GAS LIFT OPTIMIZATION FOR IMPROVED OIL PRODUCTION: A PROSPER ANALYSIS

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SUBMITTED TO THE DEPARTMENT OF PETROLEUM ENGINEERING

FACULTY OF ENGINEERING

UNIVERSITY OF BENIN

IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE AWARD OF BACHELOR'S DEGREE IN PETROLEUM ENGINEERING.

APRIL 2024

CERTIFICATION

This is to certify that this project work was carried out by **OTABOR OSAHON CHRISTIAN** with matriculation number **ENG1805587** in the Department of Petroleum Engineering, Faculty of Engineering, University of Benin.

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DEDICATION

This project is dedicated to God Almighty for his mercies, profound grace, infinite goodness, and protection throughout my stay at the University of Benin.

ACKNOWLEDGEMENT

I have the utmost gratitude to God Almighty for providing me with the capacity and fortitude to do my endeavour effectively.

My supervisor, Dr. O.A. Taiwo, has my deepest gratitude for his unwavering efforts, support, and enlightening criticism, all of which were crucial in enabling me to complete my thesis.

Additionally, I want to thank Engineers Ibe Alonge and Izuchukwu Ojukw for their outstanding help on this project.

I also want to express my gratitude to my parents and family for their constant love and support, which is a huge source of inspiration and motivation for me. Their unwavering trust and confidence in me give me the willpower to press on.

ABSTRACT

Among the most popular production optimisation strategies in use worldwide in oil and gas operations are artificial lift systems. Certain wells lose pressure in the system after a while, making it impossible for them to continue producing crude oil to the surface at their normal pressures. Consequently, in order to boost output, companies would need artificial lift technology. Artificial lift is utilised in the vast majority of producing wells worldwide.

An artificial lift method for extending the life of oil or gas wells is the gas lift system. To lower the hydrostatic pressure inside the production tubing, a lighter fluid is pumped into the annulus. Well, before it stopped producing, XYZ was in production for a few years. A gas lift artificial lift project was put into place to optimise its output capacity. This increased the well's longevity and revitalised it. Because it is more readily available, has a longer lifespan than other options, and requires less money to build and operate, the gas lift was selected for the candidate well. The well was modelled using PROSPER, which also supplied the ideal gas injection rate (4.318 MMscf/day) needed to start the well's flow.

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CHAPTER ONE

INTRODUCTION

1.1 BACKGROUND OF STUDY

The natural energy contained in an oil reservoir can be used to produce it initially until its economical rates are reached. The natural propulsion mechanisms (water, solution gas, or gas cap) may have run out. The installation of an Artificial Lift System (ALS) approach is typically taken into account during the well's completion process, in case it is not required right now but can be put down the road. In addition to extending the well's life, this will ensure flow and maximize production from it.

The process of raising the flow of liquids from a production well by employing techniques other than those found in nature, such as water or crude oil, is known as artificial lift. Typically, a pump or velocity string—a mechanical device installed inside the well—is used to do this, or gas is injected into the liquid a specific distance down the well to reduce the hydrostatic column's weight. Artificial lift is useful in wells where there is not enough reservoir pressure to raise the generated fluids to the surface, even though it is commonly used to increase the flow rate over what would usually flow in naturally flowing wells—which technically do not require it.

According to Silverwell (2016) and Shokir et al. (2017), gas-lift mechanisms power about 98% of artificial lift mechanisms for increased crude oil output. Gas is injected into the production tubings as part of the gas lift mechanism, an artificial lift technique that lowers back pressure and lightens the fluid's hydrostatic column. It has demonstrated efficacy in enhancing the production of reservoirs whose principal driving mechanisms have deteriorated with time. The gas lift mechanism has two modes of operation: continuous flow and intermittent flow. Continual-flow gas lift involves injecting small volumes of high-pressure gas into wells with high basic static pressure, a high Productivity Index (PI) of 0.5BD/psi, and a Gas-Liquid Ratio (GLR) of up to 2000 scf/bbl. Intermittent gas lift involves injecting large volumes of gas into an accumulated slug for a brief period of time to move the liquid slug to the surface. By introducing high-pressure gas from an external source at a maximum depth, the continuous-flow gas lift mechanism increases the primary flow of well fluids to the surface. Using primary energy from the reservoir, it is believed to be the only artificial lift mechanism.

The performance of the gas lift mechanism is dependent on a number of factors, such as gas gravity, production tubing size, PI, Gas-Oil Ratio (GOR), water cut, reservoir pressure, wellhead pressure, injection depth, injection rate, and valve spacing. Taking these variables into account, the optimal injection rate has been found to be critical for optimising the continuous-flow gas lift mechanism and enhancing well fluid production. This is due to the fact that excessive gas injection promotes the slippage between the liquid and gas phases, which lowers the production of well fluid. Because the volume of gas injected does not always match the recovered well fluids, it is imperative to determine the optimal gas injection rate.

1.2 STATEMENT OF PROBLEM

Artificial lift is frequently required when the well requires more energy from the reservoir than it can naturally supply, or when the intended production rate is higher than what the reservoir can produce. The possibility of reduced output or even total inability to flow because of the fluid's viscosity is one of the main obstacles to moving oil and gas from reservoirs to surface facilities. Developing efficient artificial lift techniques is imperative to sustain or enhance production rates, as this issue presents a noteworthy obstacle for the oil and gas sector.

An ageing oil and gas well's inherent reservoir energy diminishes with time, therefore artificial lift techniques are required to extract the well's residual hydrocarbons. Artificial lift techniques have a distinct set of challenges in addition to their potential for productivity enhancement. Numerous factors need to be considered when choosing the best artificial lift technology, such as stability, the capacity to handle solids and sand, corrosion and scale, the number of wells, the temperature and pressure limitations during flow, the well's depth, production rate, high GOR, and economics. These factors could lead to inefficiencies, shorter equipment lifespans, and financial losses if ignored. Therefore, it is essential to properly assess and choose artificial lift systems to maximize oil and gas production while lowering operating and maintenance expenses.

1.3 AIMS AND OBJECTIVES OF STUDY

This study intends to optimise oil production utilising a Gas-lift system while taking the geometry of the hole into consideration and increasing production to a low cost. It also uses effective nodal analysis to evaluate the well's production capability.

The objectives of this study are to:

1. To use the PROSPER software to model the natural base case of well XYZ and ascertain its flowing state/condition
2. To apply an effective nodal analysis approach in simulating flow and identifying the factors and parameters affecting the well’s performance.
3. To design a gas lift system for well XYZ and optimize production via the gas lift system
4. To compare the optimal outcomes regarding production capacity (production rate) at natural flowing conditions and gas lift.

1.4 SCOPE OF STUDY

The purpose of this study is to gain knowledge about artificial lift systems and the oil and gas industry's and petroleum engineering's applications. In order to increase production and prevent shutdown due to current operating and design limitations, it also attempts to build a continuous gas lift system for a well.

1.5 RELEVANCE OF THE STUDY

The result of this study would aid in the production of heavy oils in the Niger Delta using effective nodal analysis to improve gas-lift efficiency and oil recovery.

CHAPTER TWO

LITERATURE REVIEW

2.1 THE PRODUCTION SYSTEM

From the reservoir to the storage tank, oil must go through a number of obstacles, consuming some of the energy contained in the compressed fluids, which are symbolised by their temperature and pressure. The integrated system made up of the reservoir, wellbore, and surface treatment facilities is commonly referred to as the "production system" (Figure 2.1).

First, there will be a pressure reduction in the fluid before the oil travels through the reservoir rock to each well's drainage site. This pressure drop in the reservoir, which is commonly referred to as the "drawdown," is mostly caused by the fluid and geological characteristics of the reservoir.

The fluid needs to be able to cross over from the formation into the wellbore at the point where the reservoir and that particular wellbore meet. A crucial completion decision that must be made is how easy the formation and wellbore will communicate with one another. The entire cylindrical surface area of the borehole is susceptible to fluid entry from the reservoir under specific conditions when the drilled hole into the pay zone is used for production. In a different situation, the pay zone is drilled, a steel tube known as a casing or liner is inserted to line it, and a cement sheath is placed between the casing's outer diameter and the drilled hole. The number, location, and nature of these perforations will again affect the fluid flow and the resulting pressure loss. Since there will not be any fluid connectivity, specific entry points for the reservoir fluid through the casing wall are produced by perforating. The bottom hole completion pressure decrease is the result of the perforations and other near-wellbore completion equipment.

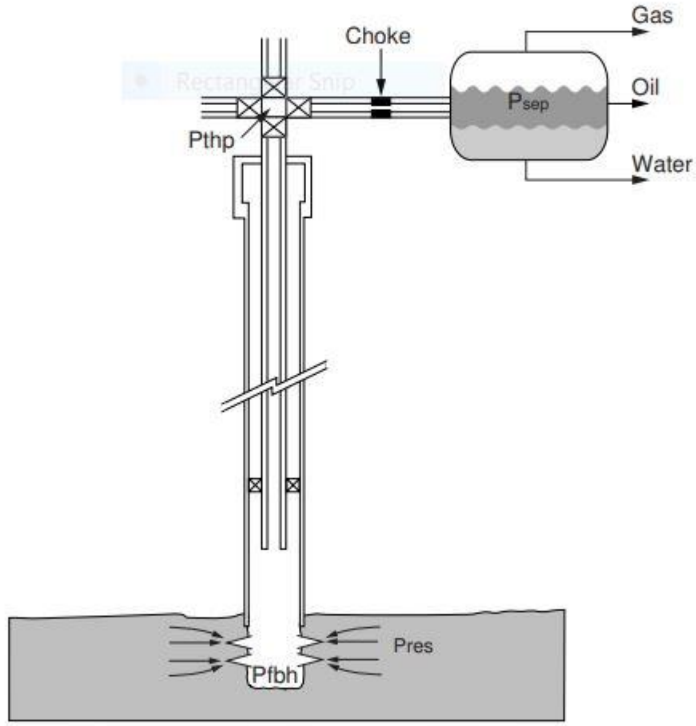


Figure 2.1: The Composite Production System

The fluid has to go through a number of tubing diameters and constraints brought on by other completion string components once it enters the wellbore. This causes the fluid pressure to drop between the surface and bottom hole position. Three major causes are responsible for these pressure dips, which are also referred to as the vertical lift pressure drop:

1. frictional pressure loss, or loss related to viscous drag;
2. hydrostatic head pressure loss because of the density of the fluid column in the production tubing; and
3. kinetic energy losses because of the fluid's expansion and contraction in the fluid flow area and the corresponding acceleration/deceleration of the fluid as it flows through various restrictions.

All three pressure losses added together equals the pressure loss associated with vertical lift. The pressure loss resulting from each individual tube component can be calculated to optimise the selection of specific components, such as downhole valves. Once at the surface, the fluid has additional pressure loss as it passes through the surface apparatus and flowline. The operating mechanisms employed on the platform will mostly determine the extent of pressure losses. If subsea or onshore wells are situated far from production manifolds or gathering stations, the losses could be significant, but they might not be noticeable for platforms with short flowlines.

The fluid then travels through a choke, a restriction designed to stabilise downstream separation and treatment operations over a wide variety of reservoir conditions by drastically lowering pressure.

The goal of a separator downstream of the bottleneck is to continuously separate the liquid phases, generating water for disposal and gas and oil for export. The pace at which oil shrinks will determine how much oil is produced per volume of recovered oil from a reservoir (figure 2.2).

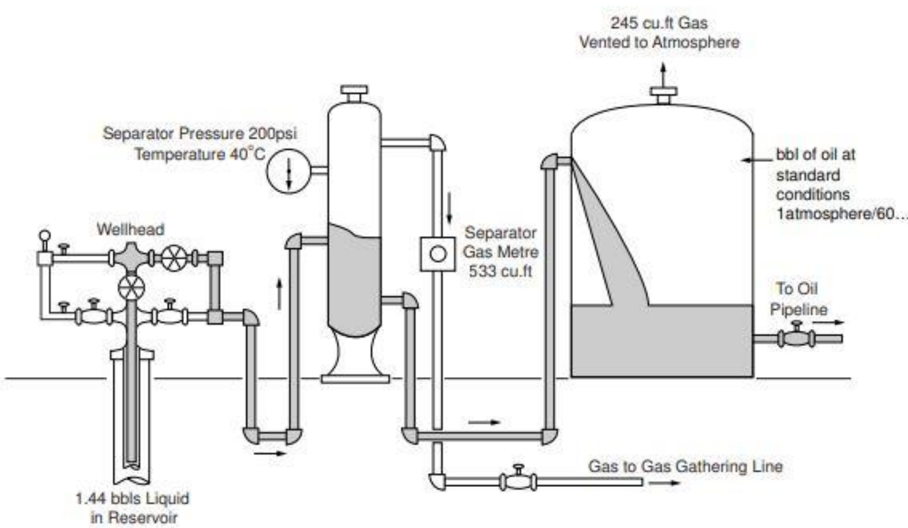


Figure 2.2: The Flow System From Wellbore to Separator

2.1.2 UTILIZATION OF RESERVOIR PRESSURE

When a hydrocarbon reservoir is established, the full pressure loss in the producing system can be compensated for by the energy stored in the compressed reservoir fluids in the case of a natural flow. The pressure loss distribution, assuming a constant operating pressure for the separator, can be represented as follows.: -

$$P_{RES} = \Delta P_{RES} + \Delta P_{BHC} + \Delta P_{VL} + \Delta P_{SURF} + \Delta P_{CHOKE} + P_{SEP} \qquad (1)$$

Where;

P_{RES} is known as the reservoir's wellbore drainage area's initial or average pressure.

The fluid flow pressure loss from the reservoir to the wellbore is called ΔPRES.

The overall pressure loss brought on by the bottom hole completion configuration, or the layout of the fluid entrance into the wellbore, is referred to as ΔPBHC.

PVL stands for pressure drop caused by fluid ascending the production tube string in a vertical direction.

Where;

$$\Delta P_{VL} = \Delta P_{FRICT} + \Delta P_{HHD} + \Delta_{KE} \qquad (2)$$

ΔP_{FRICT} is the frictional pressure drop

ΔP_{HHD} is the hydrostatic head pressure drop

ΔP_{KE} is the kinetic energy pressure drop

ΔP_{SURF} is the pressure loss generated in exiting the Xmas tree and surface flowlines.

ΔP_{CHOKE} is the pressure loss across the choke.

P_{SEP} is the required operating pressure for the separator

Rearranging equation 1 to give;

$(P_{RES} - P_{SEP})$ = Available pressure drop for the system = ΔP_{TOT}

$$= \Delta P_{RES} + \Delta P_{BHC} + \Delta P_{VL} + \Delta P_{SURF} + \Delta P_{CHOKE} \qquad (3)$$

Total system pressure drop results from the rate dependence of all the pressure drop elements in equation 3. [ΔPRES + ΔPBHC + ΔPVL + ΔPSURF + ΔPCHOKE] = ΔPTOTQ

It is possible to minimise each pressure drop independently or in combination to achieve the maximum output rate for the specified pressure drop. Production system optimisation is what we term this.

It is important to think about how each pressure decrease might be minimised in order to give the highest output rate possible.

i. Reducing the flow resistance is required to lessen the pressure loss brought on by the reservoir's flow. This can be achieved in two ways: either by using thermal recovery techniques to reduce the resistance of the formation rock, for example, by improving permeability through acidization or fracture, or by reducing the resistance of the fluid characteristics, such as viscosity, to flow. Except in some circumstances, such as chalk reservoirs or hefty crude oil reserves, these solutions may be expensive, not necessarily suitable to all reservoirs, and entail a significant technical risk or uncertainty.

ii. One of the main areas for production optimization is the pressure loss resulting from the bottom hole completing the procedure, which must be defined as part of the completion design. To maximize the system's production capacity, careful evaluation of certain factors in this area, such as perforation shot density and length of perforated interval, is probably beneficial.

iii. Similar to the bottom hole completion pressure loss, there is much room for optimization in the vertical lift pressure loss. This is because the engineer must describe the diameter and length of each tubing string piece and the specific completion components, like nipples. The well's productive capacity can be significantly increased with careful design in this section.

iv. In most cases, the surface flowline pressure loss is less significant because, while having a much shorter length than the production tubing, the in-situ phase velocities will be higher. There are certain subsea wells and widely spaced onshore wells that are exceptions. However, in some circumstances, reducing pressure loss here by choosing a pipeline with a larger diameter and limiting the number and severity of directional shifts might result in a noticeable boost in field productivity.

v. There is limited room for manoeuvre when minimising choke size because the separator needs to be stabilised by a given pressure drop at a given flow rate.

2.1.3 SUPPLEMENTING RESERVOIR ENERGY

The production rate from a well is directly related to the average pressure in the reservoir pore volume that the well drains. In order to preserve rates and cash flow, it would be better to maintain reservoir pressure. Discussions of material balance make it evident that, in order for this to occur, the reservoir would need to show no indications of pressure depletion due to one of the following:

i. its infinite size; or

ii. volumetric replacement of produced fluids through movement from an adjacent fluid-bearing portion of the reservoir, either of gas, water, or both fluids; or injection from an external source.

It is also evident that higher production rates might be reached by

a) raising reservoir pressure or

b) supplying more energy to the vertical lift operation. It is challenging to imagine raising the reservoir pressure above its starting point for two reasons:

i. To accomplish any appreciable rise in reservoir pressure decline in the event of reservoir development, fluid injection into the reservoir over an extended period of time would be required. This would usually impede any meaningful production because it would lead to the subsequent depletion of the associated hydrocarbon volume and pressure.

ii. The amount of fluid that must be injected into the reservoir in order to boost pressure will depend on how compressible the rock and fluid system together are. In comparison to other methods of increasing fluid output, the amount of fluid in commercially scale reservoirs would be huge and consequently not cost-effective.

Artificial lift is the idea of promoting fluid production by aiding the vertical lift process. Using this technique, the energy supplied by a pump either offsets the tube pressure drop or reduces the hydrostatic head pressure loss due to gas lift.

2.2 ARTIFICIAL LIFT SYSTEMS

One method for increasing reservoir pressure and encouraging oil to surface is artificial lift. When the oil in a reservoir cannot be forced to the surface by its natural driving energy, artificial lift is utilised to retrieve more oil. Although some wells naturally climb to the top, most require artificial lift since they do not have enough pressure. Even wells with naturally occurring flow to the surface eventually need artificial lift when their natural flow pressure decreases. As a result, artificial lift is often applied to every well at some point during their productive life. Though there are various ways to create artificial lifts, pumping systems and gas lifts are the two primary types.

2.2.1 PATH-SECTORS INFLUENCING THE DESIGN OF ARTIFICIAL LIFT SYSTEM

The analysis and design of artificial lift systems are influenced by four major sectors. The first and second reservoir components, which run from the boundary of the drainage area to the wellbore and then from the wellbore to the surrounding area, are symbolic of the well's ability to release fluids into the well bore. The third element of the flow path is the entire tube in the vertical, incline, and horizontal path, including all systems like non-return valves, subsurface safety valves, and down-hole artificial lift devices. The surface flow path, which comprises the flow line's diameter and length as well as valves, bends, wellheads, chokes, manifolds, separators, etc., makes up the fourth component. The parameters of other sectors are impacted by any modification in the relative parameters in any one of the four sectors. It is necessary to adjust the parameters until the flow stabilizes.

The individual sectors of the flow-path area have been discussed below:

2.2.2 FLOW THROUGH POROUS MEDIA AROUND THE WELL

In this sector of flow through porous media, no specific form of flow conduit can be imagined. Therefore, it is primarily a concern while determining the flow parameters. The basic ideas of reservoir engineering, such as the reservoir drive mechanism and the productivity index (P.I.) of individual wells, must be understood in order to comprehend this. The productivity index gauges a well's capacity to pump fluid into the wellbore. Mathematically, it can be expressed as:

$$Q \quad (P_r - P_{wf})$$

Where, Q = Total quantity of fluid

P_r = Reservoir pressure

P_{wf} = Flowing bottom hole pressure at sand face.

Therefore, Q = constant x ($P_r - P_{wf}$). This constant is the productivity index (PI) of the well and is generally abbreviated as "J". In other words,

$$J = PI = Q/(P_r - P_{wf})$$

2.3 INFLOW PERFORMANCE

The kind of reservoir, drive mechanism, production rate, production time, cumulative production, perforation density, skin, sand bridging, gas coning, infill wells during production, and other factors affect J, which is not a constant value. The idea of the inflow performance relationship (IPR) is presented to define the liquid inflow in the wellbore in order to quantify PI more accurately. In essence, it is a two-dimensional curve or straight line with Q, the flow rate, on the X-axis and P_{wf}, the flowing bottom hole pressure, on the Y-axis. The idea that J is a constant at all times is therefore false. In this case, PI is simply a point on the IPR curve. The following are some of the typical IPRs being mainly influenced by different reservoir drive mechanisms:

2.3.1 IPR IN CASE OF ACTIVE WATER DRIVE

The strongest kind of reservoir drive is said to be the water drive. Nonetheless, the intensity varies amongst various kinds of reservoirs powered by water. While some are strong, others are only somewhat so. For example, the bottom water drive is stronger than the edge water drive. In bottom water drive, reservoir pressure often does not decrease over increasing production years when the oil pool lies beneath a sizable aquifer of dynamic source. In other words, the reservoir pressure is essentially constant and unaffected by cumulative production. Here, the IPR curve will only yield one value of PI; that is, it will only be a straight line.

2.3.2 IPR IN CASE OF SOLUTION GAS DRIVE

Another name for this kind of drive is internal gas drive or depletion drive. This drive system is the least efficient. When there is an excessive draw-down, the permeability to gas increases and the permeability to liquid decreases, which significantly limits the well's capacity to transport liquids. This kind of reservoir typically has a very rapid decrease in reservoir pressure, which affects the IPR curve's pattern.

2.3.3 IPR IN CASE OF GAS CAP EXPANSION DRIVE

Due to the segregation of the oil zone from the gas zone—where the oil zone is covered by a gas zone known as the gas cap—this drive mechanism is also known as a segregation drive. Furthermore, the drive is also known as the gas cap expansion drive since the gas cap grows as output continues. This type of reservoir drive mechanism is more effective than solution gas drive, but less efficient than water drive. As a result, the gas cap expansion drive's IPR curve profile lies in between the solution gas drive's and the water drive's.

2.3.4 IPR – WHEN P_r > BUBBLE POINT PRESSURE (SATURATION PRESSURE)

AB is a straight line that represents constant PI up to point B in the profile. The reservoir's gas separation process begins at B. More draw-down, or more falling in of the bottom hole, will cause more and more gas to escape, which will alter the liquid flow since more gas will be produced around the wellbore.

2.3.5 CHANGE OF PI WITH CUMULATIVE RECOVERY (PERCENTAGE OF ORIGINAL OIL IN PLACE) WITH TIME

When a reservoir is allowed to produce over time without any pressure maintenance—either with the help of water injection or gas injection, which results in a continuous decrease of reservoir pressure—the pattern of IPR curves, with cumulative recovery, or percentage of oil in place, can be best described. Reservoir pressure shows a declining tendency in a sequence of IPR curves with the time that is obtained. The generating rate-pressure axis's origin (0, 0) is generally approached by the succeeding IPRs. The trajectory of these IPR curves shows that the reservoir is rapidly approaching senescence, which means that the reservoir pressure is exerting an excessive amount of pressure on the liquid inflow into the wellbore.

2.4 TYPES OF ARTIFICIAL LIFTS

The major forms of artificial lifts include:

- Sucker-rod (Beam) pumping
- Electrical Submersible pumping (ESP)
- Reciprocating and jet hydraulic pumping systems
- Progressive cavity pumps (PCP)
- Gas Lift

2.5 SELECTING AN ARTIFICIAL LIFT SYSTEM

To optimise the potential of every oil or gas well, the most economical artificial lift technique must be selected. Within an industry, there is a great deal of variation in the lifting techniques that have been historically used in a particular field. Among the techniques are:

- Operator Experience
- Method available for installation in certain areas of the world
- What is working in adjourning or similar fields
- Determining what methods will lift at the desired rates and from the required depths
- Evaluating the list of advantages and disadvantages

- Evaluation of initial costs, operating costs, production capabilities, etc. with the use of economics as a tool of selection, usually on a present-value basis.

These methods consider:

- Geographic location
- Capital cost
- Operating cost
- Production flexibility
- Reliability
- "Mean time between failures"

2.6 GAS LIFT

Gas lift is a fluid lifting technique that uses a mechanical process to elevate fluid through a gas with a minimum pressure of 250 psi. This type of lift is artificial. When well pressure is not high enough to maintain oil production at a high enough economic return, artificial lift becomes necessary. When a well finally shuts off naturally owing to a drop in reservoir pressure or an increase in water cut, it is common in mature oil fields. Lower bottom hole flowing pressure from a lower reservoir pressure lowers the energy required to raise the hydrocarbon liquid. Two distinct methods are typically employed to overcome this issue. The first strategy is to use bottom-hole well pumping to raise the bottomhole flowing pressure. The second involves injecting compressed gas, sometimes known as "gas lift," into the well bore to lower the density of the fluid column.

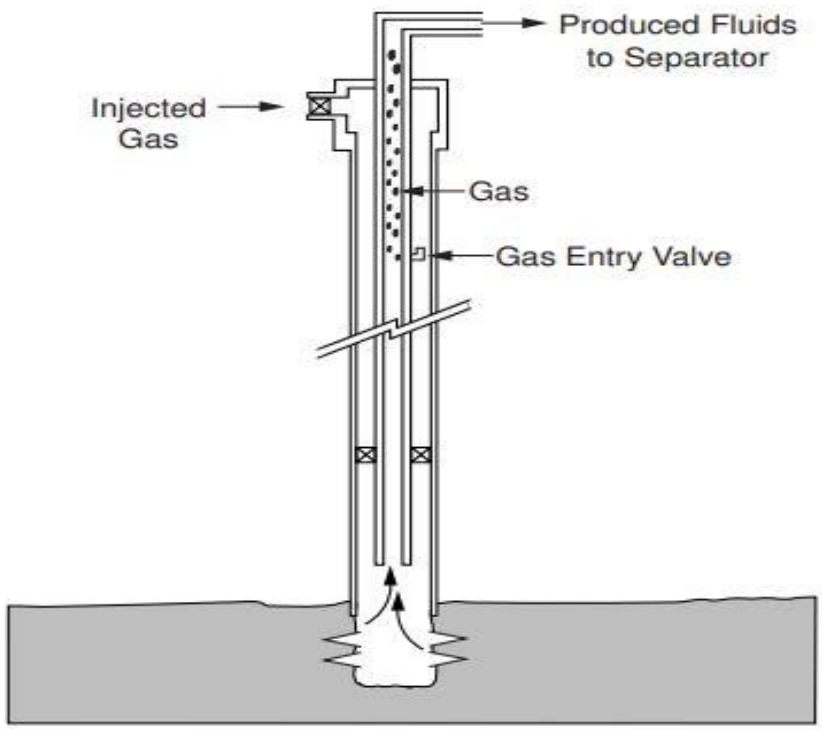


Figure 2.3: The Gas Lift Process

Gas lift is one of the most popular artificial lift types, especially for offshore installations. There is no other artificial lift type that compares to its flexibility. Gas lift mandrels and valves are frequently used to pump compressed gas into a gas lift system's production string. By reducing the hydrostatic pressure in the production string and restoring the required pressure differential between the reservoir and well bore, the injected gas causes formation fluids to rise to the surface. To increase output and reduce slugging effects—large bubbles formed when gas droplets collect and disrupt production—gas lift can be adjusted for a single well.

There are two phases involved in gas lift operations:

- The Unloading phase
- The Operating phase

Unloading is the process of gradually introducing gas through deeper unloading valves until the working valve is reached to increase the injection pressure. The operating phase involves a single-point injection over a range of injection rates through the operational valve.

2.6.1 CLASSIFICATION OF GAS LIFT

Based on the lift gas injection, there are two operational categories for gas lift.

1. Continuous Gas Lift
2. Intermittent Gas Lift

CONTINUOUS FLOW GAS LIFT

Relatively high-pressure gas is injected downhole into the fluid column as part of the continuous flow gas lift operation. To raise the fluid to the surface, this injected gas combines with the formation gas by one or more of the following processes:

1. Lowering the column weight and fluid density to enhance the pressure differential between the wellbore and reservoir
2. An increase in the differential between the reservoir and the wellbore due to the expansion of the injection gas pushing liquid ahead of it and further lowering the column weight.
3. Big gas bubbles that work as pistons push aside liquid slugs.

INTERMITTENT FLOW GAS LIFT

The intermittent gas injection theory explains this: gas lift injection stops after a given period of time. Once a specific duration has elapsed between injections, the cycle is resumed. In the intermittent flow system, fluid is allowed to accumulate in the tubing at the well's bottom. In intermittent lift, the frequency of gas injections is determined by the time it takes for a liquid slug to enter the tubing. The appropriate duration of the gas injection period is determined by the time required to push a liquid slug to the surface.

Gas lift, which involves injecting gas to artificially boost the producing GOR (gas oil ratio), is essentially an extension of natural flow. Gas lift is often required in response to a decrease in reservoir pressure or an increase in water cut. In order to reduce any potential detrimental effects on the density of the fluid column, the gas should be injected as deeply as feasible. Gas lift valves are placed in a sequence and inject gas into pocket mandrels together with the tubing string. There is only one open valve that permits gas to pass through at any given moment.

2.6.2 SYSTEM REQUIREMENTS FOR GAS LIFT

The following guidelines must be followed while evaluating the effectiveness of an existing gas lift system or looking into the viability of a possible gas lift system:

- Having a sufficient and dependable supply of high-quality lift gas available for use whenever gas lift is needed is essential to the operation of any gas lift system.
- The gas injection point ought to be situated in closest proximity to the completion interval's peak.
- The wellhead back pressure should be kept to a minimum when using gas lift systems.
- Lift should be as stable as possible
- Every gas lift system ought to take into account both current and future operation circumstances.
- It is best to steer clear of too conservative design assumptions and instead make design decisions based on the caliber and accessibility of design facts.
- It is important to consider every mode of operation when designing gas lift systems.

- The system should be able to run almost constantly in the most profitable configuration (minimize compressor downtime, for example) by optimizing lift gas availability.
- Control and surveillance must be viewed as essential components of every system. Effective gas lift operation requires the capacity to regulate gas lift distribution.

2.6.3 ADVANTAGES OF GAS LIFT METHOD

Some advantages of the gas lift method of artificial lift include:

1. It is not affected by solids in produced fluids
2. Handles large volumes in high-PI wells (continuous gas lift), 50,000 B/D (7949.37 m^3/d)
3. Unobtrusive in urban locations
4. Applicable offshore
5. Sometimes serviceable with a wireline unit
6. Not mechanically affected by the inclination of the wellbore

2.6.4 SELECTION OF GAS LIFT VALVES

It is necessary to shut off a well at a gas pressure significantly greater than its normal operating pressure after it stops producing. Gas lift valves were developed to solve the kickoff issue and are now incorporated into the whole tube string. In order to empty the well and initiate the flow, these valves permit gas to be injected to the fluid column in the tubing at intermediate depths. Usually, an annulus is injected with gas. A thorough understanding of both valve qualities and the unloading process is necessary to properly design the valve depths for unexpected unloading. A gas lift operation consists of two stages:

1. Unloading
2. Operating.

2.6.5 UNLOADING SEQUENCE

It is crucial to recognise that there are other components involved in the production tubing than just a valve, especially in the case of gas-boosted output. In order to leverage the injection pressure until it reaches the operating valve, gas is injected during unloading through deeper unloading valves. However, with the available gas down to the anticipated depth of gas injection, the gas compressor might not be able to deliver the required pressure. According to Okoro and Ossia (2015), this is because the fluid's static pressure is larger at that depth than the pressure of the injected gas. As a result, several unloading valves must be installed.

In Figure 2.4, the procedure for discharging a well is shown. Since the tubing pressures are high, all of the valves in Figure 2.4a are immediately opened. The fluid inside the tube has a static liquid column pressure gradient of Gs. As the gas passes through the top valve of the first valve in Figure 2.4b, a less dense slug of liquid-gas mixture forms in the tube above the valve depth. As the gas in the slug expands, the liquid column above it is forced to ascend to the surface.

In the event that the tubing string's check valve is not attached, the liquid at the bottom hole can possibly return to the reservoir. Both the length of the light slug and the input of reservoir fluid increase as the gas is pumped into the well. The reservoir pressure will eventually be exceeded by the bottom-hole pressure. By now, the first valve's depth pressure ought to be low enough to permit the valve's closure. Like in Figure 2.4, this will force the gas to the second valve. The liquid in the tubing between the first and second valves will change into gas when the gas is pumped into the second valve. More bottom-hole pressure reduction will result from this, which will increase inflow. A slug is used to pump gas into the tubing string. The first valve should close as soon as the slug reaches its depth, enabling the gas to be pushed into the second valve. Until the gas reaches the main valve (Fig. 2.4d), continue this procedure. Usually found close to the bottom of the tubing string, the main valve is also referred to as the master or operational valve. It functions like an aperture and is constantly open. Only the main valve is open and in use during continuous gas lift operations once the well has been fully discharged and a constant flow has been established (Fig. 2.4e).

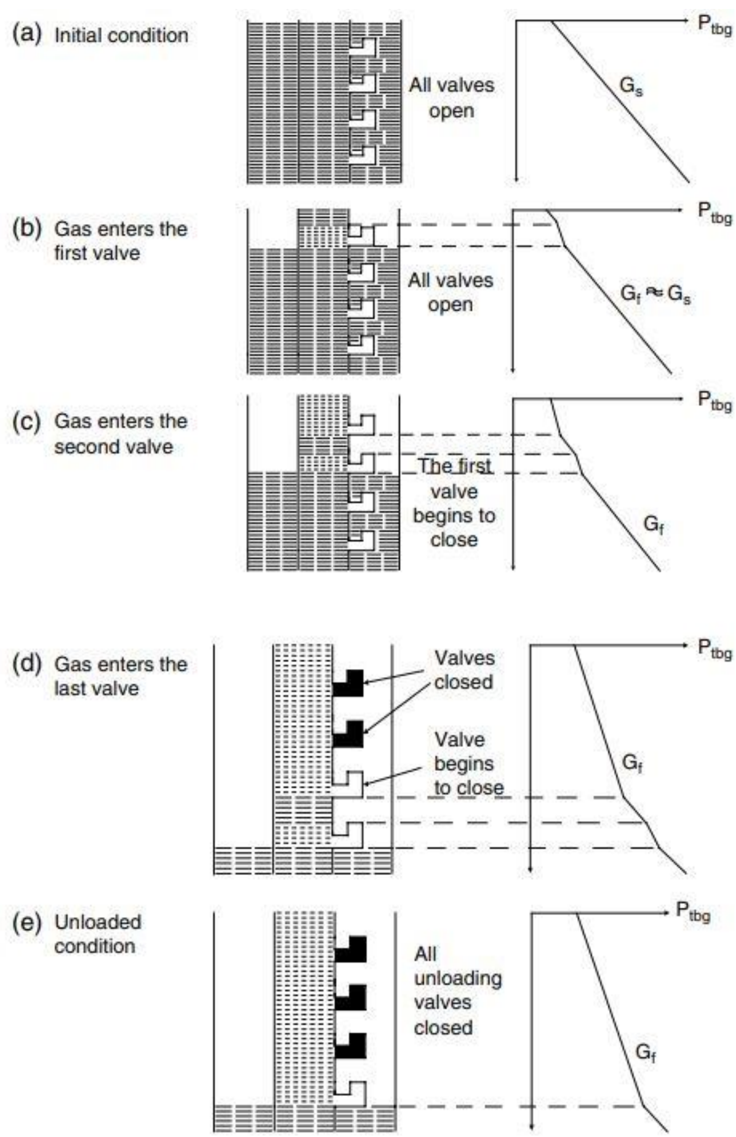


Figure 2.4: Well Unloading Sequence

2.7 GAS LIFT PERFORMANCE CURVE

By injecting gas at the ideal pace, the gas lift method is utilised in oil production systems to maximise output rates. The Gas Lift Performance Curve, which illustrates the relationship between the rate of gas injection and the rate of oil output, determines this rate. The curve, which was created by Bertuzzi et al. and Pottmann and Carpenter in 1952, is frequently used in the petroleum industry to design gas-lift systems. Any rate higher than that would decrease output and raise operating costs, therefore figuring out the ideal gas injection rate is essential. Deni (2007).

The drop in bottom-hole pressure that occurs when gas is introduced into an oil well has the potential to boost oil output. This is because more fluid is able to reach the surface since the gas thins the fluid column. However, by raising the bottom-hole pressure, excessive gas injection might impede the flow of oil. Slippage, which happens when the gas phase moves more quickly than the liquid phase through the tubing, reduces the amount of liquid that can travel through it. When the gas injection rate is too high, slippage happens. Finding the ideal gas injection rate to maximise oil production is therefore crucial.

By locating the peak of the gas lift performance curve prior to its decline, the ideal gas injection rate may be ascertained.

Figure 2.5: Gas Lift Performance Curve

At low injection rates, Figure 2.5 shows that a well's liquid production rate rises with each increase in gas volume. When injection rates rise and the rate at which liquid volume increases slows down, the maximum liquid rate is reached. Beyond this maximum gas injection point, the generation of liquid is reduced.

Another important aspect that significantly affects the performance of gas lift wells, in addition to gas volume, is gas injection pressure. It is critical to establish the optimal injection gas pressure. A well may not be producing to its full potential and gas lift operations may be unsuccessful if the injection pressure is too low. Conversely, excessive injection pressure can result in unnecessary compression costs. (Blann, 1984)

2.7 NODAL ANALYSIS

A single system component's performance can have a significant impact on a well's deliverability. A more cost-effective method of optimizing system performance is to separate each component's impact on the overall performance of the system. The entire production system is taken into consideration as a single entity using the system analysis method. Next, a node or point in the system is selected where the input and output pressures are equal. The process of system analysis is known as "Nodal analysis."

In nodal analysis, flow through the reservoir to the surface comprises of the following components:

1. Flow through a conduit (tubing or casing) + downhole restrictions (safety valves and choke
2. Flow from the reservoir (porous media) to the completion
3. Flow through the completions (perforations, gravel pack)

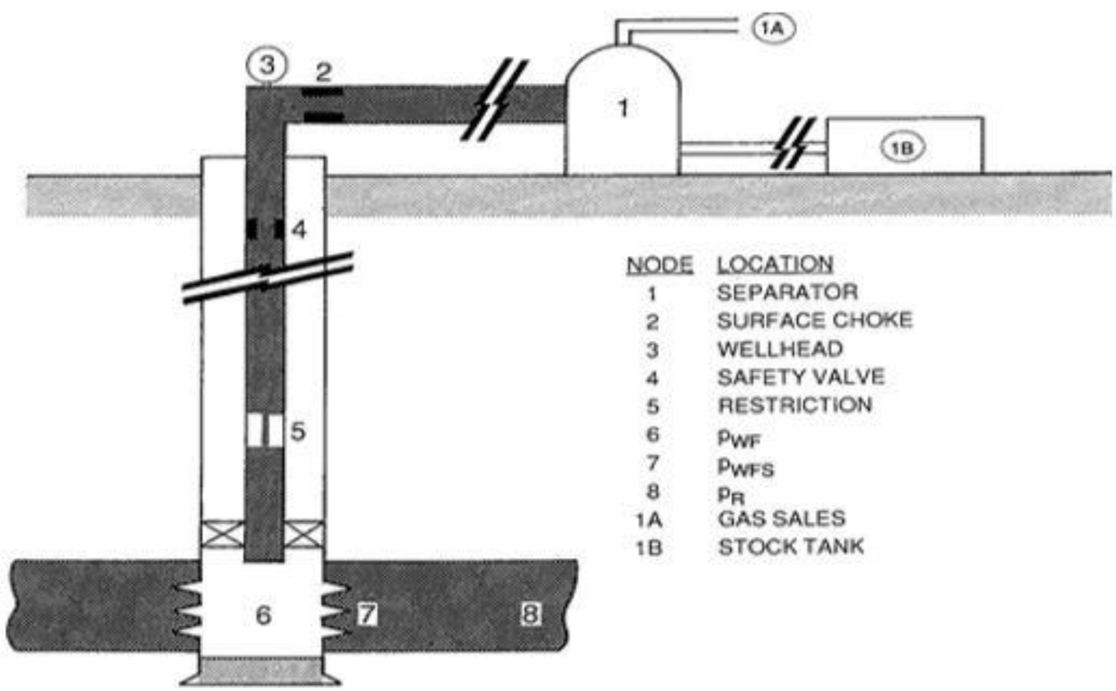


Figure 2.6: Concept of Fluid Flow Through the Production System (Dale Beggs, 2015)

The principle of nodal analysis is that the pressure losses through each component in a system add up to the overall pressure loss. By using nodal analysis-based production optimization, the aim is to decrease the pressure losses in each component to the greatest extent possible. This reduces the overall pressure loss and subsequently increases the well flow rate.

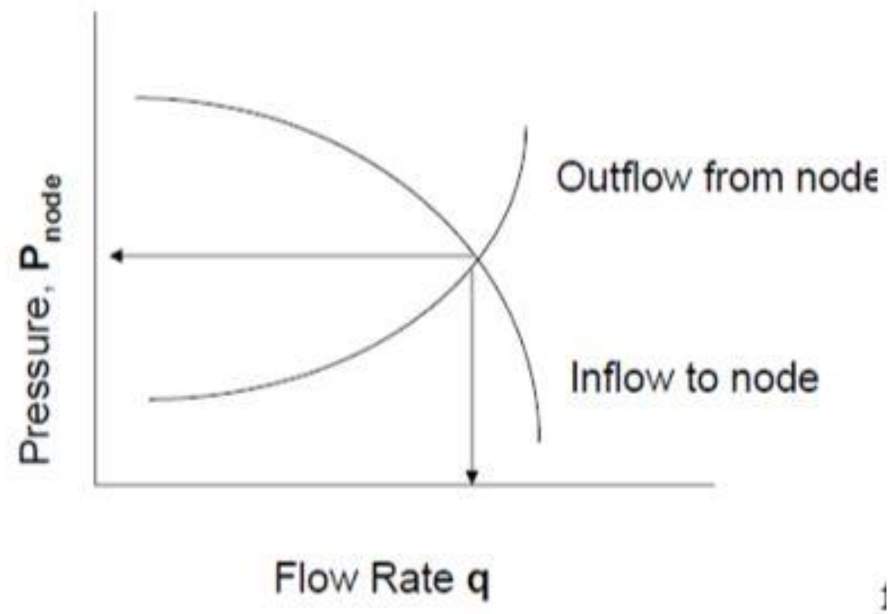


Figure 2.7: Outflow and Inflow Curve Match

The criterion is met when the inflow and outflow intersect. The best point for intersection for that flow rate is this one. Any changes to the inflow or outflow will only shift the curve; the intersection will stay the same. For instance, if the tubing diameter increases, the pressure drop will decrease and the inflow curve will rise (as shown in Figure 2.8).

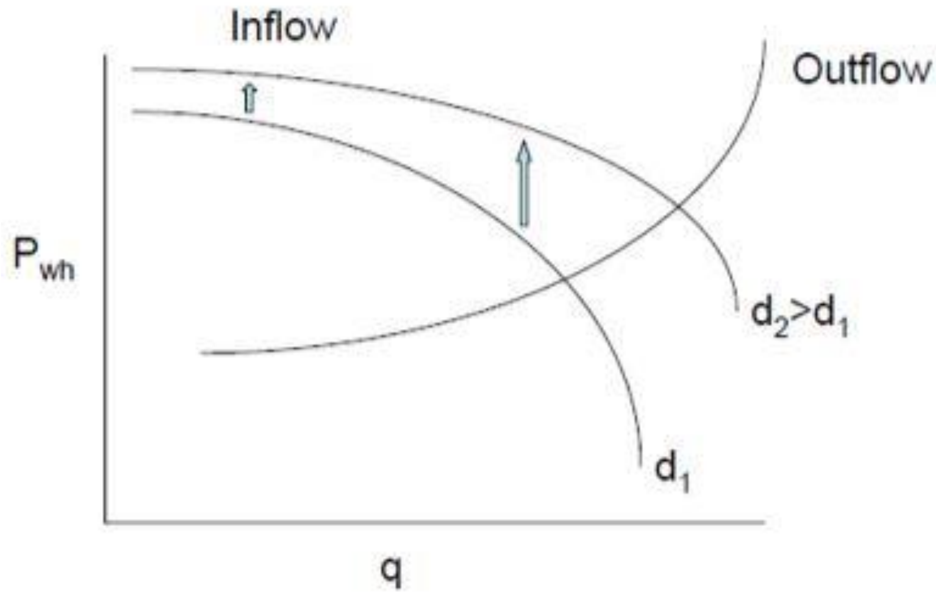


Figure 2.8: Effect of Increased Tubing Size on Inflow Curve

CHAPTER 3

METHODOLOGY

3.1 MATERIALS

PROSPER

The acronym PROSPER stands for PROduction and Systems PERformance analysis software. As per Petroleum Experts, PROSPER is an essential component of the Integrated Production Model (IPM) that connects to GAP, the program for optimising production networks, to gather system modelling, and MBAL, a tool for reservoir engineering and modelling, to create fully integrated total system modelling and production forecasting. In order to estimate the flow characteristics in the well or tubing, it is considered one of the most important tools for a production/reservoir engineer.

The tool enables the construction of well models that take into consideration all variables, such as fluid characteristics (PVT), multiphase VLP correlations, well layout, and a variety of IPR models. Real-world production data matching enables model adjustment, which also has the added benefit of improving the accuracy with which various scenarios can be represented. The most common well completion types and artificial lifting processes can be imitated using the industry-standard single well performance design and optimisation tool PROSPER. Major operators use PROSPER worldwide.

The PVT part of PROSPER may compute fluid properties using standard black oil correlations. The black oil correlations can be changed to more nearly resemble measured lab data. For use in the calculations, PROSPER makes it easier to import complete PVT data in the form of tables.

A third option is to use the Equation of State approach. This option also allows the user to enter the parameters for the equation of state model and create properties for a multi-stage separator scheme using the standard Peng-Robinson EOS model. With this capability, customers may also import all PVT data as tables, some of which may have been made with their own unique EOS models.

The program can be used to anticipate reservoir inflow performance (IPR) for single-layer, multi-layered, or multilateral wells with complex and highly deviated completions. It optimises every aspect of a completion design, including gravel packing and perforation details. Temperature and pressure profiles in injection wells, producing wells, risers, flow lines, and across chokes may all be accurately predicted with its help. The sensitivity calculations skills allow the engineer to easily simulate and optimise the performance of the surface flow line, choke, and tubing design. It can be used to design, optimise, and debug the following artificial lift systems: wells with jet pumps, wells with gas lifts, coiled tubing, PCP, ESP, and hydraulic pumps (HSP). The choke calculator can be used to predict the pressure drop across a known choke at a certain defined rate, as well as flow rates given the choke size or the choke size for a particular production rate. It can also be used to generate output that is choked. The multiphase flow correlations employed can be adjusted to match field data measurements and provide vertical lift performance curves (VLP) for use in simulators and network models.

3.1.1 PVT DATA

PARAMETERS	VALUE	UNITS
Initial reservoir pressure	4000	Psig
Reservoir temperature	150	^oF
GOR	550	Scf/stb
Gas Gravity	0.8	
API Gravity	40	API^o
CO_2	0.65	Mol%
N_2	0.77	Mol%
H_2S	0	Mol%
Water Salinity	200000	ppm

Table 3.1.1: PVT Data

3.1.2 IPR DATA

PARAMETERS	**VALUE**	**UNITS**
Reservoir pressure	2800	Psig
Reservoir temperature	150	^oF
Water cut	50	%
Total GOR	550	Scf/stb

Table 3.1.2: IPR Data

3.1.3 WELL DATA

PARAMETERS	VALUE	UNITS
Oil production rate	0	Stb/day
Water cut	50	%
WH Flowing Temperature	65	^oF
Pressure at Christmas tree	445	psig
Skin (Well test)	2.92	

Table 3.1.3: Well Data

3.1.4 WELL EQUIPMENT DATA

Node No	Component Name	Internal Diameter (ft.)	Measured Depth (ft.)
1	Outlet node / Christmas tree	-	0
2	Riser	4.77	350
3	5.5” Tubing	4.77	850
4	S.C.S.S.S.V.	3.60	850
5	5.5” Tubing	4.77	1500
6	5.5” Tubing	4.77	4000
7	5” Tubing	4.16	5600
8	Restriction	4	5600
9	Casing	6.06	6480
10	Casing	6.06	6530

Table 3.1.4: Well Equipmet Data

3.1.5 DEVIATION SURVEY

MD (ft.)	0	350	850	1500	2700	4000	5600	6480	6530.5
TVD (ft.)	0	350	850	1500	2695	3989	5577	6450	6500

Table 3.1.5: Deviation Survey

3.1.6 GEOTHERMAL GRADIENT

MEASURED DEPTH (ft)	FORMATION TEMPERATURE
0	65
6530	150

Table 3.1.6: Geothermal Gradient

3.2 CASE STUDY OBJECTIVES

- Use PROSPER to create a representative (valid) model that accurately simulates XYZ performance.

  The well is calibrated here by figuring out the fluid PVT, IPR, and VLP correlation that will accurately replicate the well that is being studied. If necessary, correlation matching will be used in this process.
- Simulate the base case projection for a range of operational circumstances. To ascertain the economic base case situation, a sensitivity run on various reservoir pressures and water cut variations is performed as part of this system study.
- Analyze several possibilities for development to maximize oil output.

A sensitivity run was conducted on all development possibilities, including altering the wellhead pressure (WHP), altering the tubing head pressure, and gas lifting to identify the ideal well-flowing state.

3.3 CREATING A BASE MODEL FOR WELL XYZ

The process of mimicking a well performance begins with a well calibration. The process of choosing or creating a set of correlations that will accurately represent the fluid and VLP properties of the specific well being studied is known as "well calibration." As a result, the integrated set of correlations will represent well performance. By choosing the features pertinent to the well's circumstances and the intended operation, the type of well to be modeled is specified in PROSPER's "Options Summary" sections. The well's description is shown in the table below.

Table 3.3.1: Data Entry in PROSPER

Fluid	Oil & Water
PVT method	Black Oil
Separator	Single-Stage Separator
Flow type	Tubing
Emulsions	No
Well type	Producer
Lift method	None
Predicting	Pressure and Temperature (Offshore)
Completion	Cased hole
Gravel Pack	No

3.3.1 Options Summary

Filling out the system summary, as shown in the image below, was the first step toward modeling the candidate well in PROSPER. The reservoir fluid is described by the Black Oil model's oil and water option. Additionally, the artificial lift method is selected here thereafter.

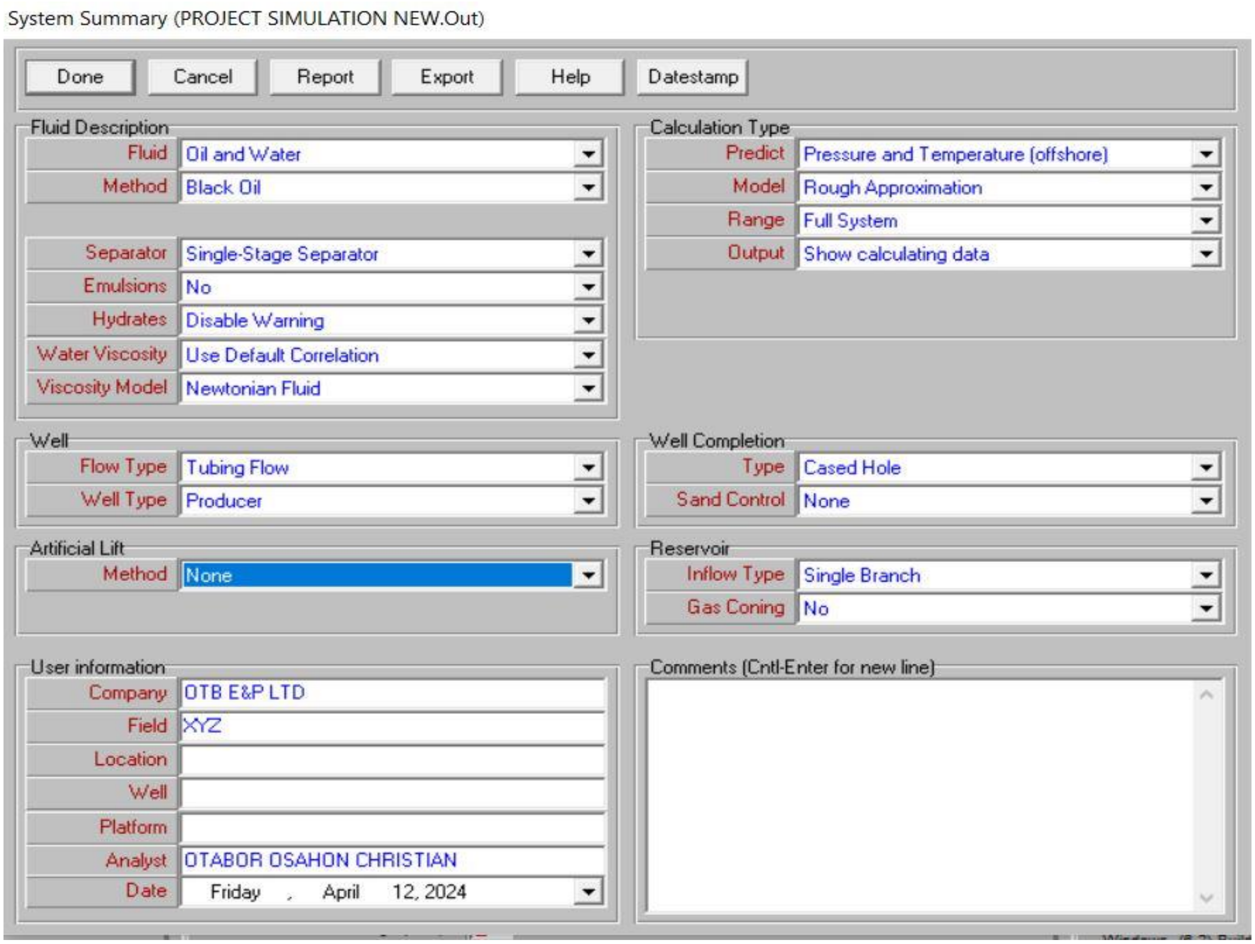


Figure 3.1: Options Summary

3.3.2 PVT Data Input

The next step is to select the PVT optionin the main menu to display the PVT input data screen.

Fill in the PVT data with parameters gotten from the table.

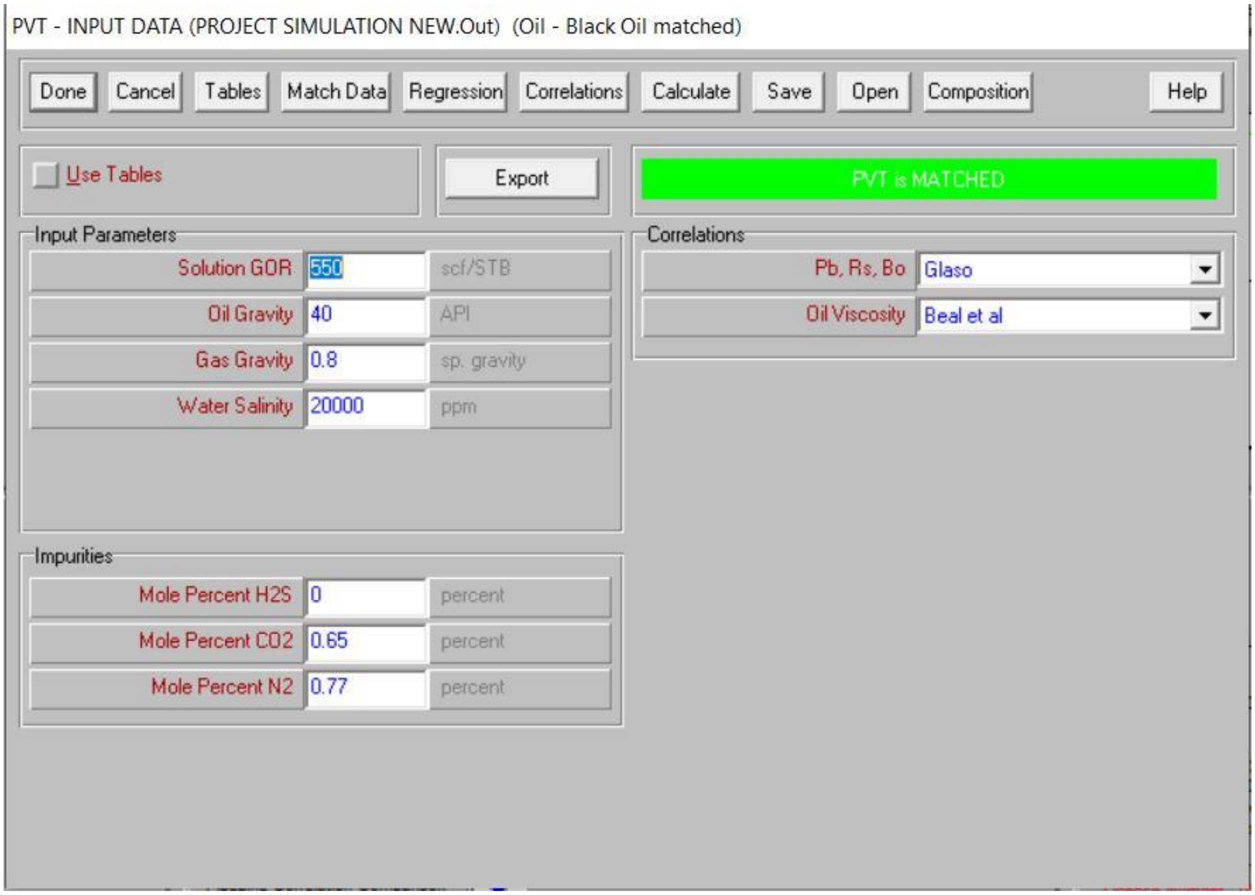


Figure 3.2: PVT Input Data Screen

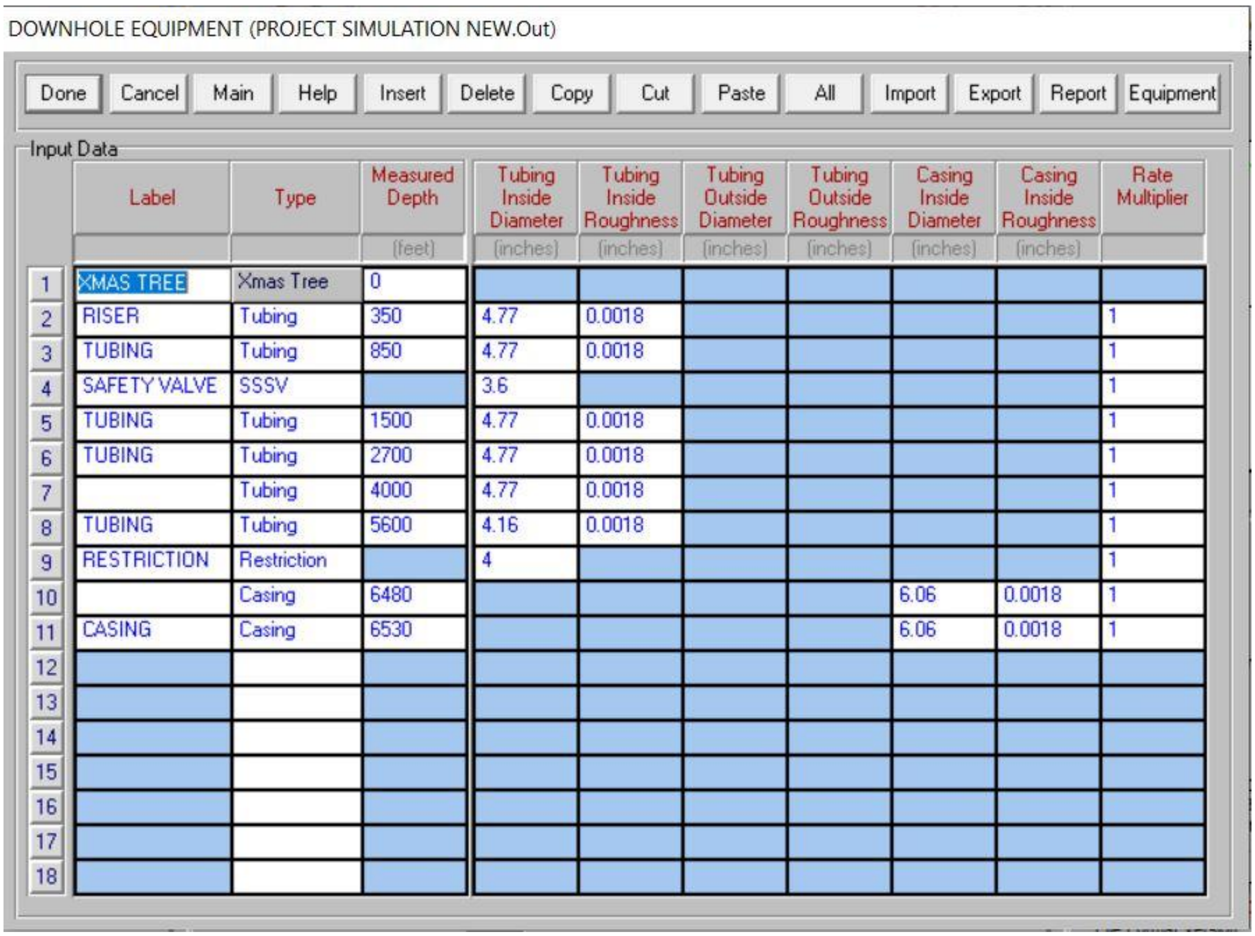
	Pressure	Gas Oil Ratio	Oil FVF	Oil Viscosity
	psig	scf/STB	RB/STB	centipoise
1	1000	244.632	1.12013	0.9293
2	1214.29	299.626	1.14664	0.84983
3	1428.57	356.577	1.17509	0.7783
4	1642.86	415.62	1.20545	0.71383
5	1857.14	476.867	1.2377	0.65571
6	2071.43	540.411	1.27182	0.60338
7	2285.71	550	1.27352	0.60321
8	2500	550	1.27007	0.61156
9	2714.29	550	1.26717	0.6199
10	2928.57	550	1.2647	0.62824
11	3142.86	550	1.26256	0.63658
12	3357.14	550	1.2607	0.64493
13	3571.43	550	1.25907	0.65327
14	3785.71	550	1.25762	0.66161
15	4000	550	1.25633	0.66995

Figure 3.3: PVT Match Data

The data matches after entering these settings. The mathematical models that most closely match the sets of observations from the laboratories are called correlations. They provide an example of typical hydrocarbon behaviour in PVT. If not exactly as predicted by the correlation, each fluid sample will react in a comparable manner overall. The correlation's adjustment variables that reduce the overall difference can be identified by comparing the values predicted by the correlation with the measured lab data. PROSPER applies a multiplier (Parameter 1) and a shift (Parameter 2) to each relationship in order to perform a non-linear regression.It displays the software's ability to match the data. It is anticipated that parameters 1 and 2 will have values that are nearly equal. The data should have the lowest possible standard deviation, which gauges how well the data are generally matched.

3.3.3 Equipment Data Input

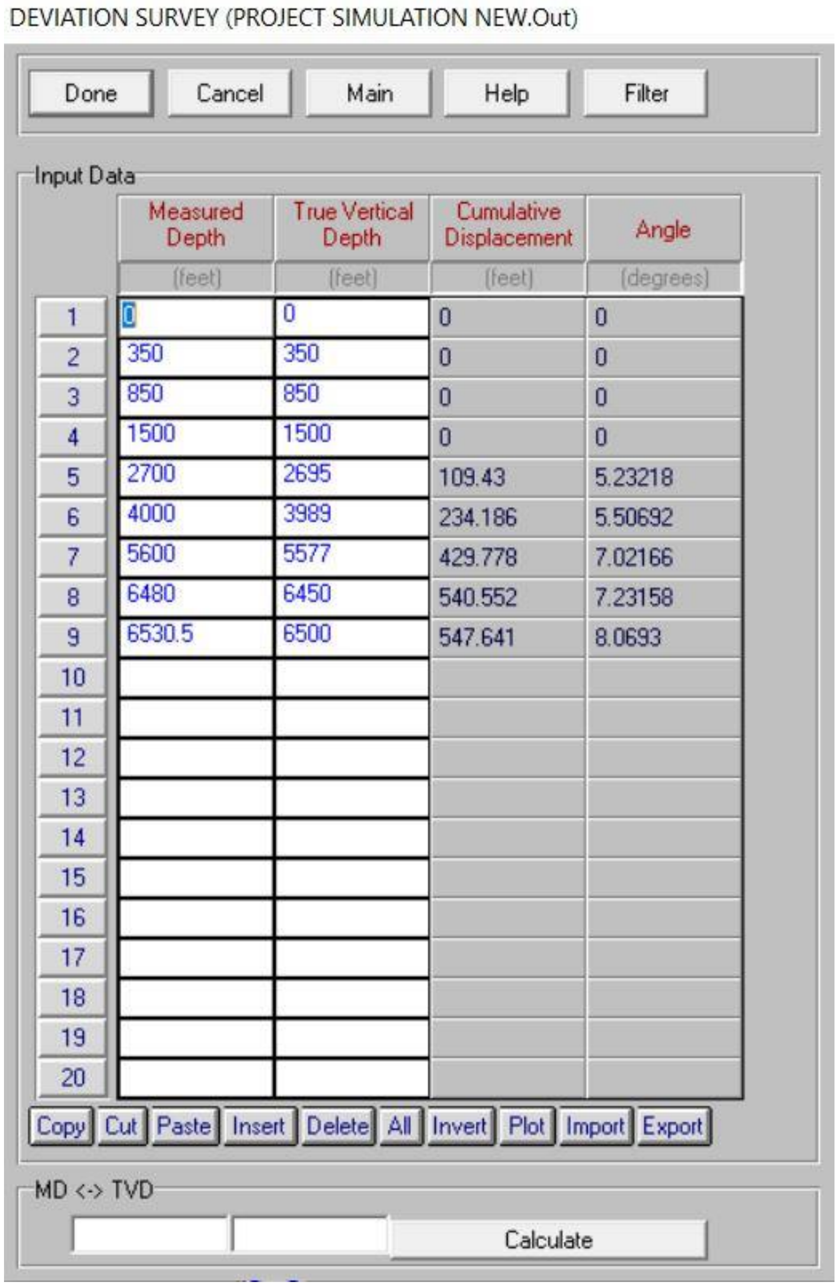
In order for PROSPER to calculate the pressure and temperature profile along the well, completion, survey, and temperature data are needed. The information submitted into PROSPER's equipment section was derived from the equipment data in the table. The inner and outer diameters of the tubing, liners, and casings are included in the model. The inner diameter of limitations, like the downhole safety valve (SSSV), is also taken into account. The inner roughness of the tubing and casing was 0.0006 inches.



	Label	Type	Measured Depth (feet)	Tubing Inside Diameter (inches)	Tubing Inside Roughness (inches)	Tubing Outside Diameter (inches)	Tubing Outside Roughness (inches)	Casing Inside Diameter (inches)	Casing Inside Roughness (inches)	Rate Multiplier
1	XMAS TREE	Xmas Tree	0							
2	RISER	Tubing	350	4.77	0.0018					1
3	TUBING	Tubing	850	4.77	0.0018					1
4	SAFETY VALVE	SSSV		3.6						1
5	TUBING	Tubing	1500	4.77	0.0018					1
6	TUBING	Tubing	2700	4.77	0.0018					1
7		Tubing	4000	4.77	0.0018					1
8	TUBING	Tubing	5600	4.16	0.0018					1
9	RESTRICTION	Restriction		4						1
10		Casing	6480					6.06	0.0018	1
11	CASING	Casing	6530					6.06	0.0018	1
12										
13										
14										
15										
16										
17										
18										

Figure 3.4: Downhole Equipment

The deviation survey data is also entered to get the well trajectory. From the data given, it can be seen that the well was deviated from a depth of about 2700ft.


DEVIATION SURVEY (PROJECT SIMULATION NEW.Out)

	Measured Depth (feet)	True Vertical Depth (feet)	Cumulative Displacement (feet)	Angle (degrees)
1	0	0	0	0
2	350	350	0	0
3	850	850	0	0
4	1500	1500	0	0
5	2700	2695	109.43	5.23218
6	4000	3989	234.186	5.50692
7	5600	5577	429.778	7.02166
8	6480	6450	540.552	7.23158
9	6530.5	6500	547.641	8.0693
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				

Figure 3.5: Deviation Survey

The geothermal gradient input data was also entered from Table 3.6. The overall heat transfer coefficient of 8BTU/h/ft^2/F was also inputted as shown in the Figure below.

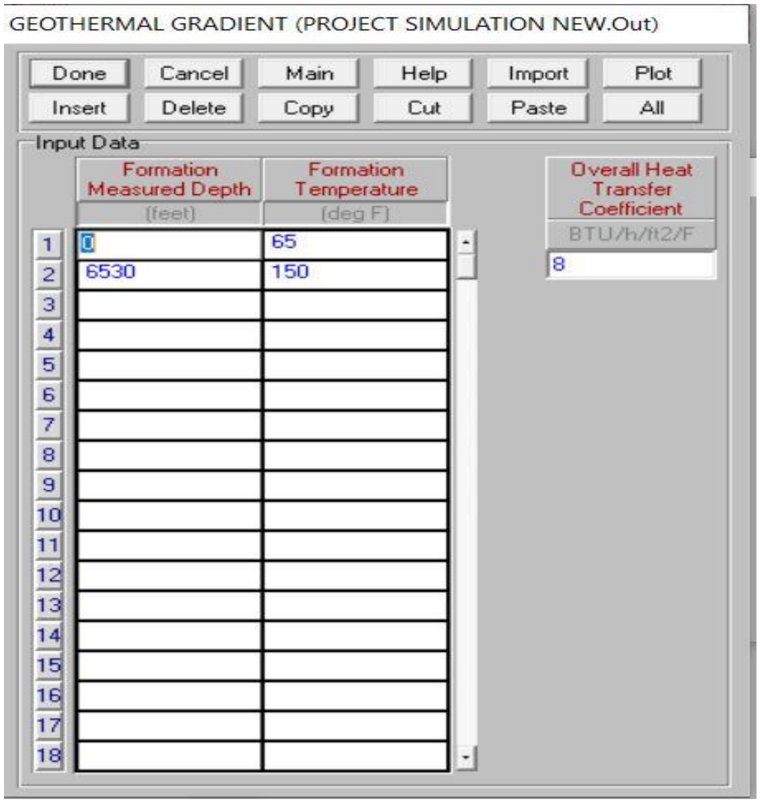


Figure 3.6: Geothermal Gradient

The average heat capacity values for oil, water and gas are also inputted in the average heat capacity section.

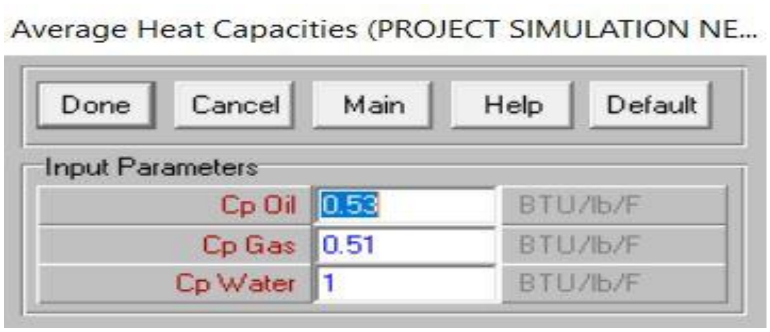


Figure 3.7: Average Heat Capacity

Following all of these, a sketch of the wellbore may then be seen.

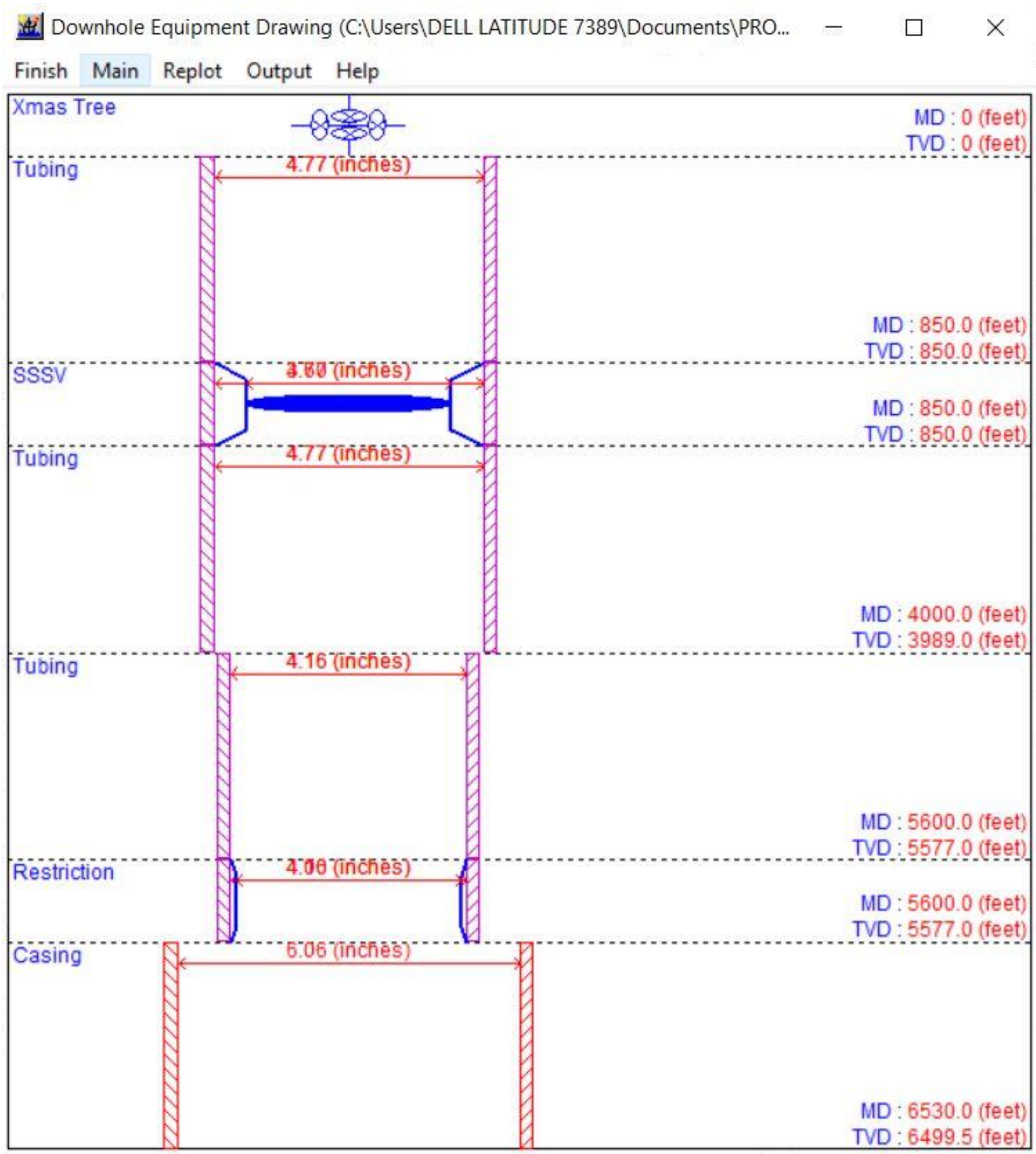


Figure 3.8: Downhole Equipment Drawing

3.3.4 IPR Data Input

The IPR curve was created once the PVT data was correctly matched. There were a lot of models for creating the IPR curve. The model used in this project was the “Darcy” model. The IPR data inputted was gotten from Table 3.2. and the option plot was selected which gave the IPR curve for the reservoir in figure 3.9 below.

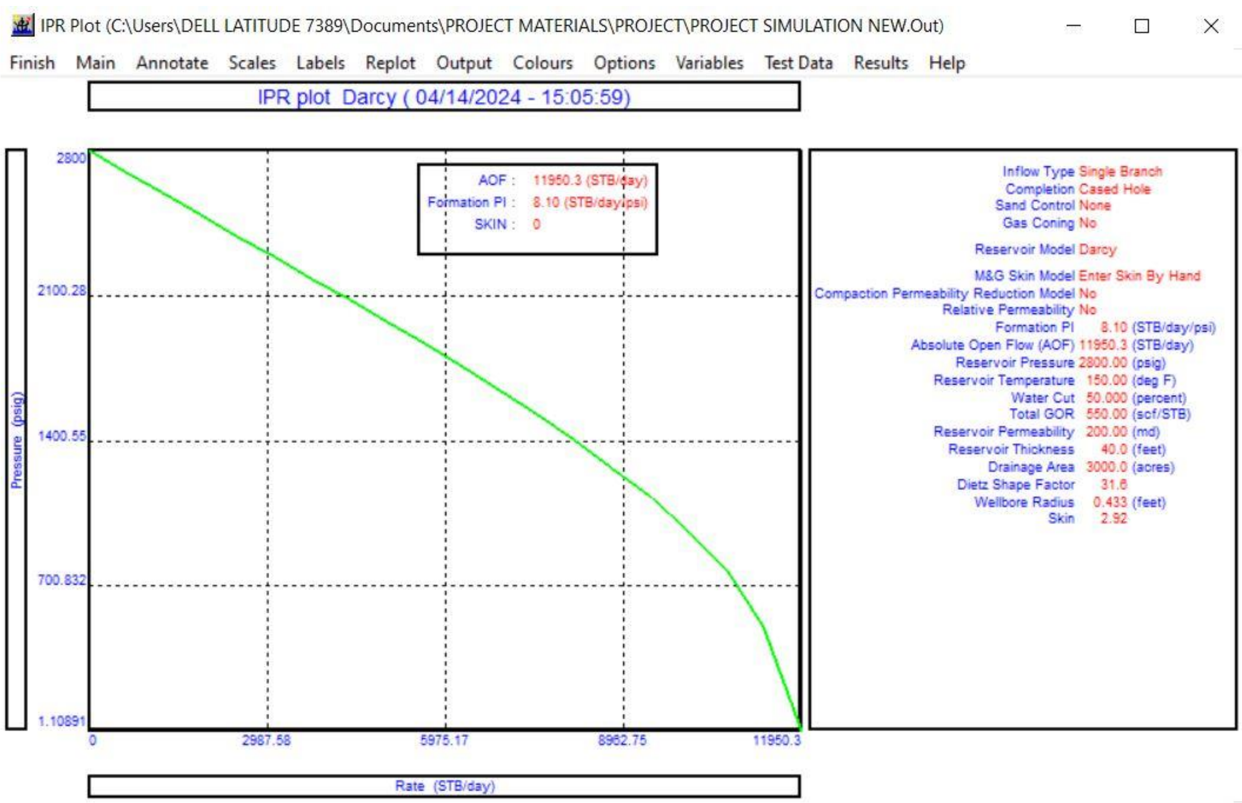


Figure 3.9: IPR PLOT

3.3.5 Calculating the well flow rate

The tubing response (VLP), reservoir data (IPR), and fluid characteristics are combined in the wellbore response. The intersection of the IPR and VLP curves can be used to determine the well flow rate given the reservoir pressure of 2800 psig and the wellhead flowing pressure of 445 psig. To get this intersection, the options |Calculation | System (Ipr + Vlp) | 3 Variables was selected on the PROSPER Interface as shown in the figure below.

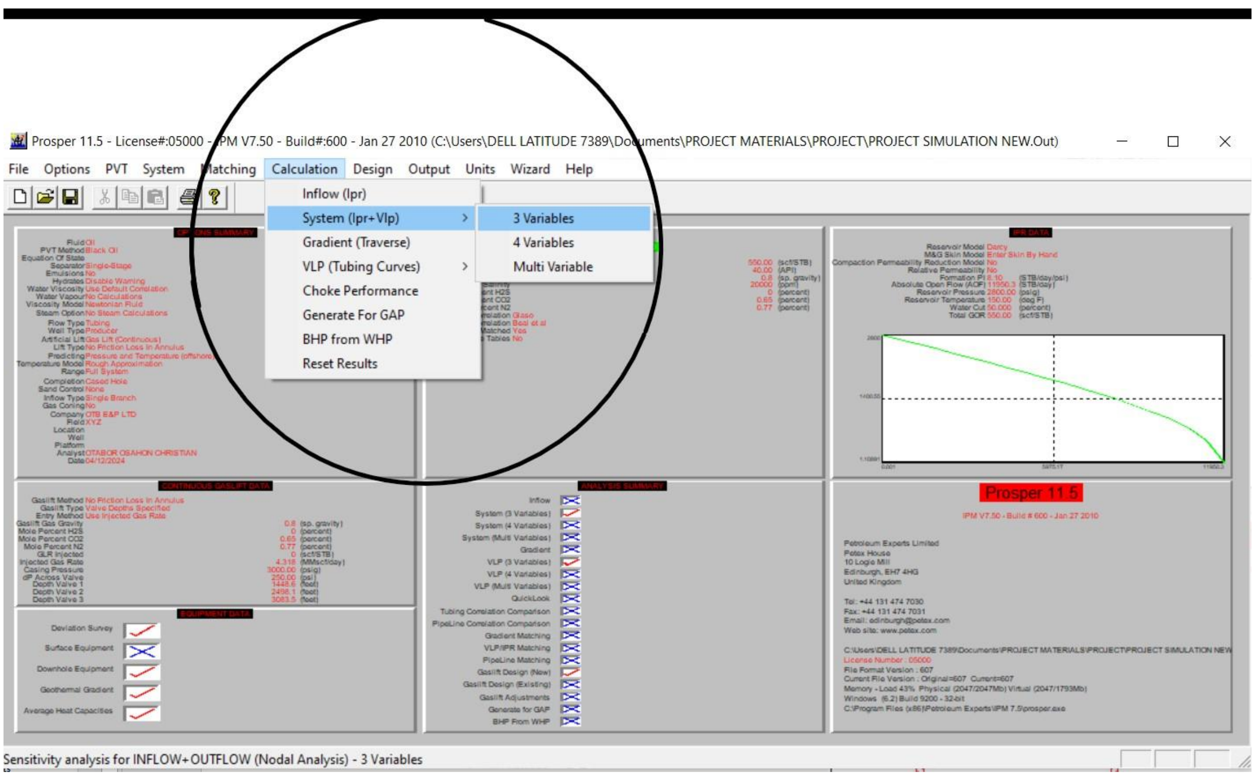
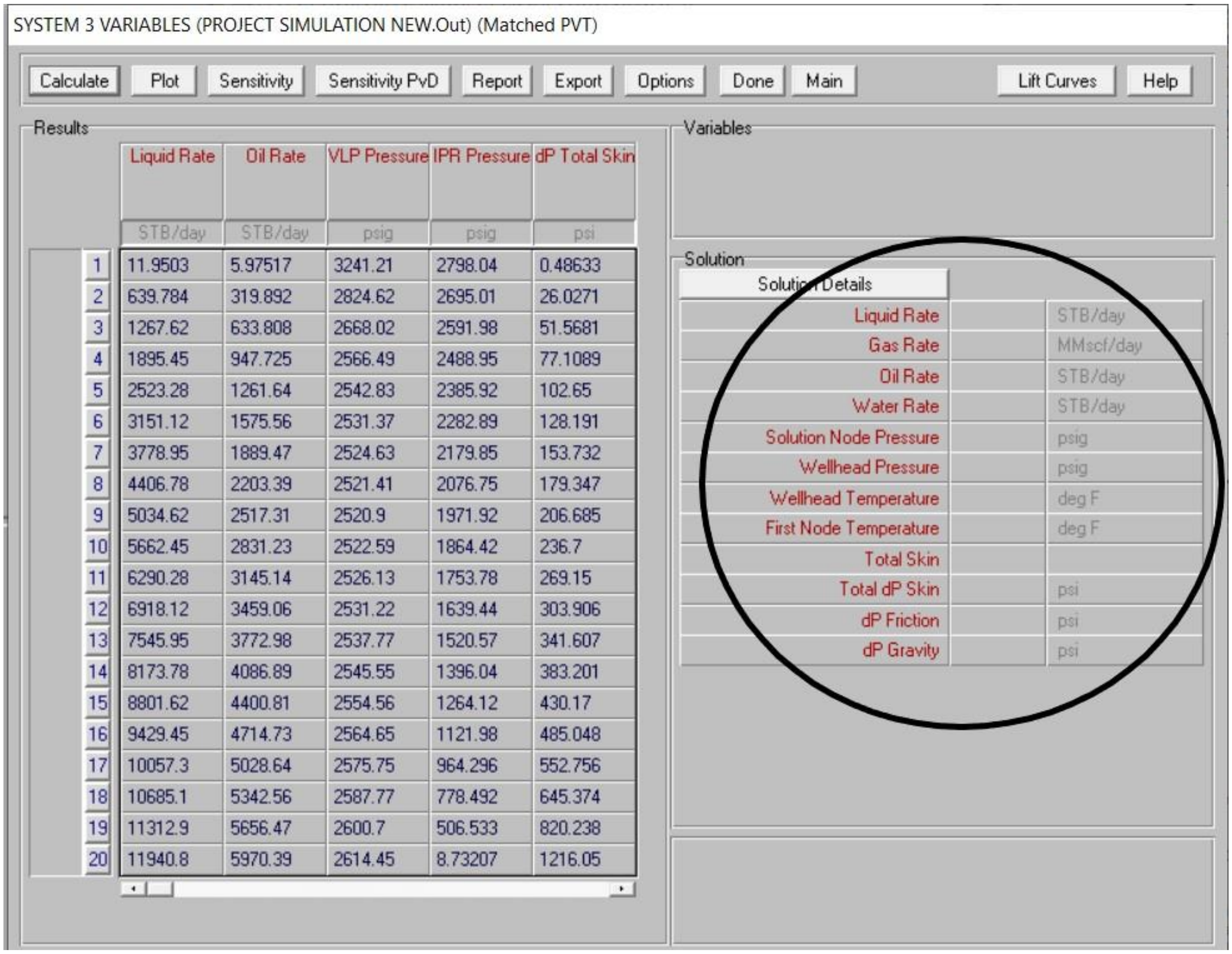


Figure 3.10: Calculations Screen Interface

Following that, the wellhead flowing pressure is entered. Since the pipeline was not accounted for in the model, the wellhead pressure was utilized as the top node pressure, even though the top node pressure is the pressure downstream.



	Liquid Rate STB/day	Oil Rate STB/day	VLP Pressure psig	IPR Pressure psig	dP Total Skin psi
1	11.9503	5.97517	3241.21	2798.04	0.48633
2	639.784	319.892	2824.62	2695.01	26.0271
3	1267.62	633.808	2668.02	2591.98	51.5681
4	1895.45	947.725	2566.49	2488.95	77.1089
5	2523.28	1261.64	2542.83	2385.92	102.65
6	3151.12	1575.56	2531.37	2282.89	128.191
7	3778.95	1889.47	2524.63	2179.85	153.732
8	4406.78	2203.39	2521.41	2076.75	179.347
9	5034.62	2517.31	2520.9	1971.92	206.685
10	5662.45	2831.23	2522.59	1864.42	236.7
11	6290.28	3145.14	2526.13	1753.78	269.15
12	6918.12	3459.06	2531.22	1639.44	303.906
13	7545.95	3772.98	2537.77	1520.57	341.607
14	8173.78	4086.89	2545.55	1396.04	383.201
15	8801.62	4400.81	2554.56	1264.12	430.17
16	9429.45	4714.73	2564.65	1121.98	485.048
17	10057.3	5028.64	2575.75	964.296	552.756
18	10685.1	5342.56	2587.77	778.492	645.374
19	11312.9	5656.47	2600.7	506.533	820.238
20	11940.8	5970.39	2614.45	8.73207	1216.05

Figure 3.11: Liquid Rate Interface

It was then calculated, yielding the following result, after that. Since there was no liquid rate, it was evident from the area that is ringed in Figure 3.11 above that the well was not flowing.

Plotting the IPR and VLP curves further revealed that the well was not flowing because the curves did not meet. The Figure below displays the structure of the plot.

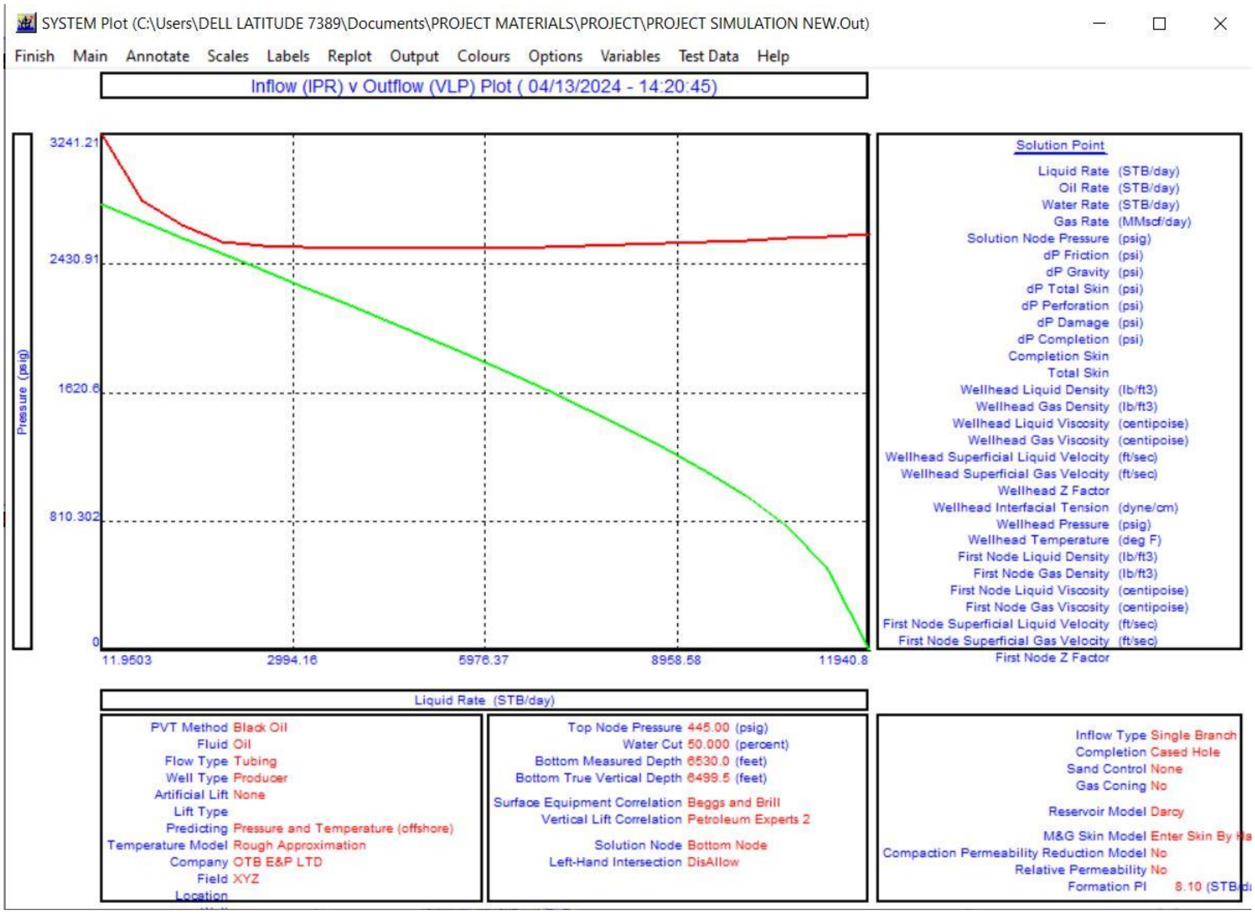


Figure 3.12: IPR Vs VLP Plot

3.4 BASE CASE SIMULATION UNDER DIFFERENT OPERATIONAL CONDITIONS

Once the PVT, VLP, and IPR match measured data, the model can be used to proceed with a System analysis. A sensitivity run using water cut ranges and variable reservoir pressure is conducted to find the Maximum Economic Base Case condition.

3.4.1 Reservoir Pressures and Water Cut Ranges

Parameter	Range
Water Cut	10, 20, 30, 40, 50 (%)
Reservoir Pressure	2700, 2800, 2900, 2950, 3000 (psig)

Table 3.10.1: Reservoir Pressures and Water Cut Ranges

3.4.2 Varying Wellhead Pressure at Different Water Cut Ranges

A decrease in WHP leads to an increase in drawdown, which raises oil output. There will be a sensitivity run on the existing reservoir conditions for decreasing wellhead pressure (WHP). In an oil well, the choke can be used to modify WHP.

Parameter	Range
Water Cut	40, 50, 60, 70, 80 (%)
Wellhead Pressure	445, 345, 245 (psig)

Table 3.10.2: Wellhead Pressure and Water Cut Ranges

3.5 GAS LIFT DESIGN

To determine the ideal gas injection rate and injection depth that would result in the well flowing and producing at its best, gas lift design is currently done using PROSPER. As seen in the figure below, the gas lift option is chosen on the option summary.

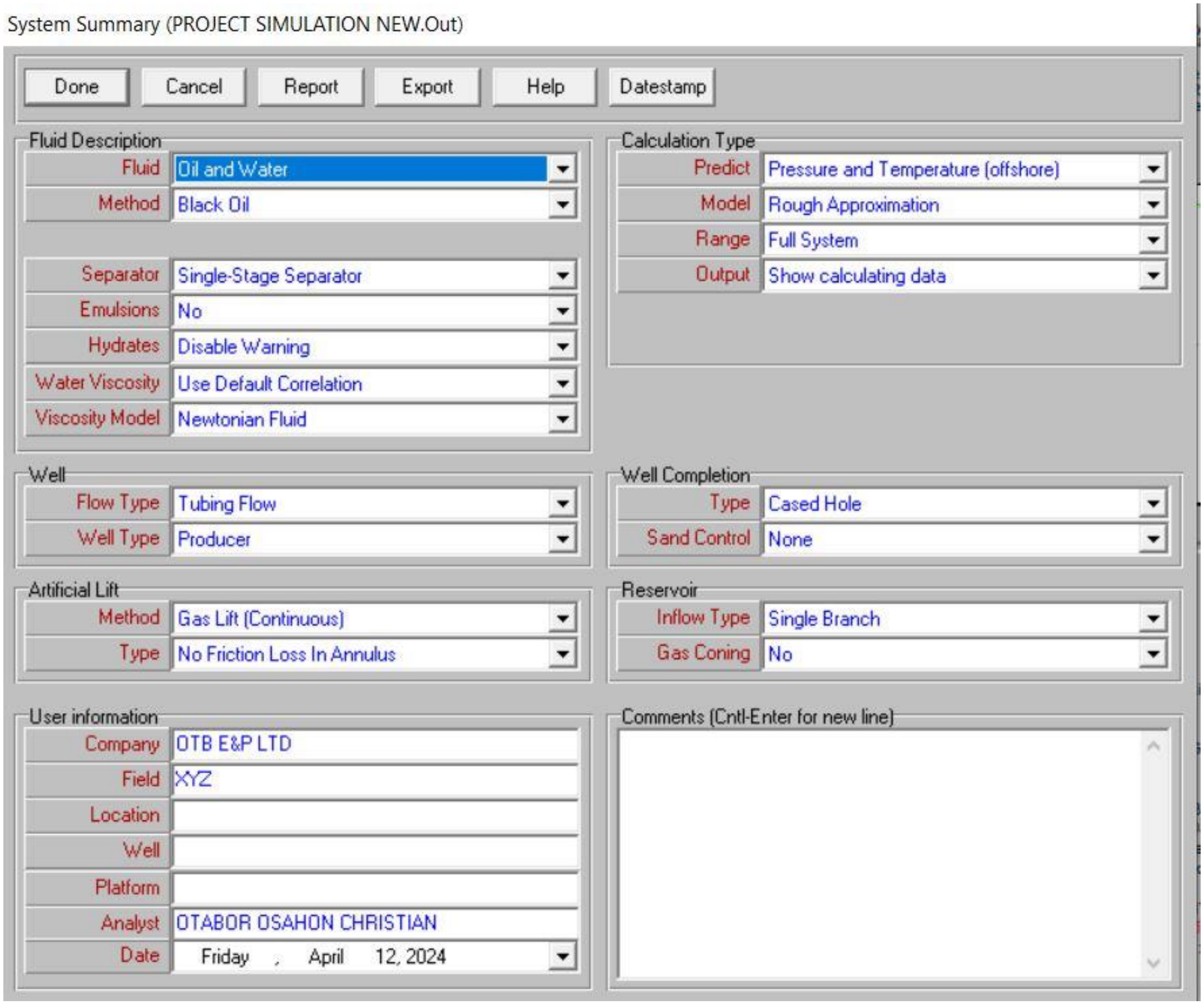


Figure 3.13: Option Summary Interface

3.5.1 Gas Lift Design

The first step is to design a new continuous gas lift system. In the main gas lift design screen, the following input data are inputted as shown in Figure 3.14 below;

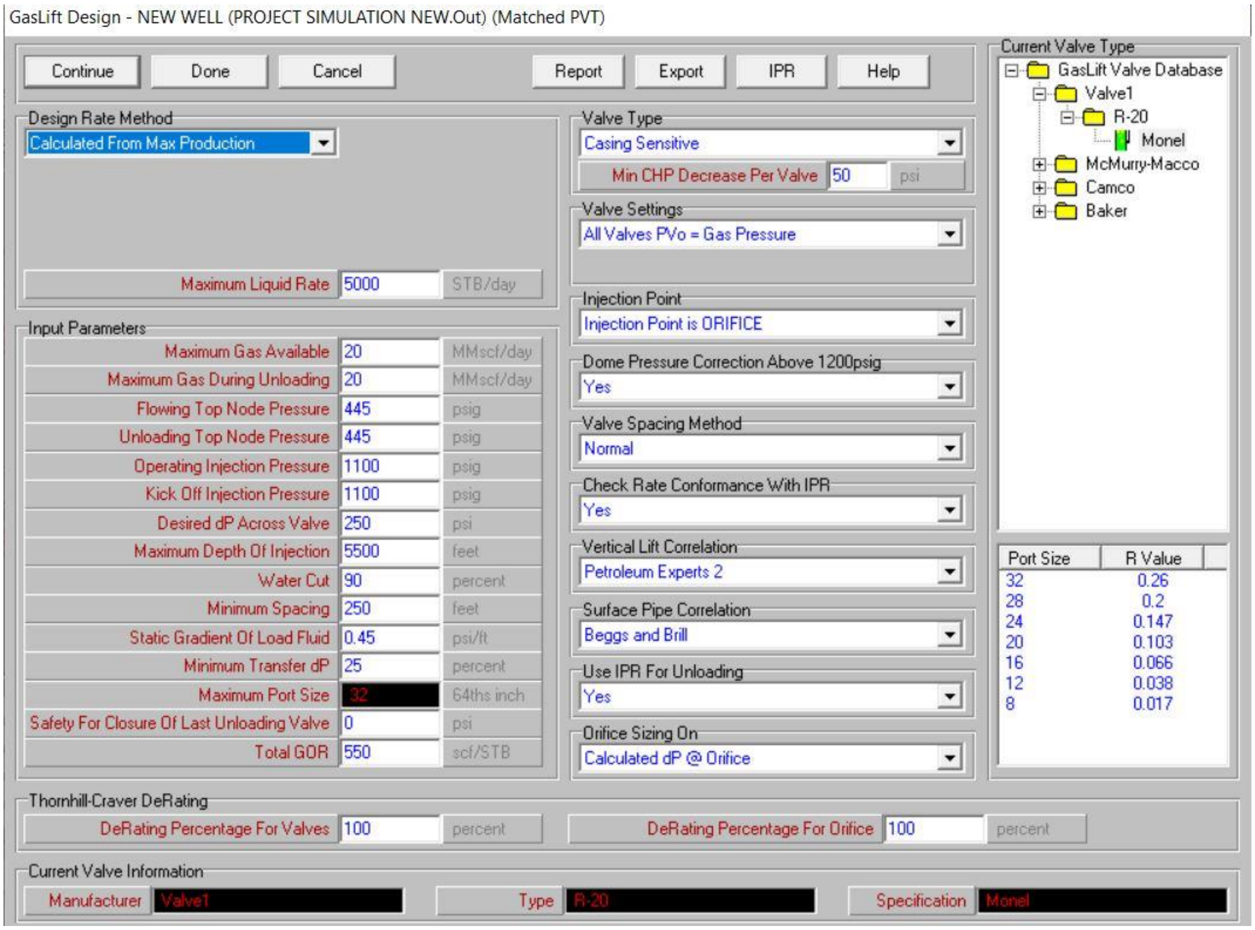


Figure 3.14: Gas Lift Design Interface

As a constant constraint on the surface facilities, the top node pressures for loading and unloading are 445 psig. The injection pressure and kick-off injection pressure, which is the first injection pressure given during the unloading process, are set at 1100 psig in order to abide by the first casing pressure constraint. The valves' dP is fixed at 250 psi. This indicates that the annulus pressure must be at least 250 psi greater than the tube pressure in order to account for valve consumption. As a safety precaution, this guarantees that gas will pass through the valve. This causes valves to be installed several feet shallower than planned during the design phase, which has an impact on the calculations. 5,500 ft MD is the maximum depth at which gas injection is permitted. The unloading valves are positioned at least 250 feet apart by default. If the next valve turns out to be less than 250 feet below the surface, the calculations will stop. Brine, which has a static pressure gradient of 0.4 psi/ft and is somewhat denser than pure water, is the completion fluid that is used. The valve response during the subcritical to critical flow transition is described by the Thornhill-Craver equation. This formula can be used to determine how much gas flows through the valve port in a minute.

It has been found, therefore, that this model exaggerates the flow through the gas lift valves. The Thornhill-Craver derating% of valves and orifices is a coefficient that is used to remedy this. This coefficient can lead to a larger predicted orifice or port size by lowering the maximum gas injection rate that can pass through a valve. 100% is the default setting.

The "casing sensitive" valve type was selected. For every valve, the reduction in casing head injection pressure is controlled by 50 psi.

The option "All valves PVo = Gas Pressure" is how the valves are configured. Both the computed closing pressure drop and the maximum pressure drop are used in PROSPER designs to close valves. By using this method, valves are prevented from closing early than intended. However, reduced output rates will be seen because there is less injection pressure available.

Compliance with the IPR is required to guarantee that the reservoir can produce the projected liquid rates. Therefore, in order to guarantee that the maximum liquid rate could be computed, an extremely high projected production rate was initially entered. The valve is sized using this injection rate.

We have chosen a "Valve1 R-20 Monel" valve from the PROSPER database for this project. The port diameters of the valve range from 8 to 32 64ths of an inch. The port sizes that will produce the maximum output will be determined by the program. PROSPER can still determine the optimal production output even if a valve from a different manufacturer calls for a different port size. Which kind of valve you choose is irrelevant as long as it is casing-sensitive.

The design phase starts as soon as the required input data is given. The injection rate that PROSPER determined to be optimal is displayed at the top of Figure 3.15. In addition, Figure 3.16 displays a gas lift performance curve. The optimum gas rate, or 4.3 million standard cubic feet per day (MMscf/day), is the largest gas injection rate that can be achieved, based on the calculations. This rate is the price of petrol at which the maximum amount of oil can be produced. However, it is important to note that this rate is not the final gas injection rate as the unloading process has not been taken into account yet.

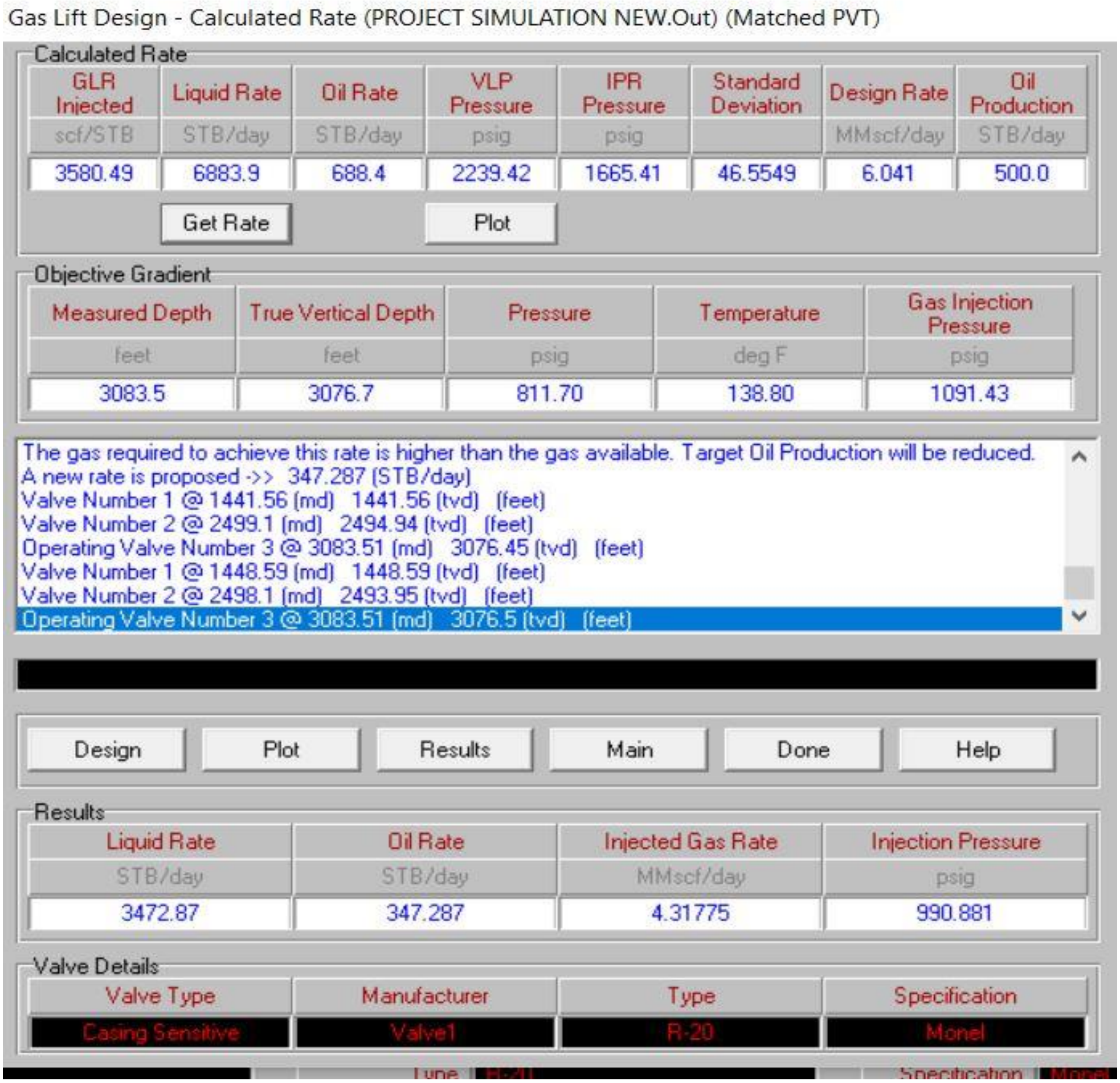


Figure 3.15: Gas Lift Design – Calculated Rate Screen

The gas lift performance curve is a result of sensitivity analysis of different injection rates at varying depths for each rate. PROSPER randomly distributes the injection rates and depths, and they are not plotted for a specific maximum depth of injection. In Figure 3.16, the randomly selected gas prices are represented by red points. The curve provides the optimal injection rate, which is utilized as a design variable for the valve spacing process.

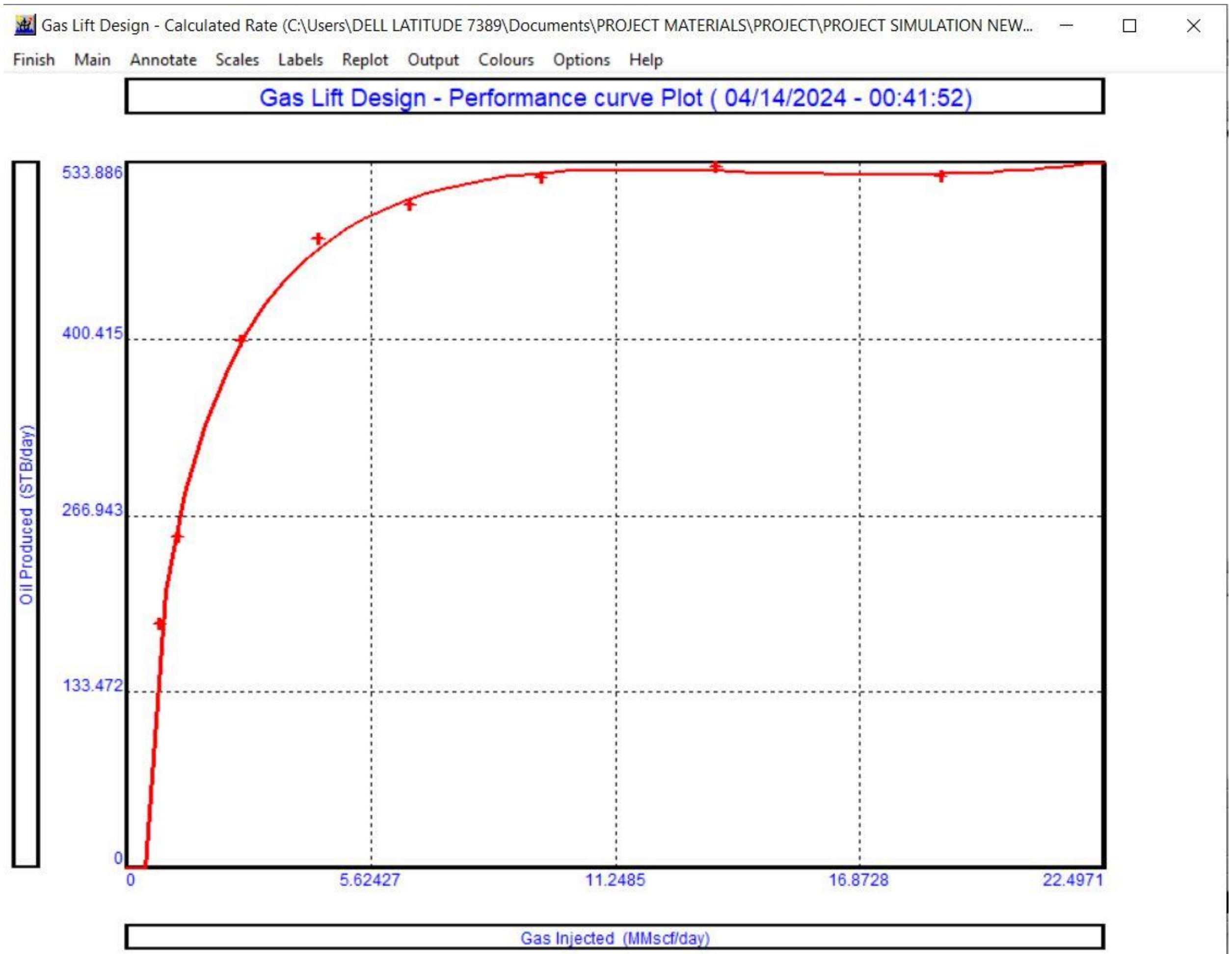


Figure 3.16: Gas Lift Performance Curve for Well XYZ

The well performance curve plot (Oil Rate vs Gas Injected) was exited using Finish and Design was chosen to carry out the GL design. Once the design was completed, the Plot tab located in the lower half of the screen was utilized to evaluate the outcomes. As depicted in Figure 3.17 below, the Gas Lift gas gravity was inputted into the Gas Lift data interface.

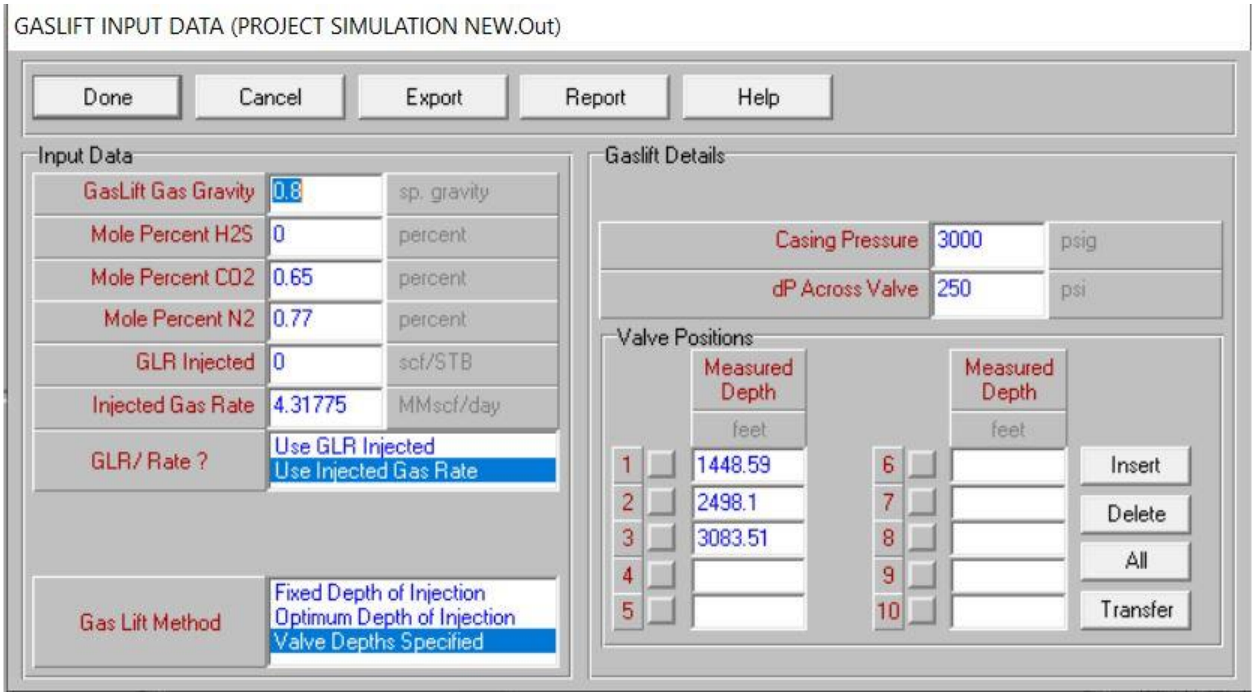


Figure 3.17: Gas Lift Input Data Screen

The computed rates for water and oil, known as liquid rates, are presented in Figure 3.18, which displays their range of values.

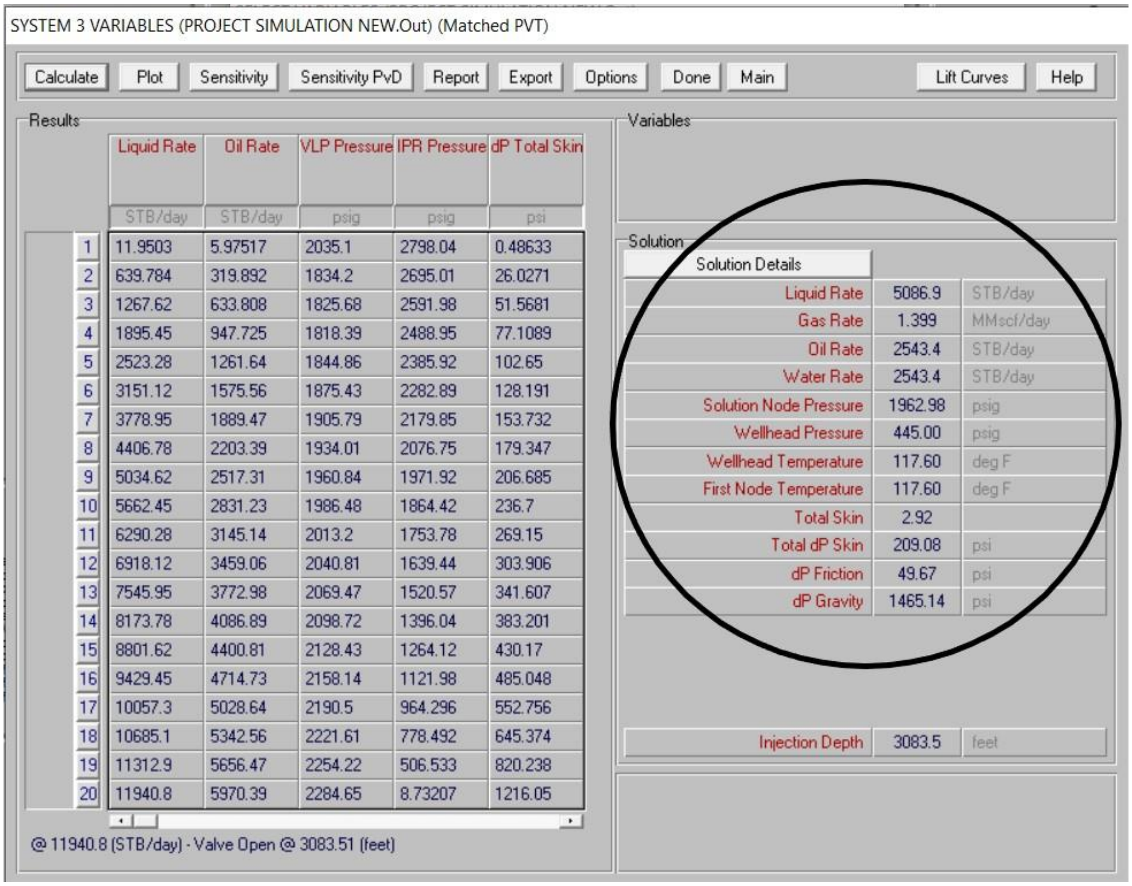


Figure 3.18: Gas Lift Liquid Rate Interface

CHAPTER 4

RESULTS AND DISCUSSION

4.1 BASE CASE SIMULATION UNDER DIFFERENT OPERATIONAL CONDITIONS

To determine the Maximum Economic Base Case condition, a sensitivity analysis is performed by varying the water cut ranges and adjusting the reservoir pressure after matching the measured data with PVT, VLP, and IPR. This allows the model to be used for a thorough system analysis.

4.1.1 Reservoir Pressure and Water Cut Ranges

The table below displays the results of the sensitivity run, outlining the outcomes achieved.

RESERVOIR PRESSURE (Psig)	**WATER CUTS**				
	10	20	30	40	50
	OIL RATES (STB/D)				
3000	5271.5	4173.3	3143	2215	1393.5
2950	5028.6	3949.6	2939	2031	1222
2900	4786.5	3724.7	2730.5	1835.4	1045.5
2800	4283.8	3254	2298	**1426**	0
2700	3761.8	2764.3	1832.6	0	0

Table 4.1.1(a): Oil Rates at Given Parameter Ranges for Well XYZ

SCENARIO	MAX. ECONOMIC WATER CUT	PRODUCTION RATE AT 50% WATER CUT
Base case	40%	0 (STB/D)

Table 4.1.1(b): Economic Base Conditions for Well XYZ

Based on the findings, it appears that an increase in water cuts leads to a decrease in production rate. Therefore, given the current reservoir pressure, the maximum economic water cut is 40%. This is because the flow rate exceeds the economic limit at the 40% water cut. Furthermore, the well will not flow with a 50% water cut in its present condition. If deemed practical and cost-effective, adjustments may be made to some or all of the well's nodes.

4.1.2 Varying Wellhead Pressure at Different Water Cut Ranges

A sensitivity analysis was conducted to determine the effect of reducing wellhead pressure (WHP) on oil output via increased drawdown. The table below displays the results of the sensitivity run, outlining the outcomes achieved.

WHP (Psig)	**WATER CUTS**				
	40	50	60	70	80
	OIL RATES (STB/D)				
445	1425.2	0	0	0	0
345	2378.5	1468	0	0	0
245	3367.4	2318.2	**1372**	566.6	0

Table 4.1.2(a): Oil Rates for Base Case at Different Water Cuts for Well XYZ

SCENARIO	MAX. ECONOMIC WATER CUT	PRODUCTION RATE AT 50% WATER CUT
Lowering Christmas tree pressure	60%	2318.2(STB/D)

Table 4.1.2(b): Economic Oil Rate With Reduced WHP for Well XYZ

This result shows that when the WHP is decreased, the drawdown increases, resulting in higher oil production. It has been observed that the maximum economic water cut is achieved at a WHP of 245 psig and a reservoir pressure of 2800 psig with a 60% water cut. Therefore, it is recommended to lower the wellhead pressure to 245 psig to extend the well's lifespan up to a 60% water cut level.

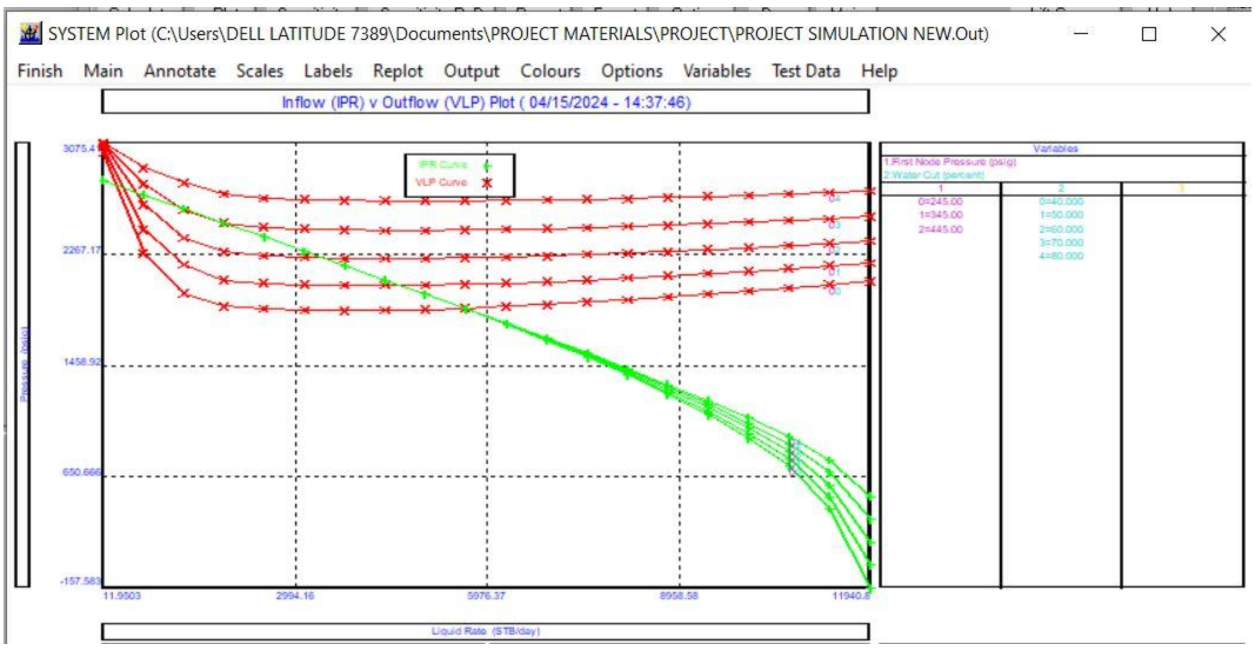


Figure 4.1.2: IPR/VLP Plot for Reduced WHP at Different Water Cuts

4.1.3 Gas Lift (Artificial Lift Method)

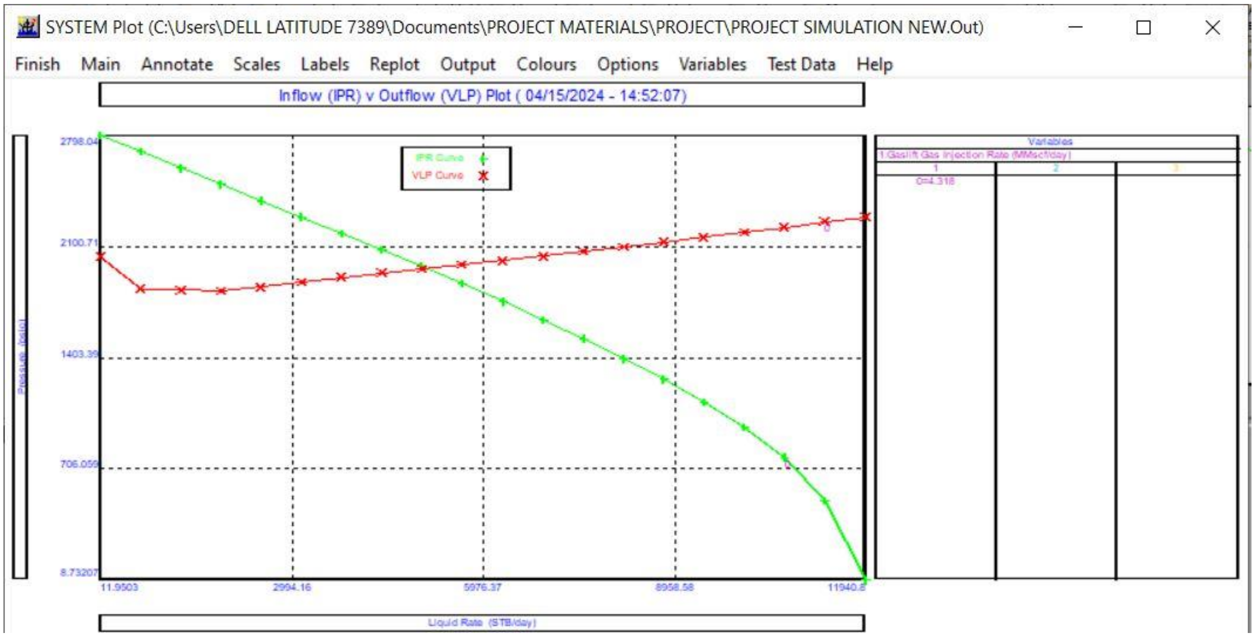


Figure 4.1.3.1: IPR/VLP Curve After Gas Lift

The table below displays the results of the sensitivity run, outlining the outcomes achieved.

GAS INJECTION (MMScf/d)	WATER CUT (%)					
	40	50	60	70	80	90
	OIL RATES (STB/D)					
4.31775	3255	2543.4	1888.4	1298.8	**781.5**	347.5

Table 4.1.3(a): Oil rates at Different Water Cuts for Gas Lift

SCENARIO	MAX. ECONOMIC WATER CUT	PRODUCTION RATE AT 50% WATER CUT
Optimized gas lift	80%	2543.4(STB/D)

Table 4.1.3(b): Economic Oil Rate with Optimized Gas Lift for Well XYZ

The study shows that using a gas lift can be cost-effective, resulting in an economic water cut of up to 80%.

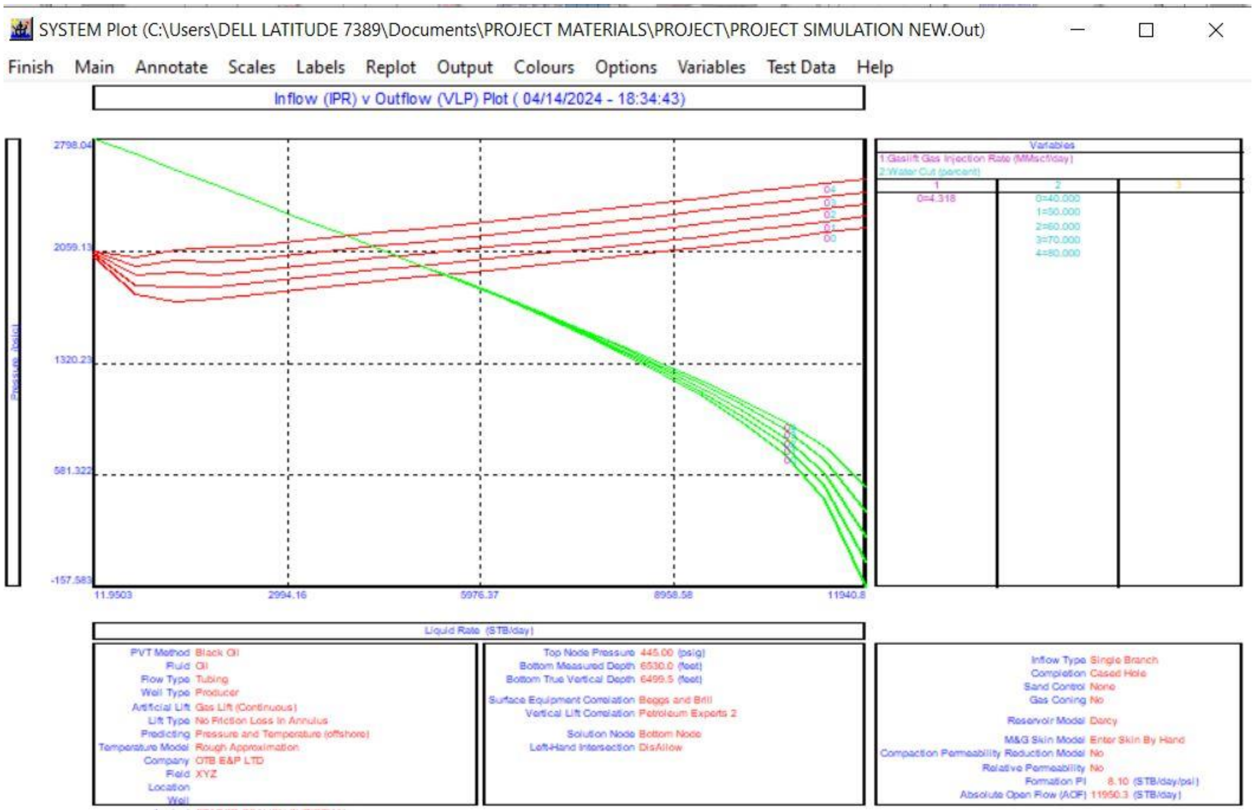


Figure 4.1.3.2: IPR vs VLP Plot for Gas Lifted Well with Varying Water Cuts

4.2 RESULT ANALYSIS

1. At base circumstances, the maximum profitable water cut for well XYZ is 40%. Production stops entirely once the water cut exceeds 50%.

2. Lowering Christmas tree pressure to 245 psig extends the well life to a water cut of 60%

3. The use of gas lift is cost-effective as it can achieve a maximum economical water cut of up to 80%.

CHAPTER 5

CONCLUSION

5.1 SUMMARY

The research had three primary objectives: to simulate Well XYZ in its natural state, and to optimize Well X using the Gas Lift Method. Historical production figures for Well XYZ indicate that production continued for a while until ceasing due to an increased water cut to 50%. To replicate the well in its natural state, PROSPER was used, and the IPR (inflow performance relationship) and VLP (vertical lift performance) curves were plotted using Chapter 3 as a guide. However, as demonstrated by the inability of the curves to join, this proved that the well was not flowing as indicated.

An artificial lift was needed for the well, and it was determined that a gas lift would be the best option since there was plenty of injection gas available. Using PROSPER, a gas lift performance curve was developed to determine the optimal gas injection rate. The system also found the ideal injection depth for installing the functional valve.

By using the recommended injection depth of 3083.5 feet and a gas injection rate of 4.318MMscf/day, the system generated an IPR and VLP curve for well XYZ producing at a water cut of 50%. The intersection of these lines showed that the well was now producing oil at a rate of 2543.4 STB/day.

Water cut sensitivity was employed to test the well's flow maintenance capacity under different water cut scenarios. Results showed that the well could maintain its flow even at high water cuts of 60%, 70%, 80%, 90%, and 100% while injecting gas at a rate of 4.318 MMsf/day at a depth of 3038.5 feet. However, the production of oil did decline as the water cut increased.

5.2 CONCLUSION

In conclusion, for well XYZ to start producing optimally at a water cut of 50%, the Gas Lift method is to be used. After modeling and carrying out system calculations with PROSPER, a gas injection rate of 4.318MMscf/day and injection depth of 3083.5ft would cause the well to produce optimally at an oil rate of 2543.4STB/day.

5.3 RECOMMENDATIONS

It is highly recommended to model the well and observe its response to flow rate using software such as PROSPER before implementing any artificial lift techniques on the actual well. This will help in determining which type of artificial lift will optimize the well most effectively.

If a well is not producing at its optimal level, it is advisable to consider gas lifting the well. This is particularly true when gas is readily available as it is often less expensive. Additionally, the well's produced gases can be utilized as lifting gas, which helps in reducing expenses.

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