). Efforts have been made for optimizing all levels of the industry, including exploration, development, production, and transportation. Operations research problems subjected from strategic planning to process control. A literature review of optimization techniques for petroleum fields by Wang, (2003), found that almost all areas of the petroleum industry somehow or other apply optimization techniques. Extra specific examples are given within gas-lift and production system, production rate allocation and design of production system, and reservoir development and management (Morken and Sandberg, 2016).

1.3 Some Applications in Production Optimization

According to Devold (2013), to make production optimization, there are nine applications which can be used in petroleum industry:

- Well control which stabilizes and optimizes gas lifts and wells that flow naturally. Increases in pressure and flow should be prevented by this application while retaining maximum production and retaining minimum back-pressure and continued production at the optimum lifting gas rate.
- Flowline control for stabilizing multi-phase flow at gathered systems, flow lines, and risers.
- Optimization of the gas lift is to guarantee the best imaginable distribution of the gas lift between the wells of gas lifted.
- Well monitoring systems (WMS) are used to predict oil, water, and gas flow rates from all oil field wells. Real-time assessment is built on available sensor information in flow lines and wells.
- Slug management did help to mitigate distinctions in the impact of inflow. The separation and operation of hydrocarbon while upset, normal and startup operation.
- Hydrate prediction devices aid prevent the formation of hydrate that might appear when the collection of subsea system is permitted for highly cooling down in advance of the necessary hydrate prevention measure to be carried out.
- The optimal operation of the wells and production facilities is defined by a set of constraints. A monitoring tool for constraints monitors proximity entire constrictions. This offers sustenance in decision-making actions needed for moving the existed operations nearer to their factual potential.
- Optimization and advanced control methods to increase product quality control performance, whereas complying to operational constrictions. Two technologies can be used to do: predictive control modeling to move the procedure nearer to targeted operation, and inferential measurement to improve the frequency of feedback data on product quality.
- Tuning devices have been structured for optimizing as well as maintaining in the process automation system in the best possible setting of control loops.

1.4 Thesis Overview

Chapter 1 begins with introduction of production optimization and the role of production engineers and it also gives some applications in production optimization.

Chapter 2 is the literature review, which shows type of fluid, flow regime, inflow in reservoir, and vertical flow inside well, it also gives some previous works that has been done on production performance and gives detailed information about production system.

Chapter 3 is the problem statements, which describes the problem of this study, it also highlights the importance and goals of this research.

Chapter 4 is the methodology which shows methods which can be used to calculate flow in the reservoir as well as the flow inside the tube gives a brief description about used software.

In chapter 5, a detailed optimization model of the well has been described step by step in order to construct the inflow and outflow curves, the matching point for inflow performance and tube performance curves have been done with regards to available data of well-A, and discussions have been made on the results.

Chapter 6 shows the analyses which have been done in order to find out and analyze the effects of changing some variables on the well performance.

Chapter 7 is about conclusions of this study; It also gives some recommendations regarding this study.

CHAPTER 2

LITERATURE REVIEW

2.1 Types of Fluids

The coefficient of isothermal compressibility is basically the primary factor in defining reservoir fluid types. Fluids in reservoirs (Figure 2.1 and Figure 2.2) are usually categorized into three classes (Ahmed and Meehan, 2012):

1. Compressible fluids.
2. Slightly compressible fluids.
3. Incompressible fluids.

The coefficient of isothermal compressibility (c) is mathematically defined in Equation 2.1 and 2.2 by two equivalent expressions:

In aspect of fluid volume, isothermal compressibility coefficient has been presented in Equation 2.1.

$$c = (\frac{-1}{\mathrm{V}})(\frac{\partial \mathrm{V}}{\partial \mathrm{p}}) \tag{2.1}$$

In aspect of fluid density, isothermal compressibility coefficient has been presented in Equation 2.2.

$$c = (\frac{1}{\rho})(\frac{\partial \rho}{\partial \mathrm{p}}) \tag{2.2}$$

Where,

V = volume of fluid.

ρ = density of fluid.

p = pressure in psi.

c = coefficient of isothermal compressibility.

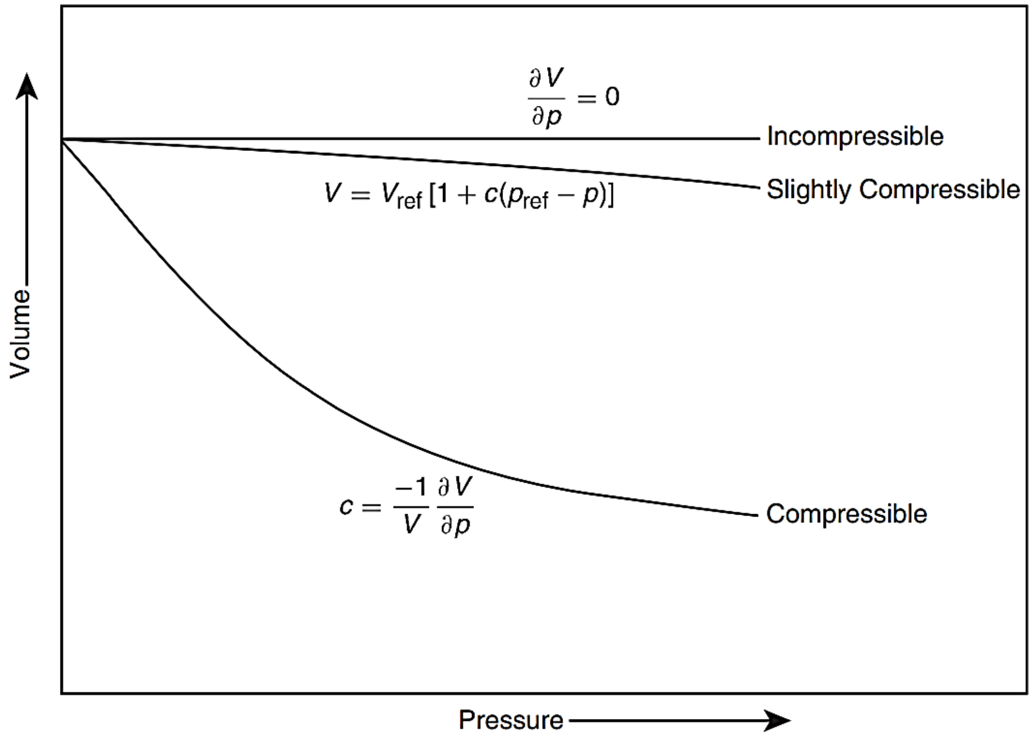


Figure 2.1: Pressure - volume relationship (Ahmed and Meehan, 2012)

Figure 2.1 shows how reservoir fluids are responding due to the change of pressure verses volume. An incompressible fluid (Equation 2.3) is a fluid whose density or volume does not vary with pressure. (Ahmed and Meehan, 2012).

$$\frac{\partial V}{\partial p} = 0 \quad \text{and} \quad \frac{\partial \rho}{\partial p} = 0 \qquad (2.3)$$

Figure 2.2 illustrates response of reservoir fluids due to variation of the fluid density versus pressure. In general, the incompressible fluids do not exist, although, in some of the cases, this behavior can be assumed to simplify the derivation of many flow equations and the final form. Slightly compressible fluids show a slight change in volume or in density, with changes in pressure. It should be noted that this category includes a lot of crude oil and water systems. Depending on the pressure, compressible fluids are identified as fluids with big volume changes. All gases and liquid gas systems can be treated as fluids which are compressible (Ahmed and Meehan, 2012).

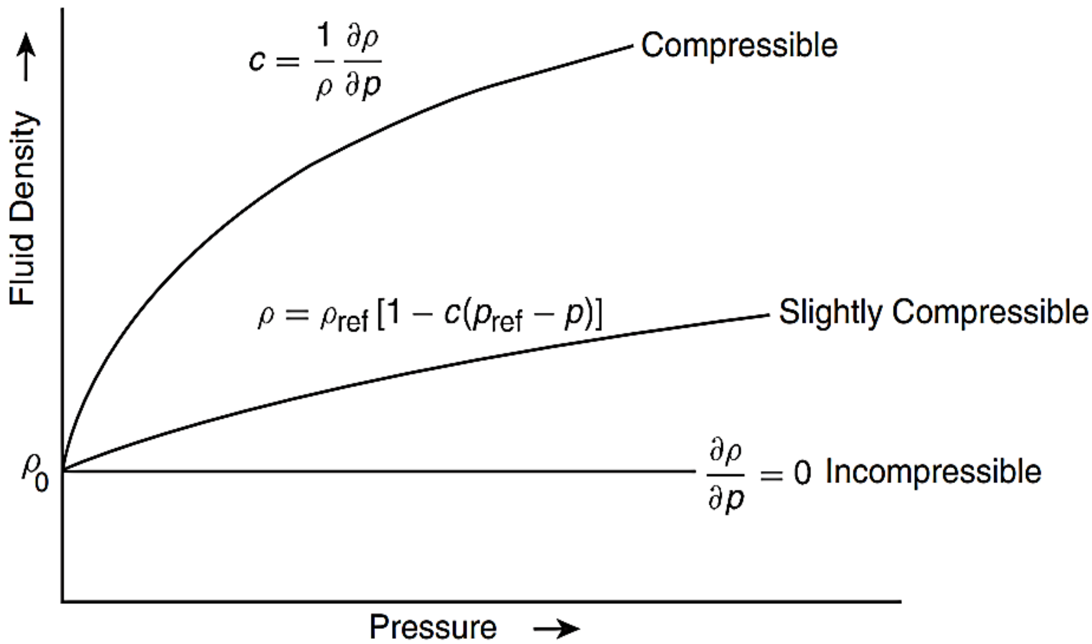


Figure 2.2: Density of fluid vs. pressure for various types of fluid (Ahmed and Meehan, 2012)

2.2 Natural Flow Performance

Flow into porous media is a complicated matter and this cannot be implicitly defined as flow via pipes or pipes, but flowing into a porous media is vary because there are no specific pathways of flow that allow for measurement. Analyses of the fluids flow in porous media have advanced two fronts over the years: analytical and experimental (Ahmed and Meehan, 2012). Pressure and flow rate are the most two essential parameters used to analyze petroleum fluid performance or behavior from the upstream level (in a reservoir) to the downstream level (on the ground). Production rate is a measure of the fluid and reservoir pressure at the lowest part of a well for a defined pressure of reservoir according to the basic flow of fluid through the reservoir. The flowing bottom-hole pressure needed the liquid can be lifted to the surface be affected by the tube string size, choke installed surface or down-hole, and the pressure loss along the pipeline. The flow system can be divided into at least four components in oil and gas fields (Lyons et al., 2016):

- Surface flowline
- Chokes and valves
- Wellbore
- Reservoir

In general, there are three categories of the flow system (Ahmed and Meehan, 2012):

1. Flow of single phase (oil, water, or gas);
2. Flow of two phase (oil-water, oil-gas, or gas-water);
3. Flow of three-phase (oil, water, and gas).

As number of mobile fluids increases, it becomes more complex to define the fluid flow and then analyze the pressure data (Ahmed and Meehan, 2012). A multi-phase flow issues can be separated into different directions which are horizontal, vertical, directional, and inclined flow (Figure 2.3) (Brown and Beggs, 1977). Fluid flows through different stages and directions in the production system, and all these stages together create a total production system which is shown in Figure 2.3.

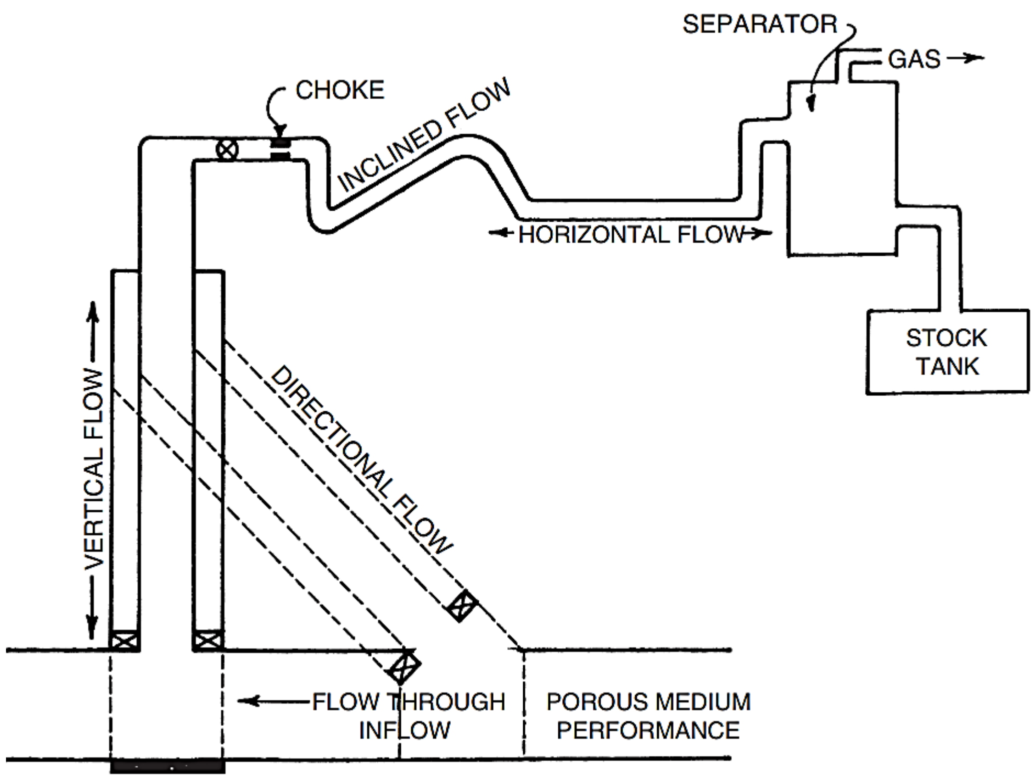


Figure 2.3: Total production system (Lyons et al., 2016)

Of course, every single element by which the fluid flow in a reservoir will have its own performance and affects one another. Good understanding of flow performance in production engineering is very important. Combined performance is mostly used as a tool for optimizing technology for good delivery and size. In addition, engineering and financial decisions can rely on valuable information on predictions for the future performance of well and reasonably (Lyons et al., 2016).

2.3 Flow Regimes

Basically, it is necessary to identify three types of flow regimes to describe fluid flow behavior and reservoir pressure distribution as a function of time. These three flow schemes are listed (Ahmed and Meehan, 2012) and shown in Figure 2.4.

1. Steady state flow.
2. Unsteady state flow.
3. Pseudo steady-state flow.

All three type of flow regimes have been shown in Figure 2.4, and it also shows that the flow regime is known as a steady-state flow when pressure remains constant at all locations of reservoir and will not change over time. This situation can be described mathematically as (Ahmed and Meehan, 2012):

$$\left(\frac{\partial p}{\partial t}\right)_i = 0 \qquad (2.4)$$

Where;

p = pressure.

t = time.

Equation 2.4 states that at any location (i) the rate of pressure change (p) in relation to time (t) is zero. Flowing in steady-state conditions in reservoirs may occur only once the reservoir is fully resupplied and backed by processes of heavy water or pressure maintenance (Ahmed and Meehan, 2012).

Unsteady state flow (commonly named a transient flow) is known as a situation of fluid flow whereby pressure change rate is not zero or constant with regard the time at any reservoir location. This description implies that the time pressure derivative is basically a feature of both the (i) and time (t) positions as shown in Equation 2.5 (Ahmed and Meehan, 2012).

$$\left(\frac{\partial p}{\partial t}\right) = f(i, t) \qquad (2.5)$$

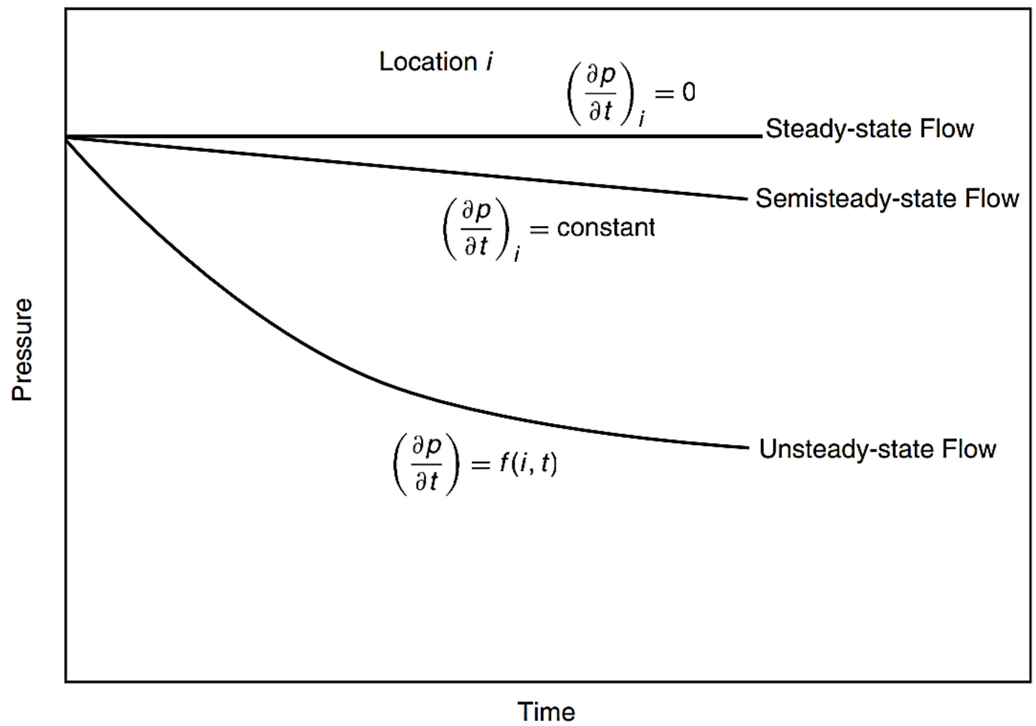


Figure 2.4: Type of flow regimes (Ahmed and Meehan, 2012)

Pseudo steady state flow, when the pressure decreases linearly as flow situation is characterized as a time dependent at different locations in reservoir, e.g. at a constant rate of decrease, pseudo steady state flow. Numerically, the Equation 2.6 states that at each position the amount of pressure difference is constant with regard to time (Ahmed and Meehan, 2012).

$$\left(\frac{\partial \mathrm{p}}{\partial \mathrm{t}}\right)_{\mathrm{i}} = \text{constant} \tag{2.6}$$

Pseudo state flow is commonly called semi state flow and semi state flow and can be used for fluids which are slightly compressible.

The following are the steps in determining the flow regime (Lyons et al., 2016):

1. Calculate parameters without dimensions.
2. Link to the flow regime maps spread in coordinates of these parameters.
3. By locating the operating point on the map of flow regime, determine the flow regime.

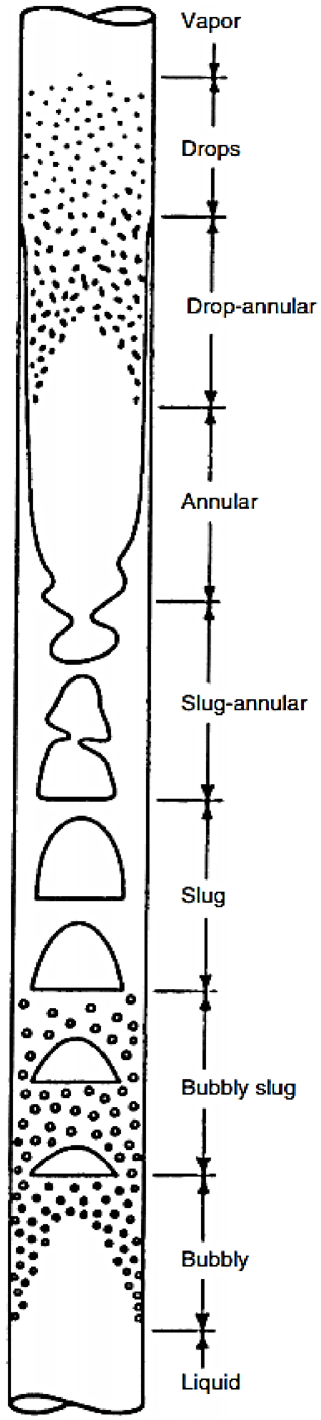


Figure 2.5: Possible type of flow regimes in a vertical tube (Lyons et al., 2016)

Discussions in the following sections deal with vertical upward flow regime maps are equal to 90, with slightly inclined downward inclinations ranging from 15 to −10 and vertical downward. In order to calculate type of flow, the superficial velocities for each phase of flow must be calculated, type of flow which can be existed as seen in Figure 2.5 (Lyons et al., 2016).

In the following equations, the oil, water, and gas simplistic velocities are shown (Lyons et al., 2016).

$$vso = \frac{qo}{Ap} \tag{2.7}$$

$$vsw = \frac{qg}{Ap} \tag{2.8}$$

$$vsg = \frac{qw}{Ap} \tag{2.9}$$

Where;

v = velocity in ft/sec.

Ap = flow of pipe area in ft^2.

q = volumetric flow rate at conditions of flow in ft^3/s.

Mixture velocity that has been shown in Equation 2.10, in some calculations, sum of the superficial gas and liquid velocities type will be used (Lyons et al., 2016).

$$vm = vsL + vsg \tag{2.10}$$

The velocity in though all phases is combined with the superficial velocity of the liquid holdup (Lyons et al., 2016).

$$UL = vL = \frac{vsL}{HL} \tag{2.11}$$

$$Ug = vg = \frac{vsg}{1 - HL} \tag{2.12}$$

For a homogeneous model, it is assumed that both phases have the same velocity as shown in Equation 2.13 and that each is equal to a two-phase speed (Lyons et al., 2016):

$$vL = vg = vm \tag{2.13}$$

HL in both Equation 2.11 and Equation 2.12 refers to liquid holdup.

From Figure 2.5 and Figure 2.6, different flow regimes can be observed along the tube well, ranging from a mist flow in the small-pressure area to a single-phase flow of pressure if all gas is in the solution. The transition from slug to annular can only be applied if the size of pipe D is greater than a critical diameter D_{crit} (Lyons et al., 2016).

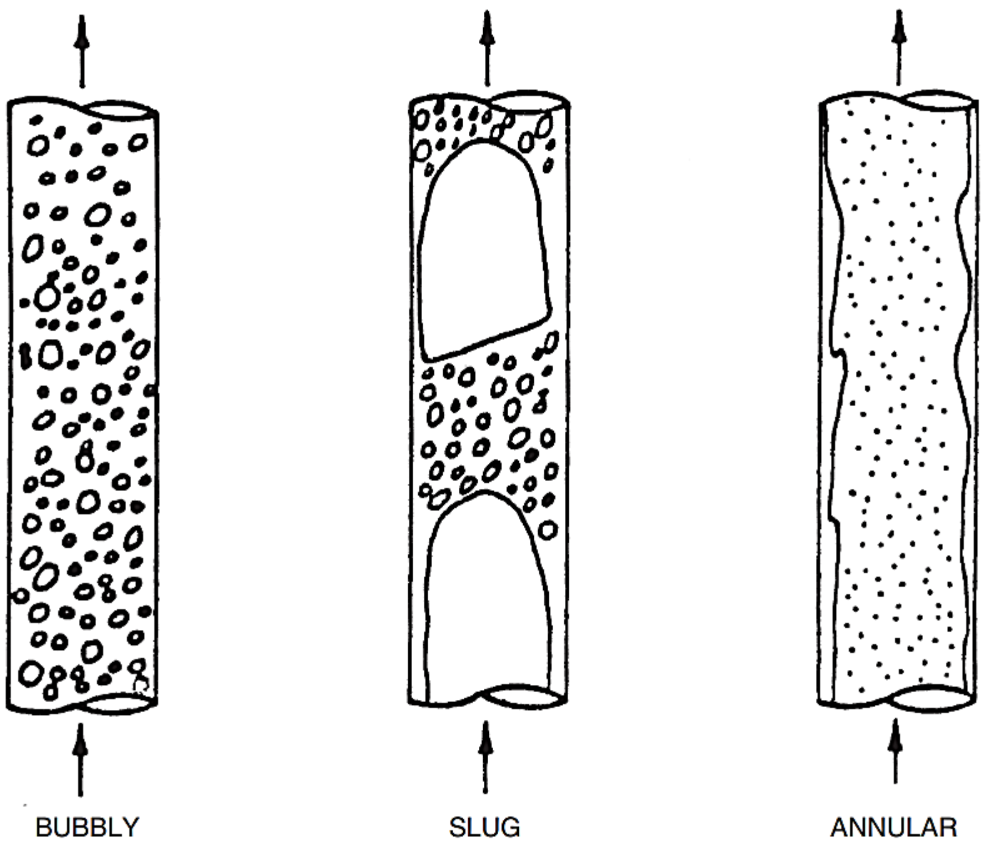


Figure 2.6: Vertical Gas–liquid flow regimes (Lyons et al., 2016)

Liquid holdup as it is shown in Equation 2.14, is known as ratio of the pipe segment's volume to the pipe section 's volume (Lyons et al., 2016):

$$HL = \frac{\text{liquid volume in a pipe segment}}{\text{pipe volume segment}} \tag{2.14}$$

In some situations, liquid holdup can be calculated for e.g. horizontal divided flow system Equation 2.15 (Lyons et al., 2016).

$$\mathrm{HL} = \frac{\mathrm{AL}}{\mathrm{AL} + \mathrm{Ag}} \tag{2.15}$$

Where;

AL = area of cross sectional filled with liquid (oil and water).

Ag = area of cross sectional filled by gas.

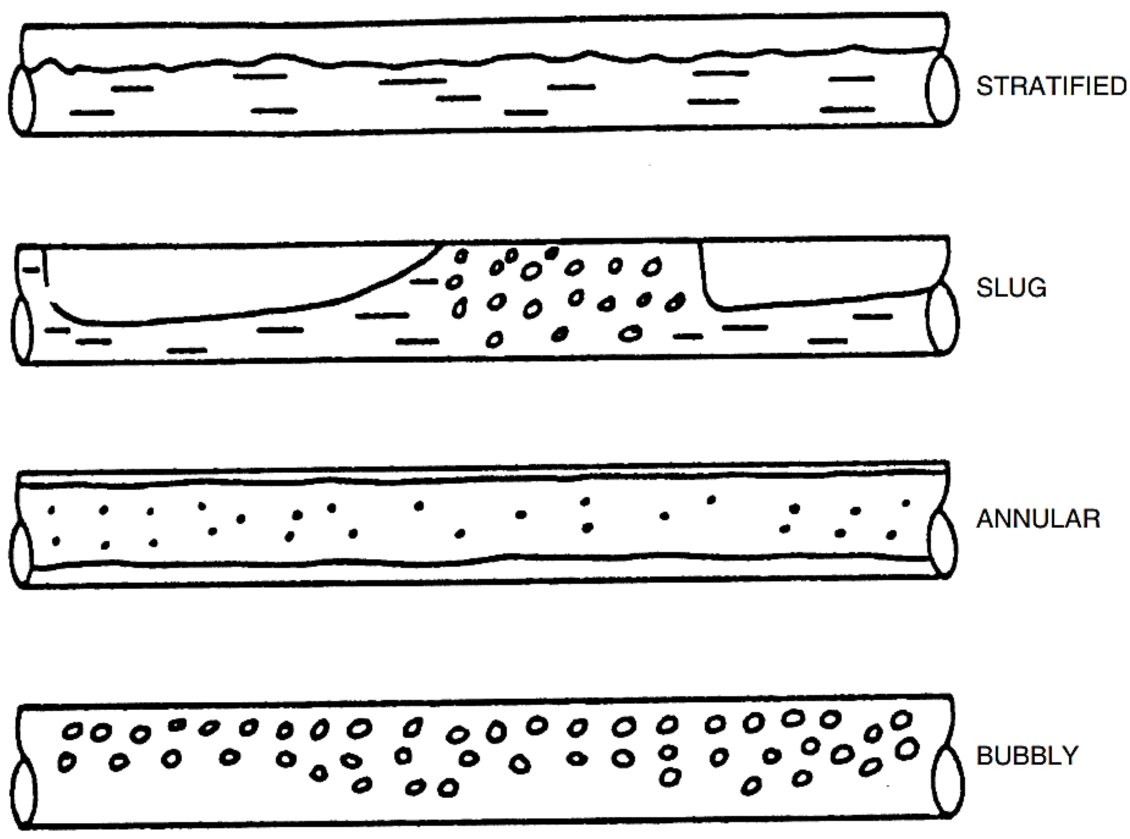


Figure 2.7: Horizontal Gas–liquid flow regimes (Lyons et al., 2016)

Figure 2.7 shows that, four income flow regimes are present: slug, stratified, bubbly and annular, and also three transitional flow regime zones (Lyons et al., 2016). Around a horizontal well-bore, the complex flow regime is likely to prevent the construction of an IPR using a method as simple as Vogel's (Beggs, 2008).

2.4 Darcy's Law

Darcy's law is the basic fluid movement law in porous media. Darcy developed a mathematical expression in 1856 which states that in a porous medium, the fluid's velocity is directly related to the pressure differential and oppositely related to the fluid's conductivity. In a linear horizontal system, this connection has been expressed in Equation 2.16 (Ahmed and Meehan, 2012).

$$v = \frac{q}{A} = -\frac{k}{\mu}\frac{dp}{dx} \tag{2.16}$$

Where;

υ = apparent velocity in cm/s.

q = rate of volumetric flow in cm^3/s.

A = rock cross sectional area in total in cm^2.

μ = viscosity.

k = permeability.

The pressure gradient in a horizontal radial method is positive, thus, Darcy equation can be expressed in Equation 2.17 as a generalized radial form (Ahmed and Meehan, 2012).

$$v = \frac{q_r}{A_r} = \frac{k}{\mu}\left(\frac{\partial p}{\partial r}\right)_r \tag{2.17}$$

Where;

q_r = rate of flow of volumetric at radius r.

A_r = cross sectional area to flow at radius r.

$\left(\frac{\partial p}{\partial r}\right)_r$ = pressure gradient at radius r.

υ = apparent velocity at radius r.

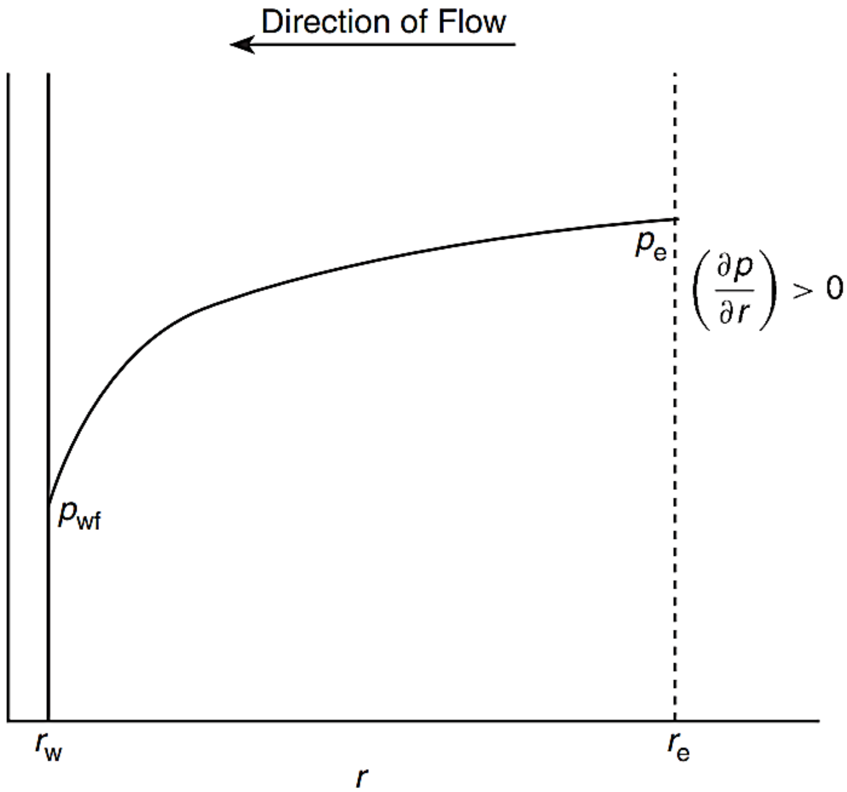


Figure 2.8: Pressure gradient in radial flow (Ahmed and Meehan, 2012)

As it is shown in Figure 2.8, the pressure begins to decrease as the fluid flows from the tank to the well-bore.

2.5 Inflow Performance Relationship

2.5.1 The importance of inflow performance

Inflow performance is a reservoir's behavior in oil production inside the well, the performance of the inflow may differ from one well to another for a reservoir which is heterogeneous. The performance is commonly defined on the cartesian coordinate in aspects of ground production plot (stb/d) against low-hole flow (Pwf in psi) pressure. Such a graph curve is known as an IPR (Inflow Performance Relationship) graph and is much more beneficial in predicting capacity of well, developing tube strings, and planning an artificial lifting mechanism (Lyons et al., 2016). The difference between a well's reservoir pressure and BHP is the driving force for the wellbore inflow. Inflow of well resistance depends on the rock reservoir properties, properties of fluid, details completion of well, and occasionally Late impacts of drilling as well as workover operations These factors together calculate performance of well's inflow. Because all the fluids crossing the wellbore must move across a narrow section across the wellbore, the reservoir is the one who has highest flow rates and therefore any increased flow opposition has a significant impact on well's performance. Since inflow performance performs this significant role, it must be calculated on a regular basis across production tests, i.e. flowing a well across a test separator and calculating oil, gas, and water flow rates as a parameter of well-bore pressure. An inflow performance relation (IPR) between BHP pwf and all the oil flow rates qo that usually describes the production performance of this zone. In practice, the IPR in such a case could also be described as a productivity index (PI) , PI or J can be described as the ratio between qo and pressure drawdown Δp that is difference between static or closed BHP (Pws) and the dynamic or flowing BHP (Pwf) (Jansen and Currie, 2004).

2.5.2 Single-phase liquid flow performance

Tubing performance relationship (TPR) or IPR defines an attitudes of the well's flow rate of production and pressure, that could be an effective method to know the reservoir's behavior and measure the production rate. Frequently, IPR is needed to design well completion, optimize production well, calculate nodal analysis, and design artificial lift. In the petroleum industry, there are currently different IPR correlations, the most widely used models are still Vogel's and also Fetkovitch's, in regards to a few evaluative correlations, which generally suffer restricted in applicability (Fattah et al., 2014)

IPR is used to assess the deliverability of reservoirs inside production engineering. An IPR curvature is a diagram display of relationship among both bottom-hole flow pressure as well as a rate production of liquids. Figure 2.9 gives a usual IPR graph. The slope magnitude of IPR graph can be named the productivity index (J), which does not seem to be a fixed point of the two-phase flow area J (Guo et al., 2007).

By knowing the pressure of the reservoir (Pr), IPR curve of the oil can be made on a well from a single flow.

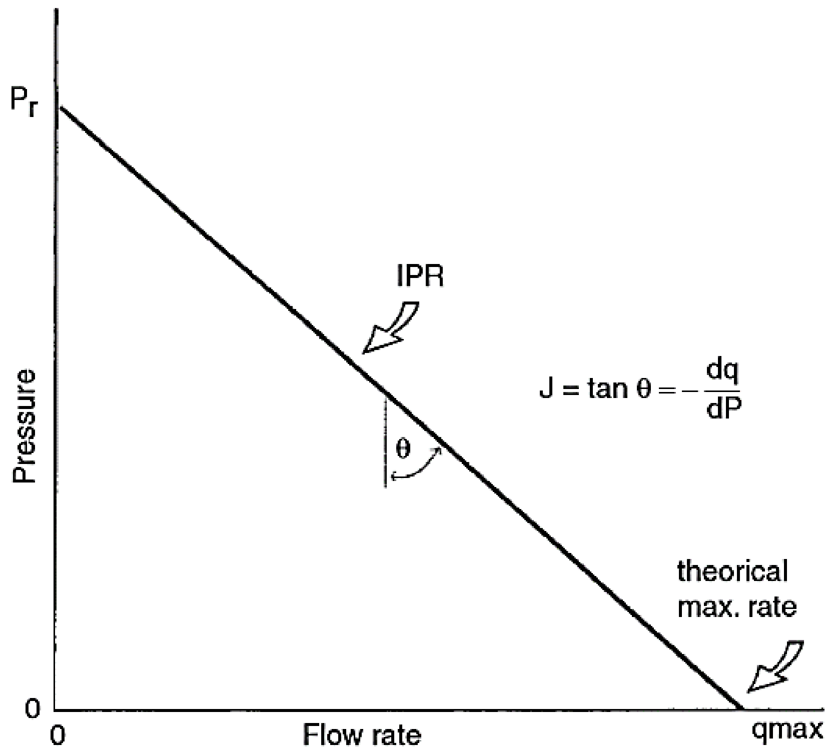


Figure 2.9: Single phase inflow performance relationship for oil reservoir (Lyons, 2010)

Figure 2.9 shows the single-phase behavior of liquid flowing over The Pwf range and the flowrate (q) and flow pressure (Pwf) are constantly proportional. The plot (q) versus (Pwf) must therefore be linear on a cartesian laminar flow coordinate. However, reservoirs generated at Pwf and Pr higher than pressure at bubble point Pb and high water-driven reservoirs may show straight line IPR in real cases (Lyons, 2010).

2.5.3 Productivity index and performance of well inflow

Maybe the simplest and most commonly used equation for IPR is the straight-line IPR, which indicates that the flow rate and pressure drop in the reservoir is directly related (Golan and Whitson, 1991). The steady performance proportionality of the well is a productivity index (PI) of a well. (Archer and Wall, 1986).

$$\mathrm{PI} = \frac{\text{production rate}}{\text{drawdown}} = \mathrm{J} = \frac{\mathrm{q}}{(\mathrm{P} - \mathrm{Pwf})} \tag{2.18}$$

Where;

q = production rate m^3/D or b/D.

P = static pressure/reservoir average.

P_{wf} = flowing bottom hole pressure at q rate.

Using such an index means It is a fixed feature of a well, that is with no true implies, but this has been using it for long as a principle for productivity of well representation and as a principle for evaluation. As shown in Equation 2.18, there would be a linear relationship between draw down (P-Pwf) and flow rate (q) for a constant PI and at any moment the relationship with Pwf would be linear in reality, the productivity index will differ with flowrate if the amount is big and there are original impacts, change with pressure when gas included, with optimal permeability for oil, and over time when saturations of water, gas, oil, and also their viscosities differ when rates of testing are artificially limited to principles which are much lesser than usual well improvement rates, and when straight line observation could be over optimistic, particular care should be taken in planning. The relationship between the input performance (IPR) is described as the full relationship across the flowrate and the draw-down (as well as the flowing down-hole pressure) (Archer and Wall, 1986).

2.5.4 Multiphase flow performance

Nearly every oil well produces a certain quantity of gas, water and occasionally sand in addition to oil. These wells are known as multi-phase oil wells (Guo et al., 2007). The basic formula of output performance that the productivity index is not changing, will be no more applicable if a pressure of reservoir is less than the pressure of the bubble point. As shown Figure 2.10, in that condition, the flow rate of oil will decline much more rapidly (Lyons et al., 2016) However, The solution gas flows below the pressure of the bubble point from the oil that outcomes gas which is free. Free gas covers a section of space inside the pore in which reduces the flowing of oil. The decrease in relative permeability quantifies this affect. viscosity of oil also improves as content of the gas solution decreases. Combining effect of relative permeability with the effect of viscosity at a provided pressure at downhole results in a reduced production rate of oil. It therefore causes IPR curve to fall below the pressure of the bubble point from the linear trend, as it is shown in Figure 2.10, The lesser the pressure, the greater the difference. When the pressure in reservoir is less than the original pressure at bubble point, the whole reservoir domain will have two phase oil and gas flows, and thus the reservoir is ascribed to as a 'two phase-reservoir'. Only analytical equations are available to design the two phase IPR in reservoir. These analytical equations include the equation of Vogel (1968) extended by Standing (1971), the Fetkovich formula (1973), the Bandakhlia-Aziz formula (1989), the Zhang equation (1992), and the Retnanto-Economides equation (1998). Vogel's formula is yet highly used at the industry (Guo et al., 2007).

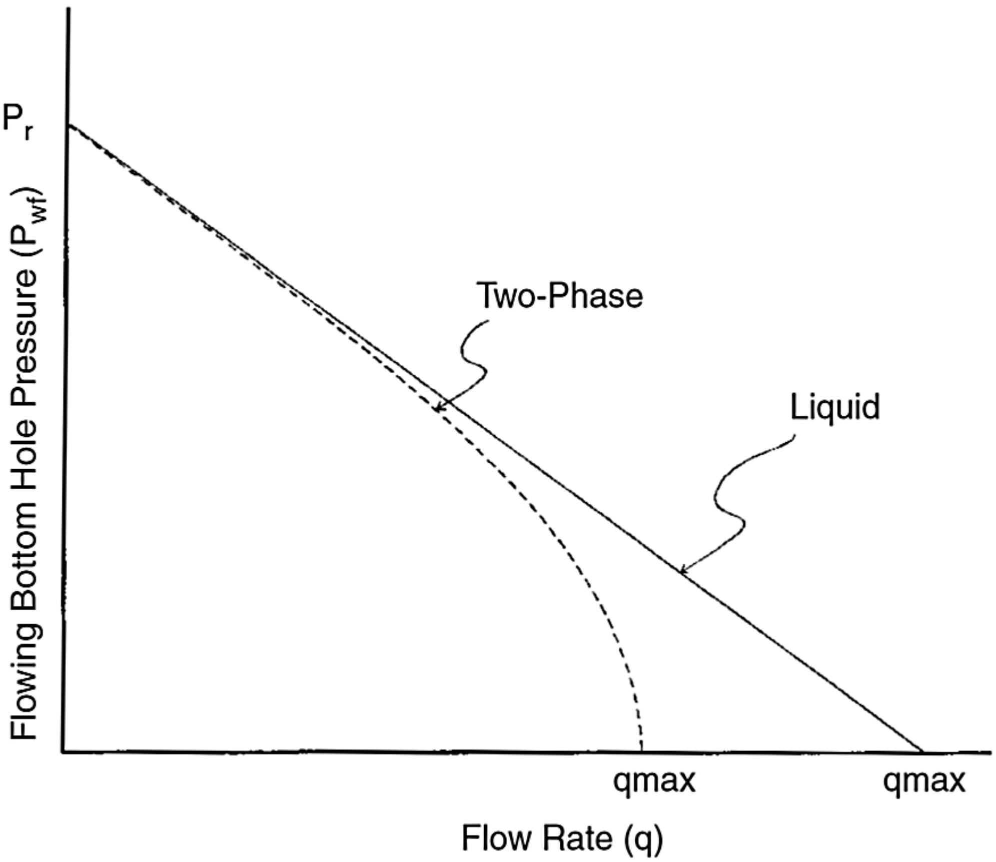


Figure 2.10: Effect of changes in productivity index on IPR curves (Lyons et al., 2016)

Figure 2.10 shows that PI is not fixed and then IPR will be curvilinear when the pressure close the wellbore drops underneath the bubble point or when orbital impacts at increased rates get to be curvilinear (Archer and Wall, 1986).

The straight-line equation of IPR curve (Figure 2.9) can only be applied to undersaturated oil when the pressure of reservoir is more than bubble point and the pressure drops underneath the point of bubble then the straight line begins to make a curve and the PI equation is no longer valid for this situation. The performance curve in single phase flow is a linear-line as shown in Figure 2.10, however, when the fluid moves in the reservoir at a pressure under bubble point, it's not a linear relationship, it is two phase flow and the straight line begins to make a curve. (Ba-Jaalah and Waly, 2015). When the tested pressure of bottom-hole is lower than the pressure at the bubble-point, constant model J will be calculated using Equation 2.19 (Lake and Clegg, 2007).

$$J = \frac{q}{\left((Pr - Pb) + \frac{Pb}{1.8}\left[1 - 0.2\left(\frac{Pwf}{Pb}\right) - 0.8\left(\frac{Pwf}{Pb}\right)^2\right]\right)} \tag{2.19}$$

Where;

J = productivity index.

Pb = pressure at bubble point.

Pr = reservoir pressure.

q = flow rate.

P_{wf} = bottom-hole pressure flow at (q) rate.

In addition, there will be no inflow if well-bore pressure is equivalent to pressure in reservoir. When the wellbore pressure is zero, maximum possible absolute open flow would be the inflow (AOF). The inflow will be different for intermediate wellbore pressures. There can be a special relation between the rate of inflow and pressure of well-bore for each reservoir (Ba-Jaalah and Waly, 2015).

2.5.5 Predicting future inflow performance relationship

It is often necessary to predict well deliverability in the future in many of oil fields, some of the causes are (Lyons et al., 2016):

1. Preparing to select future methods of artificial lifting.
2. To estimate the capability and to analyze whether the tube has to be changed.
3. To predict when to change or adjust the choke in order to preserve the rate of production.
4. Planning for maintenance of reservoir pressure or secondary recovery programs.

2.6 Vertical Lift Performance

Tube performance relationship or vertical lift performance curves are used to calculate a well's production capacity by plotting vertical life performance (VLP) and inflow performance relationship (IPR) (Lyons et al., 2016). In an oil, single phase flow occurs only if pressure of the well is higher than pressure at bubble-point of oil, and this is not normally a true thing (Guo et al., 2007). However, for effective operations, understanding of tubing performance flow of well is valuable. It is possible to evaluate the present and future performance of wells. Figure 2.11 show the concept of tube size effects and IPR change on good performance. If it is possible to predict the estimated future range rate and gas oil ratios, the tube size will be selected (Lyons et al., 2016).

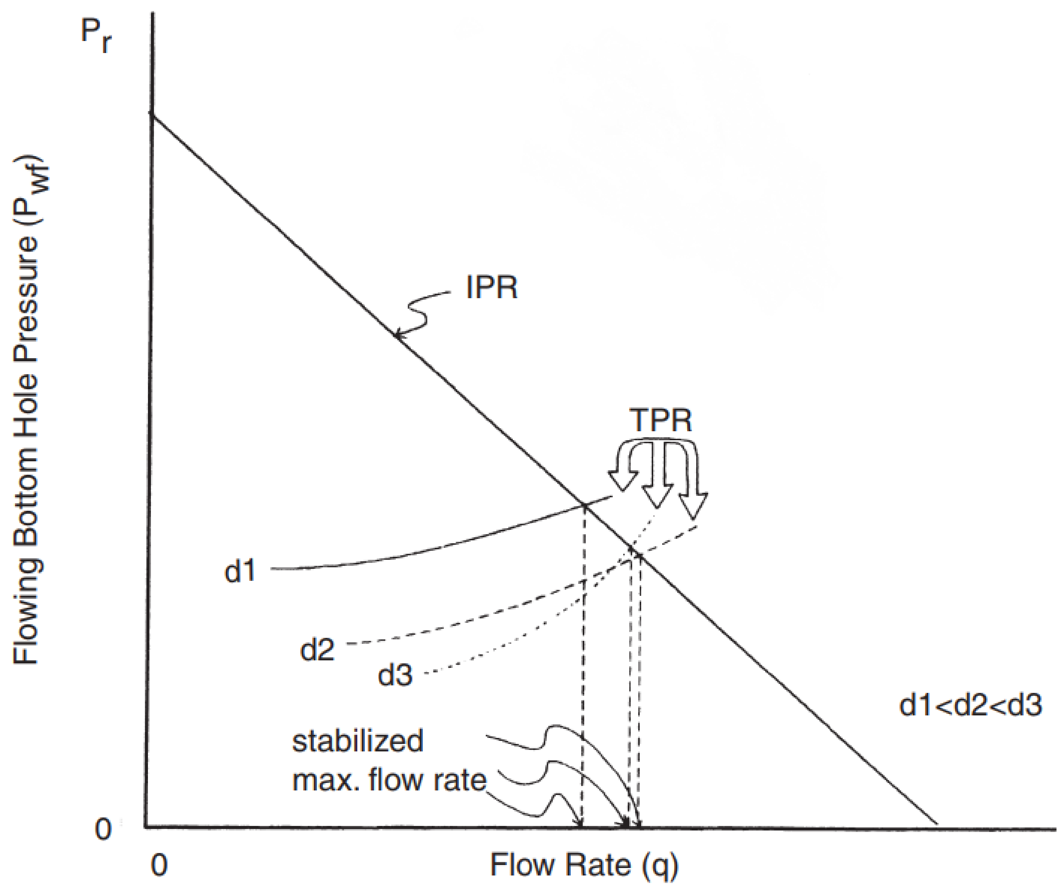


Figure 2.11: Effects of tubing size on a well productivity (Lyons et al., 2016)

As seen in Figure 2.11, the impact of using wide range tube size on well productivity if the performance of constant inflow is assumed (Lyons et al., 2016). As the size of the tubing increases, the losses of friction reduction, resulting in a lower flowing well pressure (pwf) and thus a greater inflow. However, as the tube size increases further, the well starts to load with liquid and the flow becomes random or unstable (Beggs, 2008).

2.6.1 Turbulent flow factor

The flow velocity raises during radial flow as the wellbore approaches. This velocity increase could cause turbulent flow round the wellbore to develop. If there is turbulent flow, gases are most likely to appear, and it causes a similar drop in added pressure to that induced by skin effect. The industry has implemented the term "non-Darcy flow" to define the additional drop in pressure caused by the turbulent (non-Darcy) flow (Ahmed and Meehan, 2012).

2.6.2 Liquid holdup

The quantity of pipe fully filled with a fluid phase can often be distinct in multi-phase flow in its ratio of the total volumetric rate of flow. This is because of the distinction in density among phases. The distinction in density leads the dense phase in an upward flow to slip down (i.e. the movements of the phase which is denser will be slower than lighter phase). this because denser phase's in situ fraction volume will then be larger than that of the denser phase's input volume fraction (i.e. the phase which is denser is "held up" inside pipe relative to the phase which is lighter). Therefore, liquid holdup can be expresses in Equation 2.20 as (Guo et al., 2007).

$$y_L = \frac{V_L}{V} \tag{2.20}$$

Where;

y_L = fraction liquid holdup.

V_L = volume of liquid phase of pipe segment, cu ft.

V = volume of pipe segment, ft^3.

2.7 Production Systems

One of the main objectives of the engineer engaged in petroleum production processes is to transfer the fluid from some area through an underneath of reservoir to a storage tank or to a pipe-line which can be used for transportation (Lyons et al., 2016). It is also essential to understand the fundamentals of fluid flow across the production system to predict the performance of individual wells and to optimize the productivity of wells as well as reservoirs. The production system is, under the most general way, the system that carries reservoir fluids from the reservoir to the ground. The basic components of the production system are the reservoir; well-bore; tubular goods and related equipment; well-head surface, flow-lines and refining equipment; and artificial lifting equipment (Lake and Clegg, 2007).

The primary goals of a system for oil and gas production are (Jansen and Currie, 2004):

- Give a good pathway for fluid flow from inside the reservoir to the point of release on the ground and sometimes from the surface to the underground.
- Divide the fluids obtained from the reservoir from each other.
- Reduce the by-product production or negative impacts.
- Store the fluids that are produced if they cannot be transferred directly.
- Calculate the quantities of fluids produced and regulate the production mechanism.
- Offer some of the best resources needed to carry fluids across the system.

The main component of a system of production are (Jansen and Currie, 2004):

- The near well-bore location of reservoir, i.e. a multi-meter radial zone in a radial way around the wells at reservoir depth.
- The wells on ground from the reservoir to the well-head.
- The flow-lines run from the well to the ground facilities.
- Surface tools consist of pumps, separators, compressors as well as other treatment and scale tools.
- Storage tanks and pipelines until the point of departure or the point of sale, that may be, for example, a valve at the gate to a gas pipeline transport or the point of departure of an oil terminal providing tankers.

Every system element could be divided more into sub-item. The flow path through the well-bore, in specific, it can comprise of (Jansen and Currie, 2004):

- Perforations in the formation (i.e. rock) and the cement round the casing, and through the casing itself.
- Equipment for controlling sand which consist of dense gravel (sand well sorted) or metal screens at the down of the well.
- The tubing, a pipe moving from the down of the well to the ground surface.
- A surface controlled sub-surface safety valve (SCSSV) for closing the well when the ground control is mistakenly lost and the well-head, a set of manually or remotely controlled valves for closing the well with wire-line equipment and a choker bean, a changeable size limit for controlling the flow from the well. Well heads are often referred to as trees of Christmas (Xmas trees).

2.8 Production Systems Analysis

In order to transfer oil or gas in its initial place in the reservoir to the stock tank or business line, any production well is drilled and finished. Movement or transporting these liquids and gases needs energy in order to overcome system friction losses and for raising the products to the ground. gas and liquids have to move across reservoir and piping network and finally flow in to a separator for splitting between gas and liquids. The production system can sometimes be relatively easy or can involve multiple elements where pressure or energy loss occurs. For example, in a diagram of a complex production system (Beggs, 2008).

That the fluid tends to flow from reservoir through and into the production system, it encounters pressure drops continuously, the pressure drops greatly as the fluids of the reservoir are produced on the surface. It is the duty of the petroleum engineer to optimally use this pressure loss. The decrease in pressure changes depending on the rate of production at the same time, the rate of production depends on the change in pressure. In order to estimate the performance of existing oil and gas wells, knowing the connection between pressure and production rate is essential (Lake and Clegg, 2007). Possible pressure losses in a complete production system and producing pressure profile are illustrated in Figure 2.12 (Lyons et al., 2016).

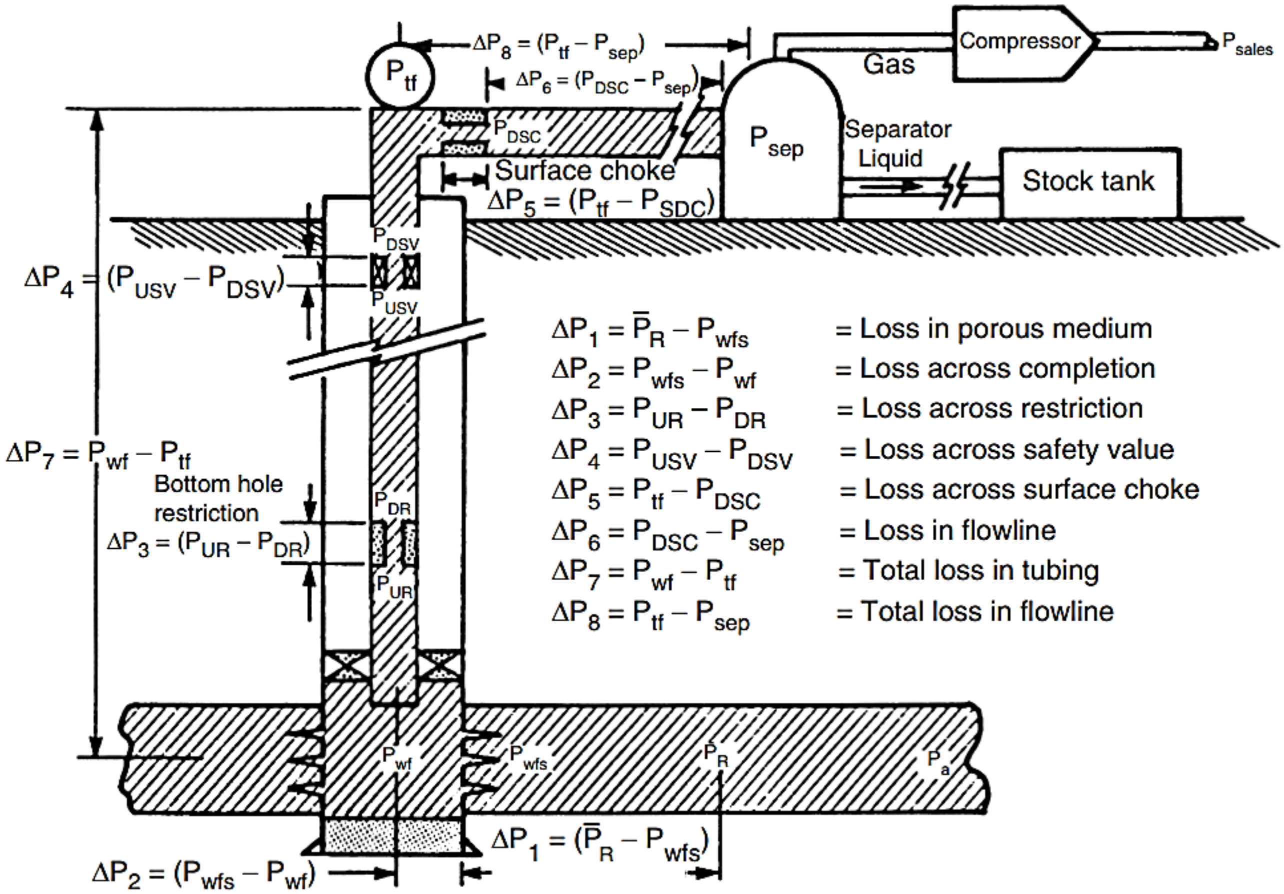


Figure 2.12: Pressure losses in the production system (Lyons et al., 2016)

In reality, whenever fluid moves there will be loss in the friction. In the system, this loss explains the difference in total pressure at two points (Lyons et al., 2016).

2.9 Nodal Analysis

The fluid characteristics of gas and oil production change in the system with area-dependent temperature and pressure. It is essential for a system to "break" it into specific nodes that distinct system components (tool parts) to simulate the flow of fluid throughout a system. Locally, fluid characteristics are analyzed at the components. In petroleum engineering, the system analysis for calculating the pressure and rate of fluid production at a given access point is known as "Nodal analysis". Nodal analysis is carried out on the theory of continuity of pressure, in which in a given node there is only one special pressure value, irrespective of whether the pressure is calculated from the performance of upstream tools. The upstream equipment's performance curve (pressure-rate relationship) is termed as "inflow performance curve"; the downstream equipment's performance curve is named as "outflow performance curve". The intersected point of the two performance curves describes point of operating at the given node, i.e. operating pressure and flowrate (Guo et al., 2007). The approach of nodal systems analysis is a very flexible technique that can be used for improving a performance of many systems in a well. To use the systems analysis procedure for a well, it is necessary to be able to determine the pressure depletion that has been shown in Figure 2.13 (Guo et al., 2007)..

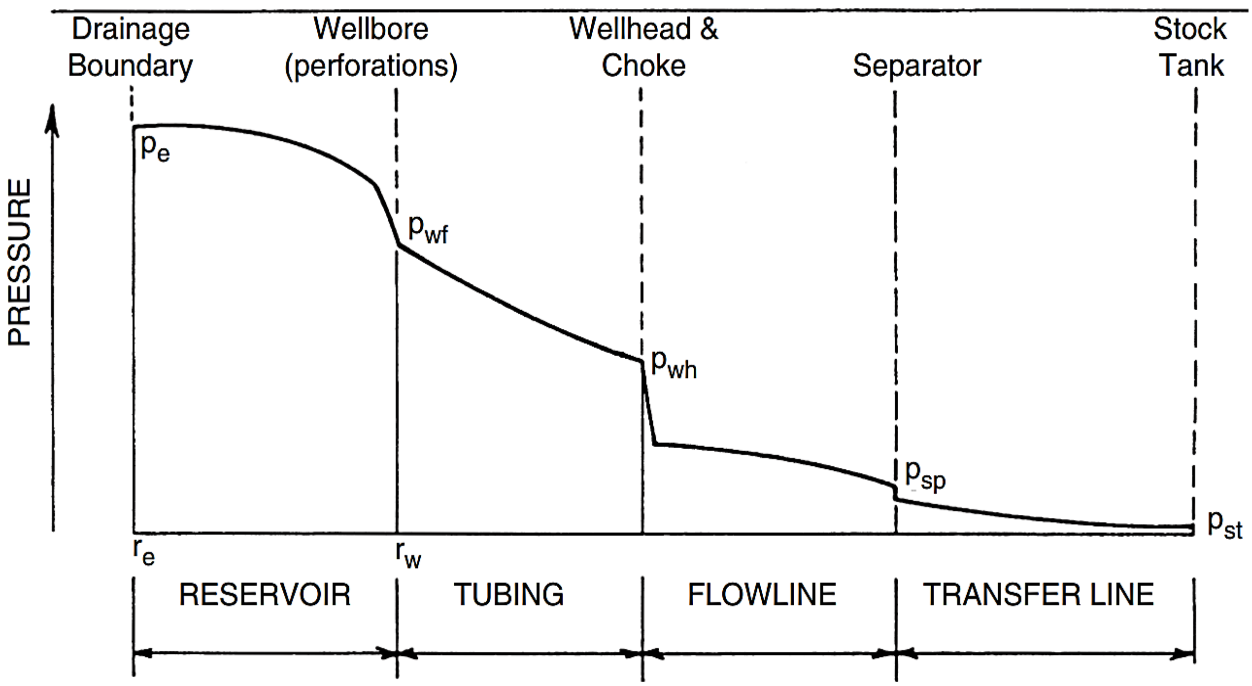


Figure 2.13: Production pressure depletion profile (Lyons et al., 2016)

As shown in Figure 2.13, along the path from the reservoir to the storage tank or pipe-line, changes occur in fluid's pressure, temperature, and hence the composition of all phases. In situation of a reservoir which is dry gas, verity in temperature, and pressure will not result in a multi-phase flow, and in situation of black oil with a GOR which is very small, a two-phase flow cannot be assumed (Lyons et al., 2016).

These pressure drops, which will occur in all components of the system, depend not only on the flow rate, but also on the size and other component characteristics. Unless accurate methods for calculating drops in these pressures can be found, the analysis of the systems can generate erroneous results (Beggs, 2008). Nodal analysis is generally can be done using the down-hole or well-head as the solution node for the simplicity of a used calculated pressure data which generally at either bottom hole or well-head (Guo et al., 2007).

2.9.1 Node point

The entire production system is viewed as a unit in Nodal Analysis. So, a certain point in the system is selected to be analyzed, e.g. the bottom-hole or the well-head. Inflow is considered upstream of the node and outflow is considered downstream of the node. Both the flow rate and the outflow rate are merged to provide certain node flow pressure for a particular flow rate (Tetoros, 2015).

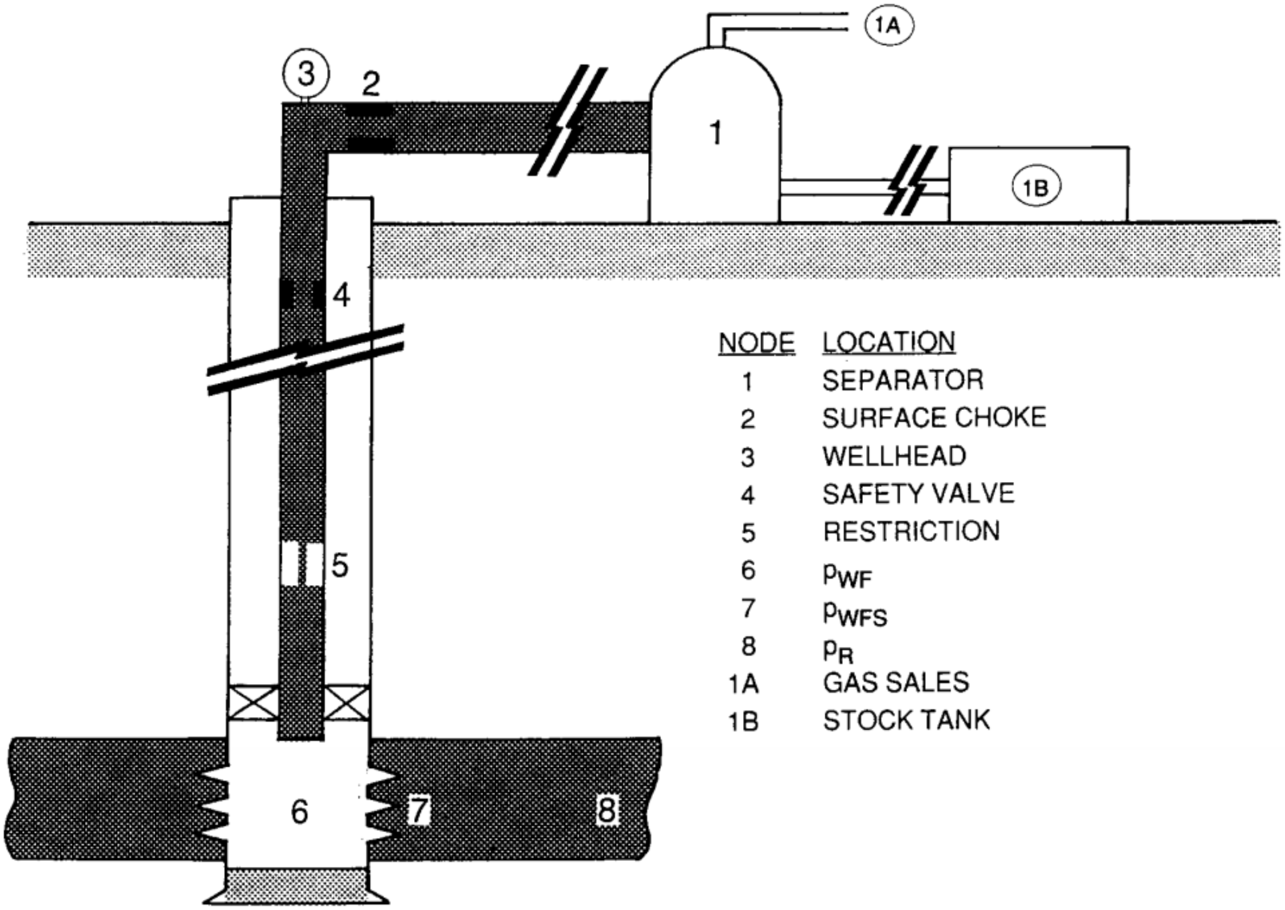


Figure 2.14: Various node locations (Beggs, 2008)

Figure 2.14 illustrate the locations of the most commonly used nodes, the procedure consists of selecting a node or division point in the well then dividing the system at that point (Beggs, 2008).

2.9.2 Bottom-hole node analysis

Inflow performance is the well-inflow performance relationship (IPR) if the bottom-hole is used in nodal analysis as a solution node, and outflow performance is the tubing performance relationship (TPR) when tubing shoe placed to top of pay zone. Nodal analysis at the bottom-hole could be operated by constructing the curves of IPR and TPR and by obtaining the solution graphically at two crossing point curves. The solution could be calculated easily with usage of modern computer technologies without constructing the curves, however, the curves are yet plotted for graphical identification (Guo et al., 2007).

2.9.3 Well-head node analysis

The curve of inflow performance is the well-head performance relationship (WPR) which can be gained by turning the IPR into a well-head through the TPR when the well-head in nodal analysis being used as a solution node. The performance of the outflow curve is performance relationship of the well-head choke (CPR). Nodal analysis with well-head as a solution node is produced by constructing the curves of CPR and WPR and discovering crossing solution point for both curves. Again, solution could be computed in a fast way with usage of modern computer technologies without constructing the curves, however, curves are yet plotted as a confirmation. (Guo et al., 2007).

2.9.4 Choke performance

In order to manipulate natural flow or pressure, a choke can be placed at down-hole or at the well-head. In oil fields, chokes are commonly being used. there are many various reasons for implementing chokes include controlling production rate, protecting surface equipment from slugging, avoiding sand issues caused by excessive draw-down, or controlling flowrate to prevent coning by gas or water. There are generally two used forms of well head choke, positive chokes as well as adjustable chokes. A positive choke has a non-changeable diameter size to displace it in order to control the rate of production. An adjustable choke allows the opening size to be gradually changed. Putting a choke at well-head could also mean fixing the pressure of the well-head, and therefore, the pressure and production rate of the bottom-hole flows for a provided well head pressure, the bottom-hole flowing pressure can be calculated by determining the pressure drops in the tube (Lyons et al., 2016).

2.10 Nodal Analysis Procedure

To apply nodal analysis in the petroleum industry, a suggested procedure can be given as follows (Beggs, 2008):

I. Specify which components can be changed in the system. Changes are restricted by previous decisions in some cases. For instance, after a certain hole size is drilled, the size of the casing and, thus, the size of the tubing is restricted.
II. Choose one of that components that can be optimized.
III. Choose the location of the node that best emphasizes the reflected possible effect in the chosen component. This is not critical because it will predict the same general outcome regardless of the position of the node.
IV. Develop expressions for the inflow and outflow.
V. Acquire the data required to calculate the pressure drop versus the rate of all elements, which may require more data than available, which may require analysis of possible ranges of conditions.
VI. Calculate the impact of changing the characteristics of a chosen component via plotting by reading the intersection point between inflow versus outflow.
VII. For each component to be optimized, repeat the same procedure.

2.11 Nodal Analysis Applications

The nodal system analysis approach can be used to analyze many oil and gas well issues. If the impact of the artificial lift technique on the pressure can be described as a function of the flow rate, the procedure can be implemented to both flowing and artificial lift wells. The procedure can also be implemented to a well performance injection analysis by doing an appropriate modification in the expressions of the inflow and outflow. A partial list of possible applications is given as follows (Beggs, 2008):

- Choosing size of the tubing.
- Predicting the effect of depletion on producing capacity.
- Artificial lift design.
- Choosing size of the flowline.
- Design of gravel pack.
- Sizing of surface choke.
- sizing of subsurface safety valve (SSV).
- Analyzing an existing system for abnormal flow restrictions.
- Well stimulation evaluation.

- Determining the effect of compression on gas well performance.
- Analyzing effects of perforating density.
- Relating field performance to time.
- Analyzing a multi-well producing system.
- Allocating injection gas among gas lift wells.

2.12 Artificial Lift Method

The pressure of reservoir will drop to such levels after a long production period that the oil rates observed will not be economically sustainable. The worst situation could be noticed when the pressure to lift the liquids to the surface is insufficient and production will finally take control. The need to keep production as long as possible has led industry engineers to start developing methods for reinitiating or increasing production. The methods of production optimization are called artificial lift methods and relates to the use of mechanical tools (such as pumps) to help production by decreasing the pressure drop throughout the well, or lightening the hydrostatic column by injecting gas into the production tube. With some type of artificial lift, a large number of oil wells around the world produce (Tetoros, 2015).

CHAPTER 3

PROBLEM STATEMENT

In this chapter, the problem of this research has been described, also the objective of this thesis with the provided data for well-A and the importance of this research are highlighted.

3.1 Thesis Problem

A company has decided to make a production optimization based on the given data for a well which is named here as well-A located in the northern part of Iraq, the task of this project is to make optimization analyses for the well and for this purpose a computer software will be used as a tool to do these analyses to find out the best performance for the well.

3.2 Available Data

The main data that have been used in this study with regards to well-A are presented in Tables 3.1 to 3.5:

Table 3.1: Wellbore data

Type of Data	Amount	Unit
Measured Depth (MD)	4000	ft
True Vertical Depth (TVD)	4000	ft
Angle	0	degree
Tubing Depth	3900	ft
Tubing Inside Diameter (ID)	2.441	inches
Tubing Outside Diameter (ID)	3.5	inches
Tubing Inside Roughness	0.0006	inches
Casing Depth	4000	ft
Casing Inside Diameter (ID)	6.5	inches
Casing Inside Roughness	0.0006	inches

Table 3.2: PVT properties data

Type of Data	Amount	Unit
Oil Gravity	35.0	API
Gas Gravity (γ_g)	0.825	sp. gravity
Water Salinity	0	ppm
N2	1	percentage
CO2	2	percentage
H2S	3	percentage
GOR (Rs)	800	SCF/STB

Table 3.3: Fluid flow data

Type of Data	Amount	Unit
Reservoir Pressure (Pr)	3000	psig
Reservoir Temperature (Tr)	120	F°
Wellhead Pressure (Pwh)	100	psig
Fluid Rate (Qf)	1000	STB/day
Water Cut	30	percentage
Oil Rate (Qo)	700	STB/day
Water Rate (Qw)	300	STB/day
Tubing Gas Rate (Qg)	560000	SCF/day
Overall Heat Transfer Coefficient	15.9	BTU/hr-ft2-F
Bubble Point Pressure (Pbp)	2000	psig
Bubble Point Temperature (Tb)	140	F°

Table 3.4: Production test data

Flowing Bottom-hole Pressure (Pwf)	**Total Fluid Production (Q)**
Psig	STB/day
1800	684

Table 3.5: Some other useful data

Type of Data	**Amount**	**Unit**
Separator Pressure	50	psig
Separator Temperature	80	F°

3.3 The Aim of the Thesis

This research presents principals of production optimization and evaluation of the well performance with the aid of computer programs when necessary. The objective of this project is to make an optimization analyses for the production performance of the well through the intersection point between inflow performance relationship (IPR) and vertical lift performance (VLP) curves with regards to the pressure, flow rate, and other provided variables in order to find the maximum oil production rate that could be achieved for the whole production system and to make some decisions for the optimization of well-A.

3.4 The Importance of the Thesis

The concern of this study is to use computer technology to assist the petroleum production engineers in choosing the most accurate methods and correlations for their problems. The main significance of this project is to:

- Make some sensitive analyses to improve the well performance.
- Differentiate between the flow methods in the reservoir and in the wellbore and to select the best correlation method.
- Make usage of computer software to analyze and design the well with optimum flow rate and pressure.

- Know the effect of changing variables on the well performance.
- Differentiate between the methods for constructing inflow performance relationship (IPR) and vertical lift performance (VLP).
- Analyze the fluid behavior based on the given data.
- Understand the effect of the fluid properties as the fluids are produced to the surface.

CHAPTER 4

METHODOLOGY

This chapter is about some of the methods that can be used to calculate the fluid flow in the reservoir and the fluid flow inside the tubing, it also gives a brief information about the computer software which has been used as a tool in some stages of the research in order to implement some of the methods.

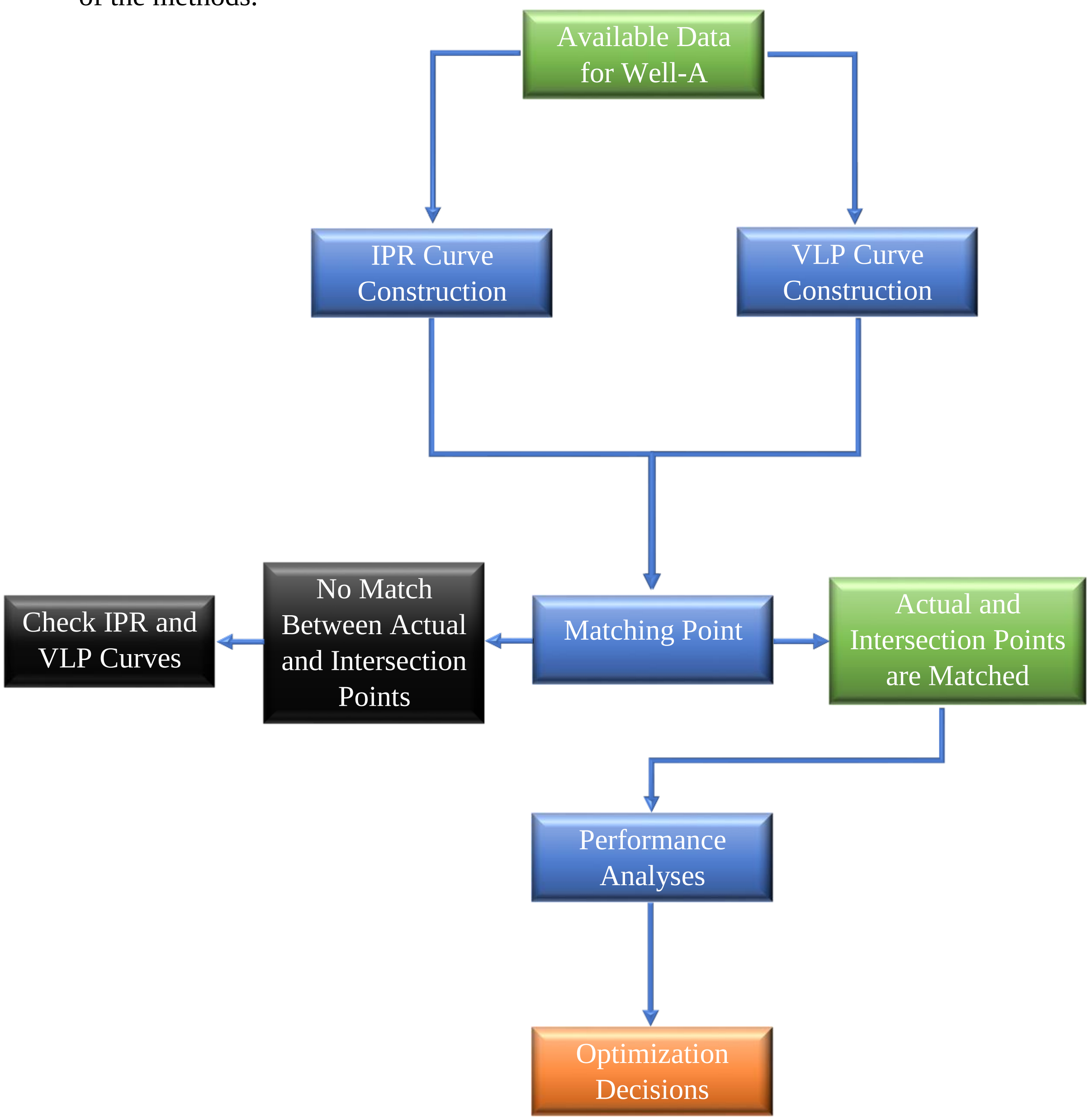


Figure 4.1: Flowchart of the research procedure for optimization

4.1 Required Data

The needed data in order to run analyses could be listed into followed categories:

- Fluid characterization (PVT) data.
- Reservoir inflow (IPR) data.
- Tool data: surface equipment, deviation survey, equipment of down-hole, average heat capacities, geothermal gradient.
- Production test data: flowrate and flowing bottom-hole pressures.

4.2 Vogel Method

The Vogel method was developed to generate IPRs for a wide of situations using reservoir model proposed by Weller (1966). He then replotted the IPR’s as low or dimension-less pressure versus flow rate without dimensions. A dimension-less pressure is described as the well-bore flowing pressure separated by Pwf / PR, the average reservoir pressure. The dimensional flow rate is described as a flow rate which would lead in the importance of Pwf being taken into account, separated by the flow rate resulting from a zero well-bore pressure, that's q/q_{max}. It was discovered that with all the situations analyzed, the general form of the dimensionless IPR was closely related to one another. After plotting dimensional IPR curves to all considered cases, Vogel finally arrived at the relationship which was shown in Equation 4.1 between dimensional-less pressure and dimensional-less flow rate (Beggs, 2008).

$$\frac{q}{qmax} = 1 - 0.2\left[\frac{Pwf}{PR}\right] - 0.8\left[\frac{Pwf}{PR}\right]^2 \tag{4.1}$$

Where;

P_R = average reservoir pressure existing at the time of interest.

Pwf = flowing well-bore pressure.

q = inflow rate corresponding to wellbore flowing pressure Pwf.

q_{max} = inflow rate equivalent to zero well-bore flow pressure, (AOF).

Vogel used a computer software based on the assumptions of Weller (1966) and 21 data sets of the reservoir to improve a dimensionless IPR for oil wells which shown in Equation 4.2:

$$\frac{q}{qmax} = 1 - 0.2\left[\frac{P}{Pwf}\right] - 0.8\left[\frac{P}{Pwf}\right]^2 \tag{4.2}$$

Where;

q = flow rate.

P = static pressure, average of reservoir.

q_{max} = theoretical flow rate at zero bottom hole.

P_{wf} = flowing down hole pressure at q-rate.

It was discovered that somehow the curve of the relationship of inflow performance is reasonably well fitted properly for a wide range of different reservoir situations by a quadratic equation (Archer and Wall, 1986). IPR curve constructions in the two-phase reservoirs using generalized Vogel equations have been illustrated in Figure 4.2.

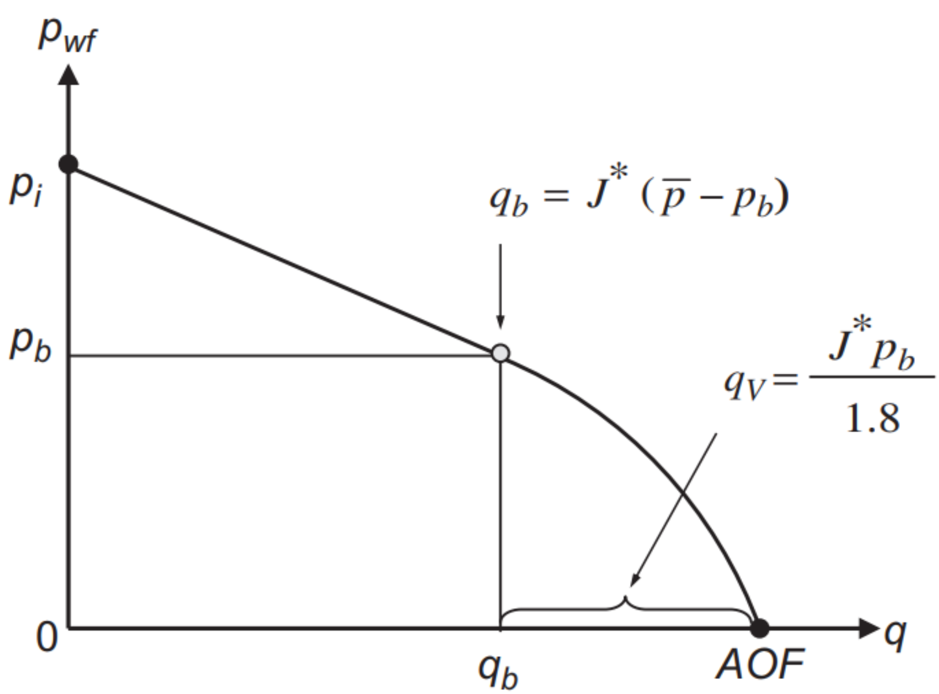


Figure 4.2: Generalized Vogel IPR model for partial two-phase reservoirs (Guo et al., 2017)

Vogel formula will be easily used to estimate producing rates and pressures lower than pressure of bubble-point. It also possible to be used if data are available from just one test of production unless it becomes near to the static case (Lyons et al., 2016). Application of Vogel's method is almost as simple as the constant J method which has been shown in Figure 4.2 that only one actual well test is required (Beggs, 2008). When reservoir pressure exceeds pressure of bubble point, but when bottom-hole flowing pressure was in range of pressure at bubble-point, generalized IPR by Vogel could be used as shown in Equation 4.3:

$$q = qb + qv\left[1 - 0.2\left(\frac{Pwf}{Pb}\right) - 0.8\left(\frac{Pwf}{Pb}\right)^2\right] \tag{4.3}$$

Where;

qb = flow rate at bubble point.

Pb = pressure at bubble point.

Correlation of Vogel provided a reasonable match with real early stage of inflow performance of well, however, differs later in a life of reservoir. Thus, this will effect on prediction curves of inflow performance for situation solution gas drives reservoirs due to later production levels the volume of free gas produced from the oil can be exceed the volume at the beginning levels of production (Fattah et al., 2012).

Vogel pointed out that the error in the estimating rate of inflow must be less than 10 percent in most of his method applications, but could rise to 20 percent in the end levels of drops. Errors made by assuming a constant J were found to result in errors ranging from 70% to 80% at low pwf values. It has also been shown that the method of Vogel can be applied along with the oil and gas to wells producing water, since the increased saturation of gas will also reduce the water permeability. This has been shown as a validation for the wells that produce water cuts of up to 97% (Beggs, 2008).

According to Production Technology (2017) there are many inflow performance relationships (IPR's) have been found and have been described in the literature. Figure 4.3 briefly present three of the most universally used IPR's to describe the well performance.

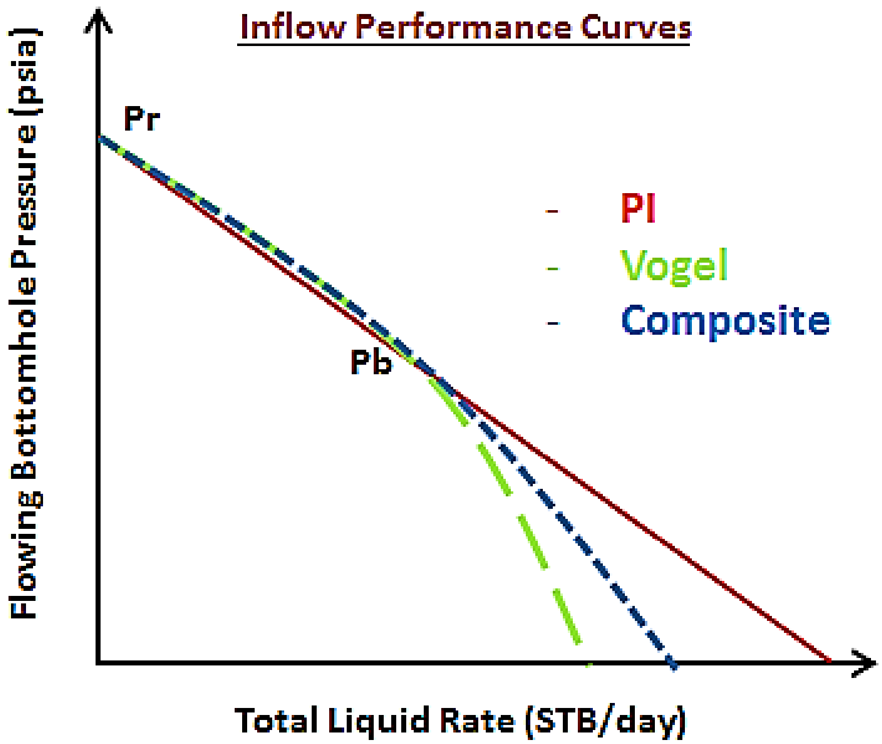


Figure 4.3: IPR behavior above and below bubble point (Production Technology, 2017)

This relationship (Figure 4.3) should theoretically be used at below the bubble point pressure and a linear relationship at higher than bubble point, however, at this level the Vogel relationship will be counted sufficient as a first approximation to the curvilinear IPR. Simulation research would, of course, produce IPRs for complicated situations, although, this is usually a production engineering goal (Archer and Wall, 1986).

4.3 Fetkovich's Method

Fetkovich in Fetkovich (1973) introduced a calculation method the in-flow performance of oil wells with the same equation kind which was used in many years to analyze gas wells. The procedure was confirmed by the analysis of isochronal and flow-after-flow tests carried out in reservoirs with permeability ranging from 6 md to over 1000 md. pressure conditions in reservoirs varied from deeply undersaturated to saturated at original pressure and largely dropped fields with over-saturated gas. In every scenario, it was found that the oil-well back pressure curves followed the same general shape as used for describe the gas-flow relationship (Beggs, 2008), which is shown in Equation 4.4:

$$q_{\circ} = C\left(PR^2 - Pwf^2\right)^n \tag{4.4}$$

Where;

$q_{\circ}$ = producing rate.

P_R = average pressure of reservoir.

Pwf = flowing pressure of well-bore.

C = flow coefficient

n = exponent depending on well characteristics.

The For the 40 field tests evaluated by Fetkovich, n ranged from 0.568 to 1.000 (Beggs, 2008). Fetkovich found that the curves of back-pressure for oil wells carried similar shape as for gas wells (Lyons et al., 2016).

4.4 The Duns-Ros Method

This correlation was proposed specifically to predict of pressure losses in vertical oil well tubing for the upward flow of multiphase well fluids (Lawson and Brill, 1974). And it is applicable for a large of gas and oil mixes range for different water-cuts and flow schemes. While the correlation is planned to be applied on a mixed "dry" oil / gas, wet mixtures with appropriate correction could also be applied. Method of Duns-Ros (with a correction factor) was known to well's work in the bubble, slug (plug) and froth regions for water content below 10 percent. (Lyons et al., 2016).

The Duns-Ros correlation's performance of the pressure profile prediction is listed below with regards to the various flow factors considered (Lawson and Brill, 1974):

- Tube size: The pressure dropping for a size range of tube diameters between 1 and 3 in general is over-predicted.
- Gravity of oil: good pressure profile predictions for a wide oil gravity range are achieved (13 to 56◦ API).

- Gas liquid ratio (GLR): For a wide GLR range, the drop-in pressure is over estimated. The errors for GLR higher than 5000 are particularly large (> 20 percent).
- Water cut in Duns-Ros's model could not applied for gas, oil, and water multi-phase flow mixtures. Although, the method could be applied with an appropriate correction factor.

4.5 The Beggs-Brill Method

Correlation of Beggs and Brill was developed for tubing strings in inclined wells and hilly pipelines terrain. This method was the result of experiments using air and water across large variety of parameters as test fluids (Lyons et al., 2016).

The performance of the correlation is given below (Vohra et al., 1974) :

- Tube size: the pressure losses are properly predicted for the range within which the experimental investigation was operated (i.e., tube between sizes of 1 and 1.5 in.). Any further increase in the tube size appears to lead to a prediction over the loss of pressure.
- Oil gravity: a sensibly good performance in a wide range of oil gravities is gained.
- Gas liquid ratio: generally, with increasing of GLR, an over-predicted pressure drop is achieved. The errors for the gas-liquid ratio above 5000 are particularly large.
- Water-cutting: the pressure profile accuracy is usually good up to 10% water-cutting.

4.6 About Used Software

For this research, PROSPER has only been used as a tool to achieve the matching point between IPR and VLP and to do some analyses, The used software is one of the most powerful tools that can predict the well performance and the production capability, through building a well model using the major well aspects such as PVT (fluid characterization), IPR (reservoir inflow), and VLP correlations (for determination of tubing and flowline pressure loss). It is a well design and optimization software, located in UK and owned by Petroleum Experts Limited company (Petroleum Experts Ltd, 2010).

CHAPTER 5

MODEL SETUP FOR OPTIMIZATION

RESULTS & DISCUSSIONS

In this chapter the model setup has been described step by step. Although, several methods and correlations have been used in this case study in order to find out and construct the most accurate curve plots that can be possible for inflow performance relationship (IPR), vertical lift performance (VLP) and to get an accurate matching intersection point between these two curves with regards to the provided data of well-A.

In order to generate IPR and VLP curves and to achieve the matching point between these two curves with regards to the provided data of well-A, the steps have been listed:

1. Options Summary.
2. PVT Data.
3. IPR Data.
4. Equipment Data, Analysis Summary.
5. Analysis Summary.

The information is grouped into the following categories: PVT Data, System Input Data, Analysis Data, and Output Data.

5.1 Options Summary

The interface window is a system summary in which there are some information that have been given with regards to well-A data which were used for this case study, and the given information fall into these categories: fluid description, well, artificial lift, calculation type, well completion, reservoir, user information.

The main characteristics of the well in this section have been given in Table 5.1 to 5.6:

Table 5.1: Selected option for fluid description

Fluid Description	**Selected Option**
Fluid	Oil and Water
Method	Black Oil
Separator	Single-Stage Separator
Emulsions	No
PVT Warnings	Disable Warning
Water Viscosity	Use default correlation
Viscosity Model	Newtonian Fluid

Table 5.2: Selected option for well

Well	**Selected Option**
Flow Type	Tubing Flow
Well Type	Producer

Table 5.3: Selected option for artificial lift

Artificial Lift	**Selected Option**
Method	None

Table 5.4: Selected option for calculation type

Calculation Type	**Selected Option**
Predict	Pressure and Temperature (on land)
Model	Rough Approximation
Range	Full System

Table 5.5: Selected option for well completion

Well Completion	Selected Option
Type	Cased Hole
Sand Control	None

Table 5.6: Selected option for reservoir

Reservoir	Selected Option
Inflow Type	Single Branch
Gas Coning	No

5.2 PVT Data

In this section, as shown in Table 5.7, 5.8 and 5.9, the PVT data and PVT match data has been given to match the data in order to choose the best correlations that can be used regarding this field data for well-A.

Table 5.7: PVT input data

Input Parameters	Amount	Unit
Solution GOR (Rsb)	574.7	SCF/STB
Oil gravity	35.0	API
Gas gravity (γ_g)	0.825	sp. gravity
Water salinity	0	ppm
H2S	3	percentage
CO2	2	percentage
N2	1	percentage

Table 5.8: PVT input match data for bubble point condition

Temperature	**Bubble Point**
deg F	psig
140	2000

Table 5.9: PVT other input match data

Pressure	**GOR**	**Oil FVF**	**Oil Viscosity**
psig	scf/STB	RB/STB	centipoise
200	43.6	1.0527	2
400	90.6	1.0726	1.5
600	142.2	1.0954	1.3
800	197.3	1.1205	1.1
1000	255.2	1.1477	1
1200	315.5	1.1768	0.8
1400	377.7	1.2076	0.8
1600	441.8	1.24	0.7
1800	507.5	1.274	0.6
2000	574.7	1.3094	0.6
2400	574.7	1.3015	0.6
2500	574.7	1.2998	0.6
3000	574.7	1.2921	0.7

After all the available sets of data have been inserted into PVT section, it was found that for black oil, there are many correlations which were developed based on experimental data in order to predict the bubble point (Pb), solution gas oil ratio (Rs), oil formation volume factor (Bo), and oil viscosity (μoil). The correlations that were used to predict Pb, Rs and Bo are listed bellow:

- Glaso
- Standing
- Lasater
- Vasquez and Beggs
- Petrosky et al
- Al-Marhoun

Table 5.10: Standard deviation output for different correlations in PVT section

Type of Correlation	Bubble Point (Pb)	Solution GOR (Rs)	Oil FVF (Bo)
Glaso	---	2.72608	0.0053937
Standing	---	1.40064	0.00043905
Lasater	---	9.83118	0.0050181
Vasquez and Beggs	---	1.16779	0.0037456
Petrosky et al	---	6.55391	0.0057842
Al-Marhoun	---	9.42974	0.0053914

After all the data have been matched and analysed for all correlations, as shown in Table 5.10, the best correlation that has been found with regards to the available data for well-A based on the smallest amount of standard deviation was Standing correlation. Furthermore, with comparing to the other correlations, Standing has given the most accurate value with the lowest standard deviation to match PVT for this case study. and the correlations that have been used to predict oil viscosity are listed bellow:

- Beal et al
- Beggs et al
- Petrosky et al
- Egbogah et al
- Bergman and Sutton

Table 5.11: Standard deviation output using different correlations for oil viscosity in PVT section

Type of Correlations	Oil Viscosity
Beal et al	0.073467
Beggs et al	0.034008
Petrosky et al	0.061254
Egbogah et al	0.099604
Bergman and Sutton	---

As shown in Table 5.11, for the oil viscosity, the best correlation based on the lowest standard deviation regarding the available data for well-A was found to be Begges et al. Now PVT data at every pressure and temperature can be predicted with the adjusted correlations.

5.3 IPR Data

The flow from the reservoir into the well is known as the inflow performance, and the curve of producing rate versus flowing bottom hole pressure is called the inflow performance relationship or IPR or inflow curve. An equation is needed to calculate the pressure drop in a reservoir that describes the pressure losses as a function of flow rate. This equation has different forms depending on fluid type and formation type, but all are based on the fundamental equation known as Darcy's Law. This approach can also be achieved by using computer software and by selecting a node inside the well and dividing the system at that point. This is often called the solution node. And this can be the bottom node, top node, or wellhead (Petroleum Experts Ltd, 2010). Where in this case study the bottom hole has been chosen as a solution node point, which means the flow from reservoir to the bottom hole of the wellbore has been treated as inflow which will be reflected in IPR curve plot, and the flow through tubing from the bottom hole of the wellbore to the well-head has been treated as outflow, which mean will be reflected in VLP curve. Therefore, for constructing IPR curve, the data which are required have been provided, the inserted data are presented in Table 5.12 to 5.14:

Table 5.12: IPR input parameter

Type of Data	Amount	Unit
Reservoir Pressure (Pr)	3000	psig
Reservoir Temperature	120	F°
Water Cut	30	percentage
Tubing GOR (R)	800	SCF/STB

Table 5.13: Selected option in IPR input section

IPR section	Selected Option
Compaction Permeability Reduction Model	No
Relative Permeability	No

There are several reservoir modelling methods that are available for constructing IPR curves, some of which are listed below:

- PI Entry
- Vogel
- Composite
- Fetkovich
- MultiRate Fetkovich
- Jones
- MultiRate Jones

Any of these models can be used in different situations and each one them needs a specific type of data. Thus, with regards to this case study for well-A, production test data which is shown in Table 5.14 has been provided. Therefore, in model and global variable selection, Vogel reservoir model has been used for constructing IPR curve (Figure 5.1).

Table 5.14: IPR input production test for Vogel reservoir model

Type of Data	Amount	Unit
Test Rate	684	STB/day
Test Bottom Hole Pressure	1800	psig

The straight-line has been used in inflow relationship higher than the bubble point (Pb) and the Vogel empirical solution lower than the bubble point. The calculation of the IPR is based on a single flowing bottom hole pressure and surface test rate. The Vogel equation can be used below Pb. Vogel method require a production test point, and it has been given (Table 5.14) in order to construct IPR curve.

Figure 5.1 shows the construction of IPR curve using Vogel method which is based on the available production test that has been given.

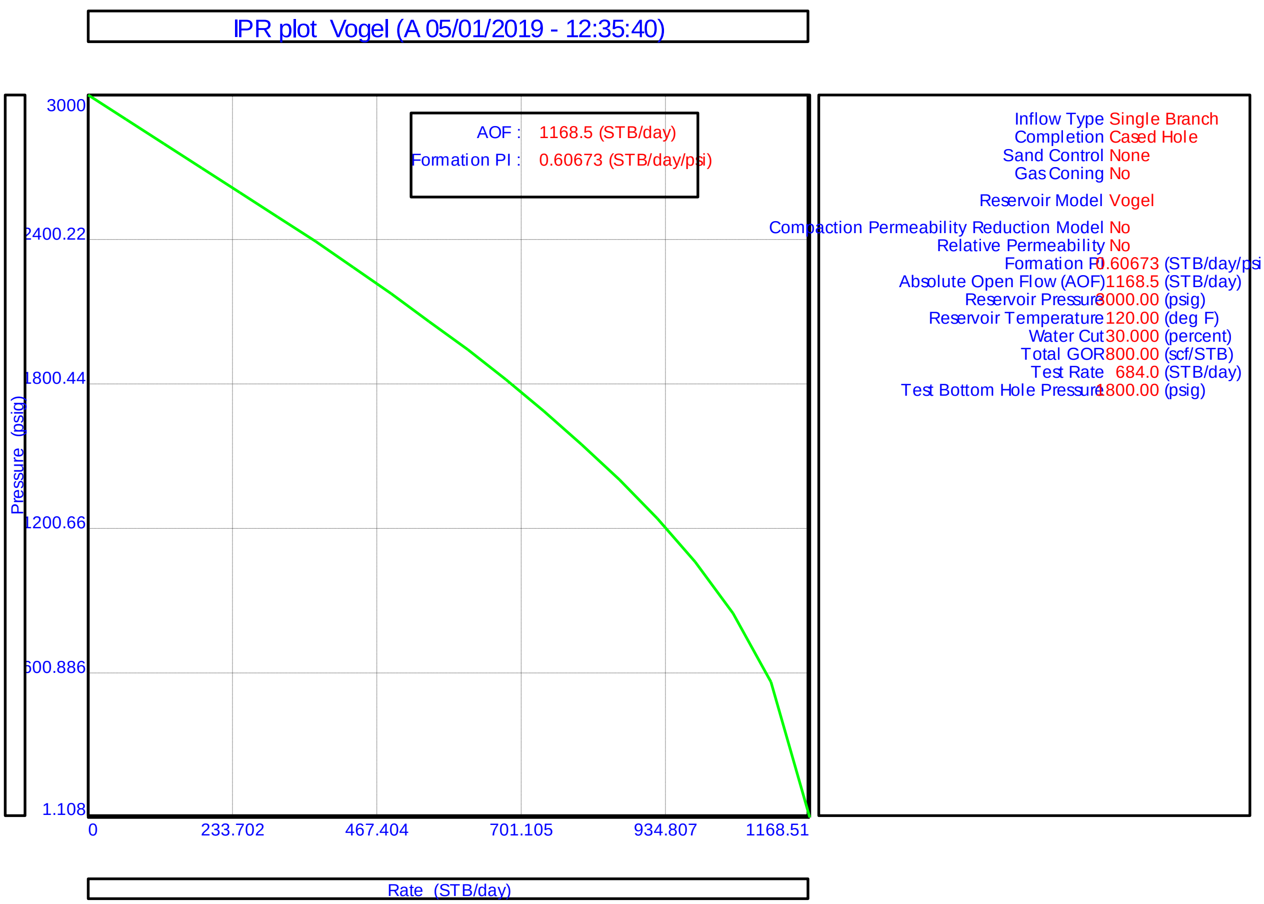


Figure 5.1: IPR curve using Vogel method

As seen in Figure 5.1, the absolute open flow (AOF) that has been calculated is 1168.5 (STB/day) and the formation productivity index (PI) is 0.60673 (STB/day/psi). Vogel has given the most accurate and closest results to the actual value regarding the available data for well-A.

5.4 Equipment Data

In this section, a detailed trajectory description regarding this case study has been gıven, and ıt was devided into five catagories: deviation survey, surface and downhole equipment, geothermal gradient and average heat capacities which are explained below:

5.4.1 Deviation survey

It is the first part of the equipment data section which calculates the angle of deviation for a given data. To obtain accurate calculations in the VLP section, a consistent deviation survey is required (Table 5.15).

Table 5.15: Input data for deviation survey

Measured Depth	True Vertical Depth	Cumulative Displacement	Angle
Feet	feet	feet	dgrees
0	0	0	0
200	200	0	0
400	400	0	0
600	600	0	0
800	800	0	0
1000	1000	0	0
1200	1200	0	0
1400	1400	0	0
1600	1600	0	0
1800	1800	0	0

2000	2000	0	0
2200	2200	0	0
2400	2400	0	0
2600	2600	0	0
2800	2800	0	0
3000	3000	0	0
3200	3200	0	0
3600	3600	0	0
4000	4000	0	0

As shown in Table 5.15, there is no inclination regarding the provided data of well-A, and it shows that this well is a vertical well in which there is no diviation from the top of the well to the deepest point of the well.

5.4.2 Surface equipment

In this section, no data has been provided because it was decided to put the furthest node point at the top of the wellhead, and the manifold TVD was set at 0’ TVD.

5.4.3 Downhole equipment

For the downhole equipment, the Christmas tree or known as Xmas tree is set at the top of well head at zero, and the data for tubing has been presented in Table 5.16.

Table 5.16: Input data for downhole equipment

Type of Equipment	**Measured Depth**	**Inside Diameter**	**Outside Diameter**	**Roughness**	**Rate Multiplier**
Xmas Tree	0	---	---	---	---
Tubing	3900	2.441	3.5	0.0006	1
Casing	4000	6.5	---	0.0006	1

Due to intermittent sections of dual completion, the rate multiplier column allows the simulation of the pressure drop. The tube fluid rate is multiplied by the entered value. It has been entered as default value which is 1 for a standard single tube completion.

5.4.4 Geothermal Gradient

In geothermal gradient, formation measured depth and formation temperature for the entire well have been provided respectively with regards to well-A, which are presented in Table 5.17.

Table 5.17: Input data for geothermal gradient

Formation Measured Depth	**Formation Temperature**
Feet	deg F
0	60
200	63
400	66
600	69
800	72
1000	75
1200	78
1400	81
1600	84
1800	87
2000	90
2200	93
2400	96
2600	99
2800	102
3000	105
3400	111
4000	120

As shown in Table 5.17, the formation temperature at every depth inside the well have been computed, and the over heat transfer coefficient for this case study was 15.9 BTU/h/ft2/F, it was given as shown in Table 5.18.

Table 5.18: Input data for overall heat transfer coefficient in geothermal gradient section

Input Parameter	Amount	Unit
Overall Heat Transfer Coefficient	15.9	BTU/h/ft^2/F

5.4.5 Average heat capacities

In this section of the downhole equipment, an average Cp based on the entered values and the mass flow rates of each phase has been generated, this calculated average Cp is used for the entire well. Therefore, the parameters that are presented in Table 5.19 have been left as default.

Table 5.19: Input data for average heat capacities

Input Parameters	Amount	Unit
Cp Oil	0.53	BTU/Ib/F
Cp Gas	0.53	BTU/Ib/F
Cp Water	1	BTU/Ib/F

5.5 Tubing Correlation Comparison

By using any of the standard correlations, this module will enable the calculation of a pressure gradient (traverse) at a given surface rate and can serve as quality control boundaries for down-hole measurements. For comparison with the pressure computed from the correlations, actual calculated pressure can be input and plotted on the same graph. Table 5.20, 5.21 and 5.22 shows the input parameters which were used for finding the match points between tubing curve and given data points of well-A in order to predict the pressure losses inside the tubing.

Table 5.20: Input data for tubing correlation comparison

Input Parameters	Amount	Unit
Wellhead Pressure	100	psig
Water Cut	30	percent
Liquid Rate	1000	STB/day
GOR	800	SCF/STB
GOR Free	0	SCF/STB

From Table 5.20, The gas oil ratio (GOR) should be the same as the solution GOR entered in the PVT and at no time should it exceed the initial solution GOR. The sum of GOR and GOR Free should be equal to the total GOR which is 800 SCF/STB, the GOR can also be entered as Total GOR (solution + free GOR), and GOR free set to nil.

Table 5.21: Selected option in tubing correlation comparison

Type of Parameters	Selected Option
Rate Type	Liquid Rates
Pipeline Correlation	Biggs and Brill

As shown in Table 5.21, liquid rate has been chosen in rate type option, it is also possible to choose only oil rate without water but then in Table 5.20 the rate amount for oil should also be changed to 700 SCF/STB respectively as given in the data sheet for well-A, and for pipe correlation, Biggs and Brill has been selected for this case study because this correlation is mainly used for the correlation of pipelines and generally over predicts the pressure drops in the vertical and deviated wells.

Table 5.22: Measured input data for tubing correlation comparison

Point	Depth	Pressure
	feet	psig
1	400	148.1
2	800	201.0
3	1200	259.3
4	1600	324.1
5	2000	394.6
6	2400	471.7
7	2800	555.8
8	3200	647.6
9	3600	747.9
10	4000	859.3

Table 5.22 shows the depth and pressure of 10 points that were inserted in order to construct tubing correlation comparison plot regarding the given data of well-A. After all required data have been given, these correlations which have been listed down were available in order to construct the tubing correlation comparison plot:

- Duns and Ros Modified
- Hagedorn Brown
- Fancher Brown
- Mukerjee Brill
- Biggs and Brill
- Petroleum Experts
- Orkiszewski
- Petroleum Experts 2
- Duns and Ros Original

➢ Petroleum Experts 3
➢ GRE (modified by PE)
➢ Petroleum Experts 4
➢ Hydro-3P
➢ Petroleum Experts 5
➢ OLGAS 2P
➢ OLGAS 3P
➢ OLGAS3P EXT

Some of these correlations have been used to construct tubing correlation comparison plot which is presented in Figure 5.2.

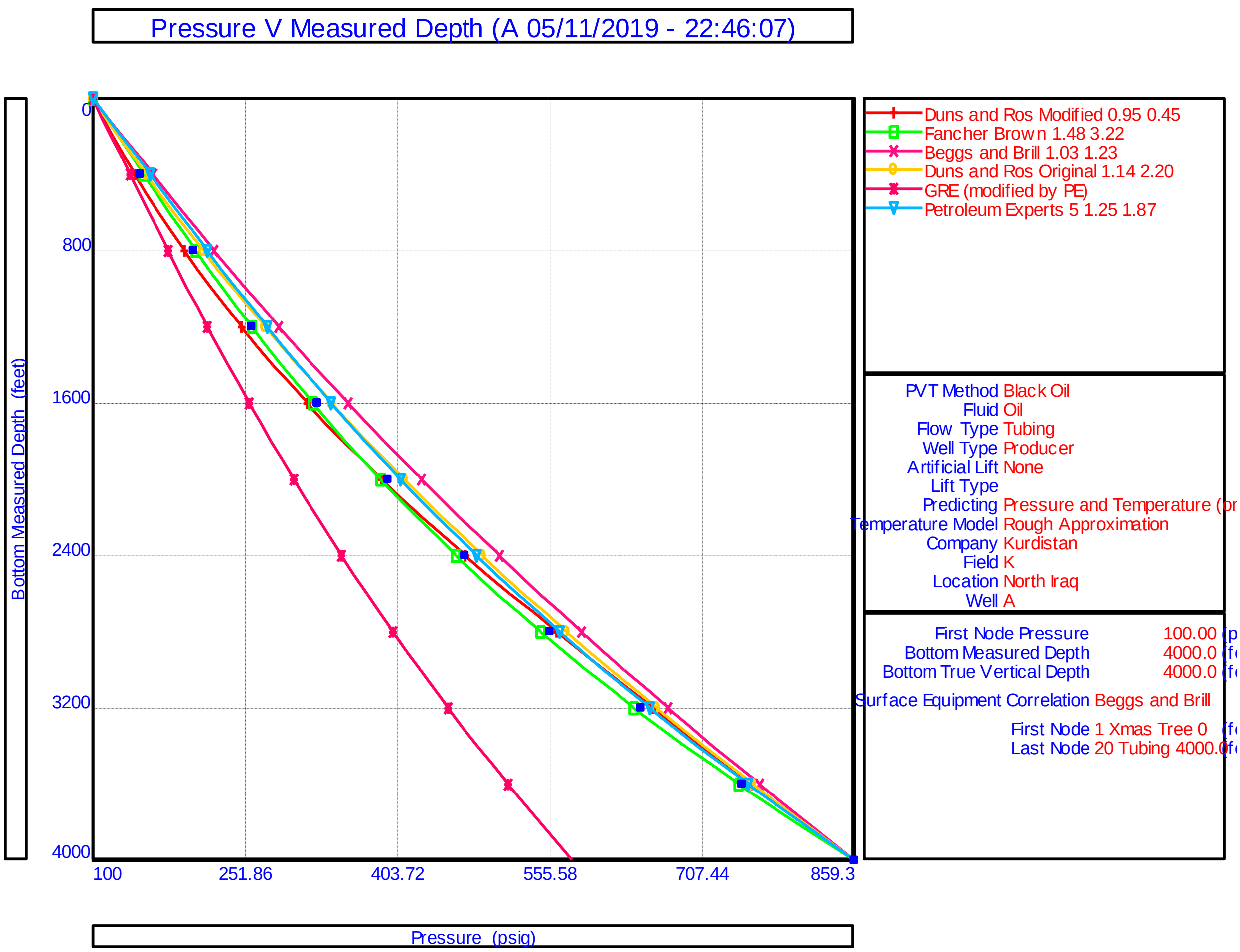


Figure 5.2: Tubing correlation comparison using different correlation methods

Figure 5.2 shows some of the correlation methods which have been selected in order to find a correlation which matches the given data for well-A. Although, most of the used correlations were close to the matching points of the given data of well-A, Fancher Brown gives the lowest and highest pressure drops (no slip) and for the oil wells, Duns and Ros Modified gives highest pressure drop in the slug flow regime. Therefore, the best correlation for the given data was found to be Duns and Ros Modified which is presented in Figure 5.3.

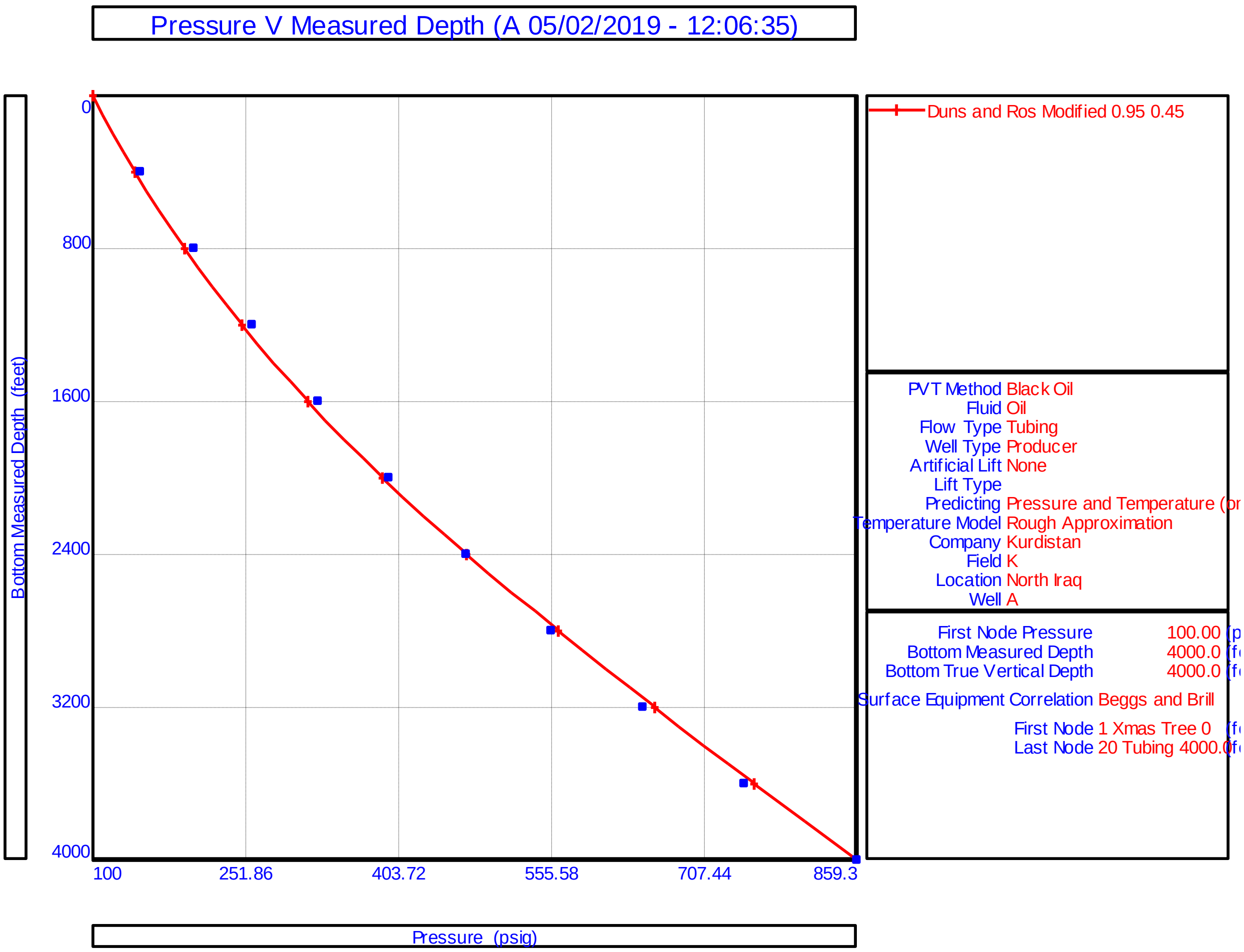


Figure 5.3: Tubing correlation comparison curve using Duns and Ros Modified

As it is shown in Figure 5.3, Duns and Rose Modified has been chosen as the best correlation method that matches all the points for tubing correlation comparison with regards to the given data for this case study, this correlation has also shown the most accurate results in predicting the pressure drops (Table 5.24) for the available data of well-A compared to the other correlations such as GRE (modified by PE) which was very far from the matching points.

Table 5.23 shows the results for Duns Ros Modified correlation, from the results it has been noticed that the detected flow regime throughout the tubing from the bottom hole up to the wellhead was slug, it also shows when the fluid inside the well is moving up, the liquid density as well as the liquid viscosity are increasing while the pressure loss per foot is decreasing.

Table 5.23: Tubing correlation comparison for Duns and Ros Modified – gradient traverse calculations results

True Vertical Depth	**Pressure**	**Temperature**	**Liquid Density**	**Liquid Viscosity**	**Gradient**	**Holdup**	**Regime**
feet	psig	deg F	Ib/ft^3	centipoise	psi/ft	---	---
0	100	74.16	---	---	---	---	Wellhead
400	143.27	80.04	55.424	6.9009	0.11438	0.28413	Slug
800	193.52	85.86	55.216	5.0342	0.13263	0.33897	Slug
1200	251.55	91.59	54.989	3.8000	0.15275	0.39809	Slug
1600	318.01	97.17	54.740	2.9535	0.17425	0.46068	Slug
2000	393.19	102.54	54.471	2.3572	0.1963	0.52557	Slug
2400	477.47	107.58	54.181	1.9283	0.21949	0.5947	Slug
2800	569.61	112.13	53.876	1.6170	0.2341	0.63719	Slug
3200	665.36	115.92	53.569	1.3949	0.24256	0.6642	Slug
3600	764.49	118.58	53.270	1.2381	0.25097	0.69137	Slug
3999.8	859.26	120.00	52.995	1.1317	0.22075	0.71207	Slug

The major pressure loss producing liquid inside tubing is due to the gravity, and the other pressure losses throughout the tube has been shown in Table 5.24.

Table 5.24: Pressure drop summary for tubing correlation comparison

Correlation	Pressure	Total Pressure Loss	Friction Pressure Loss	Gravity Pressure Loss	Acceleration Pressure Loss
	psig	psi	psi	psi	psi
Duns and Ros Modified	859.25	759.26	20.91	737.06	1.29

Table 5.24 shows that the total pressure loss throughout the tubing that has been calculated by this correlation method was 759.26 psi which was exactly the same as the actual data for well-A, and 100 psi was remained at the wellhead. It further calculated that, 737.06 psi of the total loss was due to the gravity, and 20.91 psi was caused by friction and the rest of the pressure losses were due to acceleration which was 1.29 psi (Figure 5.4), the type of the flow regime which was calculated as slug for well-A was an important factor for the distribution in the pressure losses.

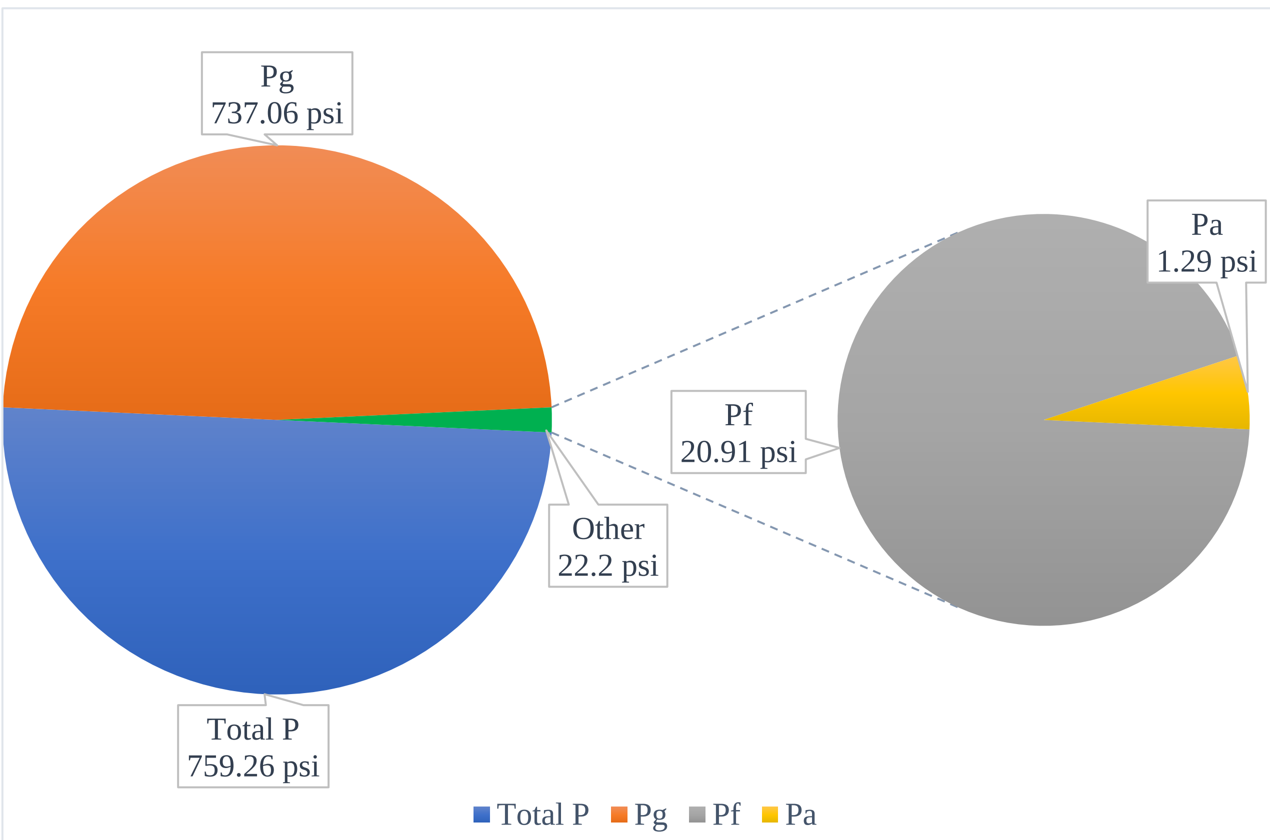


Figure 5.4: Pressure depletion distribution in the tubing

Table 5.25 shows the calculated corresponding value of the grain size, erosion velocity and liquid loading and pigging when gradient transversal measurements are carried out.

Table 5.25: Calculated input data for tubing correlation comparison

Grain Size	**Erosional Velocity**			**Liquid Loading**	**Pigging**
Density of Sand	Sand Production Rate	C-Factor	S-Factor	Turner Constant	Pigging Efficiency
g/cc	Ibm/day	---	---	---	friction
2.65	0	400	0.05	2.04	0.95

The system attempts to try to estimate the velocity at which erosion takes place, erosion may be generated by the repeated impact of solid particles on tubing and pipelines. This calculation is used to determine the minimum fluid velocity required to remove liquid droplets. The equation is used to determine the minimum velocity of the fluid needed to push liquid droplets away. All these have been shown in Table 5.25, which the calculations automatically have been done after running the calculation in tubing correlation comparison section (Petroleum Experts Ltd, 2010).

It is possible to visualize a plot of the critical transport velocities (velocity vs gravel size) that has been shown in Figure 5.5, which represents the minimum velocity that is required to lift grains of sand of a certain size for given produced fluid properties (density and viscosity) (Petroleum Experts Ltd, 2010).

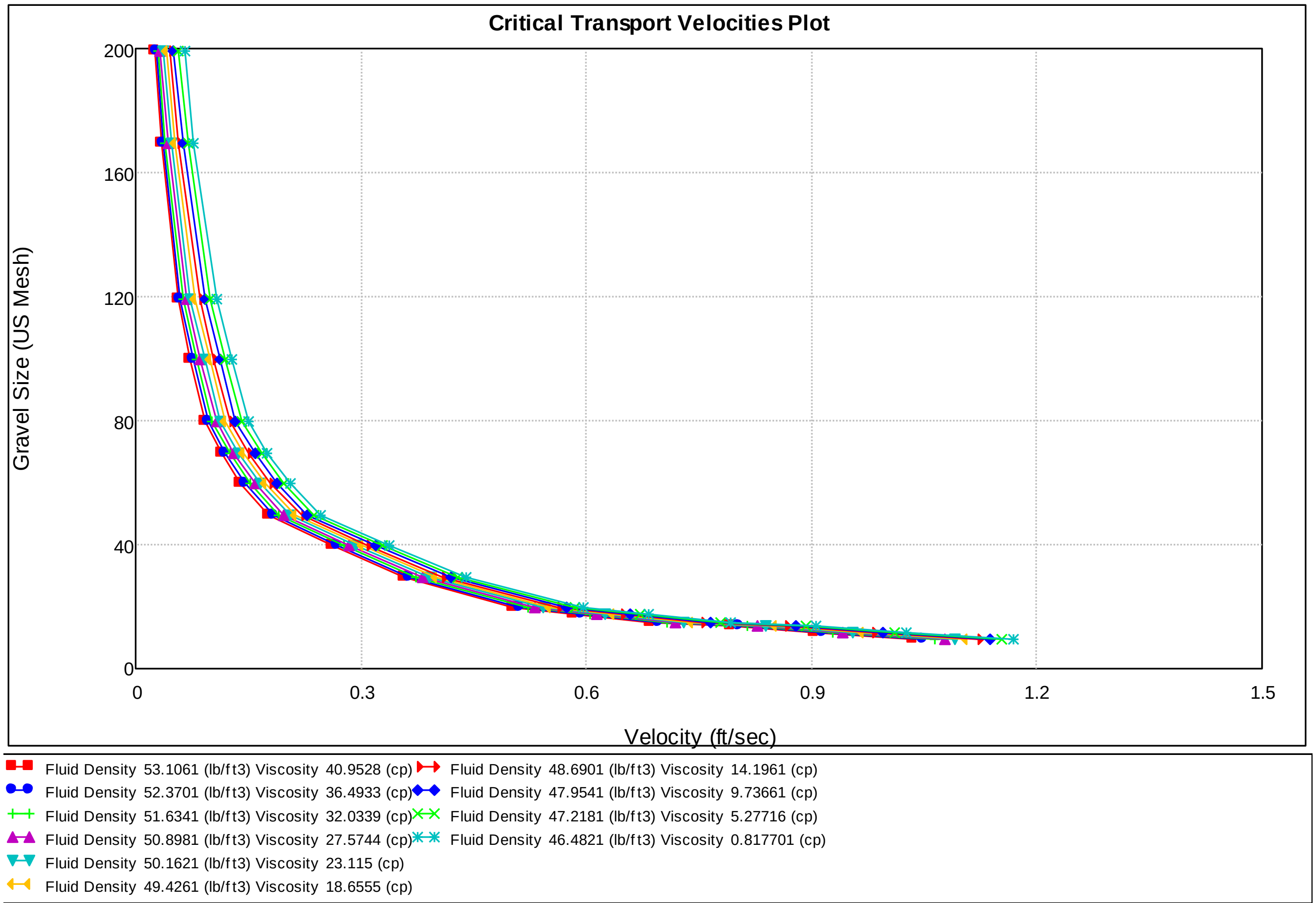


Figure 5.5: Critical transport velocities

5.6 VLP Generation

In this section, tubing lift curve has been generated. This option will calculate VLP responses, it also enables the user to perform sensitivity analysis with a wide range of variables. The input data that were used to construct VLP curve are presented in Table 5.26 and Table 5.27.

Table 5.26: Input data for VLP

Input Data	Amount	Unit
Wellhead Pressure	100	psig
Water Cut	30	percent
Total GOR	800	SCF/STB

Gauge 1 (Measured) Depth	0	feet
Gauge 2 (Measured) Depth	4000	Feet

Table 5.26 shows that the wellhead pressure has been inserted as 100 psig. This point has been chosen because it is the furthest point from the reservoir.

Table 5.27: Selected option for VLP

Type of Parameters	**Selected Option**
Surface Equipment Correlation	Biggs and Brill
Vertical Lift Correlation	Duns and Ros Modified
Rate Method	Automatic – Linear

As seen in Table 5.27, No surface equipment data has been provided. Therefore, Biggs and Brill correlation was set as a default method. In case of slug flow, Duns and Ros Modified overestimates the pressure drop. That means if the flow regime is slug, this correlation represents the maximum limit for the pressure gradient, thus, this correlation has been used to construct VLP curve as shown in Figure 5.6, and afterwards it has been compared to other correlations (Figure 5.7) to find out which of the correlations gives the best and most accurate matching point for VLP/IPR curve intersection. In order to find out which of the correlations is the most accurate one for the intersection point between IPR and VLP regarding the given data of well-A for matching VLP/IPR, required data for constructing VLP has been entered in Table 5.28.

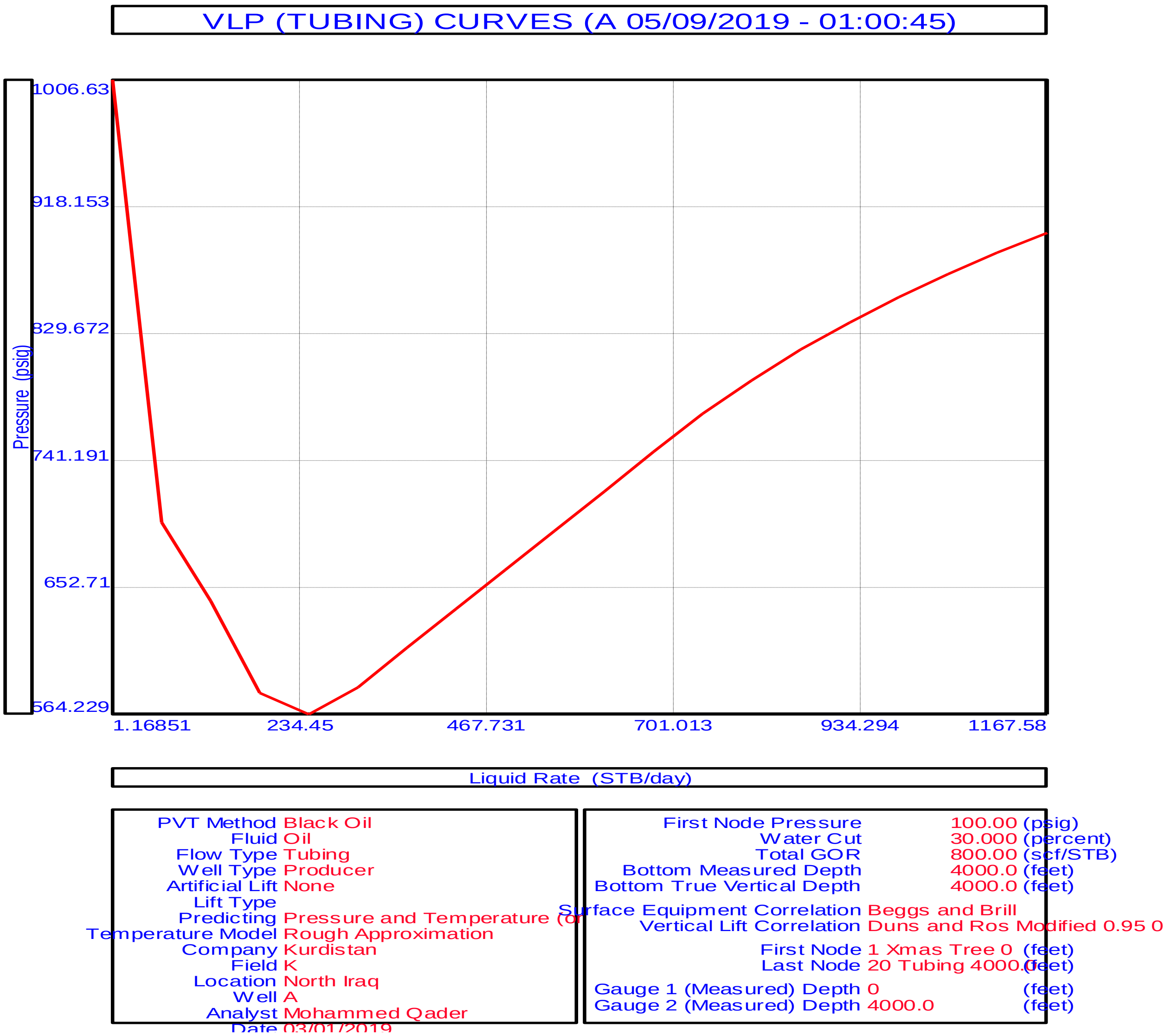


Figure 5.6: VLP curve plot using Duns and Ros Modified

Table 5.28: VLP vs. IPR – input match data

Input Data	Amount	Unit
Tubing Head Pressure	100	psig
Tubing Head Temperature	60	deg F
Water Cut	30	percent
Liquid Rate	1000	STB/day
Gauge Depth (Measured)	4000	feet

Gauge Pressure	859.3	psig
Reservoir Pressure	3000	psig
Gas Oil Ratio	800	SCF/STB
GOR Free	0	SCF/STB

Table 5.28 shows that the tubing head pressure and temperature has been inserted from the given data of well-A, and in rate type option, liquid rate was chosen, therefore, 1000 SCF/day has been entered as an amount of liquid rate, it is also possible to choose only oil rate without water but then in Table 5.28 the rate amount for oil should also be changed to 700 SCF/STB respectively as given in the data sheet for well-A, it also shows gas oil ratio was inserted as total GOR (solution + free GOR). Therefore, the GOR free has been entered as zero. Different VLP correlations were used for plotting VLP curve (Figure 5.7) to match the intersection point with the constructed IPR curve

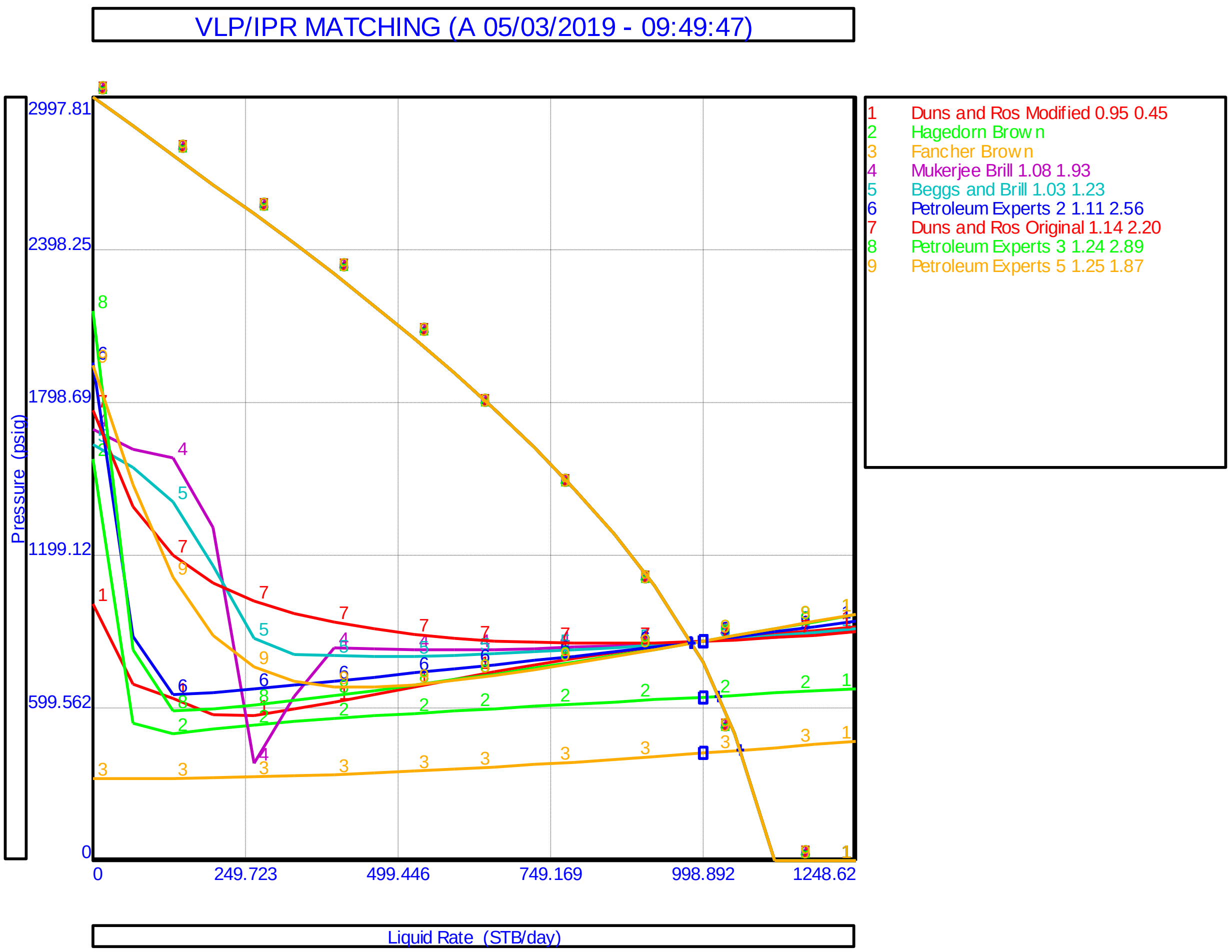


Figure 5.7: VLP vs. IPR matching using different correlation methods

Table 5.29 presents the standard deviations that have been found for each of the correlations which were used to construct VLP curve and to choose the VLP correlation that gives the closest intersection point with the lowest standard deviation regarding the given data of well-A.

Table 5.29: VLP stander deviation result for different correlations

Type of Correlations	Parameter 1	Parameter 2	Stander Deviation
Duns and Ros Modified	0.94585	0.4516	0.00036621
Hagedorn Brown	1.15935	3.96761	0.000061035
Francher Brown	1.48391	3.21666	0.000061035
Muskerjee Brill	1.07675	1.934363	0.00012207
Beggs and Brill	1.03394	1.22651	0.00012207
Petroleum Experts	1.13146	2.65056	0
Orkiszewski	1.45014	2.78832	0.00097656
Petroleum Experts 2	1.11433	2.56108	0.000061035
Duns and Ros Original	1.1353	2.19819	0.00024414
Petroleum Experts 3	1.23706	2.88632	0.00097656
Petroleum Experts 4	1.24213	1.81512	0.000061035
Petroleum Experts 5	1.2485	1.87111	0.00054932

Table 5.29 shows parameter 1 which is the multiplier for the gravity term in the correlation of the pressure drop, the parameter 2 for the gravity term in the correlation of the pressure drop, standard deviation as an indication of the goodness-of-fit for each modified correlation to the match data. The match parameters shall be displayed along with each matching correlation after the matching process is completed. Comparison of standard deviations and the magnitude of the corrections made to both parameters. Although some correlations such as: Muskerjee Brill, Beggs and Brill

and Petroleum Experts 5 are giving good results for constructing VLP curve, however, Duns and Ros Original which is specifically use for vertical well , and it has been chosen as the best correlation and most accurate correlation compared to the other correlations with regards to the given field data for well-A for constructing VLP curve. This correlation method gave a standard deviation of 0.00024414.

Thus, from the VLP correlations option which was shown in Table 5.27, Duns and Ros Original has been selected for constructing a new VLP curve as shown in Figure 5.8.

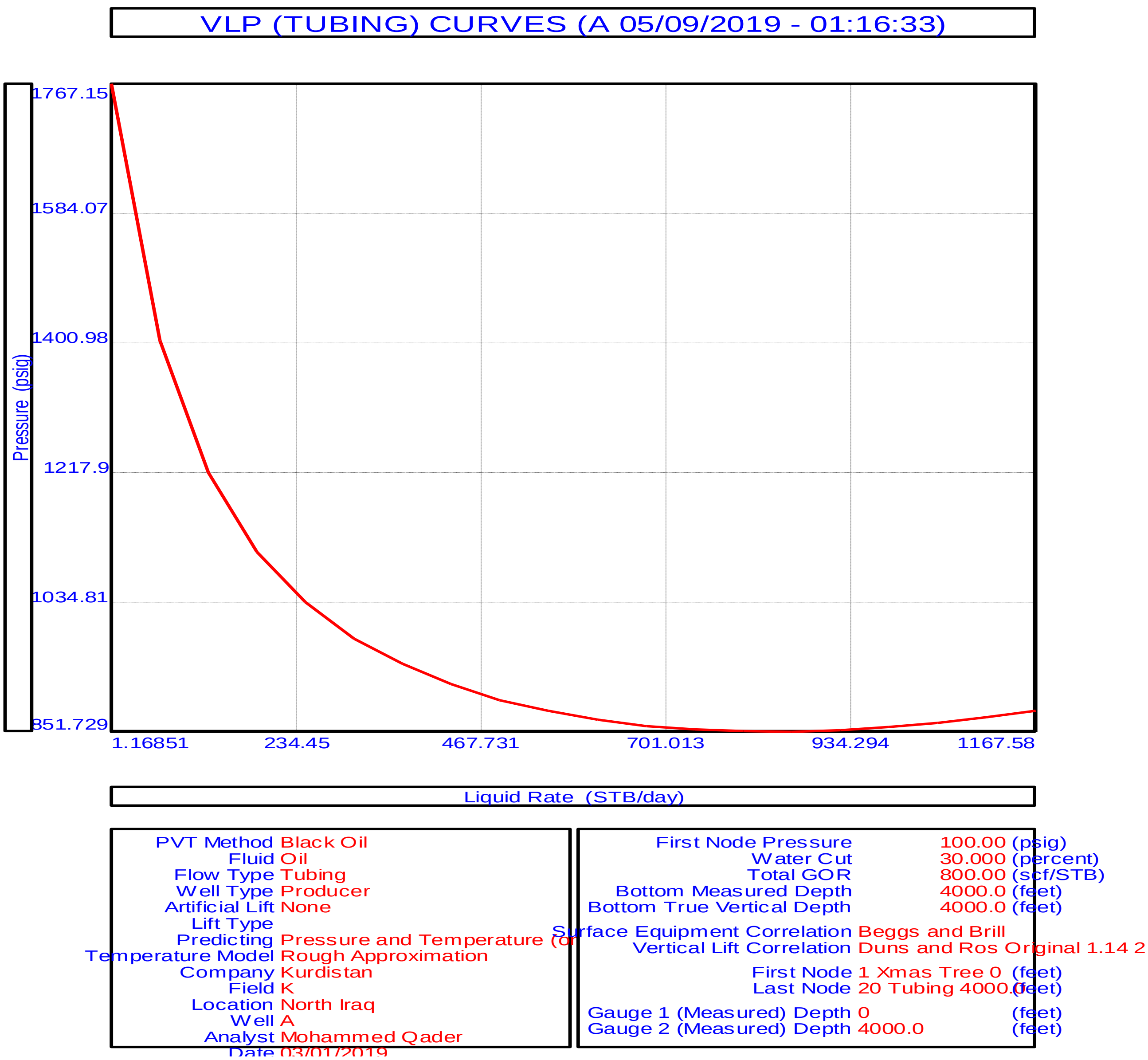


Figure 5.8: VLP curve for Duns and Ros Original

Figure 5.8 shows vertical lift performance curve using Duns and Ros Original which has been selected based on the standard deviation as the best correlation method for constructing VLP curve regarding the given data for well-A.

In the VLP/IPR matching section the construction of IPR curve using Vogel method versus the VLP curve using Duns and Ros Original have been presented in one plot as shown in Figure 5.9. Liquid rate and bottom hole pressure result for the intersected line and matched point regarding the data for well-A.

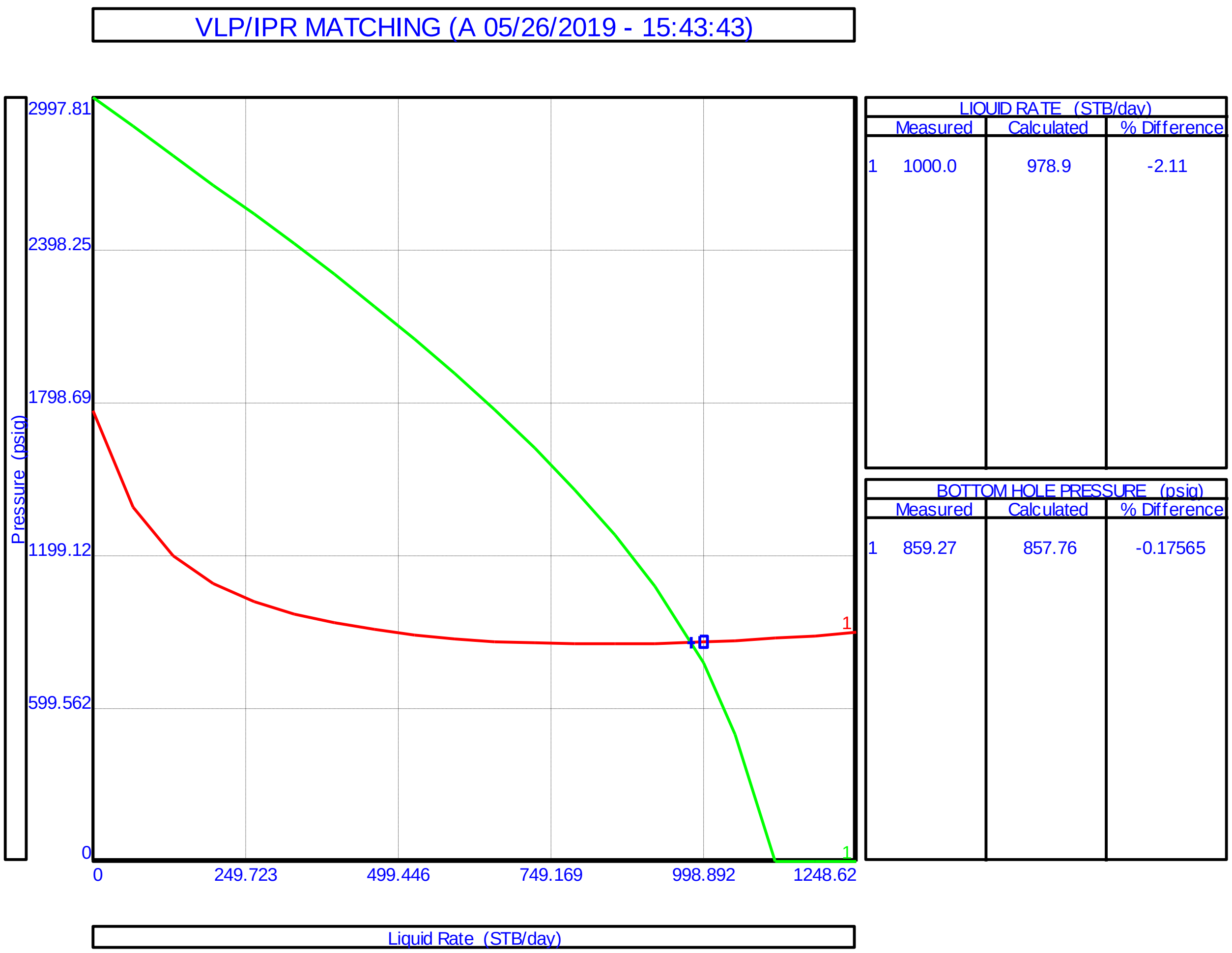


Figure 5.9: VLP vs. IPR intersection point

It is shown in Figure 5.9, the calculated result that has been obtained for the liquid rate was 978.9 STB/day which is very close to the measured data for well-A with 2.11 percentage differences, and the calculated result for bottom hole pressure was obtained to be 857.75 psig which is almost the same value with measured data for well-A with only 0.17565 of percentage differences between the two results, all results are presented in Table 5.30.

Table 5.30: VLP vs. IPR matched results

Results	Liquid Rate	Oil Rate	Bottom Hole Pressure
	STB/day	STB/day	psig
Measured	1000.0	700.0	859.26
Calculated	978.9	685.3	857.75
% Difference	-2.10514	-2.10513	-0.17565

Table 5.30 shows measured, calculated and percentage differences results for each liquid rate, oil rate and bottom hole pressure.

The intersection point has matched between both IPR and VLP curves with regards to the given data of well-A. In chapter 6, further analyses have been done based on the matched point.

CHAPTER 6

EFFECTS OF ANALYSES ON PRODUCTION PERFORMANCE

This chapter describes some possible analyses decisions that can be made with regards to the available data of well-A in order to optimize and improve production performance of the well regarding this case study.

6.1 Analyses Summary

In this section, some analyses have been done in order to see the effect of some variables on the well production performance.

The available analysis options are listed below:

- Inflow
- System Variables
- VLP
- Tubing Correlation Comparison
- Pipeline Correlation Comparison
- Gradient Matching
- VLP/IPR Matching
- Pipeline Matching

System variable has been used in order to analyze the effects of changing variables on well production performance.

System variable section will calculate the outflow of the tubes (VLP) and the intake of the tubes (IPR), determine the operating rate of the system and the flow pressure of the bottom hole (BHFP) and it also enables a wide range of variables to perform sensitive analysis. Plots of sensitive analyses can be generated easily. The general input data which were used to do the sensitive analyses have been presented in Table 6.1 and Table 6.2.

Table 6.1: Input data for system variable

Input Parameters	Amount	Unit
Wellhead Pressure	100	Psig
Water Cut	30	Percent
Total GOR	800	SCF/STB
Gauge 1 (Measured) Depth	0	Feet
Gauge 2 (Measured) Depth	4000	Feet

Wellhead pressure was given as 100 psig as shown in Table 6.1, this point has been chosen because it is the furthest point from the reservoir and no data for surface equipment have been inserted.

Table 6.2: Selected option for VLP vs. IPR curve

Type of Parameters	Selected Option
Surface Equipment Correlation	Biggs and Brill
Vertical Lift Correlation	Duns and Ros Original
Solution Node	Bottom Node
Rate Method	Automatic – Linear
Left-Hand Intersection	DisAllow

As shown in Table 6.2, Biggs and Brill correlation has been used as a default method. However, it is a good correlation for pipeline, no surface equipment data has been provided. Duns and Ros Original, in case of slug flow, overestimates the pressure drop. Which means, if the flow regime is slug, this correlation represents the maximum limit for the pressure gradient. Hence, this correlation has been used to construct VLP.

In changing system variable, the analyses are based on the matched point for VLP versus IPR intersection for the available data of well-A, where the solution node has been putted at the bottom hole. Three or four variables can be entered simultaneously depending on which calculation option the user have chosen. Each variable maintains its own list of values. Sensitivity variable values can be entered in any order. The calculations option analyzing the effect of changing variables on well performance will be done in such a way that the VLP or IPR will only be recalculated if parameters affecting them are updated. Effect of some of the variables on the production performance regarding this case study for well-A are shown in proceeding sections.

6.2 Effect of Changing Water Cut

The water cut have effects on production performance. Therefore, different water cut percentages were given (Table 6.3) in order to know how the change in water cut affects the flow and performance of the well.

Table 6.3: Input data for water cut variable

Type of Variable	Unit	First Amount	Second Amount	Third Amount
Water Cut	Percent	30	50	70

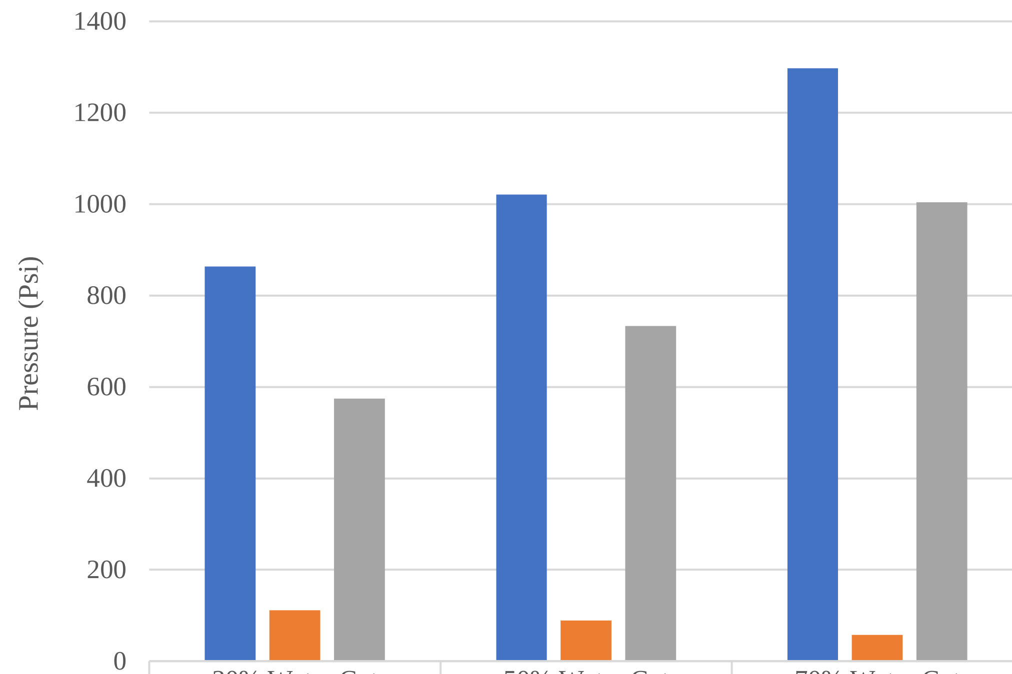
Table 6.3 shows three different amounts of water cut in which 30% is the original water cut for well-A, where 50% and 70% were also entered, different responses and results for each percentage of water cut have been obtained (Table 6.4).

Table 6.4: Results of system sensitive analysis for different water cut

Type of Parameter	30% Water Cut	50% Water Cut	70% Water Cut	Unit
Liquid Rate	1040.6	1028.0	958.5	STB/day
Oil Rate	728.5	514.0	287.6	STB/day
Water Rate	312.2	514.0	671.0	STB/day
Gas Rate	0.58276	0.41121	0.23004	MMscf/day

Table 6.4 shows that, when the water cut percentage increased from 30% to 50%, the production of oil rate was reduced to 514.0 STB/day and the gas rate reduced to 0.41121 MMscf/day while the water rate increased to 514.0 STB/day and the cause of this is obvious, because more water entered into the reservoir, therefore, the production of water was increased. When the water cut

percentage increases to 70%, the oil rate and gas rate were further reduced to 287.6 STB/day and 0.23004 MMscf/day respectively while the water rate increased to 671.0 STB/day. For 30, 50, and 70 percentages of water cut, different results for pressure losses were observed while the fluid was being produced at the surface (Figure 6.1).



	30% Water Cut	50% Water Cut	70% Water Cut
Solution Node Pressure	863.57	1020.98	1297.62
Friction Pressure Depletion	111.2	88.65	57.46
Gravity Pressure Depletion	574.62	733.14	1004.28

Figure 6.1: Pressure depletion distribution for different water cut percentages

As seen in Figure 6.1, when the water cut increases from 30% to 50%, the pressure loss due to friction reduces to 88.65 psi, pressure loss which is caused by gravity increased to 733.14 psi, and the solution pressure also increased to 1020.98 psig. When the water cut increases to 70%, the pressure loss due to friction was further reduced to 57.46 psi, in the other hand, pressure loss which is caused by gravity increased to 1004.28 psi, and the solution pressure also increased to 1297.62 psig. This is an indication that, because water is heavier than oil and gas, as water cut percentage increases, more pressure will be required to produce the fluid to the surface.

Figure 6.2 shows the percentage increment of water cut from 30% to 50% and to 70%. Different reflections were found for VLP and IPR curves, which indicates that, changes in water cut percentage has affected both reservoir and well performance.

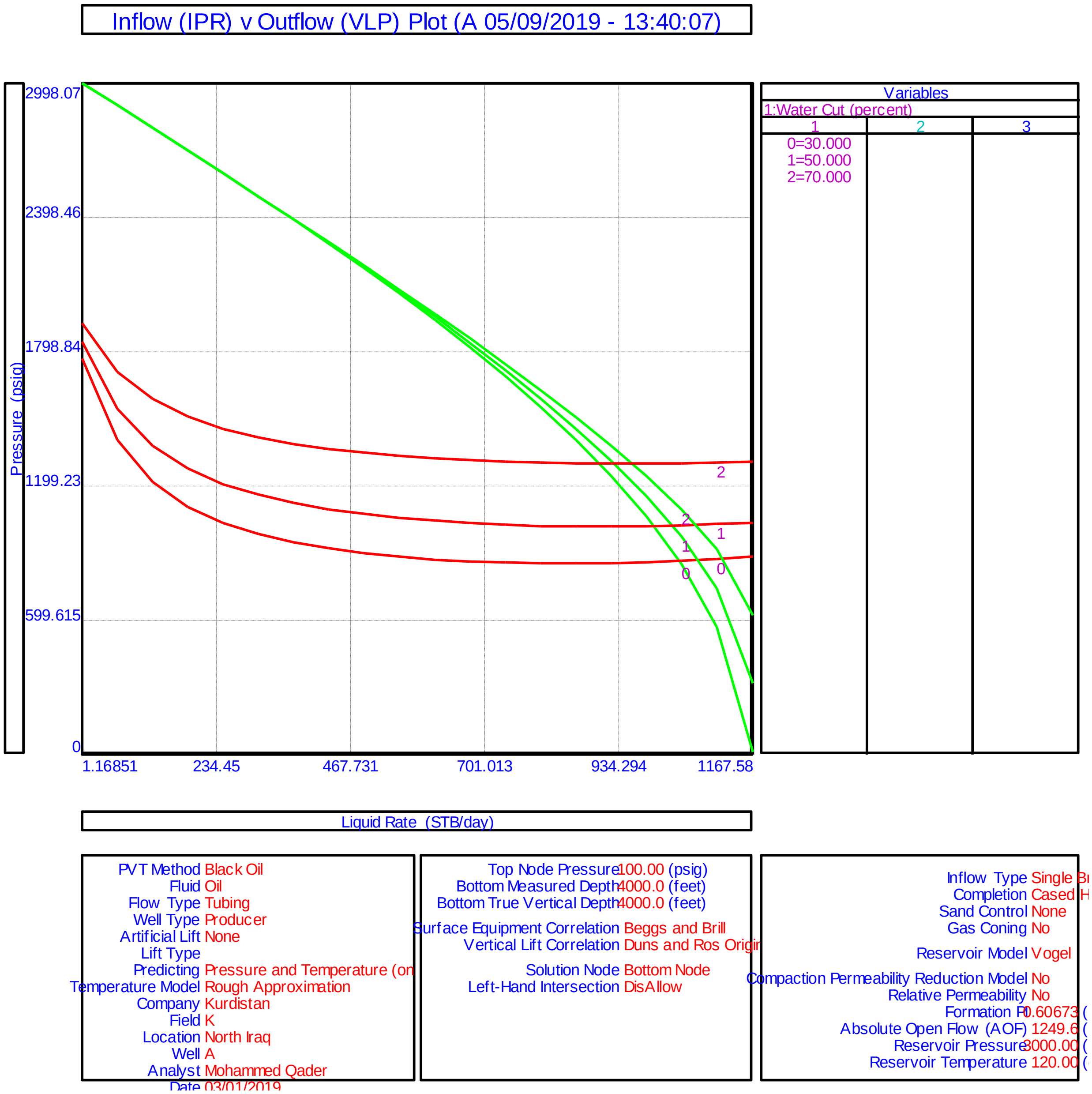


Figure 6.2: Effect of changing water cut on inflow (IPR) vs. outflow (VLP) curves

As seen in Figure 6.2, when the water cut percentage increases, IPR curve of the liquid will be declined and VLP curve will be declined as well because the density of water is more than the density of oil. Thus, when the water cut percentage increases, the oil rate decreases and the hydrostatic pressure will overcome the pressure that is caused by oil which causes a decrease in oil production.

6.3 Effect of Changing GOR

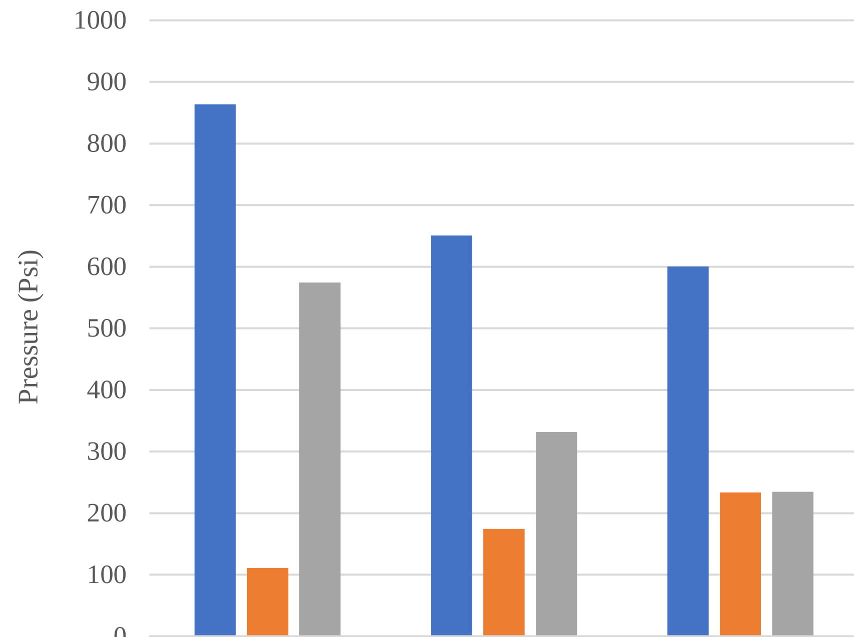
Gas oil ratio (GOR) includes solution and free gas from the reservoir (gas cap). In this section, it has been shown that the change in GOR has effect on production performance. For this reason, two different other GOR have been assumed (Table 6.5), which are based on the actual given amount of GOR for well-A which is 800 scf/STB.

Table 6.5: Results of system sensitive analysis for different GOR

Type of Parameter	**GOR 800 (scf/STB)**	**GOR 1600 (scf/STB)**	**GOR 2600 (scf/STB)**	**Unit**
Liquid Rate	1040.6	1064.0	1072.1	STB/day
Oil Rate	728.5	744.8	750.5	STB/day
Water Rate	312.2	319.2	321.6	STB/day
Gas Rate	0.58276	1.192	1.951	MMscf/day

It has been shown in Table 6.5 that, gas oil ratio (GOR) has increased from its original amount which was 800 scf/ST. When the GOR rate is increased to 1600 scf/STB, the amount of produced liquid and gas have increased to 1064.0 STB/day and 1.192 MMscf/day respectively. When the GOR rate increased to 2600 scf/STB, both liquid and gas rate have further increased to 1072.1 STB/day 1.951 MMscf/day respectively.

Figure 6.3 shows the pressure depletion distribution inside the well as the GOR rate increases from 800 to 1600 and to 2600 scf/STB.



	800 (scf/STB) GOR	1600 (scf/STB) GOR	2600 (scf/STB) GOR
Solution Node Pressure	863.57	650.93	600.18
Friction Pressure Depletion	111.2	174.31	233.62
Gravity Pressure Depletion	574.62	331.73	234.79

Figure 6.3: Pressure depletion distribution for different GOR

It is seen in Figure 6.3, as GOR was increased from 800 scf/STB to 1600 scf/STB, friction pressure depletion has been increased to 174.31 psi, while both solution node pressure and gravity pressure depletion decreased to 650.93 psig and 331.73 psi respectively, which is an indication that lesser pressure will be needed to move and produce the fluid to the surface with compared to the original GOR of well-A. When the GOR rate increased to 2600 scf/STB, friction pressure depletion has been further increased to 233.62 psi, while both solution node pressure and gravity pressure depletion decreased to 600.18 psig and 234.79 psi respectively, which means that, in fact lesser pressure will be needed for producing the fluid due to the small amount of pressure losses that was caused by gravity. Therefore, based on the results, increasing in the GOR has improved the production rate and the well performance.

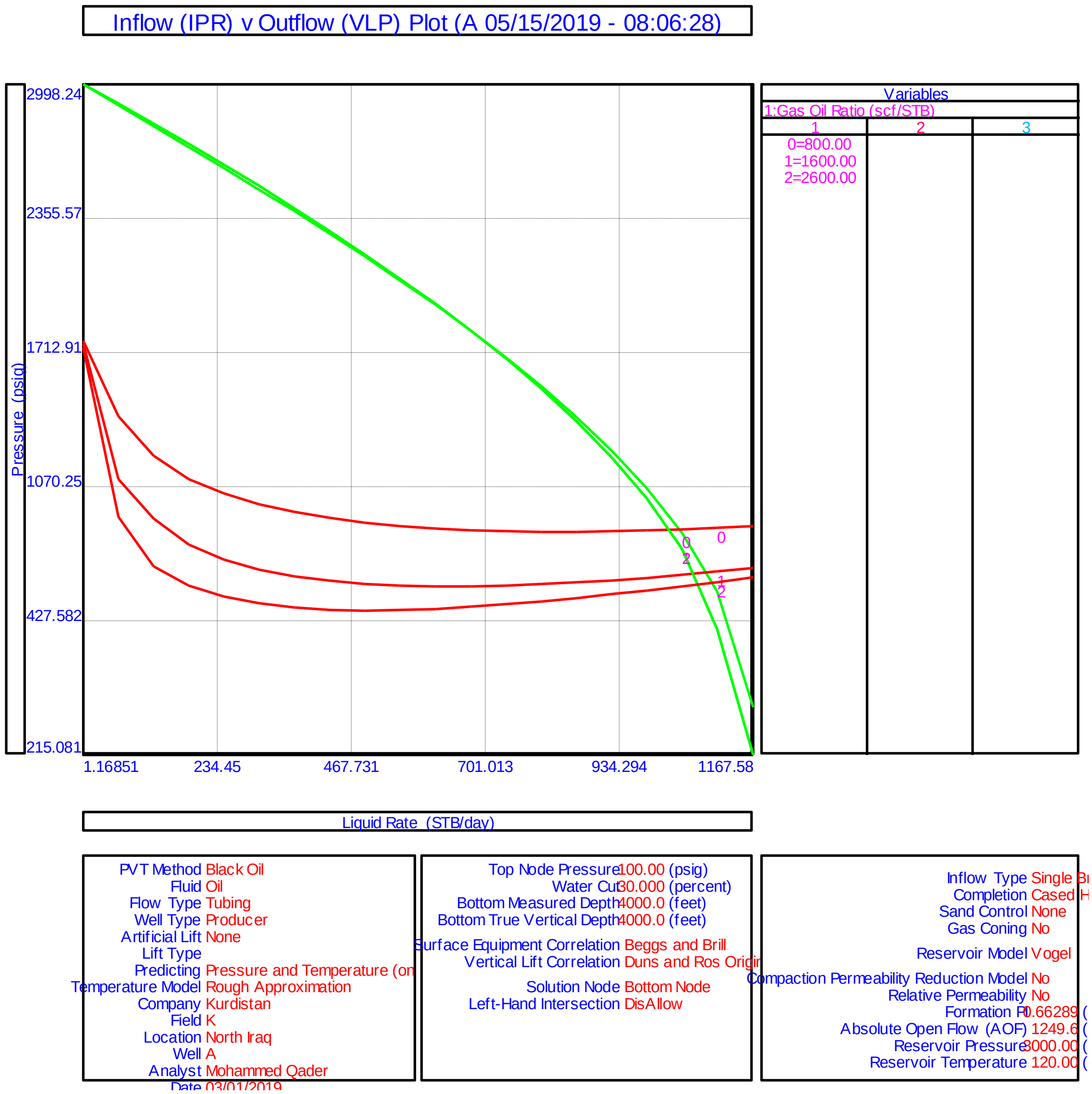


Figure 6.4: Effect of changing GOR on inflow (IPR) vs. outflow (VLP) curves

As shown in Figure 6.4, changing the GOR rate has effect on both inflow performance relationship (IPR) in the reservoir as well as vertical lift performance (VLP) inside the tubing, it shows that when the GOR increases from 800 scf/STB to 1600 scf/STB, the liquid production rate increased and the solution node pressure decreased, and when the GOR has further increased to 2600 scf/STB, with compared to the other GOR, the liquid production rate increased more and the solution node pressure decreased more; it is an indication that when the GOR increases, lesser pressure will be needed for producing the fluid to the surface. Therefore, increasing the GOR could lead to a better well performance, however, by applying this technique alone, well-A might not obtain a very significant result to achieve optimization.

In Tetoros (2015), a gas lift design was done in order to increase the production performance and to achive obtimization. However, in this case study for well-A, setting a gas lift design for the well might not give a significunt results because it was found that when the GOR rate increased to more than 2600 scf/STB, the production performance of the well started to decline. Hence, by applying gas lift method, well-A might not give significant results for achieving the optimization of the well.

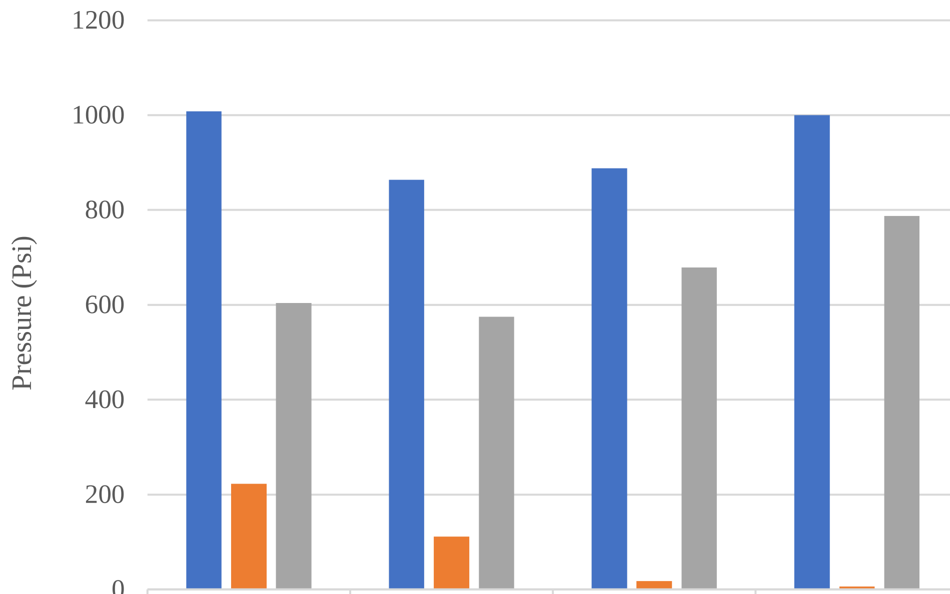
6.4 Effect of Changing Tubing Size

This option is useful for calculating the effect of increasing and decreasing size of the tubing on the well production performance. In order to change tubing size, in diameter variable range selection, the first and last tubing points were selected and the calculations have been performed, the results displayed for three other different tubing size which are shown in Table 6.6.

Table 6.6: Results of system sensitive analysis for different tubing diameter

Type of Parameter	**Tubing Inside Diameter 2.06 (inches)**	**Tubing Inside Diameter 2.44 (inches)**	**Tubing Inside Diameter 3.50 (inches)**	**Tubing Inside Diameter 4.25 (inches)**	**Unit**
Liquid Rate	998.7	1040.6	1033.5	1001.2	STB/day
Oil Rate	699.1	728.5	723.5	700.8	STB/day
Water Rate	299.6	312.2	310.1	300.4	STB/day
Gas Rate	0.55926	0.58276	0.57876	0.56065	MMscf/day

Table 6.6 shows that, when the tubing size has been changed to 2.0625, 3.5, and to 4.25 inches, the well performance was not improved rather it led the situation to be in a worse scenario, and with compared to actual tubing size which is 2.441 inches, the other tubing sizes gave lesser fluid production and a higher pressure will be needed for producing the fluid to the surface due to pressure losses, the pressure losses were mainly caused by gravity which creates a force against the fluid from flowing inside the tubing to the surface (Figure 6.5).



	2.06 (in) Tubing ID	2.441 (in) Tubing ID	3.50 (in) Tubing ID	4.25 (in) Tubing ID
Solution Node Pressure	1008.47	863.57	888.21	999.86
Friction Pressure Depletion	222.66	111.2	17.89	6.02
Gravity Pressure Depletion	604.08	574.62	678.52	787.31

Figure 6.5: Pressure depletion distribution for different tubing diameter

As seen in Figure 6.5, in both cases of increased and decreased tubing dimeter from the original given size which was 2.442 inches, as the tubing dimeter increases, the pressure depletion that was caused by the friction will be reduced because there will be less contact between the fluid and the tubing wall. The figure also illustrates that when the tubing size was changed, the pressure at the solution node to the surface has increased and also the pressure depletion due to the gravity increased, which means in the other scenarios, the well will have lesser performance with compared to the original tubing size and more pressure will be needed to produce the fluid to the surface.

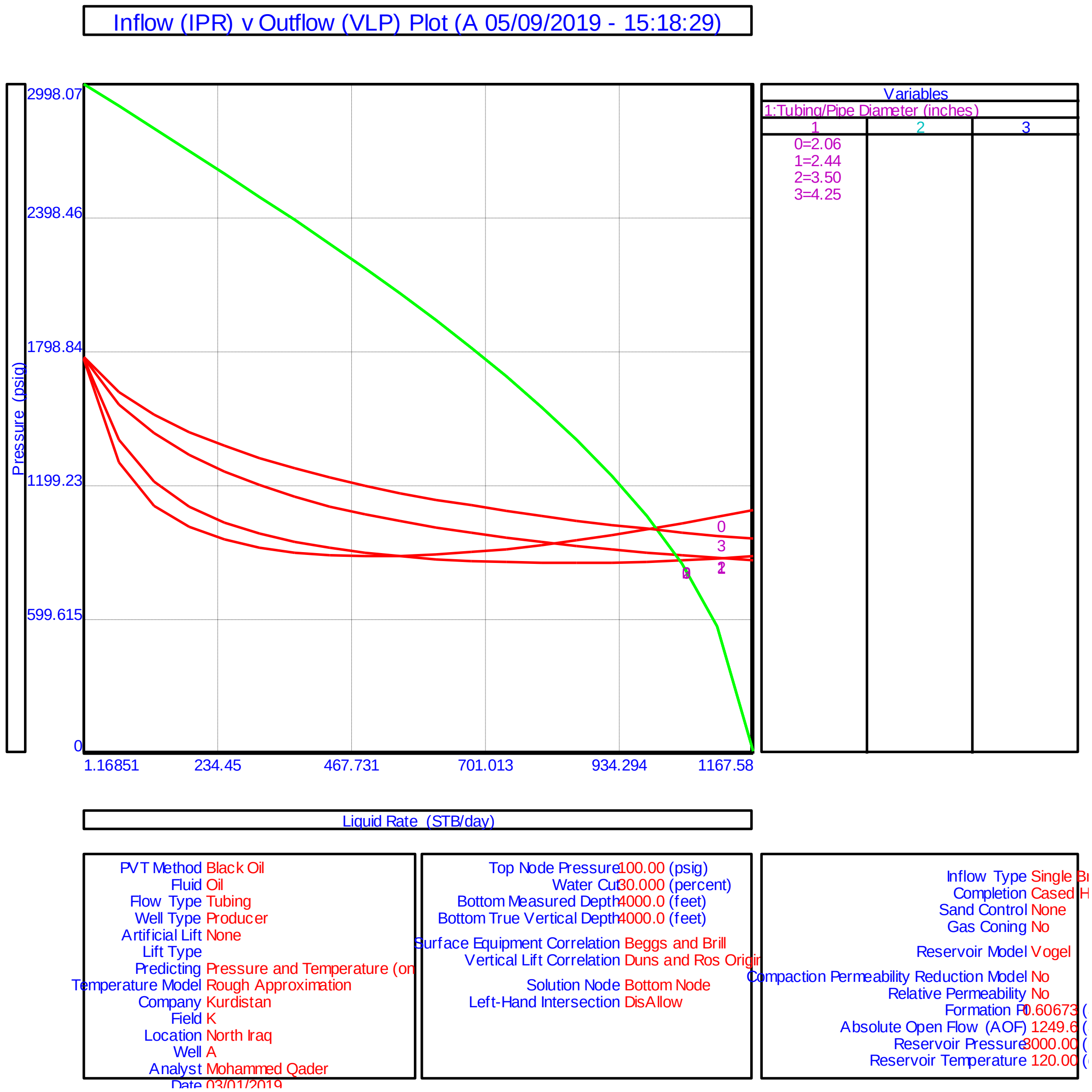


Figure 6.6: Effect of changing tubing diameter on inflow (IPR) vs. outflow (VLP) curves

As seen in Figure 6.6, actual tubing size that represents line number 1 on the plot, gives the best performance comparing to the other tubing sizes. Even the production rate using the actual tubing size is more. Threfore, according to the obtained results, changing the tubing size from the actual size which is 2.441 inches to the other sizes might not give a better performance rather it may give a low well production performance with regards to the provided data of well-A.

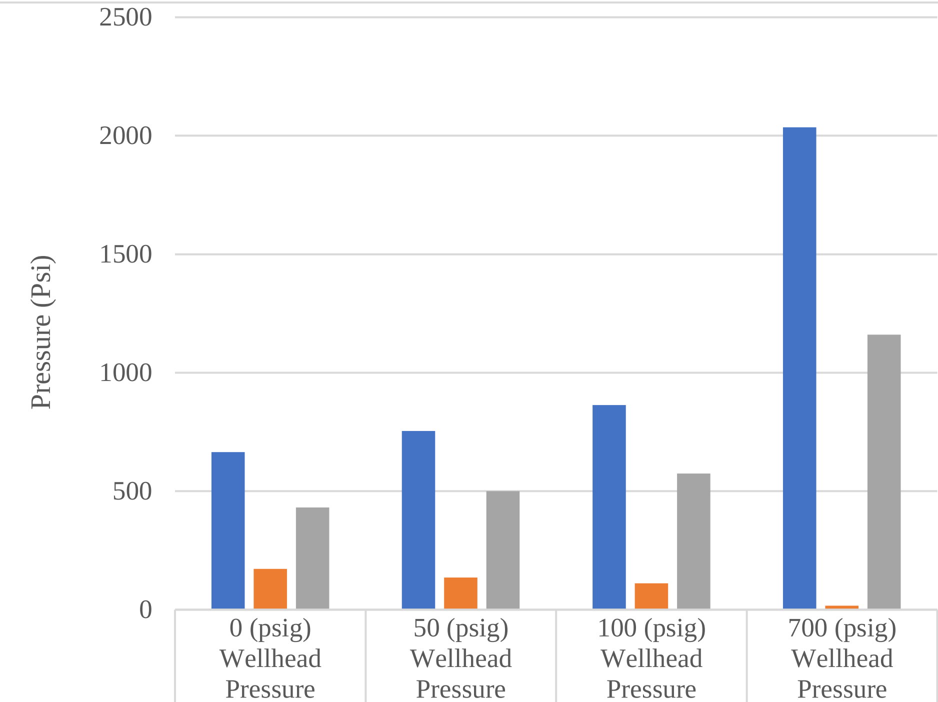
6.5 Effect of Changing Wellhead Pressure

Wellhead pressure for well-A has been chosen as the furthest pressure node point from the reservoir. In this section, it will be shown how increasing and decreasing the wellhead pressure will affect the well performance, for this reason, the pressure at the wellhead was changed, and it has been given more and less values than the actual value which is 100 psig, the results are shown in Table 6.7.

Table 6.7: Results of system sensitive analysis for changing of wellhead pressure

Type of Parameter	**Wellhead Pressure 0 (psig)**	**Wellhead Pressure 50 (psig)**	**Wellhead Pressure 100 (psig)**	**Wellhead Pressure 700 (psig)**	**Unit**
Liquid Rate	1085.0	1065.5	1040.6	565.2	STB/day
Oil Rate	759.5	745.8	728.5	395.6	STB/day
Water Rate	325.5	319.6	312.2	169.6	STB/day
Gas Rate	0.6076	0.59668	0.58276	0.31651	MMscf/day

As shown in Table 6.7, changing in the wellhead pressure affected the well performance. When the wellhead pressure has been decreased to 50 psig, which means that the distance between the wellhead and the separator tower has been reduced, then the liquid rate increased to 1065.5 STB/day, and the amount of produced gas rate also increased to 0.59668 MMscf/day. Furthermore, when the wellhead pressure has decreased more to 0 psig, which means that the separator tower was putted at the wellhead, the liquid rate increased more and become 1085.0 STB/day, and the amount of produced gas rate also increased to 0.6076 MMscf/day. In the other hand, when the wellhead pressure was increased to 700 psig, which means that the distance between the wellhead and the separator tower will become more, in this case, the well will not show a better performance from its actual given value, rather the production rate of liquid will be decreased to 565.2 STB/day, and the amount of produced gas rate also decreased to 0.31651 MMscf/day. Thus, based on the results, decreasing wellhead pressure will lead to the improvement of the well performance, However, by applying this technique alone, well-A might not give a very significant result for achieving optimization with regards to the provided data. When the wellhead pressure has changed, different results for the pressure depletion inside the tubing were observed (Figure 6.7).



	0 (psig) Wellhead Pressure	50 (psig) Wellhead Pressure	100 (psig) Wellhead Pressure	700 (psig) Wellhead Pressure
Solution Node Pressure	664.58	754.16	863.57	2035.92
Friction Pressure Depletion	171.78	136.27	111.2	17.56
Gravity Pressure Depletion	431.73	500.21	574.62	1161.24

Figure 6.7: Pressure depletion distribution for different wellhead pressure

Figure 6.7 shows different amounts of wellhead pressures, it has been seen that when the wellhead pressure was reduced from the original amount which was 100 psig to 50 psig, the friction pressure depletion increased to 136.27 psi, while both the solution node pressure and the gravity pressure depletion reduced to 754.16 psig and 500.21 psi respectively, which is an indication that, lesser pressure will be needed for producing the fluid to the surface. Furthermore, when the wellhead pressure further reduced to 0 psig, friction pressure depletion increased more and become 171.78 psi, both solution node pressure and gravity pressure depletion reduced to 664.58 psig and 431.73 psi respectively, which means that even a lesser pressure will be needed for producing the fluid to the surface with compared to the other wellhead pressures. But when the when the wellhead pressure has increased to 700 psig, the friction pressure depletion decreased to 17.56 psi, while both solution node pressure and gravity pressure depletion increased to 2035.92 psig and 1161.24 psi respectively, that is to say, a very high pressure will be required for moving and producing the fluid to the surface, and this pressure drops were mostly caused by gravity. Hence, the best result was obtained when the separator design was set at the wellhead.

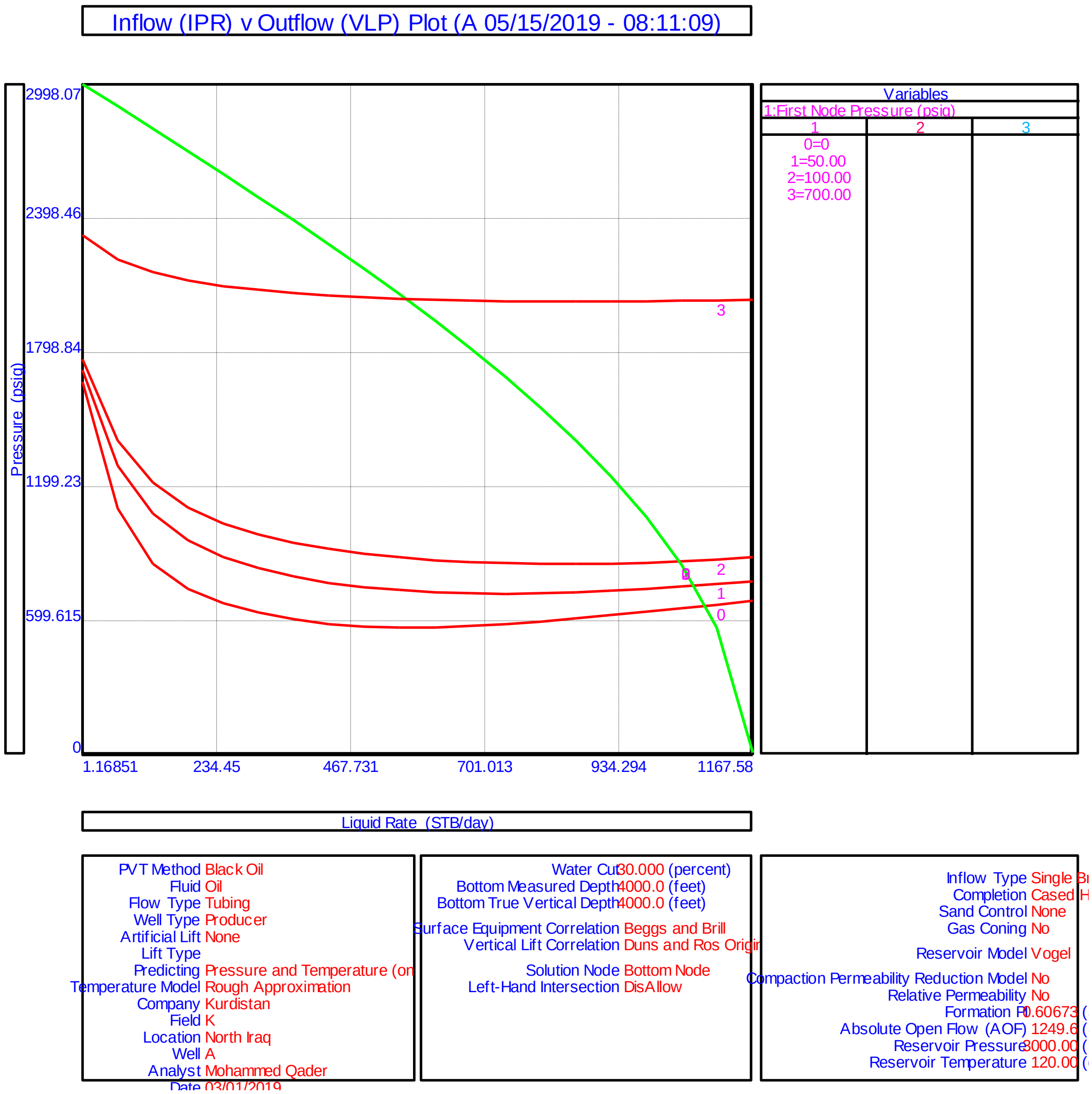


Figure 6.8: Effect of changing wellhead pressure on inflow (IPR) vs. outflow (VLP) curves

As it is seen in Figure 6.8, when the wellhead pressure was reduced from its actual amount which is 100 psig to 50 psig then to 0 psig, the VLP curves have shown better performances and more fluid has been produced compared to the actual wellhead pressure. On the other hand, when the pressure at the wellhead was increased from 100 psi to 700 psig, the VLP curve has given a lesser performance compared to the actual wellhead pressure.

6.6 Effect of Changing Reservoir Pressure

Normally it takes a long time before the pressure of reservoir starts to deplete, however, it has been assumed that when the reservoir pressure decreases to a certain pressure, what effect it will have on the production performance. Therefore, three different reservoir pressures beside the actual reservoir pressure which is 3000 psig have been given, and the results are presented in Table 6.8.

Table 6.8: Results of system sensitive analysis for different reservoir pressure

Type of Parameter	Reservoir Pressure 3000 (psig)	Reservoir Pressure 2000 (psig)	Reservoir Pressure 1500 (psig)	Reservoir Pressure 1000 (psig)	Unit
Liquid Rate	1040.6	536.5	256.0	---	STB/day
Oil Rate	728.5	375.6	179.2	---	STB/day
Water Rate	312.2	161.0	76.8	---	STB/day
Gas Rate	0.58276	0.30045	0.14334	---	MMscf/day

As shown in Table 6.8, when the pressure of the reservoir has been decreased from 3000 psig to 2000 psig which is the pressure at the bubble point in well-A, the liquid and gas showed an enormous reduction in their rates; the amount of liquid production decreased to 536.5 STB/day, and the amount of produced gas rate also decreased to 0.30045 MMscf/day. The friction pressure depletion decreased to 33.56 psi, whereas both solution node pressure and gravity pressure depletion increased to 885.25 psig and 662.10 psi respectively, that is to say that more pressure will be needed for producing the fluid to the surface due to the pressure drops which is mainly caused by gravity. When the pressure of reservoir has depleted more and decreased down to 1500 psig which is the pressure below the bubble point in well-A, liquid and gas showed an drastic reduction in their rates, the amount of liquid production will highly be reduced to become 256.0 STB/day, and the amount of produced gas rate will also be decreased to 0.14334 MMscf/day. The friction pressure depletion decreased to 8.98 psi, while both solution node pressure and gravity pressure depletion increased to 1026.60 psig and 808.26 psi respectively, which means that, the production will be difficult because a high pressure will be needed for producing the fluid to the surface due to the pressure drops which is mostly caused by gravity. It also shows that, when the well reaches to a scenario where the reservoir pressure is depleted to 1000 psig, there will be no intersection point between IPR curve versus VLP curve. Thus, there will be no flow inside the well, and as such there was no fluid production for well-A. The pressure losses due to the depletion in the reservoir is shown in Figure 6.9 and the IPR and VLP curves in all reservoir pressure depletion scenarios have been plotted in Figure 6.10.

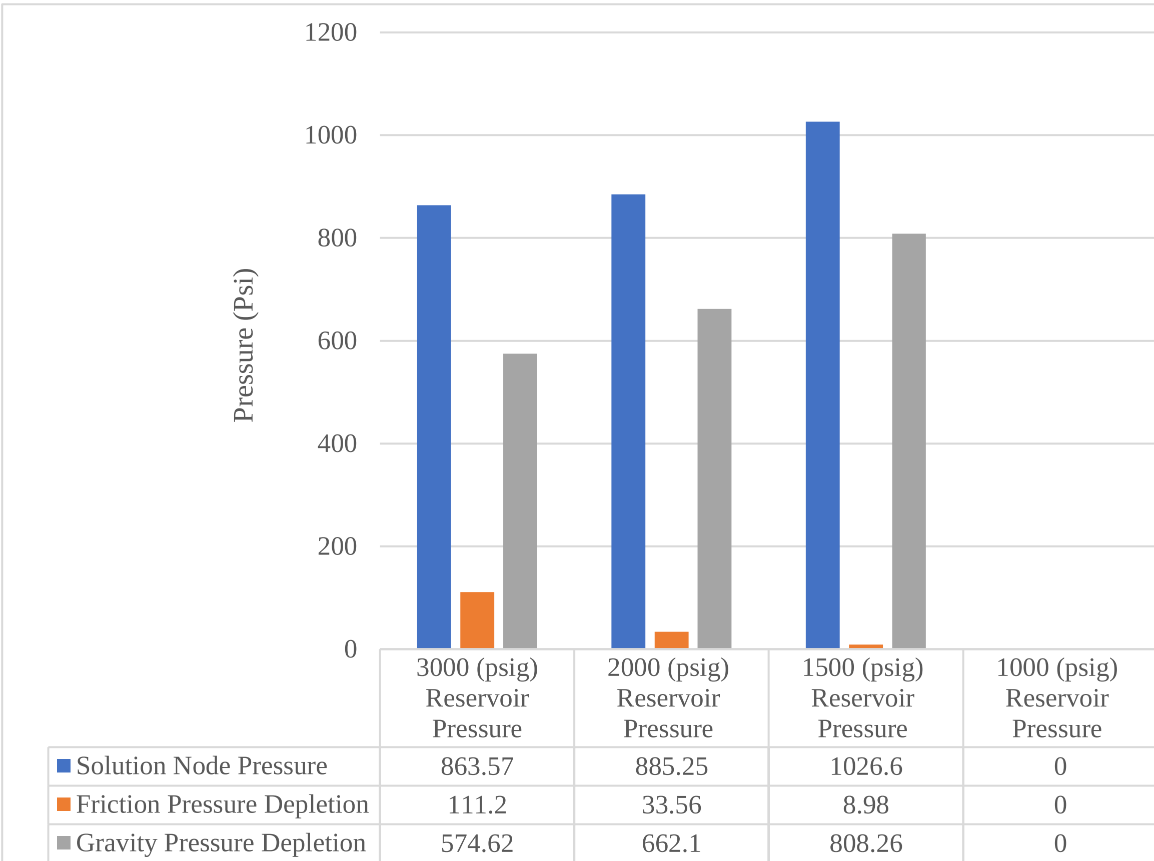


Figure 6.9: Pressure depletion distribution for different reservoir pressure

It is seen in Figure 6.9, as the reservoir pressure starts to deplete from 3000 psig, the pressure loss at the solution node has increased as well as the pressure loss due to gravity, while the pressure depletion which is cause by friction was reduced. When the well comes to the scenario where the reservoir pressure will be depleted to 1000 psi, in that situation there will be no flow because there will be no intersection point between VLP and IPR curve (Figure 6.10).

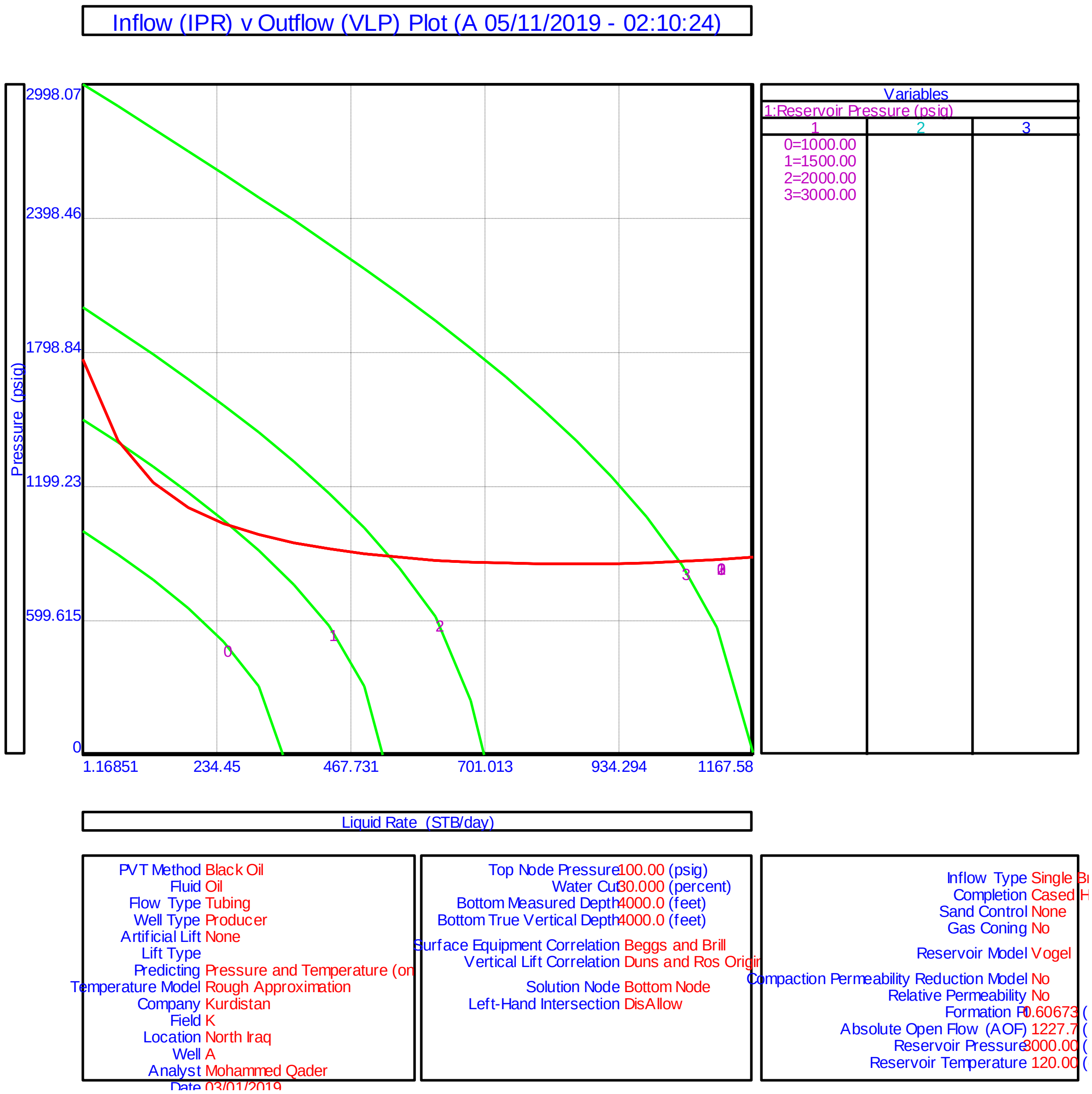


Figure 6.10: Effect of changing reservoir pressure on inflow (IPR) vs. outflow (VLP) curves

As shown in Figure 6.10, change in the reservoir pressure has an immense effect on the well performance and the production rate, when the pressure reduces to 2000 psig, the amount of liquid production as well as gas production will be reduced and pressure losses due to gravity will be more, which means that more pressure will be required for producing the fluid to the surface, and when the reservoir pressure declines to 1500 psig, the pressure losses due to gravity will be very high thereby, the amount of liquid and gas production will be very small; which indicates the difficulty of producing the fluid, hence, it will require a higher pressure to move the fluid to the surface. It was also seen that when the reservoir pressure was depleted to 1000 psig, then in that situation there will be no flow, and as such there will be no fluid production.

6.7 Electrical Submersible Pump

Designing an installation of an electrical submersible pump (ESP) requires a method of system analysis that is separate from that for a well that flows naturally. The ESP solution starts on the sand face, determining the pressure drop up to the intake of the pump which use standard PVT and tube size data at the target production which is specified. The ESP design section enables to measure the needed pump head in order to obtain a specified production rate and to choose an optimal pump and motor combination for the application.

Table 6.9: Selected method for artificial lift

Artificial Lift	**Selected Option**
Method	Electrical Submersible Pump

As shown in Table 6.9, electrical submersible pump (ESP) was used to make an artificial lift design, and the data that have been used for this ESP design are given in Table 6.10 and 6.11.

Table 6.10: ESP design input data

Type of Parameter	**Amount**	**Unit**
Pump Depth (Measured)	2800	psig
Operating Frequency	50	Hertz
Maximum Pump OD	5	inches
Length of Cable	2500	feet
Gas Separator Efficiency	0	percent
Design Rate	1100	STB/day
Water Cut	30	percent
GOR	800	scf/STB
Wellhead Pressure	100	psig
Motor Power Safety Margin	0	percent

Pump Wear Factor	0	fraction

Table 6.11: Selected equipment data

Type of Parameter	**Amount**	**Unit**
Pump	CENTRILIFT FC6000	---
Motor	Boret EDB125-117B5	---
Meplate Power	168	hp
Plate Voltage	2100	volts
Plate Current	49	amps
Cable	#1 Aluminium	---

Table 6.12 shows the required powers that will be needed for designing CENTRILIFT FC6000 pump.

Table 6.12: ESP design result

Type of Parameter	**Amount**	**Unit**
Number of Stages	191	psig
Power Required	34.7703	hp
Pump Efficiency	68.2589	percent
Pump Outlet Temperature	113.381	deg F
Motor Efficiency	76.0725	percent
Motor Power Generated	34.7703	hp
Voltage Drop Along Cable	8.84605	volts
Voltage Required at Surface	2108.85	volts
Surface KVA	38.7045	---

Torque on Shaft	61.4172	lb.ft
Motor Power Factor	0.16501	fraction

Figure 6.11 shows the design of well-A after ESP has been set in the well, in order to match the point on the best efficiency line (Figure 6.12), ESP design was set inside the tube at 2800 ft.

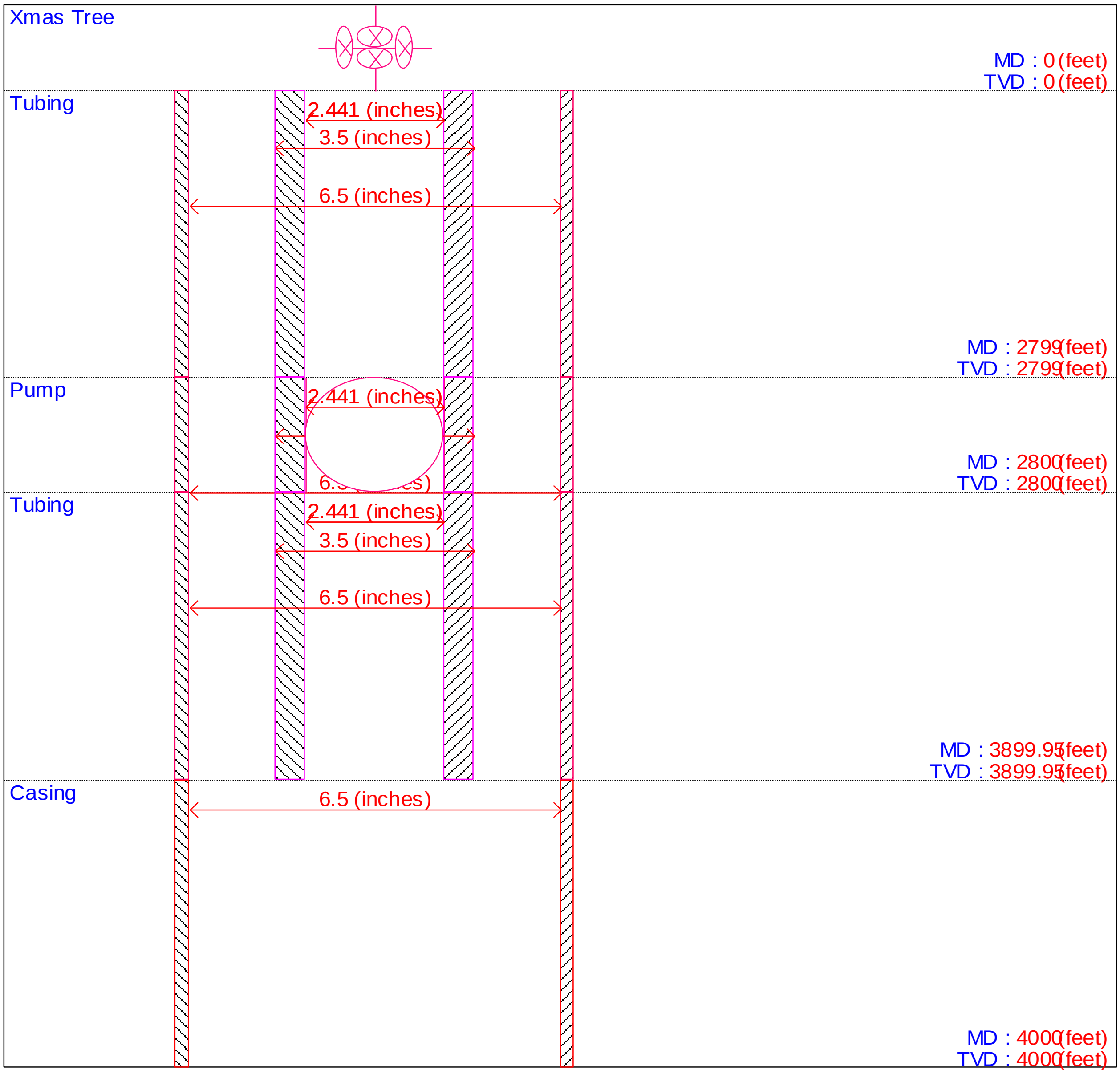


Figure 6.11: Setting ESP design for the well

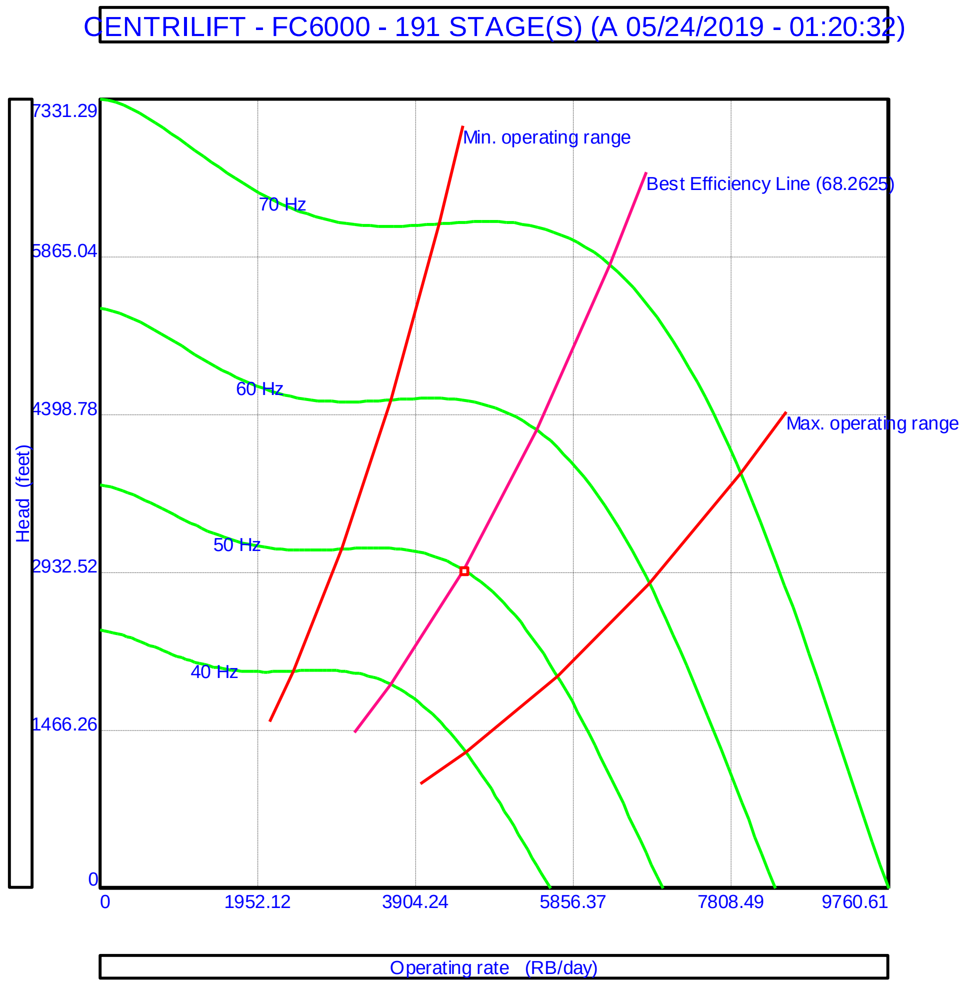


Figure 6.12: Matching best efficiency line for ESP design

As it was given in Table 6.11, CENTRILIFT - FC6000 was used to design ESP with 50 Hertz because this pump matched on the best efficiency line (Figure 6.12) which is optimum line that is located between the maximum and minimum operating range line. With compared to the other works such as the ESP design in Tetoros (2015), in which ESP design dose not match on the best efficiency, whereas the ESP design for well-A was exactly matched on the best efficiency line. Therefore, this might give a better and more optimized result.

Figure 6.13 shows that, designing ESP has improved VLP curve and it also made improvement in the well performance and it made liquid production rate to increase to 1081.7 STB/day. However, by applying this technique alone, well-A might not achieve a very significant result.

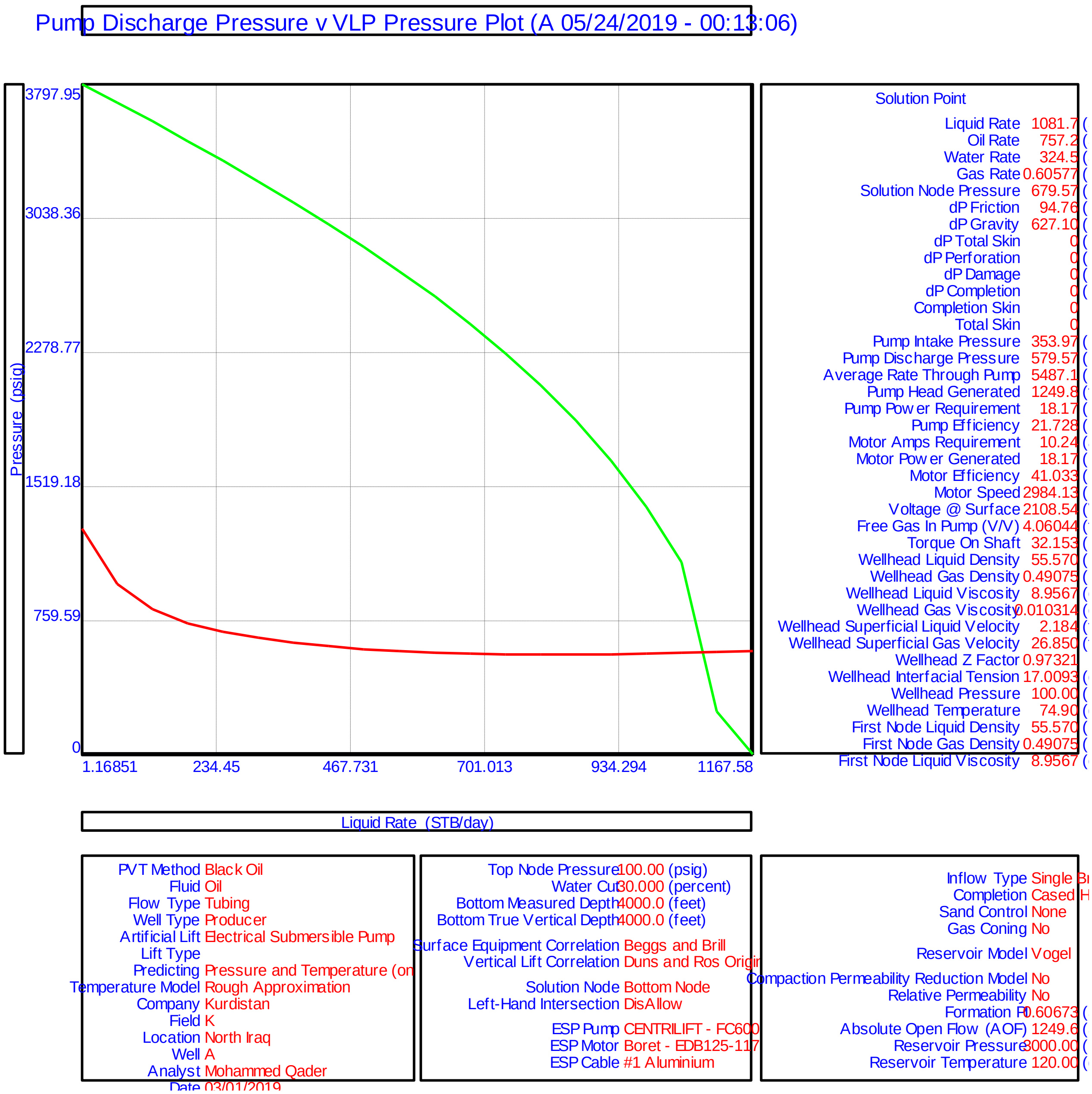


Figure 6.13: Effect of ESP design on inflow and outflow curves

Furthermore, designing an ESP can also be applied when the well cannot flow and the reservoir pressure is low. Regarding well-A, before in Figure 6.10, it was shown that when the reservoir pressure decreased to 1000 psig, there was no flow inside the well, but as it is shown Figure 6.14 after setting an ESP inside the well, the designed ESP provided enough pressure for the well to start to flow.

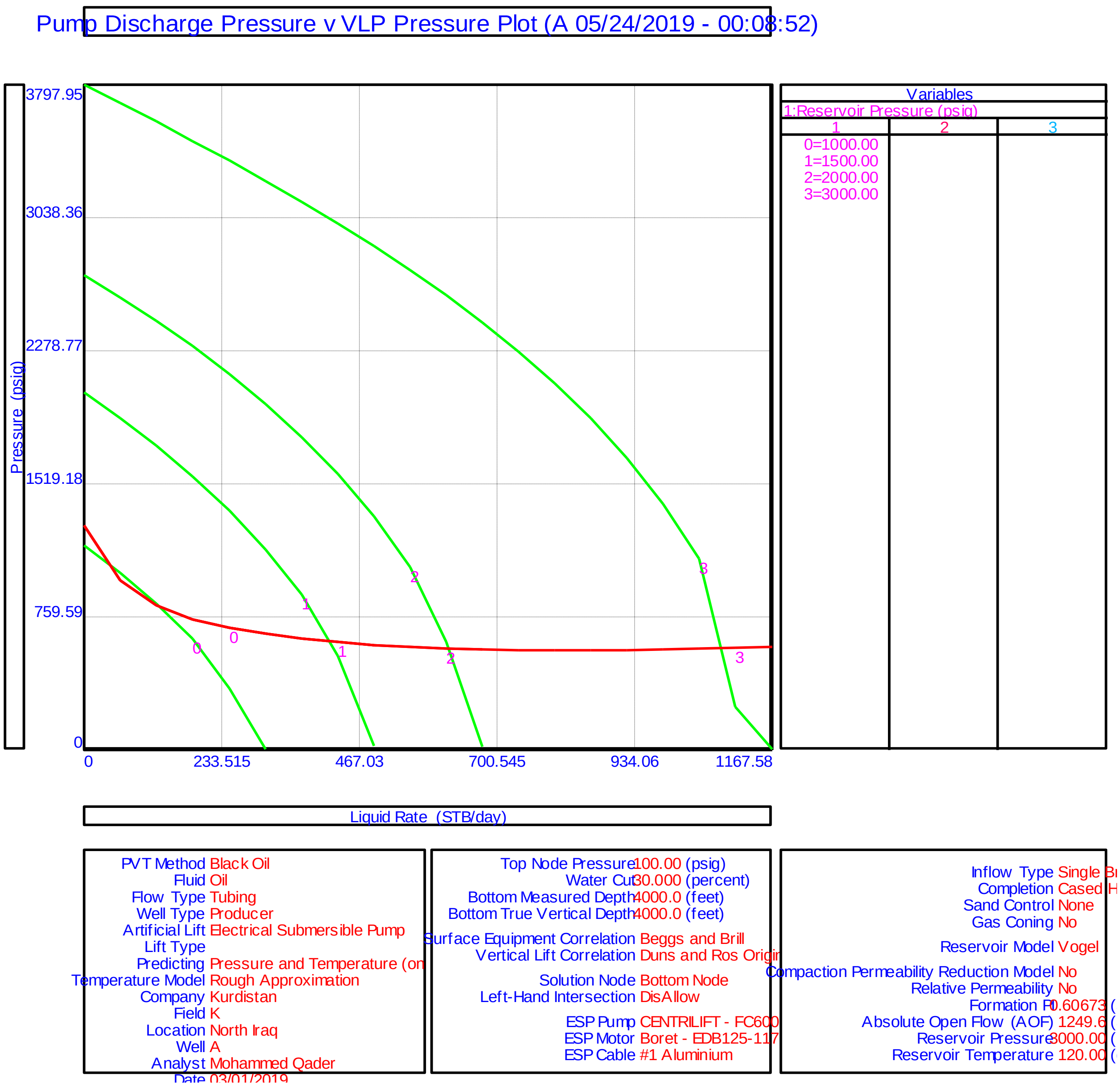


Figure 6.14: Effect of ESP on reservoir pressure depletion

Figure 6.14 shows that, using an ESP made the VLP curve to match with IPR curve even when the reservoir pressure was depleted to 1000 psig, it also made improvement in the pressure of the other reservoir flow curves which led to increase in the well performance.

Figure 6.15 shows three different operating frequencies for the designed ESP in order to see how the well production performance will respond to those frequencies.

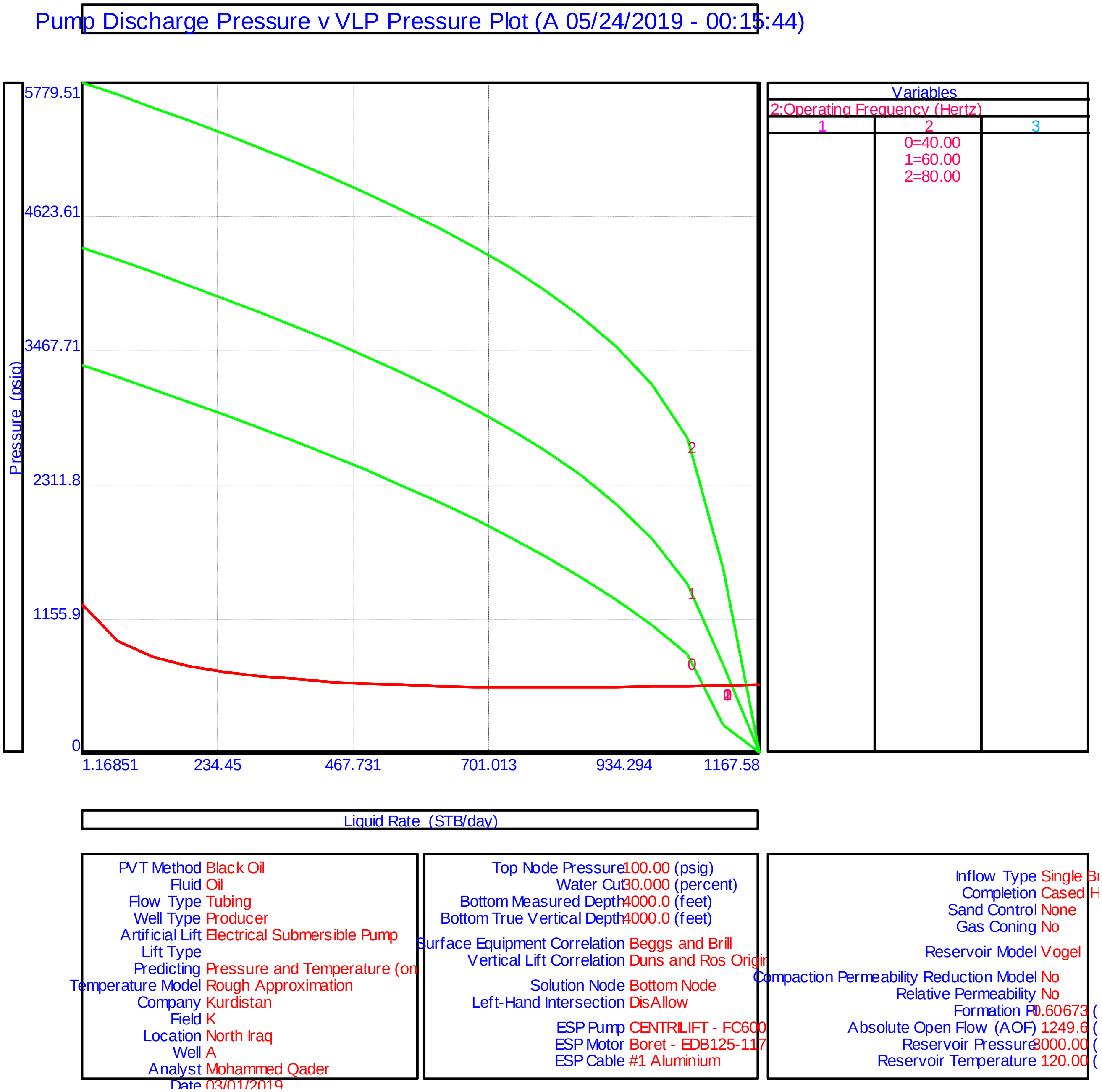


Figure 6.15: Effect of changing ESP operating frequency

It is shown in Figure 6.15, when the operating frequency for the designed ESP increased from 50 to 60 and to 80 Hertz, the well performance has also increased, and it will facilitate the achievement of the production rate. On the other hand, when the operating frequency was reduced to 40 Hertz, a lesser performance was observed in well-A.

Figure 6.16 shows the different setting depths for the designed ESP in order to see the impact of changing the depth on the well performance of well-A.

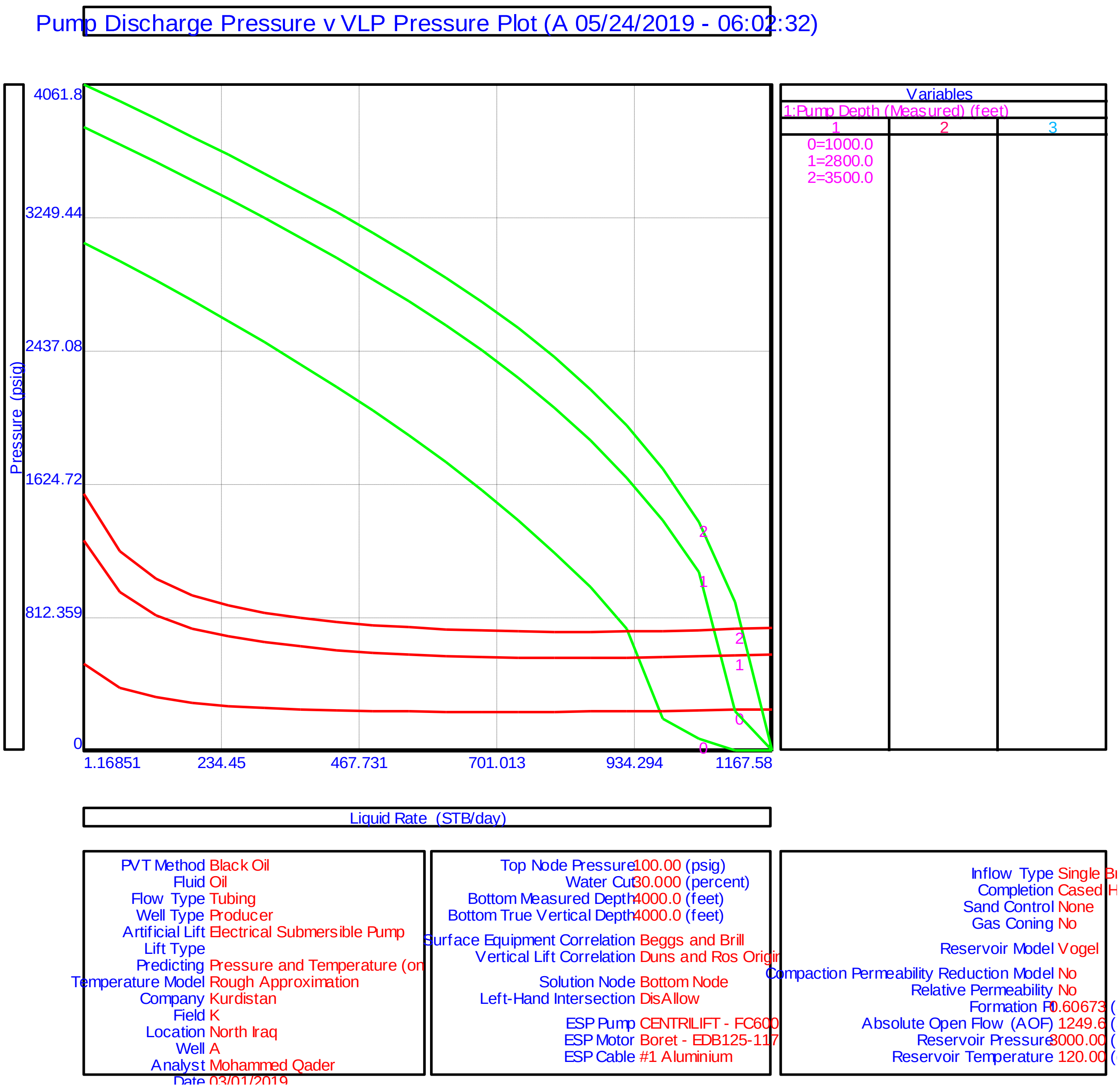


Figure 6.16: Effect of changing ESP depth

As it is seen in Figure 6.16, when the depth of the designed ESP has reduced to 1000 ft, the well performance also decreased. By putting the designed ESP deeper in the well to a certain depth which is 3500 ft, it may lead in the increment of the well performance regarding well-A because in that depth, the ESP could support the remaining reservoir pressure in producing the fluid to the surface.

CHAPTER 7

CONCLUSIONS & RECOMMENDATIONS

7.1 Conclusions

The best correlation that has been found with regards to the available data for well-A based on the smallest amount of standard deviation was Standing correlation. Standing has given the most accurate value with the lowest standard deviation which was 0.00043905 for matching PVT. Therefore, this correlation was used to predict Pb, Rs, and Bo; for the oil viscosity, the best correlation based on the lowest standard deviation regarding the available data for well-A was Begges et al with 0.034008 standard deviation.

Vogel method was used to construct IPR curve for fluid flow inside the reservoir, which was based on the available production test. Vogel has given the most accurate and closest results to the actual value. Duns and Ros Original was found as the best and most accurate correlation to construct VLP curve for the fluid flow inside the tube. The standard deviation of this correlation method was 0.00024414.

Duns and Ros Modified used to predict the pressure throughout the tubing. The total pressure loss that has been calculated by this correlation method was 759.26 psi which was exactly the same as the actual data for well-A, and 100 psi was remained at the wellhead. 737.06 psi of the total loss was due to the gravity, 20.91 psi was caused by friction, and the rest of the pressure losses were due to acceleration which was 1.29 psi.

The intersection point has successfully matched between IPR curve using Vogel method, which was the reflection of the fluid flowing from reservoir to the bottom hole versus VLP curve using Duns and Ros Original correlation method, which was the reflection of the fluid flowing inside the tubing.

The bottom hole pressure at the intersection point has been calculated as 857.75 psig, which was almost the same value with the measured bottom hole data for well-A (859.27 psig), where there were only differences of 0.17565 percentage. The liquid rate at the intersection point has been calculated as 978.9 STB/day, which was very close to the measured liquid data for well-A which was 1000 STB/day, with 2.11 percentage differences between both calculated and measured results.

Results of the analyses that have been done with regards to the available data of well-A shows that, by considering and applying some of the techniques such as increasing the GOR rate, decreasing the wellhead pressure, and by setting the ESP, well-A might successfully achieve a better performance, also it was found that the best tubing size was the original size. Decreasing in the reservoir pressure and increasing in the water cut percentage will lead to decreasing in the well performance. Therefore, all these aspects have been analyzed to maintain and improve the well performance for well-A.

7.2 Recommendations

- More accurate data (Wellbore, PVT, Flow, Production test, and Inflow...etc.) are needed to run more sensitivity analyses in order to have more accurate results.
- Choosing the correlations for constructing VLP and IPR curves could be one of the most sensitive and an important decision that one can face.
- To achieve optimization for well-A, it can also be proposed to the company to put the separator tower at the wellhead or to design the separator tower in such a way that the distance between the separator and the wellhead will be reduced to the maximum possible way. Thus, the pressure losses from wellhead to the separator will be less and the number of pipelines to transport the produced liquid will also be less.
- Prevention and preparation for water cut percentage increment should always be putted into consideration to avoid a sudden increment in the produced percentage of water, which might lead the well at a certain point to have more water production compared to hydrocarbon production.

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