**TECHNICAL UNIVERSITY OF CRETE**

**SCHOOL OF MINERAL RESOURCES ENGINEERING**

**MSc PETROLEUM ENGINEERING**

**Master Thesis**

**"LARGE-SCALE FULL-TIME FIELD GAS LIFT DESIGN"**

**Author**

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# Abstract

Nodal analysis is the standard tool to use when designing a wellbore provided that steady state flow conditions prevail in the well. However, when operating conditions such as GOR, water cut, bottomhole flowing pressure or rate vary over time nodal analysis cannot be used directly. As a result, it cannot be directly applied to the bottom hole conditions which are obtained from a reservoir simulation program. To design a well under such transient reservoir conditions, pressure traverse curves need to be combined to the well flow data.

In this thesis a dynamic reservoir model was set up and history matched by using the tNavigator reservoir simulation software. Firstly, the deviation survey of each well was needed to be designed in order to meet their location in the reservoir space. Subsequently, well flow data which is required to design the appropriate wellbore were exported and further utilized as input for the PIPESIM well flow simulator, and each well was checked for its ability to bear the prediction at the surface without the need for artificial lift.

For each well in the reservoir model that needed a gas lift, such a system was designed to compensate the required production rates while respecting the available bottom hole pressure, as indicated by the reservoir simulation scenario. The gas lift system design consisted of selecting the appropriate well tubing size, the number and depth of injection valves, the gas injection pressure and the injected gas flowrate.

Additionally, an evaluation of the well performance was run to test if the reservoir simulation schedule is running with no production problems.

# 1. Introduction

## 1.1 Importance of petroleum

Even though nowadays renewable sources of energy are coming into play and are significantly trying to compensate the need for fossil fuels, the majority of modern society energy supply is still provided from fossil fuels. Crude oil is definitely one of the most widely used fossil fuel. Its use ranges from transportation, heating and lighting, petro-chemical industry, power generation and much more. And it would be definitely hard or even impossible to imagine day-to-day life of a man without oil.

## 1.2 Extraction of petroleum

Despite the widely believed myth that petroleum is accumulated in underground lakes waiting for us to find it, the truth is quite more complicated. Before we come to production of petroleum a long and exhausting exploratory process precedes in which the main role is taken by geologists and geophysicists. By utilizing established methods and their expertise they are able to investigate deep underground geological structures that are likely to be good "candidates" of possible oil reservoirs. Drilling comes into play after the completion of the exploration phase. In this phase by utilization of specific configurations called rigs a well is created, by drilling a deep hole into the earth until connection is established from a possible reservoir to the surface. Steel pipes (casing strings) are introduced into the wellbore in order to prevent collapse, followed by the tubing which prepares the well for the production stage. As a part of completion, perforations (small holes) are penetrated at the bottom of the well in order to establish connection between the well and the reservoir zone and enable the fluid flow to the surface. Finally, a set of valves widely known in industry as "Christmas Tree" is placed at the top, by means of which pressures and flowrate are regulated.

# 1.Introduction

## 1.3 Artificial lift

The majority of reservoirs at the start of their life are able to produce fluid naturally with the use of their own energy, widely known as primary drive mechanisms. At early stages of reservoir lifetime well bottomhole pressure is often high enough to overcome total pressure loss caused by fluid flow from bottom hole to the surface and hydrostatic pressure of the column itself. This stage of reservoir lifetime is often called primary production.

Once the energy of stemming from the primary drive mechanism starts to decay or when increased water production affects negatively the hydrostatic pressure of the wells, the wells may need some artificial source of energy in order to deliver targeted quantities of fluid. In this case artificial lift methods need to be implemented such as the required bottomhole pressure can be preserved. Actually, artificial lift adds additional energy to the fluid in the well which, accompanied by the reservoir energy allows the well to flow at desired rate. (Schlumberger, Gas Lift Design and Technology, 1999)

## 1.4 PIPESIM

PIPESIM is a widely used multiphase well flow simulator which enables the engineers to design the flowlines and the pipeline systems including surface equipment (e.g. separators, pumps, compressors, chokes etc.) The fluid properties can be modeled either by black-oil correlations or in a fully compositional way.

PIPESIM offers users the following features;

- Rigorous Modelling of Oil, Gas and Condensate Multiphase flows

- Many multiphase flow modelling options

- Advanced PVT and physical properties prediction

- Efficient and Productive Windows GUI

- Powerful results features: reports & graphs

and allows the following systems to be modelled;

- Production Wells, including flowline and process equipment

- Horizontal Completion

- Surface facilities

- Injection Wells

PIPESIM, is used throughout this MSc thesis for all calculations regarding setting up of a reliable model and building on it a productive continuous gas lift system. (PIPESIM user Manual, 2017)

## 1.5 tNavigator Black oil Simulator

The tNavigator reservoir simulation software is used throughout this MSc Thesis for running and the dynamic reservoir model exporting the valuable data from that needed to be imported to the PIPESIM. The new reservoir simulator tNavigator developed by the Rock Flow Dynamics (RFD) technologies, is becoming more and more popular recently because of its obvious increase speed and accuracy to compute simulation results. The system has a user-friendly interface which makes it very attractive. According to its developers, the reason why it computes faster the results of complex reservoir models, lies in the fact that it is written in a modern code language compared to the other simulators as well as that it takes advantage of multicore and manycore shared and distributed memory computing systems.

## 2. Well Performance- Deliverability

When it comes to the performance of a well a large number of variables such as fluid properties, formation properties and reservoir pressure have a big impact and all of them are interconnected. It is actually a combination of factors that influence the productivity of the well, the performance of the flow in the reservoir and the performance of the production string.

### 2.1 Natural Drive mechanisms

In this chapter we will briefly review how the various basic concepts come together to help us understand various driving forces and their role in fluid production. Reservoir drive mechanisms are often defined as sources of energy available in the reservoir system which are driving the fluids flows inside the porous media and out through the wellbore. Despite of their significant role, it is not necessarily sufficient of lifting the fluids to the surface. The period in which reservoir depletion is mainly due to reservoir drive mechanisms is commonly referred as "primary production". A wide variety of primary oil recovery drive mechanisms might be encountered:

- Natural water drive
- Gas-cap drive
- Compaction drive
- Solution gas drive
- Gravity Drainage

*Natural water drive*

In the cases of reservoirs with neighboring aquifers (water bearing zone) a decline in the reservoir pressure caused by production of fluids, can cause initiation of water inflow into the reservoir. Aquifer water in this process acts as the displacing medium, and depending on aquifer type and size it could be a significant natural way of pressure maintenance. Due to its high sweep efficiency, natural water drive yields high overall recovery, often above 50% of OOIP. (Herriot Watt, Reservoir Engineering , 2005)

*Gas-cap drive*

For reservoirs that are initially saturated, a primary gas cap lies on top of the oil-bearing zone. Due to the compressible nature of gas it is capable of acting as an energy accumulator. High gas compressibility and the extended gas cap size ensure significant accumulation of energy, which can provide a long lasting and efficient field performance. Up to 35% of the original oil in place can be recovered under a gas-cap drive. (Herriot Watt, Reservoir Engineering , 2005)

*Compaction drive*

This drive mechanism might be triggered during depletion when rock grains are exposed to stress beyond the elasticity limit. It causes re-compaction of relatively deformed or even destroyed rock grains that might have as consequence gradual or abrupt reduction of the reservoir pore volume. (Herriot Watt, Reservoir Engineering , 2005)
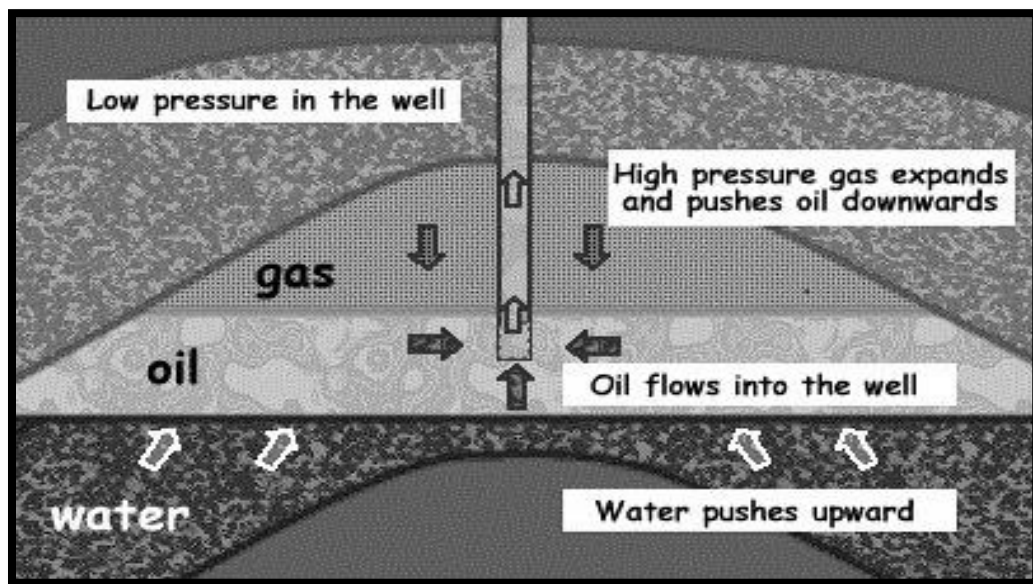


*Figure 2.1 Natural drive mechanisms occur in the reservoir*

In order to achieve higher field recovery, secondary and tertiary oil recovery methods (usually referred to as Enhanced Oil Recovery methods, EOR) often need to be implemented. (Herriot Watt, Reservoir Engineering , 2005)

*Solution gas drive*

A natural effect of reservoir depletion, is the decay of the reservoir pressure, unless it is maintained either by natural water influx or by using some pressure maintenance technology. If that is not the case reservoir pressure will eventually drop below the bubble point pressure. That has as effect dissolution of gas from the oil phase. The process itself provides energy required for oil phase displacement and as pressure drops further the highly compressible gas expands and enhances the displacing effect. (Herriot Watt, Reservoir Engineering , 2005)

*Gravity Drainage*

This production drive is considered as a minor contributor to total recovery, but generally associated with later stages of production where its effect can be recognized due to weakening of other drive mechanisms that have been dominant in earlier years of production. Gravity drainage drive is explained as effect of relative density forces of present fluids causing fluids to drain towards the production wells. (Herriot Watt, Reservoir Engineering , 2005)

## 2.2 Nodal Analysis

For many years Nodal Analysis has been the standard method for analyzing the performance of systems composed of interacting components. Electrical circuits, complex pipeline networks and centrifugal pumping systems are all analyzed using this method. Its application to well producing systems was first proposed by Gilbert in 1954 while Mach, Proano, and Brown in 1979 further developed the concept.

It is often described as the appropriate tool to use to set up a systematic approach to oil and gas wells optimization so as to optimize every component of the system in order to achieve the targeted flow rate.

The standard objectives of this method are to evaluate the flow rate which an existing well can deliver while taking into account its geometry and completion limitations. Moreover, the method is used to determine at which time and under which conditions a well could possibly load or die. or to select the most cost-effective moment for installation of artificial lift and the appropriate

artificial lift technology. Additionally, every component in the well system to be evaluated in order to determine possible bottleneck effects on oil flow rate. (Kermit E. Brown, James F. Lea, 1985)

For achieving effective optimization of the production system, each component should be firstly evaluated independently and then as a group in order to evaluate the whole well producing system. Changes in any system component can affect the entire system. These changes can often be displayed graphically as system sensitivity analysis.

In Nodal Analysis, a particular point in the system is chosen (called node) and the system is split in two segments. All of the elements upstream of the node constitute the inflow section and all elements downstream of the node constitute the outflow section. Each component performance is directly related to flow rates and pressure drop in the system. The flow rate through the whole system can be determined once the following requirements are satisfied: (H. Dale Beggs, 2008)

1. Flow into the node equals flow out of the node.
2. Only one pressure can exist at a node.
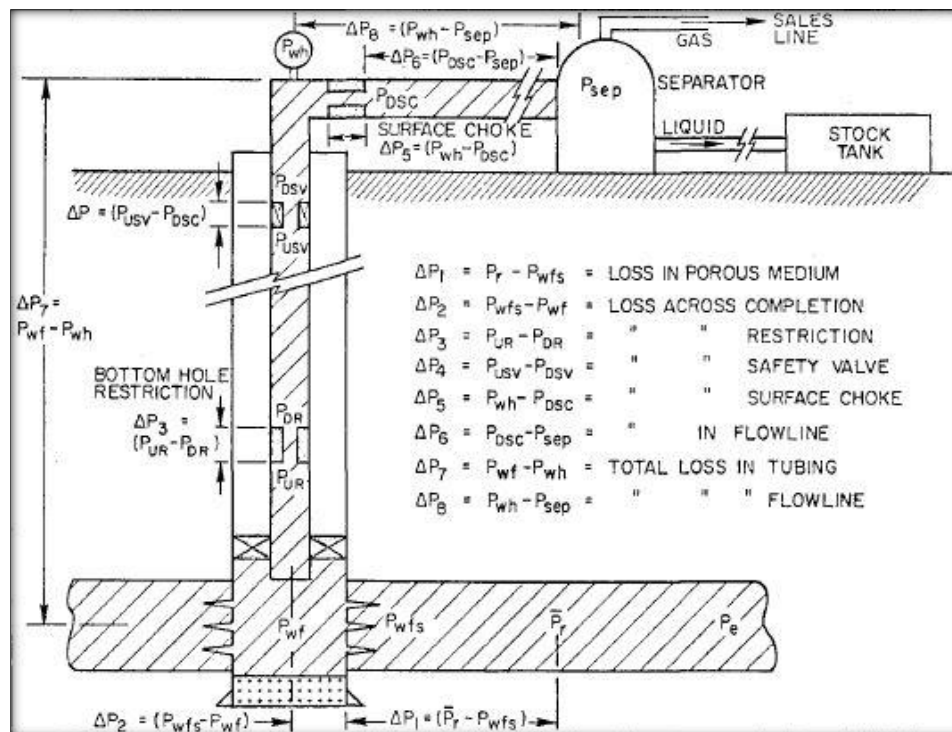


*Figure 2.2 System analysis illustration* **(Kermit E. Brown, James F. Lea, 1985)**

## 2.3 Tubing Performance of a Well

Production rates at various bottomhole pressures are used to create the tubing performance curve which reflects the capability of the completion system to deliver production up the well bore to the separator.

Tubing performance or vertical lift performance (VLP) analysis of a well is important part of the well design procedure. It provides with data needed for selecting the well completion correctly corresponding to lifting methods and plays significant role in evaluation of well's performance. (Herriot Watt, 2011)

## 2.4 Gradient Curves

The pressure gradient in a pipe line or well bore is the summation of following components:

- Hydrostatic head
- Friction head

Thus, the total pressure gradient can be written as:

$$\frac{dp}{dl} = (\frac{dp}{dl})_{hs} + (\frac{dp}{dl})_{fr} \quad [2.1]$$

The hydrostatic component is due to the density of the travelling fluid mixture at each point in the system and it is a complex function of the relative velocity of the phases present. The gravity head loss is proportional to the fluid density corrected for slip which in turn depends on the flow regime and fluid viscosity.

The friction component is controlled by fluid viscosity and geometric factors such as pipe diameter and roughness. As in the majority of the oil field application, the gravitational component normally accounts for around 90% of the overall head loss, the total pressure drop function is not that much particularly sensitive to the value of the friction loss coefficient.

## 2.5 Pressure Traverse Curves

Very often pressure calculations are presented in the form of the so-called pressure-traverse curves. Calculation is performed for a specific tubing diameter, fluid properties and production rate. These curves usually represent estimate of pressure as a function of production measured depth and they are generated for series of gas-liquid ratios, water cut values, well-head pressures e.g. they have a key role in sensitivity analysis for any of constituting parameters.

# 3. Artificial Lift Methods

## 3.1 Pump Systems

***Rod Pumps*** the most commonly used artificial lift method. This pumping system consists of a downhole plunger which oscillates up and down by a rod connected to a rotor at the surface. The plunger movement displaces produced fluid into the tubing via a pump consisting of suitably arranged travelling and standing valves mounted within a pump barrel.

***Hydraulic Pumps*** use a highly pressurized fluid to:

1. Drive a downhole turbine or positive displacement pump or
2. Flow through a venturi or jet, creating a low-pressure area which produces an increased drawdown and inflow from the reservoir

***Electric Submersible Pumps (ESP)*** utilizes a downhole centrifugal pump driven by an electric motor which is supplied with electric power via a cable that is long-drown from the surface penetrates the wellhead and is strapped to the outside of the tubing.

***Progressing Cavity Pumps (PCP)*** employs a helical, metal rotor rotating inside an elastomeric, double helical stator. The rotating action is supplied by downhole electric motor or by rotating rods. (Mauricio G. Prado)

## 3.2 Gas Lift

The gas lift method involves the supply/injection of pressurized gas at some downhole point in the tubing to aerate or lessen the fluid column, in order to reduce the average density of the fluid. Increased gas/liquid ratio passing through the port to the surface leads to the reduction of the hydrostatic pressure gradient into the tubing, which is the most significant factor of the pressure drop in vertical multiphase flow. In this way the average flowing density is decreased and finally the pressure at the bottom of the well is decreased generating or improving the drawdown and consequently the flow from reservoir to the well.

When liquid flow in vertical wells is considered, the hydrostatic head is the major component of the pressure loss since the fluid has to flow against the head whereas frictional loss which is rate dependent becomes vital only at very high flow rates. The injected gas also improves the liquid flow rate by the energy of expansion, introduced to the system due to the natural behavior of gas while exposed to pressure drop, which has positive effect on fluid flow towards the surface. (Hernandez, 2016)

The lifting of fluid can be accomplished by either continuous or intermittent gas injection.

*In continuous gas lift,* the flowing bottom-hole pressure remains constant for a specific set of conditions and is regarded as a steady state flow operation. (Schlumberger, Gas Lift Design and Technology, 1999)

*In intermittent gas lift*, the reservoir fluid is produced intermittently by displacing liquid slugs with high pressure injection gas. At intermittent lift the flowing bottom-hole pressure will vary with the particular operation time of one cycle in production. Economics are mainly dictating the design of any lift installation. Intermittent lift is applicable to low productivity wells with low reservoir pressure. (Schlumberger, Gas Lift Design and Technology, 1999)

In this thesis the continuous gas lift method is utilized. In continuous flow gas lift the compressed gas is introduced from the annulus to the tubing inside at a fixed rate, through a gas lift valve at a fixed depth. The continuous gas lift method is usually applied in wells which have high bottom-hole pressure relatively to their depths or/and with high productivity index. In this way the bottom-hole pressure is reduced.
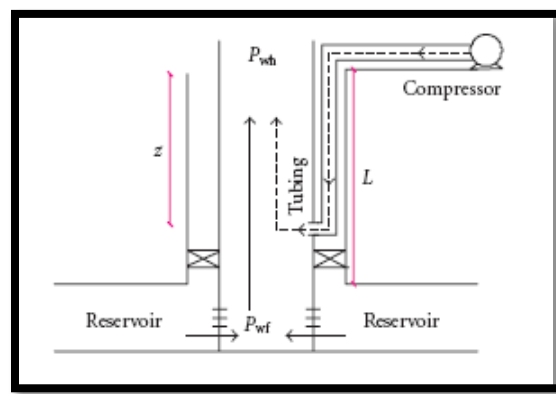


*Figure 3.1 Simple Gas Lift Schematic (Deni et al, 2007)*

## 3.3 Gas lift equipment

The gas lift mechanism equipment can be divided into two main categories: the underground equipment and the surface one. As far as the surface equipment is concerned, a gas compressor is necessary in order to achieve the desired injection pressure. It is also necessary to have a multi-distribution (manifold) gas system consisting of a safety valve, a gas meter and a distribution column for each well. The underground equipment consists mainly of gas injection valves and the cases in which they are placed (mandrels). (Schlumberger, Gas Lift Design and Technology, 1999)

The gas injection valves are the tools installed along the tubing which allow the gas to enter the tubing and they are designed to open and close according to the pressure in the casing (IPO) or the Production column (PPO).

There are many types of gas injection valves in the market. Some are designed for use in continuous gas lift and some for intermittent. The force that closes the valve type of IPO, is generated by the nitrogen pressure contained within a chamber of the valve, which is called dome, while this force for valves type PPO it is supplied by a spring.
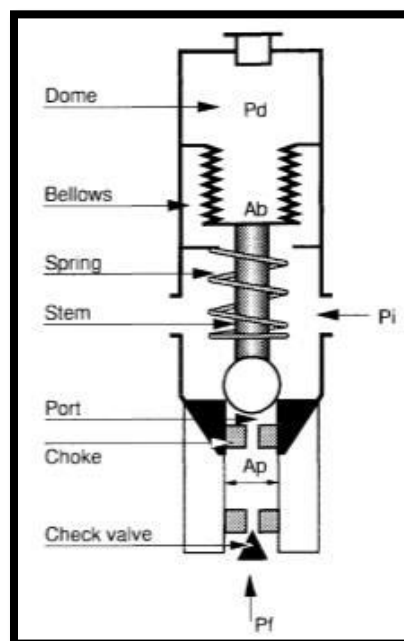


*Figure 3.2 : Gas injection valve*

### 3.3.1   Gas lift Advantages

The main advantages of the gas lift system are:

- A central gas lift system can be implemented when more than one well need it
- Gas lift is a method that can handle in the best way the sand and solid materials that enter the well while production
- Wells that are deviated can easily host a gas lift system
- It is a cost-effective method since the gas which is used is mainly the gas which solutes from the reservoir fluid

### 3.3.2   Gas Lift Disadvantages

The main disadvantages of the gas lift system are:

- In order to implement an efficient system good quality data are required
- The difficulty can be increased because of the friction
- The required gas is not always available
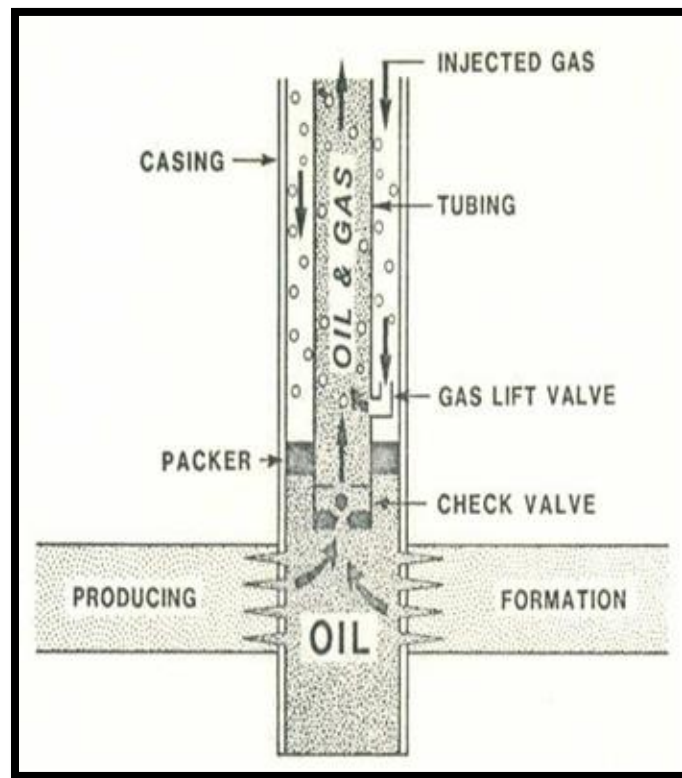


*Figure 3.3 Artificial Gas lift system*

# 4. Description of the Reservoir Model

The Reservoir model which is used in this Master thesis is the "Black Oil Demo" model, provided by the tNavigator reservoir simulation package of RFD, as part of the case studies for learning and training.

The Reservoir Model has been scheduled to operate nine producing wells and six water injection wells, which are controlled so as to deliver specific flowrates of liquid, as it can be seen in the Figure 4.1. During operating time, it can be easily observed that the pressure of the reservoir is being depleted at the early stages of production, until the injectors start water flooding. This results to the increase of water cut to most of the wells. Additionally, during the simulation run the producers start to operate at various times.
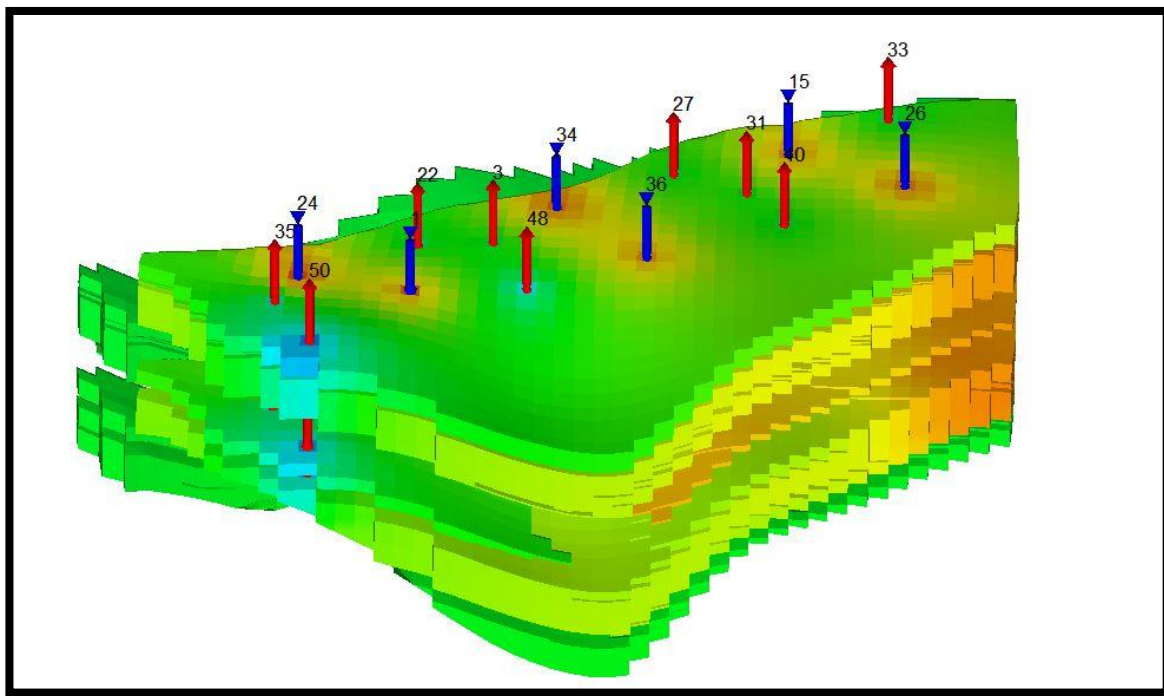


*Figure 4.1 3D Map of the pressures of the Reservoir model (tNavigator, v4.1.3, 2015)*

In Figure 4.1 we can visualize the reservoir shape and the location of the wells, whereas the water injector wells are in red color and the producers in blue.

In order to design the path of the wells it is needed to extract from the Reservoir model the distances that need to be covered by the wells' deviation survey. For this reason, the rig was selected to be placed close to the center of the reservoir footprint at the surface.

The distances of the well blocks from the rig that is positioned at block [28,19] can be seen below in Table 4.1.

| PRODUCERS | | | |
|---|---|---|---|
| WELL | BLOCK | Horizontal distance(ft) | TOPS (ft) |
| 3 | 22,20 | 1500.33 | 4676.02 |
| 22 | 18,20 | 2459.65 | 4676.12 |
| 27 | 31,12 | 1724.41 | 4663.39 |
| 31 | 35,14 | 2113.52 | 4670.60 |
| 33 | 42,6 | 4587.93 | 4651.12 |
| 35 | 11,27 | 4665.68 | 4684.25 |
| 40 | 37,17 | 2287.40 | 4679.27 |
| 48 | 24,24 | 1529.53 | 4693.04 |
| 50 | 13,31 | 4730.64 | 4694.82 |

*Table 4:1 Horizontal distances of the wells from the rig*

Finally, it is important the fact that the reservoir has two zones from which it is being produced and through which it is perforated. As the temperature value was missing from the model description, it was calculated at 150 ºF by means of a typical geothermal gradient.

## 4.1 Fluid properties

The fluid properties utilized in the reservoir model are:

| Regions | API | Sg | Specific Gravity of Water | GOR scf/stb |
|---|---|---|---|---|
| #1 | 38.41 | 0.94 | 1.012 | 218.968 |
| #2 | 38 | 0.94 | 1.012 | 459.16 |

*Table 4:2 Properties of the fluid*

It can be seen, that the reservoir contains black oil since the GOR values are relatively low to medium, the API density is in the range of the black oils, and the specific gravity of the gas is relatively high. (Petrowiki, n.d.).

The initial saturation of water is defined as the amount of the water phase that exists in the rock pores by the time of the discovery. Although, it is commonly used as the irreducible water

## 4.Description of the Reservoir Model

saturation for which below that value the water cannot flow due to surface tension forces, in the model utilized Swi is 23%. Subsequently, since the reservoir is undersaturated there is no gas phase and the existing phases are only water and oil, while the initial oil saturation is 1-Swi thus being equal to 0.77. In the graph below, the relative permeability curves of oil (red color) and of water (blue color) versus saturation are shown.
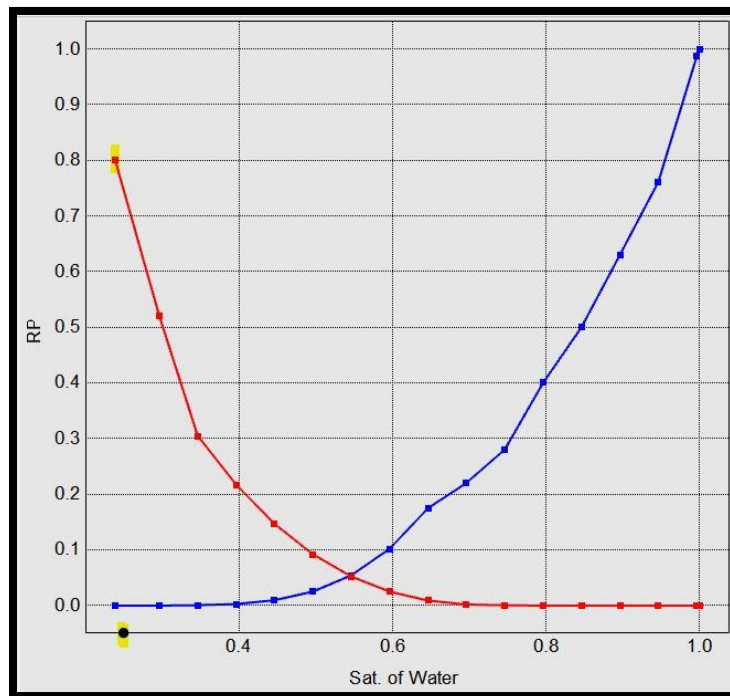


*Figure 4.2 Relative Permeabilities Curves Water-Oil (tNavigator, v4.1.3, 2015)*

### 4.2 Deviation Survey of the Wells

The wells are built in a build, hold and drop trajectory (called S-type) so as to penetrate the perforations vertically. With the information that has been obtained from the Reservoir model as far as the distances are concerned it is possible to design the well path.

For the deviation survey we assumed that the production casing is from the top to the bottom and no liners are used. As well as that the final vertical length of the starts from the top of the reservoir to the perforation's depth.
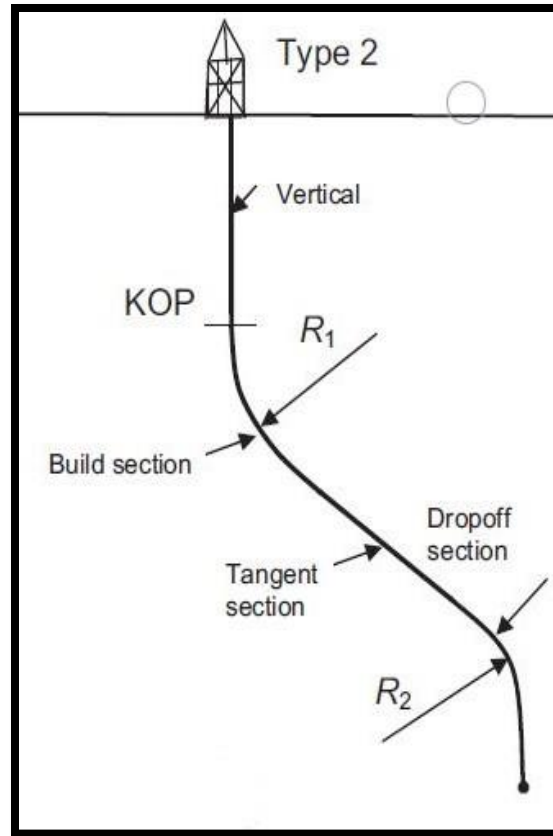
*Figure 4.3 : Design of slant well type* (**Mitchell, 2011**)

When the True Vertical Depth of each well's perforation is obtained from the software, we have to calculate the radius of curvature. For this reason, a rate of 3 deg/100ft is used.

$$r_1 = \frac{180}{\pi} \frac{1}{q} \tag{4.1}$$

In order to obtain the increments of various couples of TVD and MD, we used the following equations:

MD= KOP+ β/q     (4.2)

TVD= KOP+ R*sin(β)     (4.3)

KOP: kick off point, where the curvature starts,

4.Description of the Reservoir Model

R: radius of curvature,

β: slant angle,

When the slant angle was achieved, a tangential part was created until the point where a drop-off section equal to the buildup one would exist in order to reach the horizontal desired distance and revert back to a zero-inclination angle.

Subsequently, with this procedure we continued the calculations for all the producing wells and the following tables of True Vertical Depth and Measured Depth results were obtained.

| W3 | | W22 | | W27 | | W31 | | W33 | |
|---|---|---|---|---|---|---|---|---|---|
| TVD (ft) | MD (ft) | TVD (ft) | MD (ft) | TVD (ft) | MD (ft) | TVD (ft) | MD (ft) | TVD (ft) | MD (ft) |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 800 | 800 | 800 | 800 | 800 | 800 | 800 | 800 | 800 | 800 |
| 847 | 847 | 886 | 886 | 856 | 856 | 868 | 868 | 952 | 951 |
| 895 | 895 | 973 | 973 | 912 | 912 | 935 | 935 | 1103 | 1102 |
| 942 | 942 | 1059 | 1058 | 969 | 969 | 1003 | 1003 | 1255 | 1251 |
| 989 | 989 | 1145 | 1144 | 1025 | 1024 | 1071 | 1070 | 1406 | 1396 |
| 1037 | 1036 | 1232 | 1228 | 1081 | 1080 | 1139 | 1137 | 1558 | 1538 |
| 1084 | 1083 | 1318 | 1312 | 1137 | 1136 | 1206 | 1203 | 1709 | 1676 |
| 1131 | 1130 | 1405 | 1395 | 1194 | 1191 | 1274 | 1269 | 1861 | 1808 |
| 1179 | 1176 | 1491 | 1476 | 1250 | 1246 | 1342 | 1335 | 2012 | 1933 |
| 1226 | 1223 | 1577 | 1556 | 1306 | 1300 | 1409 | 1399 | 2164 | 2051 |
| 1273 | 1269 | 1664 | 1635 | 1362 | 1354 | 1477 | 1463 | 2315 | 2162 |
| 1321 | 1315 | 1750 | 1712 | 1418 | 1408 | 1545 | 1526 | 2467 | 2264 |
| 1368 | 1360 | 1836 | 1787 | 1475 | 1461 | 1612 | 1589 | 2618 | 2357 |
| 1415 | 1405 | 1923 | 1860 | 1531 | 1514 | 1680 | 1650 | 2770 | 2440 |
| 1463 | 1450 | 2009 | 1931 | 1587 | 1565 | 1748 | 1710 | 2921 | 2512 |
| 1510 | 1494 | 2096 | 1999 | 1643 | 1617 | 1816 | 1769 | 3073 | 2574 |
| 1557 | 1538 | 2182 | 2065 | 1700 | 1667 | 1883 | 1827 | 3225 | 2625 |
| 1605 | 1582 | 2268 | 2129 | 1756 | 1717 | 1951 | 1883 | 3376 | 2664 |
| 1652 | 1624 | 2355 | 2189 | 1812 | 1766 | 2019 | 1938 | 3528 | 2691 |
| 1699 | 1667 | 2441 | 2247 | 1868 | 1814 | 2086 | 1992 | 3679 | 2707 |
| 4103 | 3809 | 3945 | 3229 | 4034 | 3649 | 3989 | 3479 | 4790 | 2777 |
| 4150 | 3852 | 4031 | 3287 | 4090 | 3698 | 4056 | 3532 | 4942 | 2793 |
| 4198 | 3894 | 4117 | 3348 | 4146 | 3747 | 4124 | 3587 | 5093 | 2820 |
| 4245 | 3938 | 4204 | 3411 | 4202 | 3796 | 4192 | 3644 | 5245 | 2860 |
| 4293 | 3982 | 4290 | 3477 | 4259 | 3847 | 4259 | 3702 | 5396 | 2910 |
| 4340 | 4026 | 4376 | 3546 | 4315 | 3898 | 4327 | 3761 | 5548 | 2972 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 4387 | 4071 | 4463 | 3616 | 4371 | 3950 | 4395 | 3821 | 5699 | 3045 |
| 4435 | 4116 | 4549 | 3689 | 4427 | 4002 | 4463 | 3882 | 5851 | 3128 |
| 4482 | 4161 | 4635 | 3764 | 4484 | 4055 | 4530 | 3944 | 6002 | 3220 |
| 4529 | 4207 | 4722 | 3841 | 4540 | 4109 | 4598 | 4007 | 6154 | 3322 |
| 4577 | 4253 | 4808 | 3920 | 4596 | 4163 | 4666 | 4071 | 6305 | 3433 |
| 4624 | 4300 | 4895 | 4000 | 4652 | 4218 | 4733 | 4136 | 6457 | 3551 |
| 4671 | 4346 | 4981 | 4081 | 4708 | 4272 | 4801 | 4201 | 6609 | 3677 |
| 4719 | 4393 | 5067 | 4164 | 4765 | 4328 | 4869 | 4267 | 6760 | 3809 |
| 4766 | 4440 | 5154 | 4248 | 4821 | 4383 | 4936 | 4334 | 6912 | 3946 |
| 4813 | 4487 | 5240 | 4332 | 4877 | 4439 | 5004 | 4401 | 7063 | 4088 |
| 4861 | 4534 | 5326 | 4418 | 4933 | 4495 | 5072 | 4468 | 7215 | 4234 |
| 4908 | 4581 | 5413 | 4504 | 4990 | 4551 | 5140 | 4535 | 7366 | 4382 |
| 4955 | 4629 | 5499 | 4590 | 5046 | 4607 | 5207 | 4603 | 7518 | 4533 |
| 5003 | 4676 | 5586 | 4676 | 5102 | 4663 | 5275 | 4671 | 7669 | 4684 |

*Table 4:3 MD and TVD of the wells*

| W35 | | W40 | | W48 | | W50 | |
|---|---|---|---|---|---|---|---|
| TVD (ft) | MD (ft) | TVD (ft) | MD (ft) | TVD (ft) | MD (ft) | TVD (ft) | MD (ft) |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 800 | 800 | 800 | 800 | 800 | 800 | 800 | 800 |
| 952 | 951 | 879 | 879 | 848 | 848 | 951 | 951 |
| 1103 | 1102 | 957 | 957 | 896 | 896 | 1102 | 1101 |
| 1255 | 1251 | 1036 | 1035 | 944 | 944 | 1252 | 1248 |
| 1406 | 1396 | 1114 | 1113 | 992 | 991 | 1403 | 1394 |
| 1558 | 1538 | 1193 | 1190 | 1039 | 1039 | 1554 | 1535 |
| 1709 | 1676 | 1272 | 1267 | 1087 | 1086 | 1705 | 1672 |
| 1861 | 1808 | 1350 | 1343 | 1135 | 1134 | 1856 | 1803 |
| 2012 | 1933 | 1429 | 1418 | 1183 | 1181 | 2007 | 1928 |
| 2164 | 2051 | 1507 | 1492 | 1231 | 1228 | 2157 | 2047 |
| 2315 | 2162 | 1586 | 1564 | 1279 | 1274 | 2308 | 2157 |
| 2467 | 2264 | 1665 | 1636 | 1327 | 1320 | 2459 | 2259 |
| 2618 | 2357 | 1743 | 1706 | 1375 | 1366 | 2610 | 2352 |
| 2770 | 2440 | 1822 | 1774 | 1423 | 1412 | 2761 | 2435 |
| 2921 | 2512 | 1900 | 1841 | 1471 | 1457 | 2912 | 2508 |
| 3073 | 2574 | 1979 | 1906 | 1518 | 1502 | 3062 | 2570 |
| 3225 | 2625 | 2057 | 1969 | 1566 | 1546 | 3213 | 2621 |
| 3376 | 2664 | 2136 | 2030 | 1614 | 1590 | 3364 | 2661 |
| 3528 | 2691 | 2215 | 2089 | 1662 | 1634 | 3515 | 2690 |
| 3679 | 2707 | 2293 | 2146 | 1710 | 1676 | 3666 | 2706 |
| 4790 | 2777 | 3965 | 3333 | 4118 | 3817 | 4841 | 2789 |

# 4. Description of the Reservoir Model

| 4942 | 2793 | 4044 | 3390 | 4166 | 3859 | 4992 | 2805 |
|------|------|------|------|------|------|------|------|
| 5093 | 2820 | 4123 | 3449 | 4214 | 3903 | 5143 | 2834 |
| 5245 | 2860 | 4201 | 3510 | 4262 | 3947 | 5293 | 2873 |
| 5396 | 2910 | 4280 | 3573 | 4310 | 3991 | 5444 | 2925 |
| 5548 | 2972 | 4358 | 3638 | 4358 | 4036 | 5595 | 2987 |
| 5699 | 3045 | 4437 | 3705 | 4406 | 4081 | 5746 | 3060 |
| 5851 | 3128 | 4515 | 3774 | 4454 | 4127 | 5897 | 3143 |
| 6002 | 3220 | 4594 | 3844 | 4502 | 4173 | 6048 | 3236 |
| 6154 | 3322 | 4673 | 3915 | 4550 | 4219 | 6198 | 3338 |
| 6305 | 3433 | 4751 | 3988 | 4597 | 4265 | 6349 | 3448 |
| 6457 | 3551 | 4830 | 4061 | 4645 | 4312 | 6500 | 3566 |
| 6609 | 3677 | 4908 | 4136 | 4693 | 4359 | 6651 | 3692 |
| 6760 | 3809 | 4987 | 4212 | 4741 | 4407 | 6802 | 3823 |
| 6912 | 3946 | 5066 | 4289 | 4789 | 4454 | 6953 | 3960 |
| 7063 | 4088 | 5144 | 4366 | 4837 | 4502 | 7103 | 4101 |
| 7215 | 4234 | 5223 | 4444 | 4885 | 4549 | 7254 | 4246 |
| 7366 | 4382 | 5301 | 4522 | 4933 | 4597 | 7405 | 4394 |
| 7518 | 4533 | 5380 | 4601 | 4981 | 4645 | 7556 | 4544 |
| 7669 | 4684 | 5459 | 4679 | 5029 | 4693 | 7707 | 4695 |

*Table 4:4 MD and TVD of the wells*

After the calculations were completed, the obtained deviation surveys were imported into the PIPESIM software. In the figures below, we can visualize the trajectories of the wells.
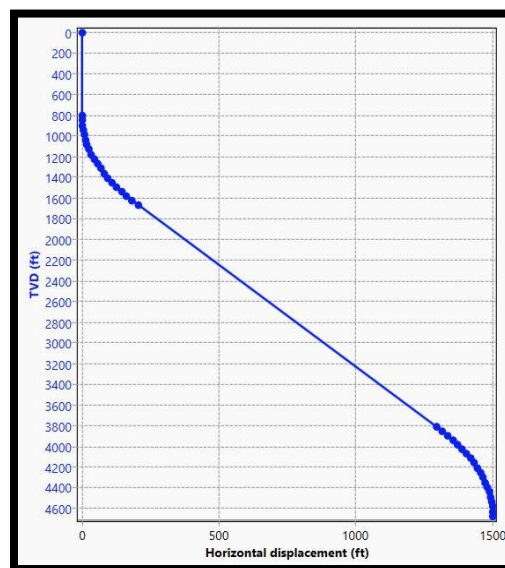


*Figure 4.4 Deviation survey W3 (PIPESIM Steady-State Multiphase Flow Simulator)*

*Figure 4.5 Deviation survey W22 (PIPESIM Steady-State Multiphase Flow Simulator)*
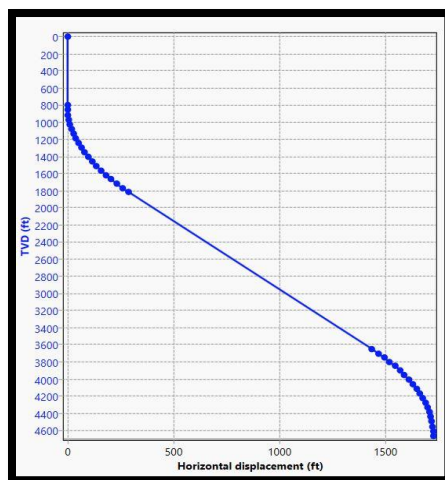


*Figure 4.6Deviation survey W27 (PIPESIM Steady-State Multiphase Flow Simulator)*
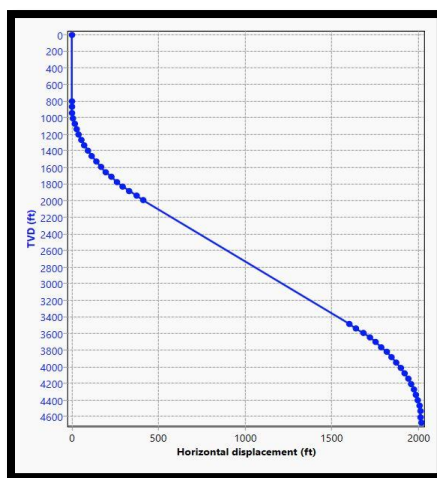


*Figure 4.7 Deviation survey W31 (PIPESIM Steady-State Multiphase Flow Simulator)*

4.Description of the Reservoir Model
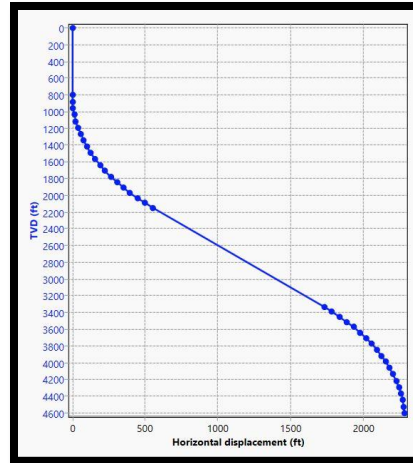


*Figure 4.8 Deviation survey W33 (PIPESIM Steady-State Multiphase Flow Simulator)*
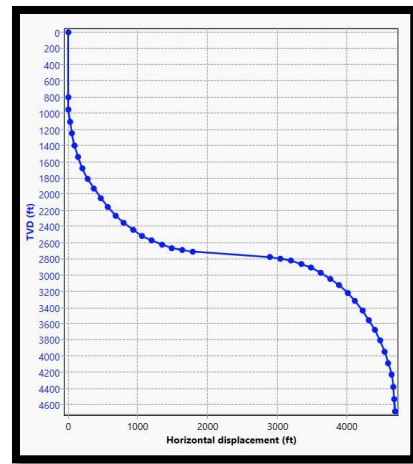


*Figure 4.9 Deviation survey W35 (PIPESIM Steady-State Multiphase Flow Simulator)*
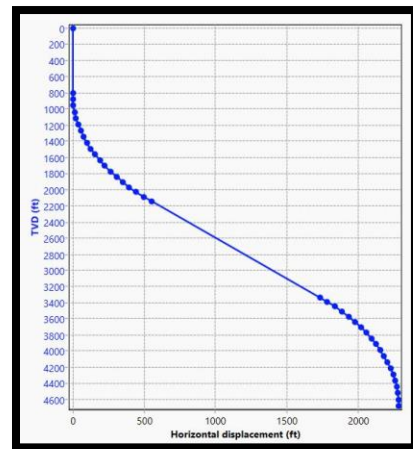


*Figure 4.10Deviation survey W40 (PIPESIM Steady-State Multiphase Flow Simulator)*
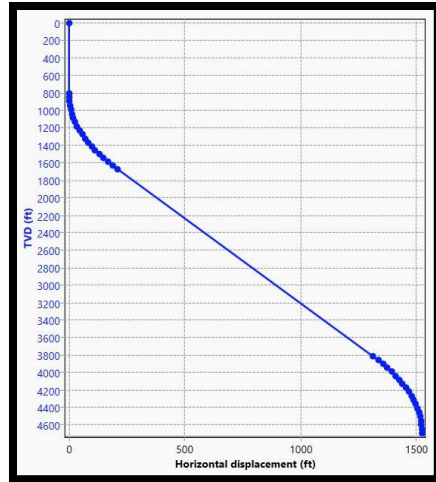
*Figure 4.11 Deviation survey W48 (PIPESIM Steady-State Multiphase Flow Simulator)*
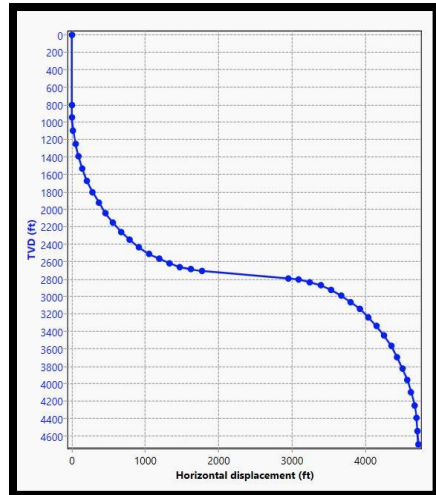


*Figure 4.12 Deviation survey W50 (PIPESIM Steady-State Multiphase Flow Simulator)*

## 4.3 Evaluation of wells' deliverability

In this paragraph we will take into account the results of the pressure traverse plots, that came out of the modeling in Pipesim, for the nine producing wells.

As mentioned before in Chapter 2, the pressure traverse curves are a common mean to estimate the pressure along the depth for certain conditions, and more specifically the pressure difference between the bottomhole and the wellhead, required to lift the liquids at surface. This way of estimating the pressures will be the guide for the current thesis in order to evaluate the wells' deliverability, as well as to decide for which wells and under which conditions, artificial gas lift

has to be designed. Therefore, a well to bring the production to the surface must exhibit a value at the end of the pressure traverse curve at least equal or lower to the bottomhole pressure under the conditions of investigation.

Practically, the PIPESIM software generates the pressure traverse plot for the conditions (e.g. flowrate, water cut) imposed by the reservoir model. The interpretation of the pressure traverse curves relies on the fact that the fluid must be able to overcome the difference of the pressure between the bottomhole and the wellhead. So, if the value at the end of the pressure traverse curve has bigger value than the reservoir model obtained bottomhole pressure, indicates that an artificial lift system must be installed. An example will be used to clarify the above statement, for the case that the well W3 has a reservoir model bottomhole pressure WBP=1296.5 psia and water cut WC=0.07%. In Figure 4.13 the pressure traverse plot is shown as it was generated from the PIPESIM software for the prevailing conditions.
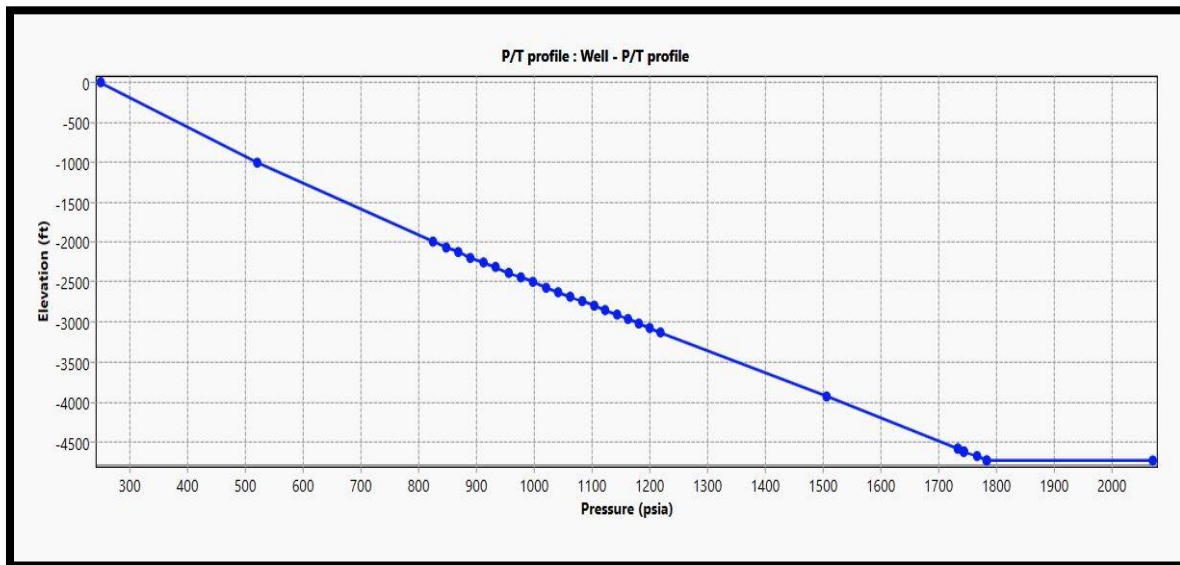


*Figure 4.13 Pressure Traverse plot for well W3 (PIPESIM Steady-State Multiphase Flow Simulator, 2017)*

The value at the end of the pressure traverse curve is of WBP=1789.3 psia which is well above the WBP of the reservoir model. In that case the pressure traverse curve implies that the well is not able to deliver the fluids from the reservoir to the wellhead and an artificial gas lift design must be implemented.

It must be taken into consideration that the well bottomhole pressures and the flowrates are fixed values, which were obtained from the reservoir simulation model.

The first condition that we investigated with the help of the pressure traverse plots is in the early stages of production for each well, that means when the water break-through occurs, with values much less than 1%. The results are shown in the Table 4.5.

| WELL | WBP (psia) | PRESSURE TRAVERSE (psia) | WC% |
|---|---|---|---|
| W3 | 1296.5 | 1789.3 | 0.07% |
| W22 | 1344.0 | 1547.3 | 0.00% |
| W27 | 1219.0 | 1204.0 | 0.07% |
| W31 | 1488.4 | 1779.9 | 0.07% |
| W33 | 1118.7 | 1533.3 | 0.04% |
| W35 | 1104.3 | 1434.6 | 0.00% |
| W40 | 1361.2 | 1296.0 | 0.00% |
| W40 | 1511.5 | 1742.2 | 0.00% |
| W50 | 1436.0 | 1710.5 | 0.00% |

*Table 4:5  Results of Pressure Traverse curves for the wells*

We can easily conclude that most of the wells are not able to deliver liquid to the surface and to respect the production rates determined by the reservoir modeling. Only two wells, W27 and W40 are able to bring the predicted oil and water rate to the surface by means of the predicted bottom hole pressure since the later exhibited higher pressure values than the computed endpoint pressure of the corresponding traverse curves.

### 4.3.1   Worst-case scenario

At this point, the worst-case scenario of the production schedule, will be identified and utilized in the study. If the gas lift system is designed so as to be able to cope with the worst-case scenario, that is the most difficult situation with respect to the available bottom hole pressure, then it can be guaranteed that it will be efficient for any other time instance during the production schedule of the reservoir. The worst-case scenario has been set to correspond to the situation of the highest

4.Description of the Reservoir Model

water cut level during the producing days for each well. The reason is that as the water fraction in the produced liquid grows the pressure loss due to gravity is becoming greater due to the higher density of the water compared to the oil, hence the increasing density of the produced liquid. Therefore, any other milder condition should be satisfied. According to this strategy, below is a list of the conditions of the worst-case scenarios which correspond to each well (Table 4.5).

| Date | Pavg | WC% | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | W3 | W22 | W27 | W31 | W33 | W35 | W40 | W48 | W50 |
| 2/1/2015 | 2616.6 | 79.62% | 47.38% | 57.72% | 80.67% | 67.47% | 80.44% | 42.50% | 43.25% | 29.51% |

*Table 4:6 Worst case scenarios of the wells*

| WELL | WBP (psia) | Pressure at the end of Traverse curve (psia) | WC% |
|---|---|---|---|
| W3 | 1827.6 | 2174.8 | 79.62% |
| W22 | 1711.4 | 2069.3 | 47.38% |
| W27 | 2061.4 | 2050.5 | 57.72% |
| W31 | 2212.5 | 2234.8 | 80.67% |
| W33 | 1982.2 | 2032.7 | 67.47% |
| W35 | 1609.1 | 2194.8 | 80.44% |
| W40 | 2114.5 | 1439.4 | 42.50% |
| W48 | 1629.3 | 1870.4 | 43.25% |
| W50 | 1219.7 | 1768.9 | 29.51% |

*Table 4:7 Results of Pressure Traverse curves for the worst-case scenarios*

In Table 4.7 between the comparison of the WBP and the value that the pressure traverse curves, it can be easily seen that only the wells W27 and W40 are able to produce according to the reservoir simulation schedule. So those two wells can deliver the fluid to the surface for the whole production time. For all other wells, it is shown that the bottom hole pressure is much less than the one that it should exhibit to ensure production. Hence, a gas lift design will be necessary and will be based for the worst-case scenarios since the rest of the wells are not able to produce from the early stages until the end of the exploitation of the field.

# 5. Gas Lift Design

The artificial gas lift procedure aims, either initiating the production in the tubing or enhancing the production that does not respect the economical limits of the reservoir simulation. Actually, gas lift design ensures that the bottomhole pressures that will allow the fluids to flow to the surface.

In this project, in order to design the gas lift system, we estimated the injection pressure values and the amount of the injection gas that was required.

## 5.1 Tubing Size Optimization

It was decided to run a sensitivity analysis to decide the best tubing size that will fit the production predictions.

When the inner diameter of the tubing increases, what it is achieved is better flowrate at a certain point. When the gas enters the tubing, it results to the decrease of the density of the fluid column. Hence, by increasing the inner diameter of the tubing more gas is expected to exist at the same depth with the liquid in the tubing, therefore the hydrostatic pressure decreases and the fluid column becomes lighter.

Additionally, when the gas that is injected occupies bigger area than the liquid itself then slip phenomenon start taking place in the tubing. Namely, to the fact that the gas flows faster than the liquids, the phenomenon that observed in this case will be the gas to be produced alone in the surface and the liquid to hold up, unable to move any more.

Been based on this principle we tried to find out the adequate tubing size for each well in order to deliver the desired amount of liquid to the surface as it was scheduled from the dynamic reservoir model.

| WELLS | $Q_L$ sbbl/day |
|-------|----------------|
| W3 | 1303.01 |
| W22 | 738.56 |
| W31 | 1776.52 |
| W33 | 1779.71 |
| W35 | 703.62 |
| W48 | 958.85 |
| W50 | 898.25 |

*Table 5:1  Liquid flowrates prediction*

### 5.1.1    Analysis for the tubing selection

As it was mentioned before, we ran an analysis to find the tubing size that will fit our production schedule. The general idea is the more the tubing inner diameter increase the better is the production flowrate. For this Master Thesis, with respect to that we made the tubing selection according to the target flowrate that must be achieved.

In this paragraph the optimum tubing size methodology will be examined that has been implemented. The procedure exhibited will be based in the worst-case scenario of the well W3 under the conditions of reservoir pressure Pavg= 2616.6 psia and water cut equal to WC= 79.62%.

Hence, after we introduced the data regarding the properties of the fluids and the well deviation survey, we generated pressure traverse plot, to determine if the well can produce for the specific case. Below, in the Figure 5.1, it is shown the pressure traverse plot for the well W3, which will be the exhibition well to show the tubing selection procedure.

The well W3, under the worst-case scenario conditions is considered to have well bottom pressure, WBP= 1827.6 psia. In the plot which was obtained from the PIPESIM software, the pressure traverse gives pressure value equal to 2174.8 psia. So, according to the principle the well is not able to deliver fluids in the surface.
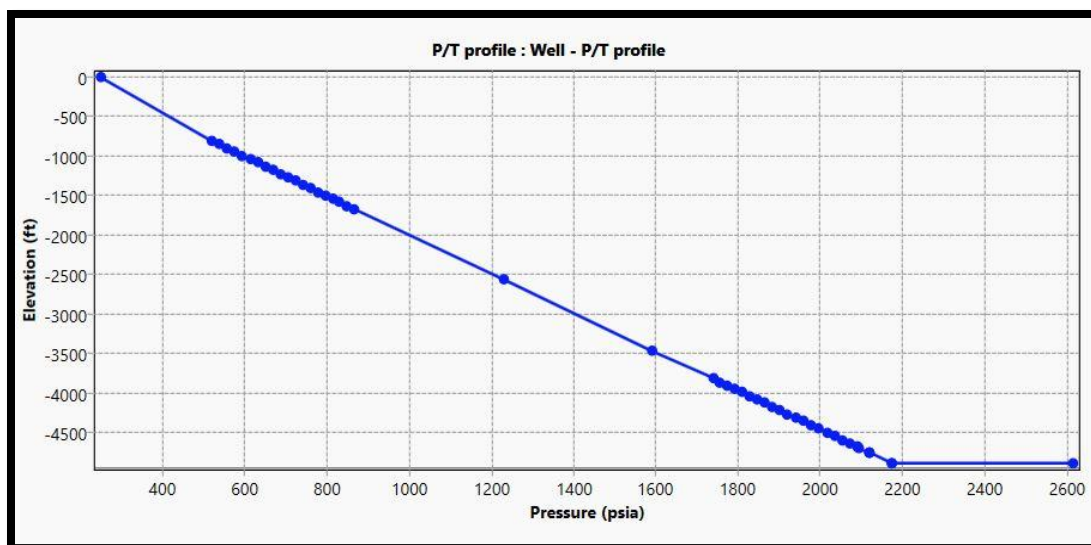
*Figure 5.1 Pressure Traverse plot for the well W3 (PIPESIM Steady-State Multiphase Flow Simulator)*

## 5.1.2   Input Data for the Gas Lift

The following tables consist the necessary input data that PIPESIM requires to process the gas lift design. These data are the output of the reservoir simulation and the designed deviation survey.

| WELL DATA | | | | |
|---|---|---|---|---|
| | MD (ft) | ID (in) | THICKNESS (in) | ROUGHNESS (in) |
| **Casing** | 5447.6 | 7.511 | 0.557 | 0.001 |
| **Tubing** | 5000 | 2.441 | 0.375 | 0.001 |
| **PACKER** | 4800 | | | |

*Table 5:2 Well Data for W3*

| FLUID MODEL | |
|---|---|
| **WC %** | 79.62 |
| **GOR #1 (scf/stb)** | 218.98 |
| **GOR #2 (scf/stb)** | 459.16 |
| **S$_g$** | 0.94 |
| **Water gravity** | 1.012 |
| **API #1** | 38.41 |
| **API #2** | 38 |

*Table 5:3 : Fluid properties for W3*

| RESERVOIR DATA |
|---|

| $P_{res}$ (psia) | 2616.6 |
|---|---|
| PI (stb/d.psi) | 0.43 |
| T (ºF) | 150 |

*Table 5:4 Reservoir Data for W3*

| GAS LIFT DESIGN DATA | |
|---|---|
| **Outlet Pressure (psia)** | 250 |
| $Q_{INJ}$ **(mmscf/d)** | 1.035 |
| $S_g$ | 0.64 |

*Table 5:5 Gas Lift Design Data for W3*

The Table 5.5 shows the data that are required in order to design the artificial gas lift in the PIPESIM software. The outlet pressure of the well is considered to be the pressure that exists at the wellhead, in the current case we assumed a typical value of 250 psia as wellhead pressure for the well W3 and the rest.

The injection flowrate is based on two criteria. Firstly, we use the needed amount of gas which is produced from the field, assuming that the cost of buying gas is not affordable. Secondly, we have to ensure that the amount of gas is available during the whole production period. So, the amount of the injected gas comes from the lowest gas production of the whole field and it is equal to 1.108 mmscf/day, at the last day of production (Figure 5.2). The injected amount of gas of each well is equal to the production of the last day subtracted the gas production of the under design well.

$Q_{INJ,i} = Q_{TOT} - Q_i$  , i= each well

$Q_{INJ,i}$ , the gas injection flowrate for each well

$Q_i$, the gas produced from each well under the prevailing conditions
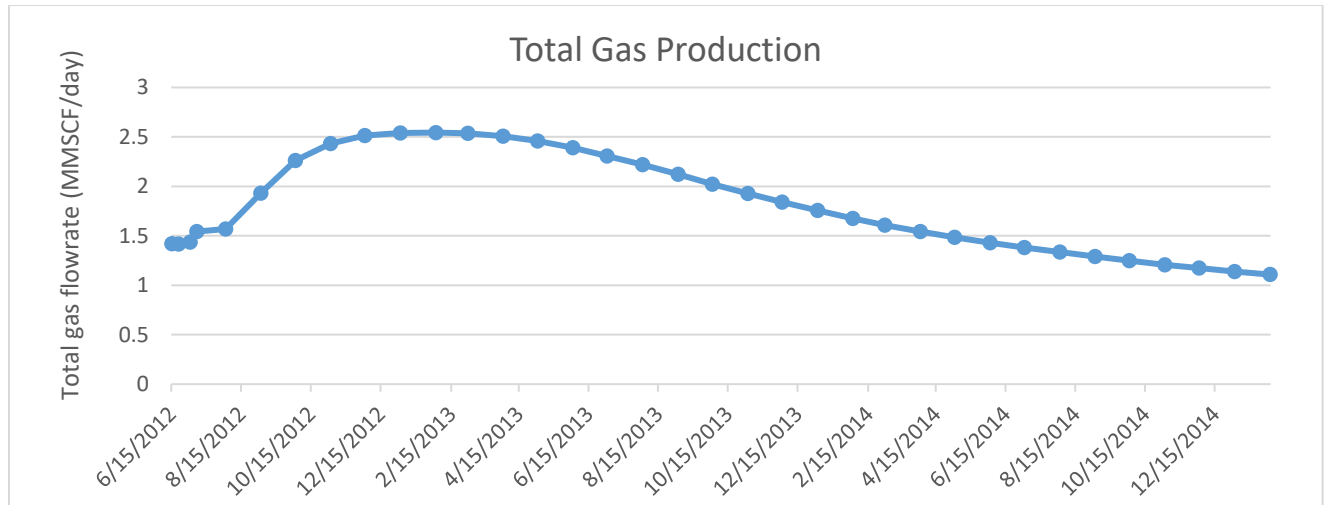
*Figure 5.2 Total Gas production of the Field*

### 5.1.3 Tubing Selection Methodology

The method used in order to find out which of the tubing inner diameter suits better the case of the well W3, follows a trial and error approach. In this approach we keep constant all the input data that were shown previously, such as deviation survey, reservoir data, well data, gas lift design data and fluid properties, but we keep changing the tubing inner diameter and the injection pressure, so as to achieve the target flowrate of 1303 sbbl/day.

The injection pressure plays significant role when the gas lift is designed, since it determines the deepest injection point. It is important to reach the deepest injection point in order to obtain less liquid hold up.

The procedure begins with constant diameter and variable injection pressure to reach the target flowrate. The same procedure was followed for the rest of the tubing inner diameters, in order to choose the suitable one which can deliver the requested amount of liquid. The appropriate tubing inner diameter of well W3 will be searched among 2.441, 2.75, 3.5, 4- and 5-inches.

The results of the above procedure can be shown in the next tables.

| ID=2.441 in | | | | | | |
|---|---|---|---|---|---|---|
| P$_{INJ}$ (psia) | 500 | 700 | 800 | 900 | 1000 | 1050 |
| Q$_L$ (stb/d) | 543.3 | 896.3 | 1056.1 | 1147.9 | 1233.4 | 1277.3 |
| Q$_{INJ}$ (mmscf/d) | 1.035 | 1.035 | 1.035 | 1.035 | 1.035 | 1.035 |
| | | | | | | |
| P$_{INJ}$ (psia) | 1053 | 1054 | 1100 | 1200 | 1300 | 2000 |
| Q$_L$ (stb/d) | 1278.6 | 1316.5 | 1316.6 | 1315.5 | 1315.7 | 1315.9 |
| Q$_{INJ}$ (mmscf/d) | 1.035 | 1.035 | 1.035 | 1.035 | 1.035 | 1.035 |

*Table 5:6  Gas lift of W3, tubing ID= 2.441in*

| ID=2.75 in | | | | | | |
|---|---|---|---|---|---|---|
| P$_{INJ}$ (psia) | 500 | 700 | 800 | 900 | 905 | 907 |
| Q$_L$ (stb/d) | 546.83 | 936.74 | 1197.21 | 1295.32 | 1299.97 | 1302.74 |
| Q$_{INJ}$ (mmscf/d) | 1.035 | 1.035 | 1.035 | 1.035 | 1.035 | 1.035 |
| | | | | | | |
| P$_{INJ}$ (psia) | 909 | 910 | 1000 | 1100 | 1200 | 2000 |
| Q$_L$ (stb/d) | 1303.28 | 1305.21 | 1381.11 | 1382.32 | 1382.31 | 1382.53 |
| Q$_{INJ}$ (mmscf/d) | 1.035 | 1.035 | 1.035 | 1.035 | 1.035 | 1.035 |

*Table 5:7 Gas lift of W3, tubing ID= 2.75in*

| ID=3.5 in | | | | | |
|---|---|---|---|---|---|
| P$_{INJ}$ (psia) | 500 | 700 | 750 | 790 | 791 |
| Q$_L$ (stb/d) | 522.31 | 1167.98 | 1237.65 | 1291.87 | 1293.63 |
| Q$_{INJ}$ (mmscf/d) | 1.035 | 1.035 | 1.035 | 1.035 | 1.035 |
| | | | | | |
| P$_{INJ}$ (psia) | 792 | 800 | 900 | 1200 | 2000 |
| Q$_L$ (stb/d) | 1362.31 | 1373.75 | 1488.52 | 1488.01 | 1488.12 |
| Q$_{INJ}$ (mmscf/d) | 1.035 | 1.035 | 1.035 | 1.035 | 1.035 |

*Table 5:8  Gas lift of W3, tubing ID= 3.5in*

| ID=4 in | | | | | |
|---|---|---|---|---|---|
| P$_{INJ}$ (psia) | 500 | 700 | 745 | 754 | 758 |
| Q$_L$ (stb/d) | 520.35 | 1264.64 | 1277.61 | 1295.3 | 1300.14 |
| Q$_{INJ}$ (mmscf/d) | 1.035 | 1.035 | 1.035 | 1.035 | 1.035 |
| | | | | | |
| P$_{INJ}$ (psia) | 759 | 760 | 800 | 1300 | 2000 |
| Q$_L$ (stb/d) | 1300.94 | 1367.06 | 1504.12 | 1529.64 | 1529.35 |
| Q$_{INJ}$ (mmscf/d) | 1.035 | 1.035 | 1.035 | 1.035 | 1.035 |

*Table 5:9 Gas lift of W3, tubing ID= 4in*

| ID=5 in | | | | | |
|---|---|---|---|---|---|
| $P_{INJ}$ (psia) | 500 | 700 | 710 | 711 | 713 |
| $Q_L$ (stb/d) | 521.45 | 1284.33 | 1295.27 | 1356.15 | 1377.11 |
| $Q_{INJ}$ (mmscf/d) | 1.035 | 1.035 | 1.035 | 1.035 | 1.035 |
| | | | | | |
| $P_{INJ}$ (psia) | 725 | 750 | 800 | 1300 | 2000 |
| $Q_L$ (stb/d) | 1398.86 | 1441.51 | 1572.55 | 1571.48 | 1571.76 |
| $Q_{INJ}$ (mmscf/d) | 1.035 | 1.035 | 1.035 | 1.035 | 1.035 |

*Table 5:10  Gas lift of W3, tubing ID= 5in*

As the above tables clearly show the tubing inner diameter of 2.441, 3.5 and 5 inches cannot reach a value as close as the reservoir simulation indicated flowrate. The tubing size of 2.75 inches delivers 1303.28 sbbl/day whereas the 4 inches delivers 1300.93 sbbl/day. Since the requested flowrate is a fixed value equal to 1303.01 the corresponding tubing diameter is 2.75 inches, with injection pressure of 909 psia and injection rate of 1.035 mmscf/day. Likewise, this method was implemented for all the wells of the field.

### 5.1.4   Conclusion

In Figure 5.4 it can be seen the plot of the injection pressures versus the produced liquid flowrate for all the tubing inner diameter cases concerning the well W3.
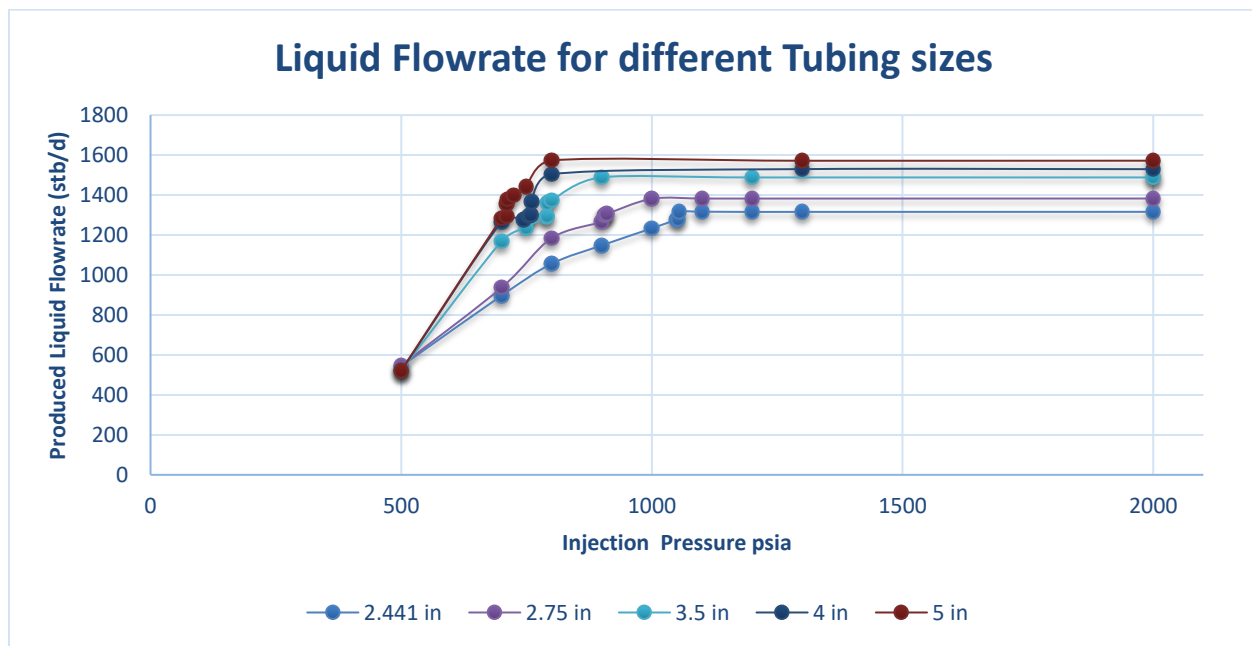


*Figure 5.3 Liquid flowrate for different tubing sizes (well W3)*

5.Gas Lift Design

It can be concluded that the produced liquid flowrate increases with respect to the increase of the tubing inner diameter and the injection pressure. Namely, the increase of the tubing size increases the liquid flowrate because the pressure loss is being reduced due to the frictional component decrease.

Furthermore, the injection pressure increase has significant effect on the liquid production up to a point that does not change further (plateau effect). That happens because the bigger the injection pressure is, the deeper the injection point the gas can reach. As a result, the fluid column becomes lighter, since the density of the gas is lower than the liquid.

### 5.1.5 Evaluation of the Gas lift design
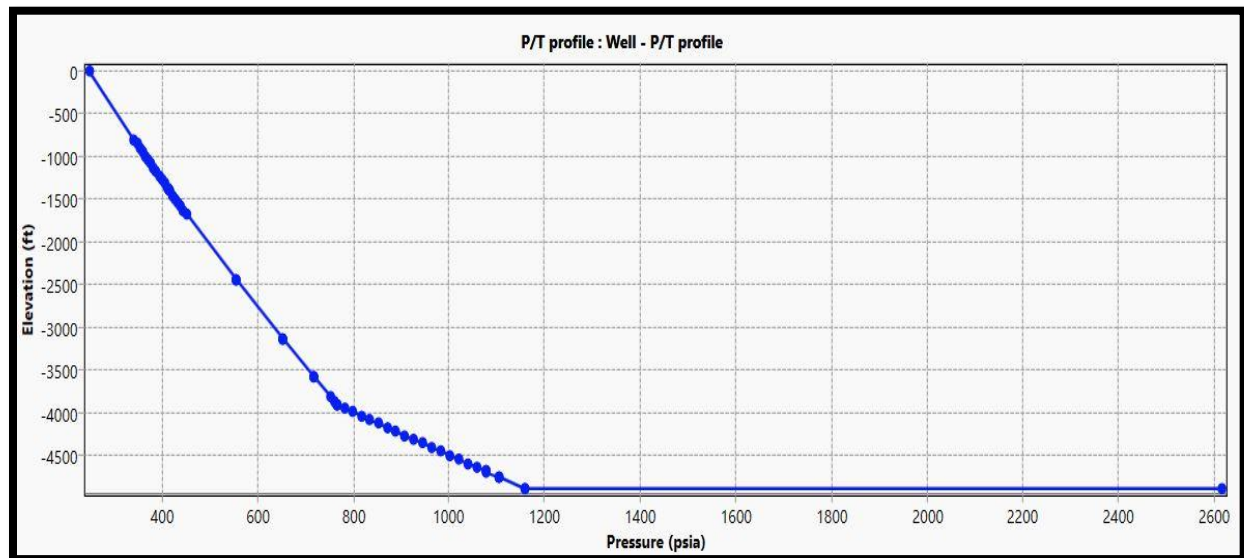


*Figure 5.4 Pressure Traverse Plot after the Gas Lift installation  (PIPESIM Steady-State Multiphase Flow Simulator)*

In Figure 5.3 can be seen the pressure traverse curve as it was generated after the installation of the optimum gas lift design with respect to the appropriate tubing size. This plot evaluates the well performance of the installed gas lift system and it can be judged as successful, since it has achieved the desired flowrate as well as the pressure at the end of the traverse curve is 1159.1 psia, less than the WBP pressure (=1827.6 psia).

### 5.1.6   Gas lift design equipment for well W3

Figures 5.4-5.5 shows the artificial gas lift data and the visualization of the well after the implementation of the system respectively.

| | Gas lift | Active | MD | Manufacturer | Series | Valve type | Port size | Ptro | St | Discharge coe... | DP to fully open | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | ft | | | | in | psia | psia | | psia | |
| 1 | SLB (Camco)_... | ✓ | 1393.235 | SLB (Camco) | R20 | IPO | 0.25 | 957.9653 | | 0.76 | 529 | ... |
| 2 | SLB (Camco)_... | ✓ | 2568.542 | SLB (Camco) | R20 | IPO | 0.25 | 966.4521 | | 0.76 | 529 | ... |
| 3 | SLB (Camco)_... | ✓ | 3341.238 | SLB (Camco) | R20 | IPO | 0.25 | 966.9497 | | 0.76 | 529 | ... |
| 4 | SLB (Camco)_... | ✓ | 3842.439 | SLB (Camco) | R20 | IPO | 0.25 | 961.9968 | | 0.76 | 529 | ... |
| 5 | SLB (Camco)_... | ✓ | 4203.062 | SLB (Camco) | R20 | IPO | 0.3125 | 992.8749 | | 0.76 | 443.2 | ... |

*Figure 5.5 Artificial Gas Lift equipment (PIPESIM Steady-State Multiphase Flow Simulator, 2017)*



*Figure 5.6 Gas Lift visualization for the Well W3 (PIPESIM Steady-State Multiphase Flow Simulator, 2017)*

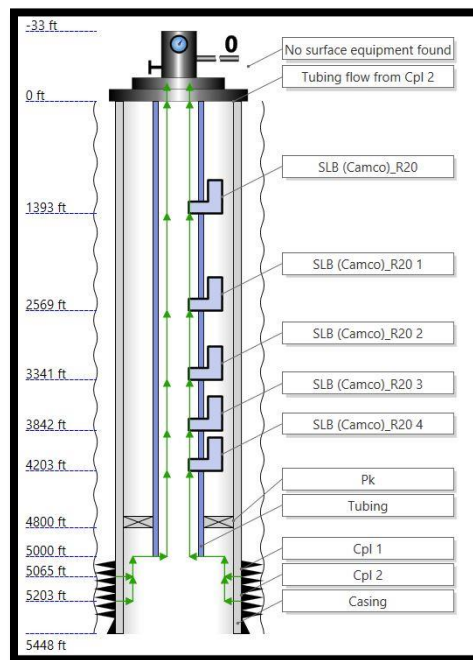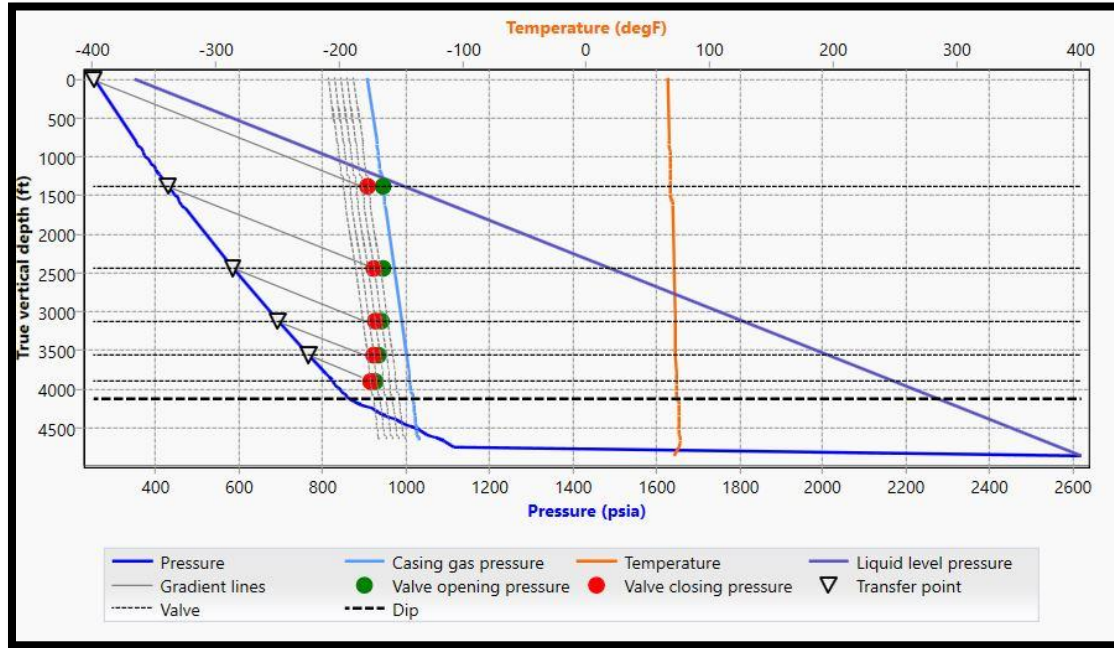*Figure 5.7 Pressure vs Depth of the Gas Lift installation (PIPESIM Steady-State Multiphase Flow Simulator, 2017)*

Figure 5.6 indicates that five valves are installed along the tubing. The valves enable the access of the gas to enter from the annulus to the tubing. PIPESIM has the option to suggest the optimum way of valves' installation, under the conditions given by the user. Moreover, PIPESIM suggests the number of valves, the deepest injection point and the valves' spacing which suit best for its configuration.

# 6. Results of the Gas lift design

According to Chapter 5, the same procedure was followed for all the wells in order to choose the suitable tubing size. In addition, through this tubing selection methodology we are able to choose the appropriate injection pressures that will fit and complete the gas lift design. Below the results for all the wells are presented after the gas lift installation.

| W3 | | |
|---|---|---|
| Reservoir Data | $P_{avg}$ (psia) | 2616.6 |
| | PI sbbl/day/psia | 0.433 |
| | WC% | 79.62 |
| | WBP (psia) | 1827.65 |
| | $Q_L$ sbbl/day | 1303.01 |
| Gas Lift Output | ID (in) | 2.75 |
| | $Q_L$ sbbl/day | 1303.28 |
| | $P_{inj}$(psia) | 909 |

*Table 6:1 Gas lift results for well W3*

| W22 | | |
|---|---|---|
| Reservoir Data | $P_{avg}$ (psia) | 2616.6 |
| | PI sbbl/day/psia | 0.392 |
| | WC% | 47.38 |
| | WBP (psia) | 1711.4 |
| | $Q_L$ sbbl/day | 738.56 |
| Gas Lift Output | ID (in) | 2.441 |
| | $Q_L$ sbbl/day | 738.52 |
| | $P_{inj}$(psia) | 544 |

*Table 6:2 Gas lift results for well W22*

# 6.Results of the Gas lift design

| W31 | | |
|---|---|---|
| **Reservoir Data** | $P_{avg}$ **(psia)** | 2616.6 |
| | **PI sbbl/day/psia** | 0.595 |
| | **WC%** | 80.67 |
| | **WBP (psia)** | 2212.5 |
| | $Q_L$ **sbbl/day** | 1776.52 |
| **Gas Lift Output** | **ID (in)** | 3 |
| | $Q_L$ **sbbl/day** | 1776.62 |
| | $P_{inj}$**(psia)** | 961.5 |

*Table 6:3 Gas lift results for well W31*

| W33 | | |
|---|---|---|
| **Reservoir Data** | $P_{avg}$ **(psia)** | 2616.6 |
| | **PI sbbl/day/psia** | 0.837 |
| | **WC%** | 67.47 |
| | **WBP (psia)** | 1982.2 |
| | $Q_L$ **sbbl/day** | 1779.71 |
| **Gas Lift Output** | **ID (in)** | 4 |
| | $Q_L$ **sbbl/day** | 1779.56 |
| | $P_{inj}$**(psia)** | 830.5 |

*Table 6:4 Gas lift results for well W33*

| W35 | | |
|---|---|---|
| **Reservoir Data** | $P_{avg}$ **(psia)** | 2616.6 |
| | **PI sbbl/day/psia** | 0.113 |
| | **WC%** | 80.44 |
| | **WBP (psia)** | 1609.08 |
| | $Q_L$ **sbbl/day** | 703.62 |
| **Gas Lift Output** | **ID (in)** | 5.5 |
| | $Q_L$ **sbbl/day** | 594.98 |
| | $P_{inj}$**(psia)** | 2000 |

*Table 6:5 Gas lift results for well W35*

| W48 | | |
|---|---|---|
| **Reservoir Data** | $P_{avg}$ **(psia)** | 2616.6 |
| | **PI sbbl/day/psia** | 0.501 |
| | **WC%** | 43.25% |
| | **WBP (psia)** | 1629.3 |
| | $Q_L$ **sbbl/day** | 958.85 |
| **Gas Lift Output** | **ID (in)** | 3 |
| | $Q_L$ **sbbl/day** | 958.82 |
| | $P_{inj}$**(psia)** | 594 |

*Table 6:6 Gas lift results for well W48*

# 6. Results of the Gas lift design

| W50 | | |
|---|---|---|
| **Reservoir Data** | $P_{avg}$ **(psia)** | 2616.6 |
| | **PI sbbl/day/psia** | 0.341 |
| | **WC%** | 25.51 |
| | **WBP (psia)** | 1219.7 |
| | $Q_L$ **sbbl/day** | 898.25 |
| **Gas Lift Output** | **ID (in)** | 3 |
| | $Q_L$ **sbbl/day** | 898.62 |
| | $P_{inj}$**(psia)** | 709 |

*Table 6:7 Gas lift results for well W50*

According to the above results it can be stated that the artificial gas lift design generated by the PIPESIM software was overall successful. Under these configurations, the gas lift installation at the wells is able to deliver almost the exact daily liquid flowrate, requested by the reservoir simulation, with the least possible deviations from the predictions. It can be recognized by the table 6.8 that the deviation between the predicted production and the production achieved after the gas lift, is of minor importance and less than 1%.

| **WELLS** | **Deviation of $Q_L$ from the predicted** |
|---|---|
| **W3** | 0.021% |
| **W22** | 0.070% |
| **W31** | 0.006% |
| **W33** | 0.008% |
| **W35** | 15.44% |
| **W48** | 0.004% |
| **W50** | 0.041% |

*Table 6:8 Deviation between the predicted and calculated production*

In contradiction with the performance of the most of the wells, it is more than obvious that the well W35 seems that is not be able to fulfill the requirements of the production prediction, even after lift help. The scheduled flowrate should reach 703.6 sbbl/day but after the gas lift system implementation the achieved maximum rate, was 594 sbbl/day.

The design of the well W35 was made to the hilt with tubing size of 5.5 inches inner diameter, as it is limited from the casing size of 7.511 inches inner diameter. Moreover, it reaches a high injection pressure of 2000 psia. It seems that the gas lift is not suitable way of artificial lift for this well and probably an ESP pump could be investigated for installation. Recall that the well W35 reaches the highest water cut of 80.44% and apparently the fluid column is heavy enough and incapable to fit the provision.

# 7. Conclusion

The scope of the present thesis was to evaluate the wells' productivity in order to estimate if the wells of the reservoir model were able to deliver the desired daily liquid flowrate to the surface.

The Pressure traverse investigation showed that most of the wells were not able to produce what was scheduled. So artificial gas lift system was implemented to provide the needed energy to the system to lift the liquid. The gas lift system was selected to be designed under the worst-case scenario for the wells. This scenario exhibits the highest water cut values since the wells are unable to produce from their early stages of life.

The gas lift system was planned after the optimum tubing size which was respective to the liquid flowrate values. After the tubing size investigation, we are able to conclude to general judgments since we witnessed the effect of the injection pressure and the tubing size at the same time.

Generally, as the injection pressure is growing, we are able to achieve higher flowrates due to the deeper injection point we reach at the well. As well as the bigger the tubing inner diameter, the more efficient -in terms of production- becomes the well. The slip phenomenon which was expected to appear with the increasing diameter of the tubing was not the case of this study since the quantity of the injected gas was low.

The results of the design can be determined as successful, considering the matching of the predicted flowrates. Only one well was unsuccessful to deliver the exact fluid amount to the surface for which we claimed that could be assisted with additional artificial lift like an ESP pump.

To conclude with, when the reservoir energy is not sufficient to supply the fluids to come to the surface, then artificial gas lift design can be implemented as a cost-effective method for the industry compared to others.

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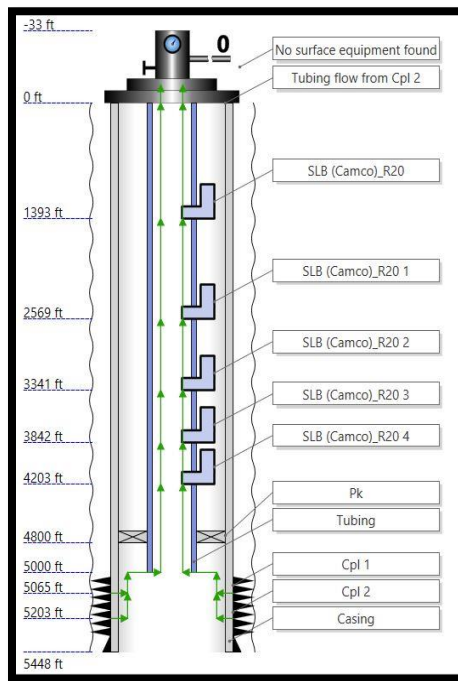
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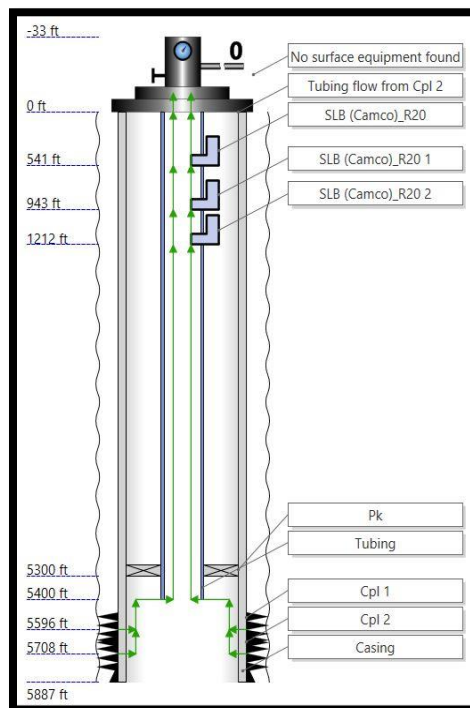*Figure 8.1 Artificial lift configuration for well W3*



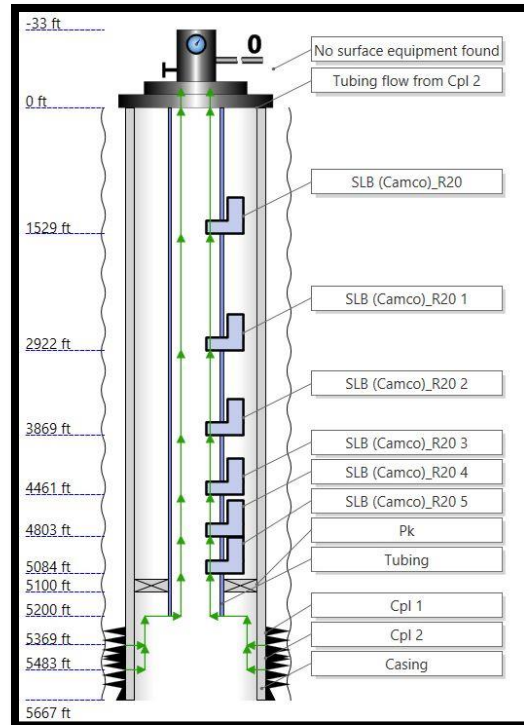*Figure 8.2Artificial lift configuration for well W22*

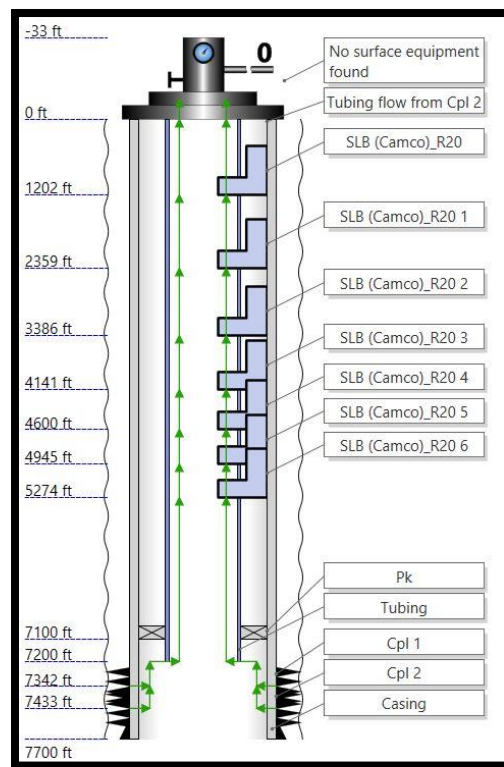*Figure 8.3 Artificial lift configuration for well W31*



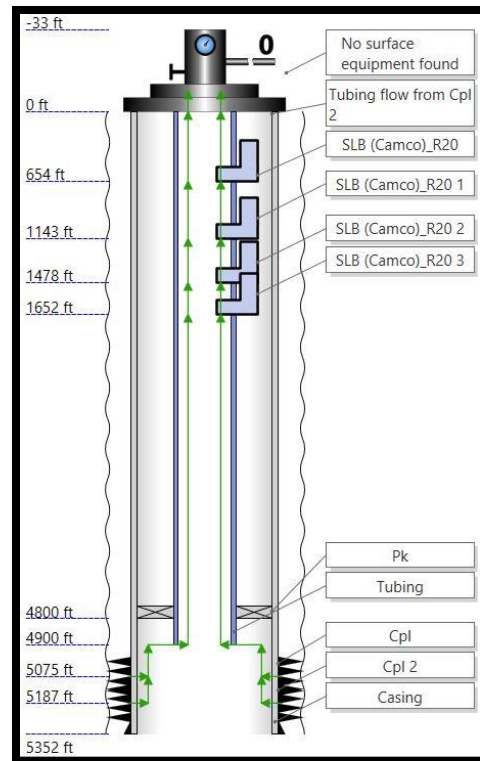*Figure 8.4 Artificial lift configuration for well W33*

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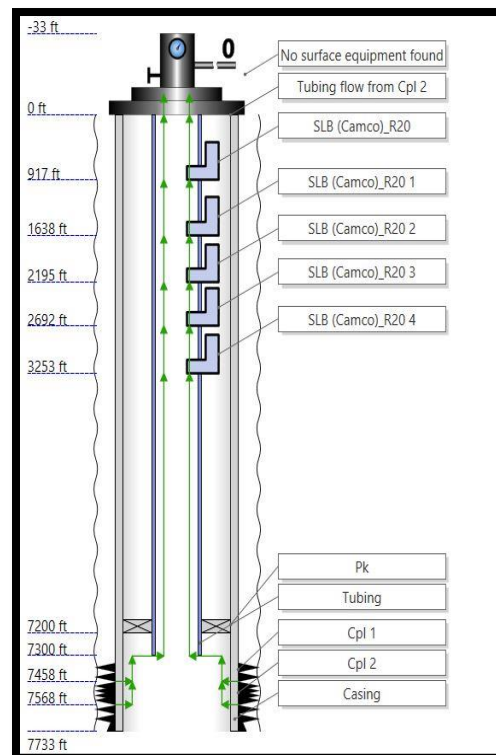*Figure 8.5 Artificial lift configuration for well W48*



*Figure 8.6 Artificial lift configuration for well W50*

| | Gas lift | Active | MD | Manufacturer | Series | Valve type | Port size | Ptro | St | Discharge coe... | DP to fully open | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | ft | | | | in | psia | psia | | psia | |
| 1 | SLB (Camco)_... | ✓ | 540.8377 | SLB (Camco) | R20 | IPO | 0.25 | 570.3163 | | 0.76 | 529 | ... |
| 2 | SLB (Camco)_... | ✓ | 942.7349 | SLB (Camco) | R20 | IPO | 0.25 | 559.1955 | | 0.76 | 529 | ... |
| 3 | SLB (Camco)_... | ✓ | 1212.109 | SLB (Camco) | R20 | IPO | 0.375 | 597.0301 | | 0.76 | 382.6 | ... |

*Figure 8.7 Artificial lift equipment W22*

| | Gas lift | Active | MD | Manufacturer | Series | Valve type | Port size | Ptro | St | Discharge coe... | DP to fully open | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | ft | | | | in | psia | psia | | psia | |
| 1 | SLB (Camco)_... | ✓ | 1529.304 | SLB (Camco) | R20 | IPO | 0.25 | 1036.371 | | 0.76 | 529 | ... |
| 2 | SLB (Camco)_... | ✓ | 2922.483 | SLB (Camco) | R20 | IPO | 0.25 | 1048.116 | | 0.76 | 529 | ... |
| 3 | SLB (Camco)_... | ✓ | 3869.183 | SLB (Camco) | R20 | IPO | 0.25 | 1050.662 | | 0.76 | 529 | ... |
| 4 | SLB (Camco)_... | ✓ | 4461.132 | SLB (Camco) | R20 | IPO | 0.25 | 1047.222 | | 0.76 | 529 | ... |
| 5 | SLB (Camco)_... | ✓ | 4803.171 | SLB (Camco) | R20 | IPO | 0.25 | 1039.497 | | 0.76 | 529 | ... |
| 6 | SLB (Camco)_... | ✓ | 5084.251 | SLB (Camco) | R20 | IPO | 0.3125 | 1072.446 | | 0.76 | 443.2 | ... |

*Figure 8.8 Artificial lift equipment W31*

| | Gas lift | Active | MD | Manufacturer | Series | Valve type | Port size | Ptro | St | Discharge coe... | DP to fully open | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | ft | | | | in | psia | psia | | psia | |
| 1 | SLB (Camco)_... | ✓ | 1201.869 | SLB (Camco) | R20 | IPO | 0.25 | 875.1407 | | 0.76 | 529 | ... |
| 2 | SLB (Camco)_... | ✓ | 2358.652 | SLB (Camco) | R20 | IPO | 0.25 | 880.2301 | | 0.76 | 529 | ... |
| 3 | SLB (Camco)_... | ✓ | 3385.698 | SLB (Camco) | R20 | IPO | 0.25 | 879.9735 | | 0.76 | 529 | ... |
| 4 | SLB (Camco)_... | ✓ | 4140.616 | SLB (Camco) | R20 | IPO | 0.25 | 875.9357 | | 0.76 | 529 | ... |
| 5 | SLB (Camco)_... | ✓ | 4600.472 | SLB (Camco) | R20 | IPO | 0.25 | 868.7222 | | 0.76 | 529 | ... |
| 6 | SLB (Camco)_... | ✓ | 4945.305 | SLB (Camco) | R20 | IPO | 0.25 | 860.2342 | | 0.76 | 529 | ... |
| 7 | SLB (Camco)_... | ✓ | 5273.677 | SLB (Camco) | R20 | IPO | 0.3125 | 886.3712 | | 0.76 | 443.2 | ... |

*Figure 8.9 Artificial lift equipment W33*

| | Gas lift | Active | MD | Manufacturer | Series | Valve type | Port size | Ptro | St | Discharge coe... | DP to fully open | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | ft | | | | in | psia | psia | | psia | |
| 1 | SLB (Camco)_... | ✓ | 6398.424 | SLB (Camco) | R20 | IPO | 0.25 | 2289.435 | | 0.76 | 529 | ... |
| 2 | SLB (Camco)_... | ✓ | 7191.677 | SLB (Camco) | R20 | IPO | 0.25 | 2292.208 | | 0.76 | 529 | ... |

*Figure 8.10 Artificial lift equipment W35*

| | Gas lift | Active | MD | Manufacturer | Series | Valve type | Port size | Ptro | St | Discharge coe... | DP to fully open | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | ft | | | | in | psia | psia | | psia | |
| 1 | SLB (Camco)_... | ✓ | 653.7766 | SLB (Camco) | R20 | IPO | 0.25 | 623.6489 | | 0.76 | 529 | ... |
| 2 | SLB (Camco)_... | ✓ | 1142.975 | SLB (Camco) | R20 | IPO | 0.25 | 614.2642 | | 0.76 | 529 | ... |
| 3 | SLB (Camco)_... | ✓ | 1477.696 | SLB (Camco) | R20 | IPO | 0.25 | 602.7532 | | 0.76 | 529 | ... |
| 4 | SLB (Camco)_... | ✓ | 1652 | SLB (Camco) | R20 | IPO | 0.375 | 643.9772 | | 0.76 | 382.6 | ... |

*Figure 8.11 Artificial lift equipment W48*

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| | Gas lift | Active | MD | Manufacturer | Series | Valve type | Port size | Ptro | St | Discharge coe... | DP to fully open | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | ft | | | | in | psia | psia | | psia | |
| 1 | SLB (Camco)_... | ✓ | 916.8637 | SLB (Camco) | R20 | IPO | 0.25 | 749.9427 | | 0.76 | 529 | ... |
| 2 | SLB (Camco)_... | ✓ | 1638.142 | SLB (Camco) | R20 | IPO | 0.25 | 745.6745 | | 0.76 | 529 | ... |
| 3 | SLB (Camco)_... | ✓ | 2195.245 | SLB (Camco) | R20 | IPO | 0.25 | 737.7045 | | 0.76 | 529 | ... |
| 4 | SLB (Camco)_... | ✓ | 2691.871 | SLB (Camco) | R20 | IPO | 0.25 | 727.4505 | | 0.76 | 529 | ... |
| 5 | SLB (Camco)_... | ✓ | 3253.288 | SLB (Camco) | R20 | IPO | 0.375 | 781.842 | | 0.76 | 382.6 | ... |

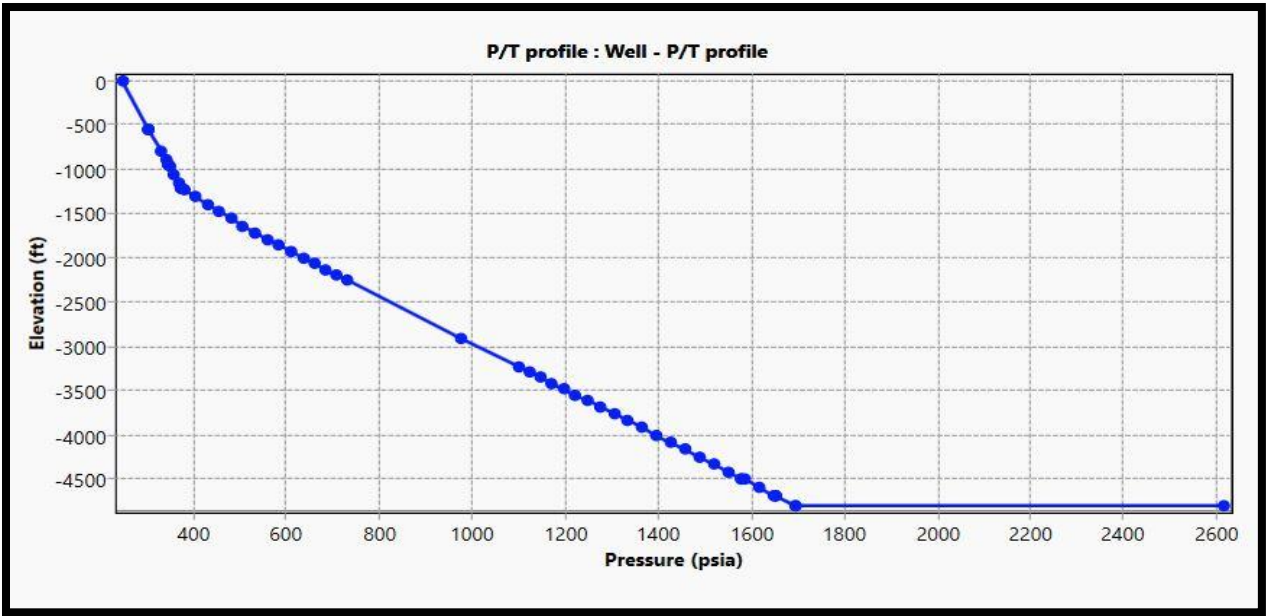*Figure 8.12 Artificial lift equipment W50*



*Figure 8.13 Pressure Traverse Curve after Gas Lift installation for well W22*
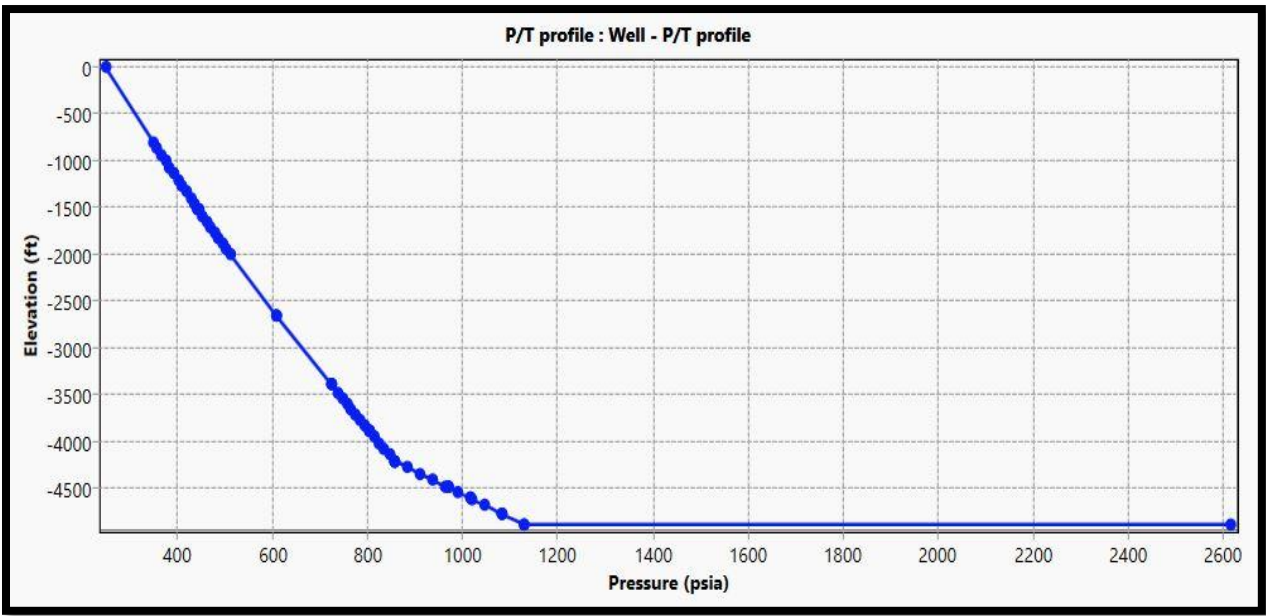


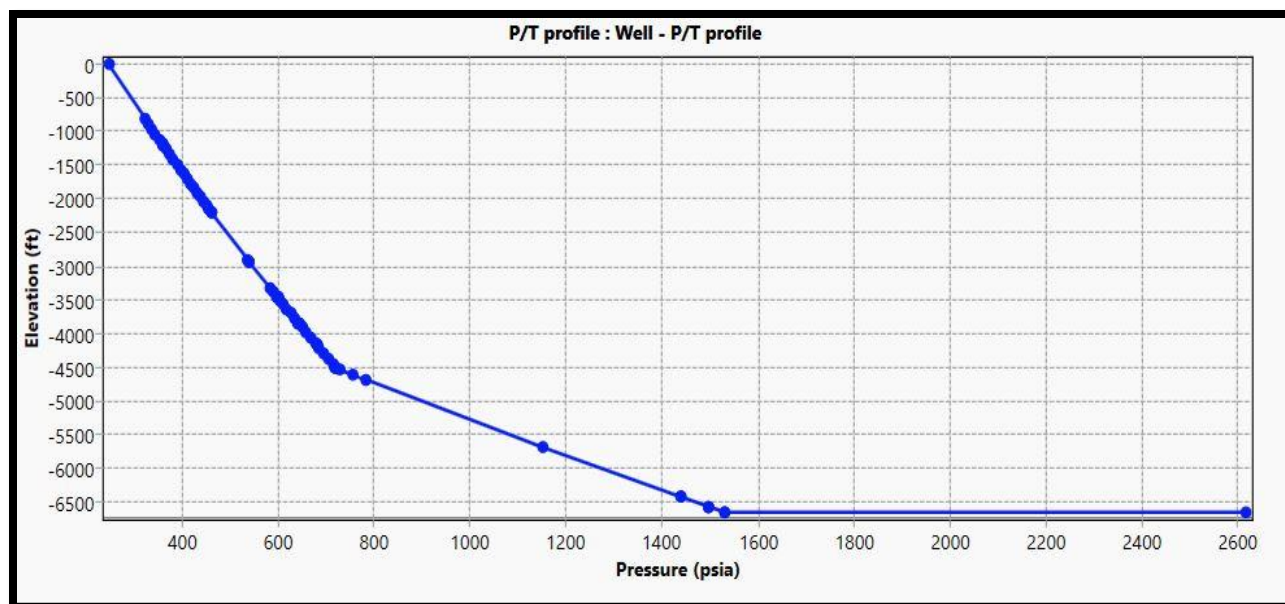*Figure 8.14 Pressure Traverse Curve after Gas Lift installation for well W31*

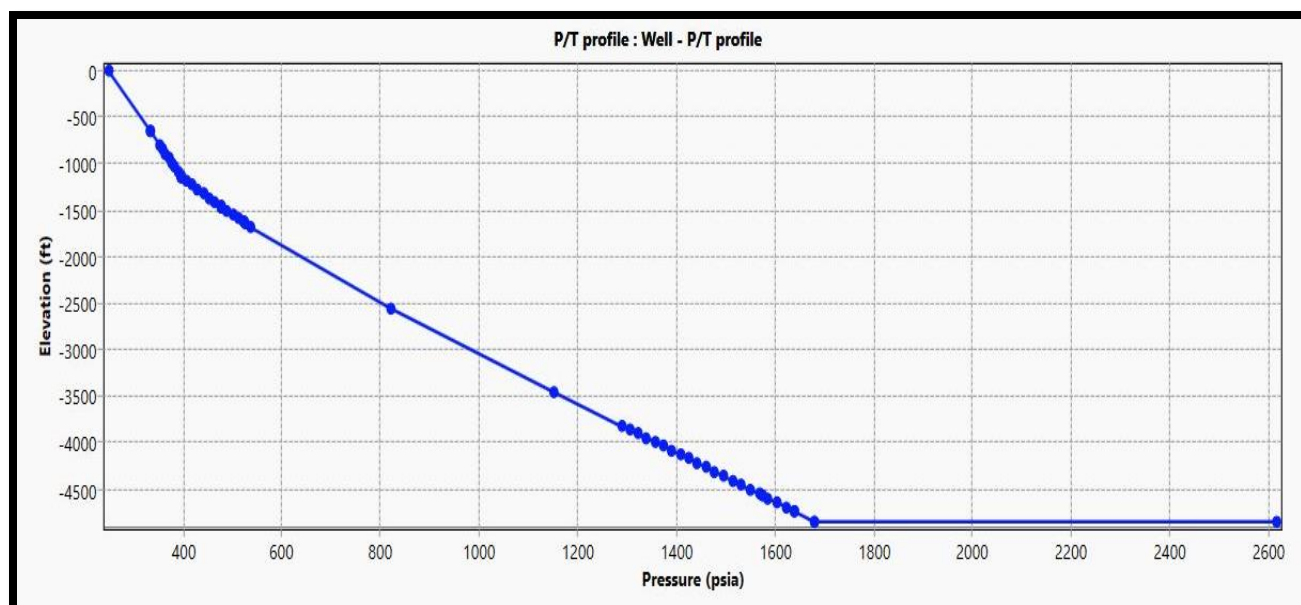*Figure 8.15 Pressure Traverse Curve after Gas Lift installation for well W33*



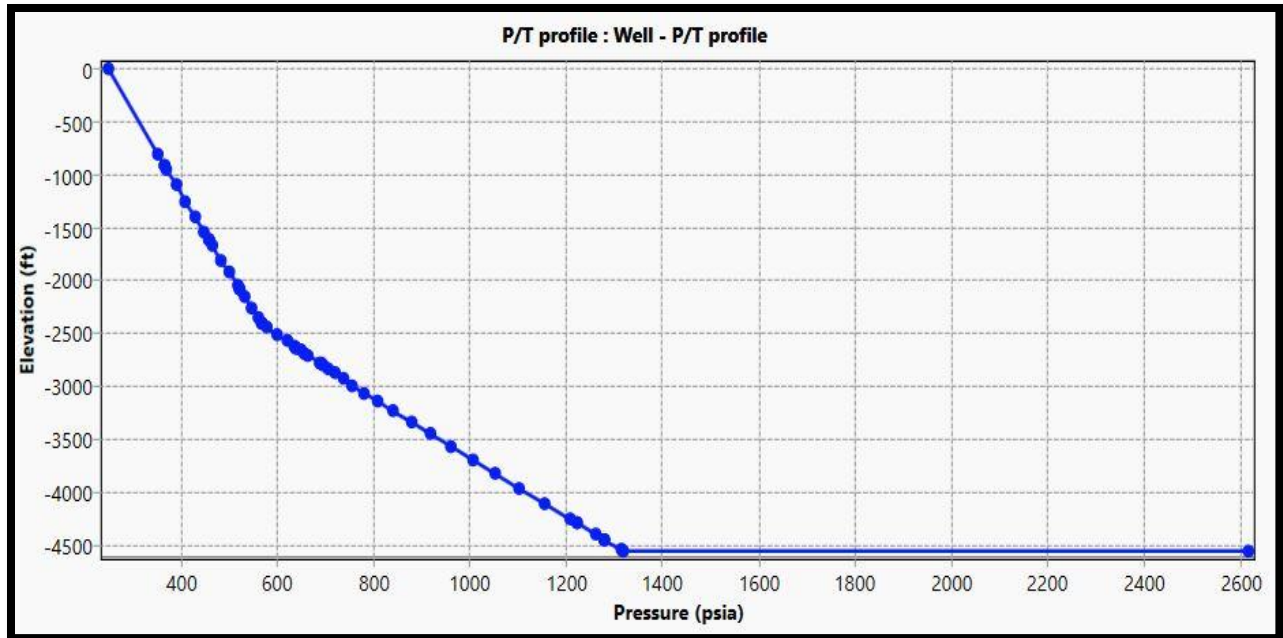*Figure 8.16 Pressure Traverse Curve after Gas Lift installation for well W48*

*Figure 8.17 Pressure Traverse Curve after Gas Lift installation for well W50*