GAS LIFT DESIGN AND OPTIMIZATION

DISSERTATION SUBMITTED IN PARTIAL FULFILLMENT OF THE REQUIREMENT FOR THE AWARD OF THE DEGREE OF

BACHELOR OF TECHNOLOGY

IN

PETROLEUM ENGINEERING

BY

Name	Roll No.	Name	Roll No.
Hasmita Kadavla	17BPE044	Darshak Sakhareliya	17BPE097
Vivek Panchal	17BPE063	Samir Vaghasiya	17BPE108
Jindal Patel	17BPE073	Nikshit Vora	17BPE115
Pranay Patel	17BPE088	Shani Suthar	16BPE125

UNDER THE GUIDANCE OF

MRS. NAMRATA BIST

PROF. SSP SINGH

SCHOOL OF PETROLEUM TECHNOLOGY

PANDIT DEENDAYAL ENERGY UNIVERSITY

GANDHINAGAR – 382007, GUJARAT, INDIA

22ND MAY, 2021

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B.Tech Dissertation Thesis Report

on

Gas Lift Design and Optimization

Mentor

Mrs. Namrata Bist

Prof. SSP Singh

Date of Submission

22nd May, 2021

Team Members

Sr. No.	Name	Roll No.
1	Hasmita Kadavla	17BPE044
2	Vivek Panchal	17BPE063
3	Jindal Patel	17BPE073
4	Pranay Patel	17BPE088
5	Darshak Sakhareliya	17BPE097
6	Samir Vaghasiya	17BPE108
7	Nikshit Vora	17BPE115
8	Shani Suthar	16BPE125

APPROVAL SHEET

This report entitled "Gas Lift Design and Optimization" by Hasmita (17BPE044), Vivek Pachal (17BPE063), Jindal Patel (17BPE073), Pranay Patel (17BPE088), Darshak Sakhareliya (17BPE097), Samir Vaghasiya (17BPE108), Nikshit Vora (17BPE115), and Shani Suthar (16BPE125) is recommended for the degree of Bachelor of Technology in Petroleum Engineering.

Examiners

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____

____

Supervisors

____

____

____

Chairman

____

Date: _______________

Place: ______________

STUDENT DECLARATION

We, **Hasmita (17BPE044), Vivek Pachal (17BPE063), Jindal Patel (17BPE073), Pranay Patel (17BPE088), Darshak Sakhareliya (17BPE097), Samir Vaghasiya (17BPE108), Nikshit Vora (17BPE115), and Shani Suthar (16BPE125)** hereby declare that this written submission represents our ideas in our own words and where other's ideas or words have been included, we have adhered to all principles of academic honesty and integrity and have not misrepresented or fabricated or falsified any idea / data / fact / source in our submission. We understand that any violation of the above will be cause for disciplinary action by the PANDIT DEENDAYAL ENERGY UNIVERSITY and can also evoke penal action from the sources which have thus not been properly cited or from whom proper permission has not been taken when needed.

(Signature)

Name: Hasmita Kadavla
Roll No.: (17BPE044)

(Signature)

Name: Vivek Panchal
Roll No.: (17BPE063)

(Signature)

Name: Jindal Patel
Roll No.: (17BPE073)

(Signature)

Name: Pranay Patel
Roll No.: (17BPE088)

(Signature)

Name: Darshak Sakhareliya
Roll No.: (17BPE097)

(Signature)

Name: Samir Vaghasiya
Roll No.: (17BPE108)

(Signature)

Name: Nikshit Vora
Roll No.: (17BPE115)

(Signature)

Name: Shani Suthar
Roll No.: (16BPE125)

Date: 22/05/2021

22th May, 2021

CERTIFICATE

This is to certify that the dissertation entitled "**Gas Lift Design and Optimization**" submitted by **Hasmita (17BPE044), Vivek Panchal (17BPE063), Jindal Patel (17BPE073), Pranay Patel (17BPE088), Darshak Sakhareliya (17BPE097), Samir Vaghasiya (17BPE108), Nikshit Vora (17BPE115), and Shani Suthar (16BPE125)** in fulfillment of the requirements for the award of the degree of **Bachelor of Technology in Petroleum Engineering**, from **School of Petroleum Technology, Pandit Deendayal Energy University, Gandhinagar** was carried out under my guidance and supervision. No part of this dissertation has been submitted for the award of any degree or otherwise elsewhere to the best of my knowledge.

Mrs. Namrata Bist
School of Petroleum Technology, Gandhinagar

Prof. SSP Singh
School of Petroleum Technology, Gandhinagar

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ABSTRACT

Gas lift is an artificial lift technique which is being used in oil fields since many decades and it has been proven successful. In gas lift the high pressure gas is injected into the well in order to reduce the density of wellbore fluid resulting in increased flow rate. Gas lift is extensively applied in the oil fields which have high GOR as well as gas lift is the first choice of artificial lift in offshore wells. There are mainly two types of gas lift systems available (1) Continuous gas lift and (2) Intermittent gas lift. Selection of the gas lift system depends on the Productivity index of the well and reservoir pressure. The efficiency of the gas lift system depends on the various parameters like design of the gas lift, injection gas rate, injection gas gravity, wellhead pressure, depth of injection etc. To maximize the efficiency of gas lift, effect of all these parameters on production rate should be studied.

Analyzing the design of gas lift is very vital step towards improving the efficiency of gas lift. It mainly includes selection of depth of gas lift valve, type of gas lift valve, gas injection rate and port size of the gas lift valve. In this project, the graphical method for designing the gas lift is illustrated for both the case continuous and intermittent gas lift. For further analysis, WellFlo software has been used to model the gas lift and find the most optimum condition at which the well should be operated. In the present case, two wells one is deviated and another vertical in the same reservoir have been considered for studying the effect of governing parameters on overall production rate. PVT models and multiphase flow correlations have been studied for the better modeling of wells and reliable results. These studies done in this project provides the ways to implement the gas lift in most efficient manner and ultimately improving the economics of the wells and oil fields.

In this project, following methodology has been implemented:

1. Design the continuous and intermittent gas lift manually by graphical method.
2. Studying the various PVT models and multiphase flow correlations.
3. Modelling and designing of the wells using the software.
4. Understanding the change in production rate by varying the governing parameters of gas lift and studying the reasons behind it.
5. Find the most optimum condition for the well to maximize the liquid rate.

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Chapter 1: Introduction

The amount of the fluid being produced from the reservoir is highly dependent on the energy available in the reservoir. In the early life of the well, the reservoir pressure is sufficient to lift the fluid from bottomhole to the surface. The wells in this phase of production are referred as naturally flowing wells.

The key factors which cause the natural flow of fluid are reservoir pressure and formation gas. As the field becomes mature the reservoir pressure drops down and the natural flow rate of well keeps on decreasing. As a result, the well ceases to flow due to the insufficient energy available to lift the fluid to the surface. In order to maintain the production rate the wells require artificial lift to maintain the bottom hole pressure. The main objective of any type of the artificial lift is to maintain the drawdown by maintaining a constant bottomhole pressure. Earlier it was a trend to implement the artificial lift in matured fields, but nowadays people are using it in younger fields to increase the production rate. Artificial lift techniques provide the more economic life of the wells which help to supplement the energy requirement of the world and boost the oil and gas business. (S. Goswami & T. Chauhan, 2015)

1.1 Artificial Lift Techniques

Here some of the major artificial lifts are shown.

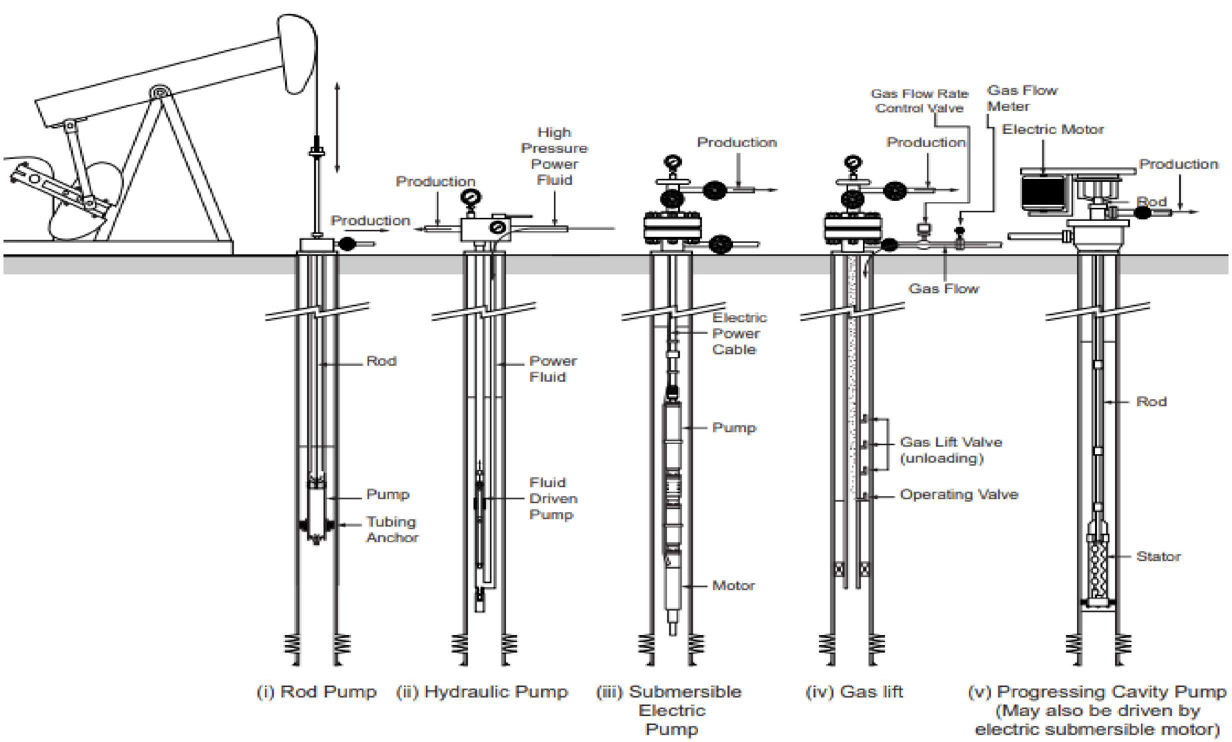

Figure 1: various artificial lift techniques

Artificial lift increases the production rate by: (S. Goswami, T. Chauhan, 2015)

- By a mechanical means such as pump
- Decreasing a overall fluid density of column by injecting high pressure gas
- Improving the lift efficiency with the use of velocity strings

1.2 Gas Lift

Gas lift is an artificial lift that uses pressurized gas into the wellbore to improve production. The principle on which gas lift system works is that high pressure gas is injected into the tubing, which helps to decrease the density of liquid in the tubing. The highly pressurized gas injected between the annulus between the tubing and casing. The gas enters in the tubing through the one or more subsurface valves also known as gas lift valves. It causes the reduction in the weight of fluid column.

The pressure drop in the well decreases and the pressure of the bottomhole becomes low to continue production. As a result, reservoir fluid experiences less resistance to travel from bottomhole to the surface. This technique is very useful in offshore due to flexibility in its production rates, it can handle corrosive fluids and also applicable for high temperature fields. (Kermit Brown, 1980)

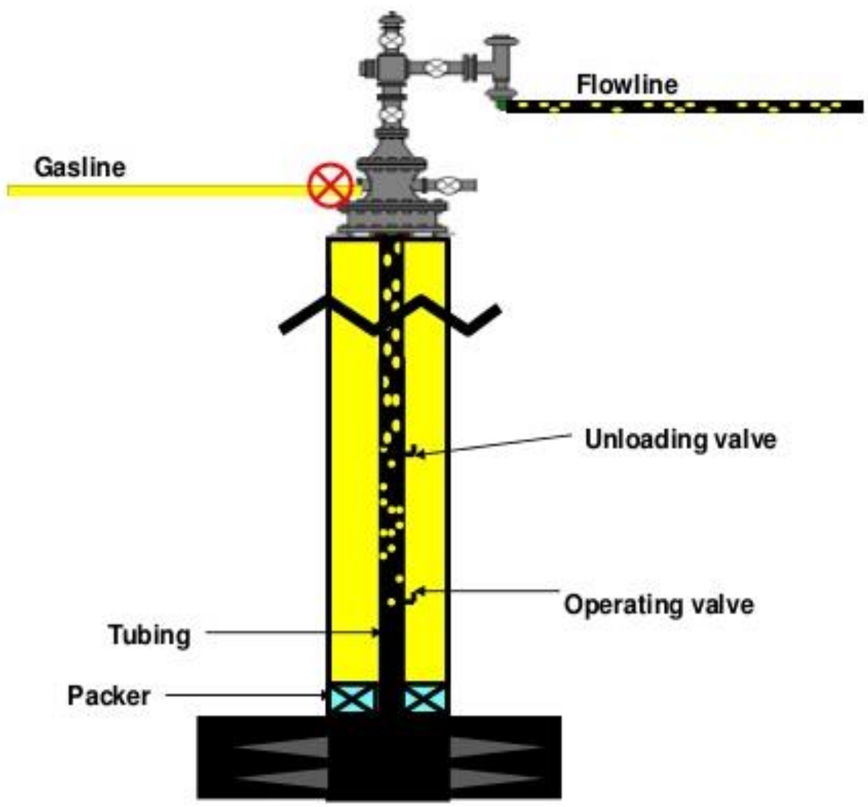

Figure 2: schematic of gas lift

There are mainly two types of gas lift techniques:

1.2.1 Continuous Gas Lift:

In this method the gas is injected into the well at a constant and uninterrupted manner. The injection valve used should be as deep as possible such that fluid becomes lighter enough to flow up to the surface. This method is applied in the well with a high productivity index and high bottomhole pressure with respect to depth.

Continuous gas lift is cost effective, easy to implement and very effective in a wide range of operating conditions. It requires very less maintenance in comparison to the other alternatives, and is considered as one of the most typical forms of artificial lift in oil production. In this type the oil production rate ranges from 200 to 20,000 bpd.

1.2.2 Intermittent Gas Lift:

This technique is used the well with (1) high productivity index with low bottomhole pressure or (2) low productivity index with low bottomhole pressure. In this technique the well is allowed to accumulate the formation fluid in the tubing. Then the slug of the gas is injected into the well which produces the accumulated liquid to the surface. This cycle is repeated again as soon as the fluid is produced on the surface.

Intermittent gas lift is used in conjunction with time cycle controller. The cycle is regulated to coincide with the fluid fill in rate from reservoir to wellbore.

1.3 History of Gas Lift

- In 1797 this form of technique was used to lift the water from th mines shaft.
- In 1864 in Pennsylvania gas lift was used to lift the oil using compressed air via air pipe bringing the air bottom of the hole. Air was also used in Texas for large scale.
- In 1920 the gas was used instead of air to lower the risk of explosion.
- From 1929 to 1945 various types of valve designed were made for gas lift system.
- Finally in 1944 W.R. King patented the bellows valve which is the most commonly used in industry today.
- In 1951 the side pocket mandrel was invented for better placement and retrieval of gas lift valve. (A. BelAmara, 2016)

1.4 Design of Gas Lift Installations

Many factors need to be considered while designing the gas lift system. One of the major thing is to determine which type of gas lift (Continuous or intermittent) should be implemented. Then the other parameters include the type of valve and the depth at the valves should be placed.

The main Objective of the Gas Lift valve is to unload the fluid from the wellbore so the gas should be injected at the optimum point in the tubing. Also, the gas injection rate should be controlled during the unloading and operating stage.

The depth of the valve in the gas lift installation is dependent on many parameters which include (1) fluid gradient into the tubing (2) available gas for unloading (3) well inflow performance (4) surface back pressure (5) bottomhole pressure and temperature (6) fluid level in casing etc.

Gas lift installations are very flexible. It can perform at any production rate satisfactorily.

1.5 Gas Lift Optimization

The success of the gas lift system depends on the design of the system, close monitoring of the system and the personnel who operates the system. The proper analyses of the system are extremely important to know whether the system is working efficiently or not. Each and every wells should be properly monitored to know whether the system is properly designed or all parameters are perfectly implemented or not. If it is found that the system is not working at required efficiency the proper remedial measures are taken in action.

There are many ways to analyze the continuous and intermittent gas lift systems. The various measurements and operations are listed below used to analyze the gas lift system.

I. Recording surface pressures on tubing and casing (two and three pen recorder)
II. Measurements of gas volume
III. Surface temperature readings
IV. Visual observation of surface installations
V. Subsurface temperature surveys
VI. Subsurface pressure surveys
VII. Combination flowing temperature and pressure surveys
VIII. Fluid level measurements using acoustic methods

A gas lift system is incomplete without the two pen pressure recording instrument. With this tool the casing head pressure and tubing pressure are measured. The analyses of these charts give the interpretation of the gas lift system. (Kermit Brown, 1980)

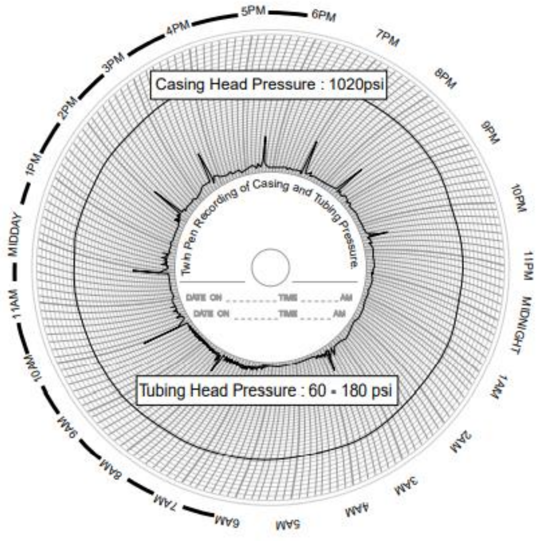

Figure 3: pen chart recorder

The objective of gas lift to maximize the oil production is also dependent on the amount of gas being injected. Therefore it is necessary to analyze the dependence of oil production on the gas injection rate. Below figure shows the typical trend of the oil production versus the gas injection rate. This graph shows that oil production increase as the gas injection rate increases, but after certain value the oil production starts to decrease. (Hariott Watt)

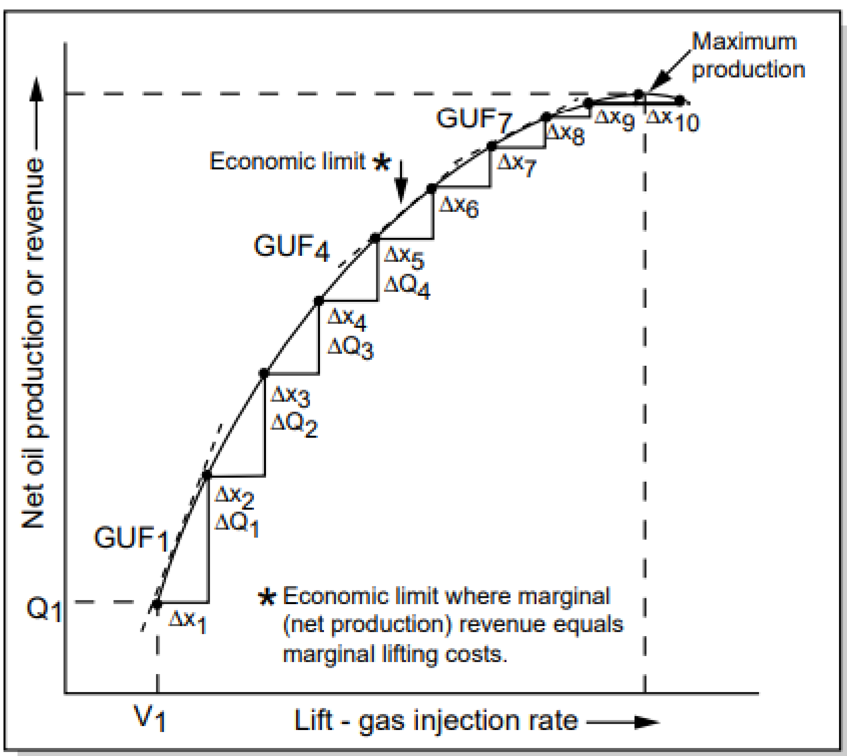

Figure 4: Oil production vs. gas injection rate

Chapter 2: Literature Survey

2.1 Gas lift

It is a methodology of artificial lift that uses an external source of high-pressure gas for supplementing formation gas to lift the well fluids. The principle of gas lift is that gas injected into the tubing reduces the density of the fluids in the tubing, and the bubbles have a “scrubbing” action on the liquids. (Hernandez, 2016)

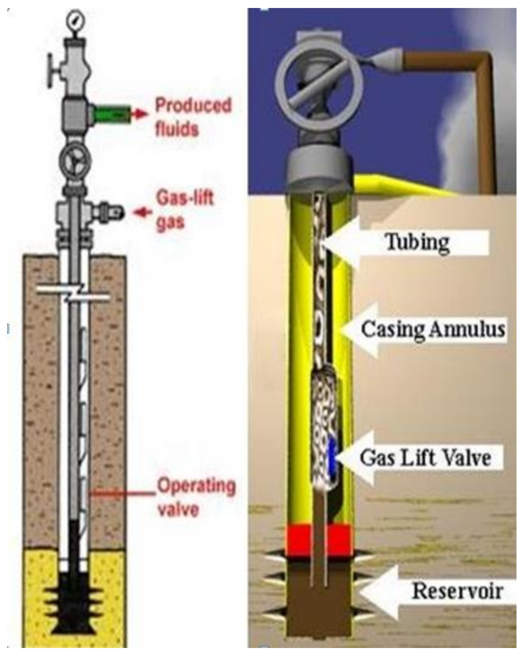

Figure 5: Gas lift (Petrowiki, 2016)

2.2 Selection of Artificial Lift System:

Importantly, the operator chooses the cheapest artificial lifting technique to appreciate the development potential of the oil or gas field. Historically, technology strategies have generally been different in the business world, including strategies for choosing lifting methods for specific areas determining what ways can lift at the specified rates and from the desired depths.

•Evaluating lists of advantages and disadvantages.

•Use of “expert” systems to both eliminate and select systems.

•Evaluation of operating costs, initial costs, production capabilities, etc. using economics as a tool of selection.

In the artificial lift design, the project faces the constraints of adequate facilities, artificial lift capacity, and good productivity of a productive elevator facility. Energy efficiency will in part decide the cost of operation, but this is as it was one of the numerous factors to be considered. In typical artificial lift problems, the type of lift has already been determined and the engineer is having difficulty implementing the system correctly. (Lea & Nickens,1999).

There are many considerations which need to be taken into consideration when these conditions are not predetermining factors:

2.2.1 Reservoir Pressure and Well Productivity:

Among the foremost necessary factors to contemplate are reservoir pressure and well productivity. If producing rate vs. flowing producing bottom-hole pressure is planned, two different IPR curve can be generated. Above bubble purpose pressure, there will be linear relationship. Below bubblepressure,a curve as represented by Vogel can occur (Vogel J.V, 1968). Some type so artificial lift are able to reduce the producing sand face pressure to a lower level than others. The reward for achieving a lower manufacturing pressure can rely upon the reservoir IPR.

2.2.2 Reservoir Fluid:

The characteristics of the reservoir fluid need to be considered. Paraffin may be a far tougher problem for a few sorts of lift than for others. The construction of artificial lift with sand will be to the detriment of some aspects of the lifting. The producing gas-liquid magnitude relation (GLR) is extremely necessary to the lift designer. Cost-effective gas and pumped water can be a significant problem for any method that lift the pump, but it is also useful for pumping up gas, which in turn modulates current carrying capacity in gas production. (Heinze, Winkler, & Lea, 1999).

2.3 Gas Lift System:

Due to low Bottom Hole Pressure (BHP), wells do not start producing the fluid naturally as BHP is insufficient to lift the fluid to the surface. At some purpose, as the reservoir energy gets depleted with time it can’t bring the produced fluid up to the surface.

One way to energize the reservoir fluid is to decrease the BHP by reducing flowing pressure gradient of the fluid column with the help of lighter fluid. Eventually the overall fluid density will decrease which leads to increment in lift capability of the reservoir to push the fluid uo to the surface. Gas lift is the type of artificial lift that almost all closely resembles the natural flow method. It may be treated as the extension of the natural flow method. In a naturally flowing well, as the formation fluid travels upward gas expands and move faster upward due to reduction in fluid column pressure.

Gas velocity should be high enough to carry formation fluid to the surface; but, if the gas velocity isn't high enough, then some liquid may start to fall off at some point near surface. Gas lift is frequently used for lifting water for the purpose of gas reliquefication. In this approach, a highly pressurized gas is injected into the fluid column to reduce the flowing pressure gradient. In different words; gas lift is that the method of supplementing additional gas (from an external source) to extend the gas-liquid magnitude relation (GLR) resulting in reducing the flowing fluid density. This method considered as growth of natural flow phase. (Fathi. 2017)

Gas lift systems can be classified into two types: continuous flow and intermittent flow. In each gas lift systems, high pressure natural gas is injected from the surface to lift formation fluid. Continuous flow gas, that is very similar to the natural flow, is the most typical gas lift technique within the petroleum industry. In this method, gas is injected into the production conduit at the maximum depth depending on the injection pressure and well depth results in an increase in the formation gas liquid ratio. Hence, both the density of the produced fluid and flowing pressure gradient of the mixture decrease which lead to reduction of bottom hole pressure. Wellbore productivity index can be improved by lowering bottom hole pressure.

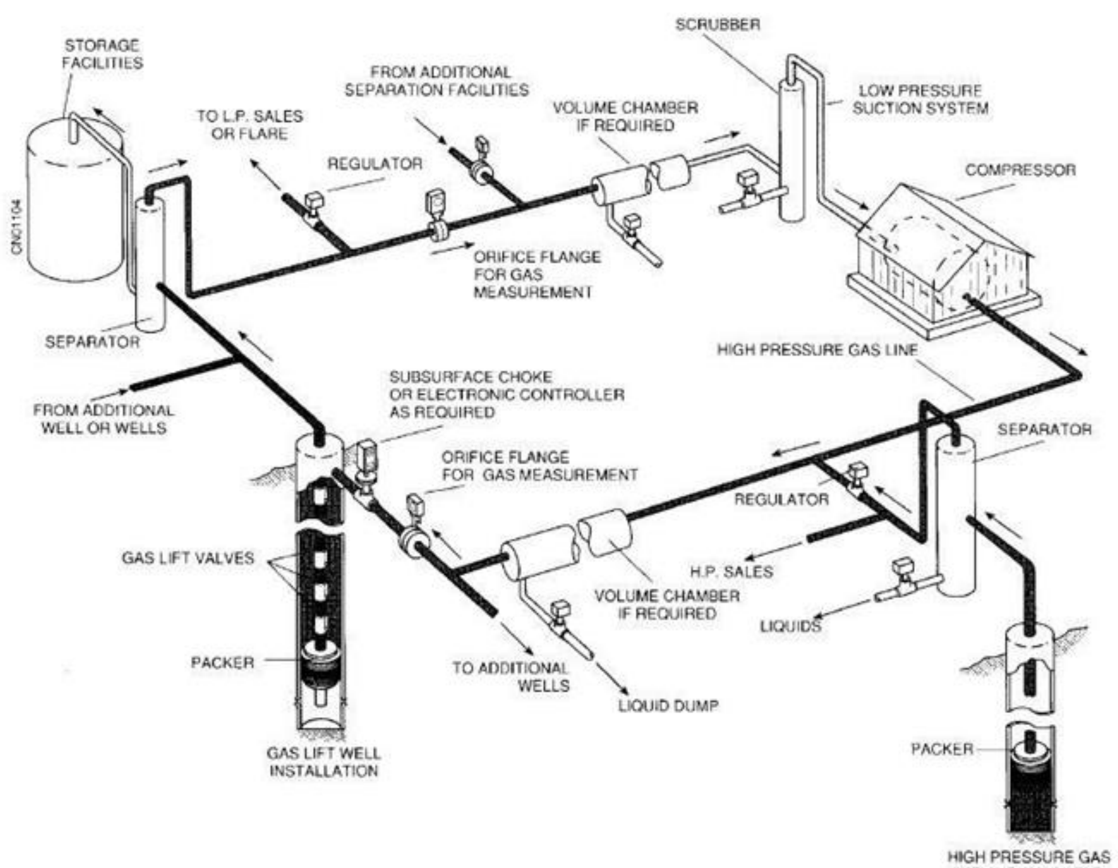

Figure 6: Basic Components of Gas lift (Schlumberger, 1999)

2.4 Gas Lift Equipment:

Equipments used in Gas lift wells mainly include gas lift valves and mandrels to place the valves.
The main equipment’s are the following:

- Compressor horsepower
- Tubing- and wireline-retrievable equipment
- Open and closed installations
- Bellows

2.4.1 Compressor horsepower:

Compressors are very similar to pumps. However, compressors are used for gas and pumps are used for liquids. The gases are compressible while the liquids are incompressible. Both pumps and compressors transport the fluids by increasing the pressure. Compressors in addition reduce the volume of fluid to increase the pressure. (API SPEC 11V1. 1995)

Figure 7: Gas compressor (Jereh Oil and Gas)

2.4.2 Tubing - and wireline-retrievable equipment:

Gas lift valve and reverse check valve was part of the tubing string. It was necessary to drag the tubing to replace a conventional gas lift valve. In 1950, selectively wireline-retrievable gas lift valve and mandrel were used for first time. A pocket receiver was installed within the mandrel in newly designed wireline-retrievable-valve mandrel. It provided an advantage that without pulling out the tubing, gas lift valves could be replaced. The tool which is used to locate the mandrel pocket and remove and install the gas lift valve is called kickover tool. Since the pocket is kept offset from the centreline of tubing, it is named as side pocket mandrel. The Internal diameter ID of tubing is equal to the full-bore inside diameter of side pocket mandrel. (API SPEC 11V1. 1995)

Wireline operations for example pressure survey are possible through mandrels. Many tools for retrieval of gas lift valves in inaccessible wells have been revolutionized after the wireline retrieval system. In highly deviated wells, to ensure successful wireline operations newly designed retrieval valve mandrel uses orienting devices.

2.4.3 Open and closed installations:

In majority of gas lift completions packers are provided with the tubing in order to prevent fluid to enter in gas lift valve and avoid injection of gas from bottom of tubing in case of low bottomhole pressure. If the installation is having packer with standing valve it is referred as closed completion. If installation does not have standing valve, it is called semi closed completion. For Continuous-flow operations this type of completion is used.

Open completion does not have packer and standing valve both. This type of completion is rarely used. For intermittent gas lift operations, the packer is very essential component to isolate the injection gas in annulus and to optimize the gas volume per cycle. In intermittent gas lift operations packer and standing valve both are recommended, but still in many wells standing valves are not used.

The installation of standing valve becomes optional, if the reservoir is having very low permeability. If the injection gas is not constantly provided or the injection line pressure changes significantly, the packers become unavoidable component. If the system does not have packers, the well needs to be unloaded after each shutdown. During unloading process there is a high risk of damage to gas lift valves. The operating fluid level changes if the injection line pressure varies, which results in liquid washing action. If the packers are used, the fluid level is maintained at stable level and unloading of wells after shutdown is not needed.(Hernandez, 2016)

Figure 8: Packer (Petroleum Technology, 2017)

2.4.4 Bellows:

Gas lift design methods and application is revolutionized with the advent of the unbalanced, single-element, bellows-charged gas lift valve. Before the bellows- charged gas lift valve, there have been differential valves and various kinds of distinctive devices used for gas lifting wells. These devices, or valves, were operated by rotating or vertically moving the tube and by means that of a sinker bar on a wireline. (Hernandez, 2016)

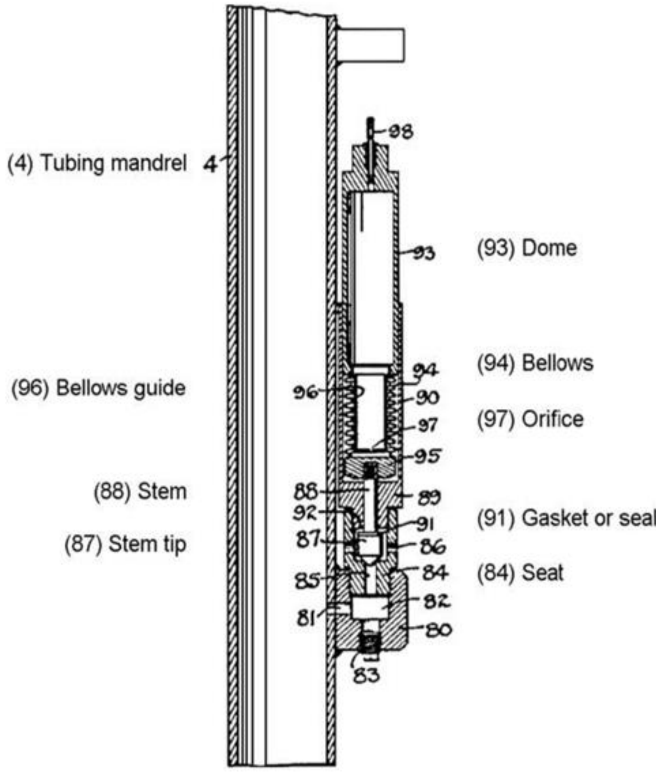

Figure 9: Bellows- charged gas lift valve on a tubing-installed mandrel (U.S. Patent No. 2,339,487)

2.5 Gas lift installation design

There are two basic types of gas lift which are in use nowadays:

(i) Continuous flow

(ii) Intermittent flow

In this research the Continuous flow and its installation design will be discussed in details.

2.5.1 What is continuous flow gas lift?

It is a high-rate method of artificial lift and it is very similar to the natural flow, as it can be abstracted from the name a volume of gas under high pressure is continuously injected into the well the injected gas will mix with the produced well fluid this will reduce the density of the fluid hence flowing pressure gradient will be reduced and the well starts to flow. for this method, plenteous amount of the injected gas must be available throughout the entire life of the project moreover this method induces a relatively high bottom hole pressure and it is suitable for well that has reached it is an economic limit due to high water cut rather than low reservoir pressure. The continuous method can be implemented for wells with reasonably high reservoir pressure relative to a good depth and high PI (0:5 stb=day=psi) in which major pumping problems could occur with other artificial lift methods or When high-pressure gas is available without compression or when the gas cost is low, gas lift is especially attractive. (McAHan, 1984).

Advantages:

- The best method to handle sand and solid material.
- Deviated or crooked holes can be lifted.
- Allows the concurrent use of wireline equipment, and such downhole equipment is easily and economically serviced. This feature allows for routine repairs through the tubing.
- Equipment can be centralized
- Takes full advantage of the gas energy available in the reservoir.

Disadvantages:

- Good data are required to make a good design. If not available, operations may have to continue with an inefficient design that does not produce the well to capacity.
- Operation and maintenance of compressors can be expensive. Skilled operators and good compressor mechanics are required for reliable operation.
- Must have a source of gas.

Depending on well conditions Different types of gas lift installations are used in the industry They fall into four categories:

1. Open installation (continues)
2. Semi-closed installation (continues and intermittent)
3. Closed installation (intermittent)
4. Chamber installation (intermittent)

2.5.2 Open installations:

No packer is set in open installations. open installation is suitable for continuous flow gas lift in wells with good fluid seal. Although this type of installation is simple, it exposes all gas lift valves beneath the point of gas injection to severe fluid erosion due to the dynamic changing of liquid level in the annulus. Open installation is not recommended unless setting packer is not an option.

2.5.3 Semi closed installation:

It is identical to the open installation except that a packer is set in the annulus (between the tubing and casing). This type of installation can be used for both continuous and intermittent-flow gas lift operations. It avoids all the problems associated with open installations. However; it still does not prevent the flow of good fluids back to the formation during unloading processes, which is especially important for intermittent operating.

2.5.4 Closed installation:

In this method, a standing valve is placed in the tubing string or can be placed below the bottom gas lift valve. The function of this valve is to effectively prevents the gas pressure from acting on the formation, which increases the daily production rate from a well of the intermittent type. (McAHan, 1984).

These three types of gas lift installations are illustrated in Figure 2.6.

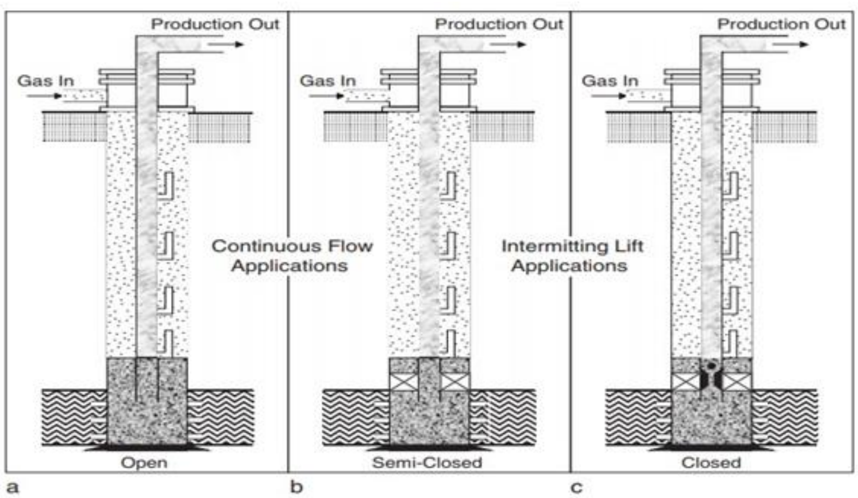

Figure 10: Three types of Gas lift completion (McAHan, 1984)

2.5.5 Chamber installations:

These installations are used for accumulating liquid volume at the bottom hole of intermittent- flow. A chamber is an ideal installation for a low BHP and high PI well. This method can be configured in various ways including using two packers, insert chamber, and reverse flow chamber. This type of chamber is installed to ensure a large storage volume of liquids with a minimum amount of back pressure on the formation so that the liquid production rate is not hindered. (illustrated in figure 2.7)

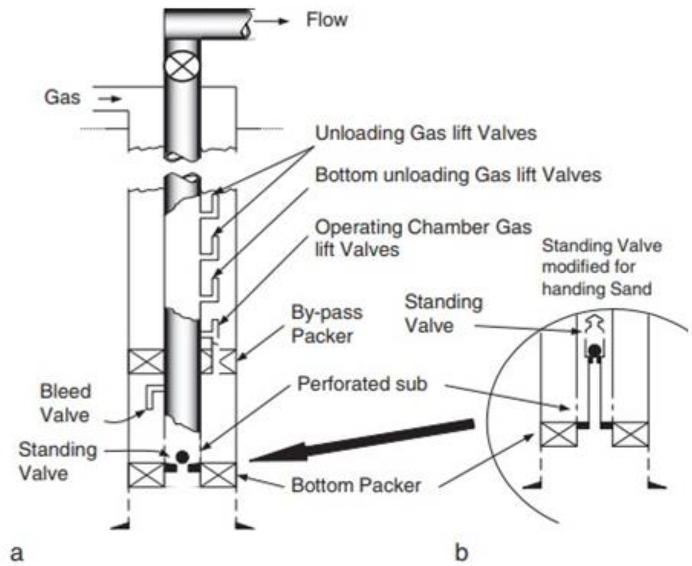

Figure 11: Chamber installation (McAHan, 1984)

2.6 Gas lift Unloading Sequence

Generally all valves are open at the starting condition due to the high tubing pressures. The fluid in tubing has a pressure gradient Gs of hydrostatic liquid column. When the gas enters the first top valve (shown in Fig.12), it produces a slug of liquid–gas mixture of less density in the tubing above the valve depth.

Expansion of the slug try to push the liquid column above it and to flow it to the surface, if there is no check valve is installed at the end of the tubing string, then it can cause the liquid in the bottom hole to flow reverse in to the reservoir. However, as the length of the light slug grows because of gas injection, the bottom hole pressure would eventually decrease below reservoir pressure (Pi), which causes inflow of reservoir fluid from reservoir to wellbore. As the tubing pressure at the depth of the first valve is low enough, the first valve should begin to close and the gas should be forced to the second valve as shown in Fig.12.

The gas injection to the second valve will gasify the liquid in the tubing which is between the first and the second gas lift valve. This would further decrease bottom-hole pressure and induce more inflow. By the time the slug approaches the depth of the first valve, the first valve should be fully shut, allowing more gas to be injected to the second valve. The exact process should occur until the gas enters the main valve (Fig. 12 D). The main valve is also called the master valve or operating valve, is usually the lower most valve in the tubing string. It is an orifice type of valve that never closes. In continuous gas lift operations, once the well is fully unloaded, the steady- state flow will be established and in this situation the main valve is the only valve which remains open in operation (Fig. 12 E) (Garcia 2012).

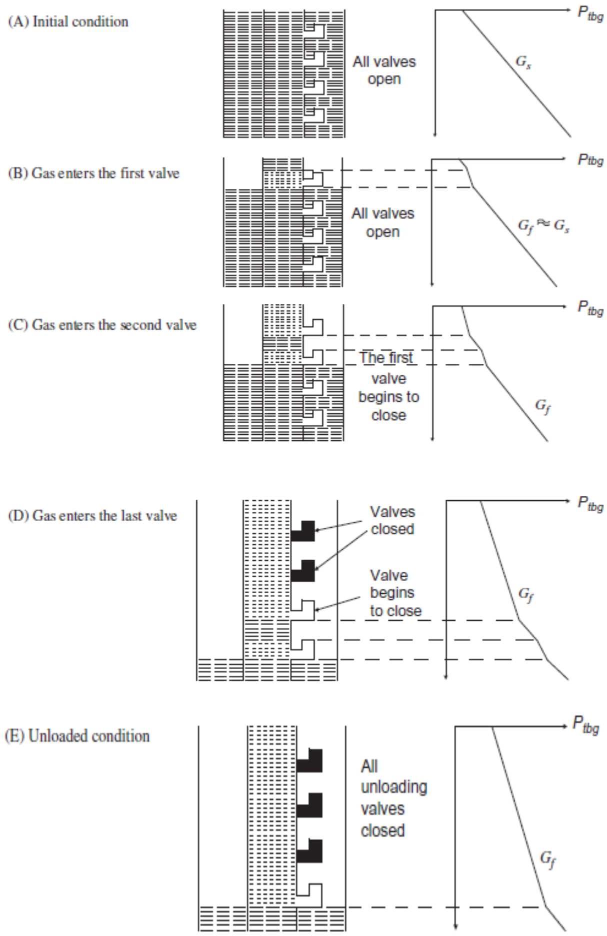

Figure 12: Unloading Sequence (Garcia, 2012)

2.7 Gas Lift Valves

The design of valve spacing for a continuous-flow gas lift valve in a well requires the ca1culation of certain pressures. After their calculations and before installation, gas lift valve operating characteristics has to be adjusted to make the unloading process hassle free. The main components of a gas lift valve are indicated in Figure 13.

Gas lift valve contains a dome that is charged with a high pressurized gas, generally nitrogen. The pressure of the gas pushes the bellows to retain the valve in closed condition. At the starting of the unloading process, the injected gas reaches the unloading valve at a particular pressure. Since the pressure is known as per the design, the pressure of the dome is lesser than the casing pressure. In this case, the valve's stem tip lifts off the valve seat and the valve will be opened. The valve will close, when gas is injected with less pressure and the gas gradient plus the injection pressure of the gas no longer overcomes the dome pressure. Since this pressure range is crucial, the dome pressure should be attuned precisely for the downhole operative conditions. The amount of uncertainty though, makes it crucial to apply a safety factor in the spacing of the valves.

There are various types of unloading valves, namely casing pressure-operated valve (usually called as a pressure valve), throttling pressure valve (also known as a proportional valve or continuous flow valve), fluid-operated valve (also known as a fluid valve), and combination valve (also known as a fluid open-pressure closed valve). Different gas lift design methods have been developed and used in the oil industry for applications of these valves.

There are primarily two types of gas lift valves:

1. Production pressure or fluid operated valves (Fluid Pressure Operated valves).

2. Injection pressure or casing pressure operated valves (Pressure valves)

→**Pressure valves are further classified as unbalanced bellow valves, balanced pressure valves, and pilot valves.** Tubing pressure will affect the opening action of the unbalanced valves, but it will not affect the opening or closing of balanced valves. Pilot valve are developed for intermittent gas lift with large ports and more control on valve spread.

2.7.1 Fluid Operated Valves

As shown in figure 13, the basic elements of a fluid-operated valve are alike to those in a pressure-operated valve excluding that tubing pressure now acts on the larger area of the bellows and the casing pressure will act on the small area of the port. This configuration makes the valve greatly sensitive to the tubing fluid pressure. Note that the port is exposed to the casing pressure and the bellows is exposed to the tubing pressure. Rather than a single flexible element, now both a spring and an optional dome charge giving the closing force.

Generally the manufacturers of this type of valve charge the dome only when high valve setting pressures require a supplement to the spring force. In this case, due to the large bellows area, the tubing pressure rather than the casing pressure controls the operation of the valve. For this specific reason, it is called a fluid-operated valve. It requires a reduction in tubing pressure to close. A cross section of a common fluid-operated valve is shown here.

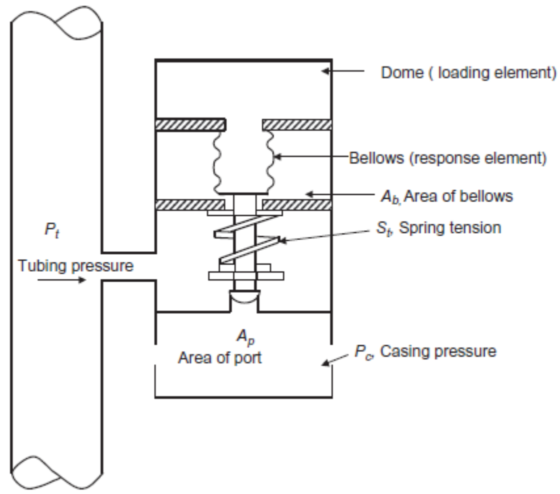

Figure 13: Fluid Operated Valve (Boyun Guo, 2017)

2.7.2 Casing Pressure Operated valves

Nitrogen is generally injected into the dome and charged to a specified pressure. The bellows serve as an elastic or flexible element. The movement of the bellows causes the stem to rise and fall and the ball to open and close above the port. When the port is open, the annulus and tubing are in contact. Because the area of the bellows (Ab) is very much larger than the area of the port (Ap), the casing pressure controls the operation of the valve. Such kind of valve is referred to as a Casing Pressure Operated valve or a 'Pressure Operated Valve'. It requires a build-up in casing pressure to open and a decrease in casing pressure to close. A cross section of a typical pressure-operated valve is shown here in figure (Heriot Watt University Production Technology -II, 2011).

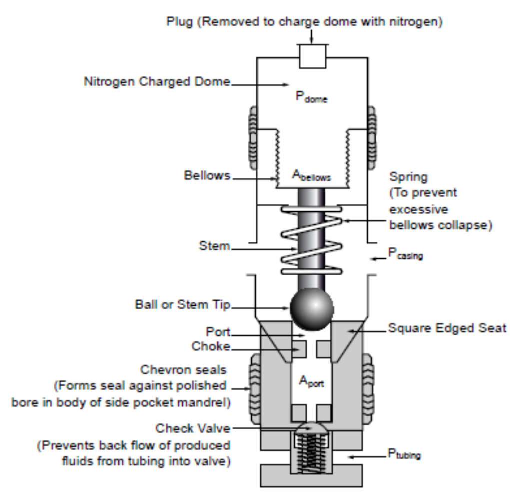

Figure 14: Casing Pressure Operated valve (Heriot Watt Prod.Tech.-II)

2.7.3 Pilot Valves

The pilot valve was developed for need of a larger port size while maintaining close control over spread characteristics. It has a small port which is useful for spread control and there is a larger port which is useful for more efficient gas passage. The pilot valve answers this two-fold need and is regularly used for intermittent gas lift operations. A photograph of a pilot valve and schematic representation are shown in figure 15 and figure 16.

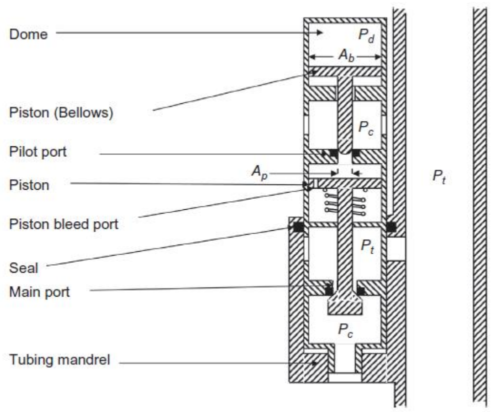

Figure 15: Cross-section of pilot valve

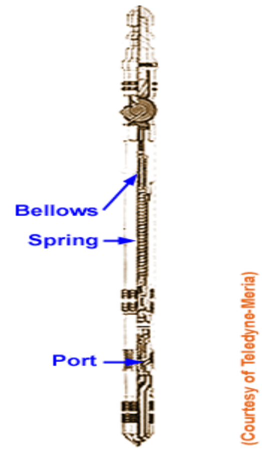

Figure 16: Pilot valve (Boyun Guo, 2017)

2.8 Valve Spacing

The main part of a gas lift design is the method known as "mandrel spacing" which is used to find the depths of the unloading valves and to establish, at each of these valves, the below parameters:

I. The unloading liquid flow rate.

II. The required unloading injection gas flow rate.

III. The valve seat diameter to be able to pass the required injection gas flow rate.

IV. The test-rack calibration opening or closing pressure, as the case might be, that will allow the unloading valves to close in a sequential manner as the unloading of the well proceeds, leaving only the operating valve open when the unloading of the well is finished.

Mandrel spacing is presented in detail in this section. This operation relies on which type of gas lift valve that will be used in the well and on the quality and quantity of the information available to do the design. The initial point for mandrel spacing calculations is to calculate the production pressure-traverse curve, the kick-off injection pressure and the operating injection pressure for the first valve. The production-pressure-traverse curve is calculated from the liquid production, which is either given by the consumer (constant- liquid-flow-rate option).

The kick-off and operating injection pressures is the function of the gas lift system as discussed in the next paragraphs. The final production-pressure-traverse curve is used only as a guide (during the mandrel spacing procedures) to calculate the production pressure (which is also known as the transfer production pressure) from which the next deeper valve is positioned (e.g., this transfer pressure will be point “1 pt” as shown in Fig. 17, to find position of second mandrel beginning at the depth of the first one). This final pressure-traverse curve is highly suggested for the injection pressure operated valves. Using the final production- pressure-traverse curve as guide will set production pressures of unloading valves (for their design calculations) as near as possible to their actual production pressures throughout the normal procedure of the well (throughout the unloading time). If the production pressures utilized for the unloading valves in their design calculations are smaller than their respective final production pressures, then the injection the opening pressure of each unloading valve will reduce when well is fully unloaded as actual higher production pressure will assist open the valve, with result of lowering its necessary injection opening pressure. This can create instability problems or stop well from unloading.

Moreover, utilizing the final pressure-traverse curve places the mandrels at shallower depths because of safety factor (in comparison to utilizing lower production pressures to set the location of the following mandrel, which can result in mandrels that might be too deep to be reached). If, on the other hand, design production pressure is very high compared with the final production pressure at a particular valve, then as the unloading proceeds, the injection opening pressure will increase. This is not a problem and it is actually useful in preventing valve instabilities; the drawback, in this case, is that the following deeper valve will be located at an unreasonably shallower depth. So, using the final production pressure as a guide during mandrel spacing and valve design procedures is suggested for injection pressure operated valves. For production pressure operated valves, it has been found useful to use a design line, such as line “Ptd-g” in Fig. 17 (instead of the final production-pressure traverse curve).

The pressures along with this type of “design line” correspond to pressures that are larger than the actual production pressures once well has been fully unloaded. In this way, each unloading production pressure operated valve will shun in as the production pressure decreases from its design value as well is being unloaded. This type of production pressure design lines is sometimes used for injection pressure operated valves, probably giving a more number of mandrels than required but the designs are also generally more flexible (which is especially useful if the data required for the design is missing or unreliable). Using a larger number of mandrels enhances the flexibility of the design but it also increases costs, number of potential failure points, and can make troubleshooting the operation of the well very difficult.

For redesign calculations, it is common to use a redesign production pressure line, see Fig. 17 the design procedure explained in Fig. 17 for gas lift valves with chokes upstream of the seat is an example of how the design production pressure line can be used for injection pressure operated valves. With some minor changes, this same design procedure (with a design production pressure line and constant unloading operating injection pressure) is used many times for normal injection pressure operated valves (with no upstream chokes) but it has to be used with caution because it might promote valve interference, give more mandrels than required, and make troubleshooting the operation of the well more hard. (Hernandez, 2016).

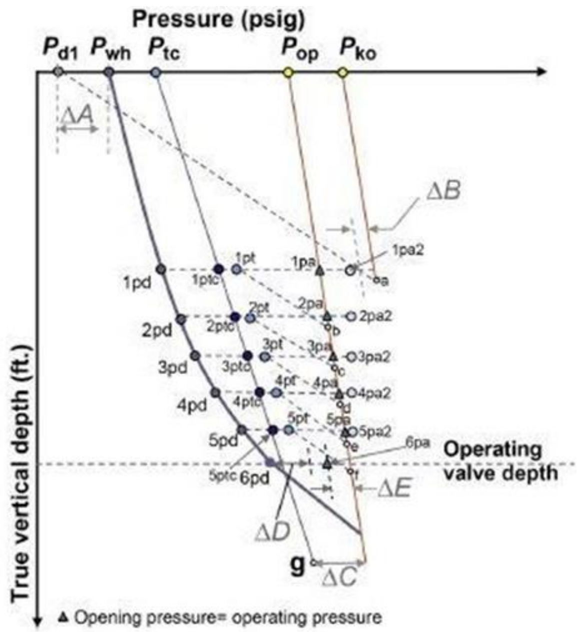

Figure 17: Valve Spacing (Hernandez, 2016)

2.9 Gas lift design: Methodology

Designing of the Gas lift system includes selection of valve depth, selection of valve size, port size, dome charge pressure, gas injection rate etc.

To successfully design the gas lift system the parameters required are listed below:

- Reservoir pressure
- Flowing bottom hole pressure
- Flowing tubing head pressure.
- Geothermal gradient
- Gas oil ratio
- Wellhead temperature

- Kill fluid gradient
- Tubing size
- Well depth
- Gas injection pressure at surface
- Specific gravity of injection gas

2.9.1 Design of Continuous gas lift system

In this section, gas lift design method has been explained in detail with the help of one example

The given data are:

1. Reservoir pressure = 2200 psi
2. Flowing bottom hole pressure = 2020 psi
3. Flowing tubing head pressure = 160 psi
4. Geothermal gradient = 0.019deg F/ft
5. Gas oil ratio = 1500 scf/bbl
6. Wellhead temperature = 74deg F
7. Kill fluid gradient = 0.45 psi/ft
8. Tubing size = 2 7/8”
9. Well depth = 6000 ft
10. Gas injection pressure at surface = 1100 psi
11. Specific gravity of injection gas = 0.65

Step 1: Calculate bottomhole temperature

1) $\text{Geothermal gradient} = \frac{\text{BHT}-\text{Tsurface}}{\text{Depth}}$

$$\therefore 0.019 = \frac{\text{BHT} - 74}{6000}$$

$$\therefore \mathbf{BHT = 188°F}$$

Step 2: Now obtain injection pressure at the depth of 6000 ft

Here GIP @surface = 1100 psi,

Calculate average temperature

2) $\text{Tavg} = \frac{74+188}{2}$

$$\therefore \text{Tavg} = 131°\text{F} = 131 + 460 = 591°\text{R}$$

GIP @6000 ft

3) $$Pd = Ps \times e^{\frac{SG \times D}{53.3 \times Z \times Tavg}}$$

$$\therefore Pd = 1100 \times e^{\frac{0.65 \times 6000}{53.3 \times 0.84 \times 188}}$$

$$\therefore \boldsymbol{Pd = 1274 \; @ \; 6000 \; ft}$$

Step 3: Plot kill fluid gradient curve and reservoir fluid gradient curve

1. Kill fluid gradient

At 6000 ft, **Pr = 0.45*6000 + 160 = 2860 psi**

2. To calculate pressure at 6000 ft for reservoir fluid, Gilbert's curve has been used.

I. Mark the pressure of THP = 160 psi on graph
II. Find the corresponding depth of this pressure and add the well depth 6000 ft in that value.
III. Find the corresponding pressure value for that depth.

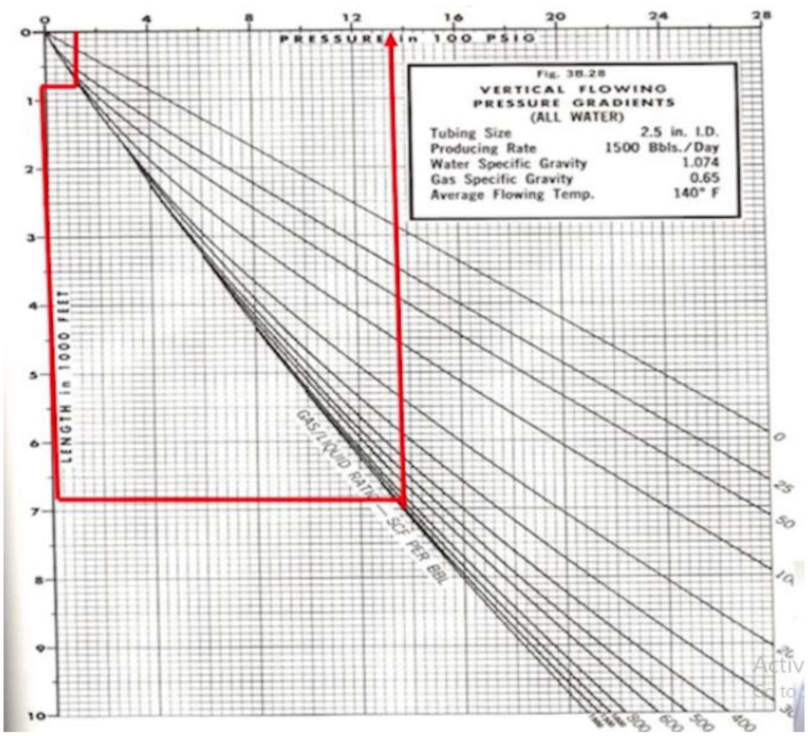

Figure 18: Gilbert chart

Step 4: Now plot the all point on Cartesian graph sheet

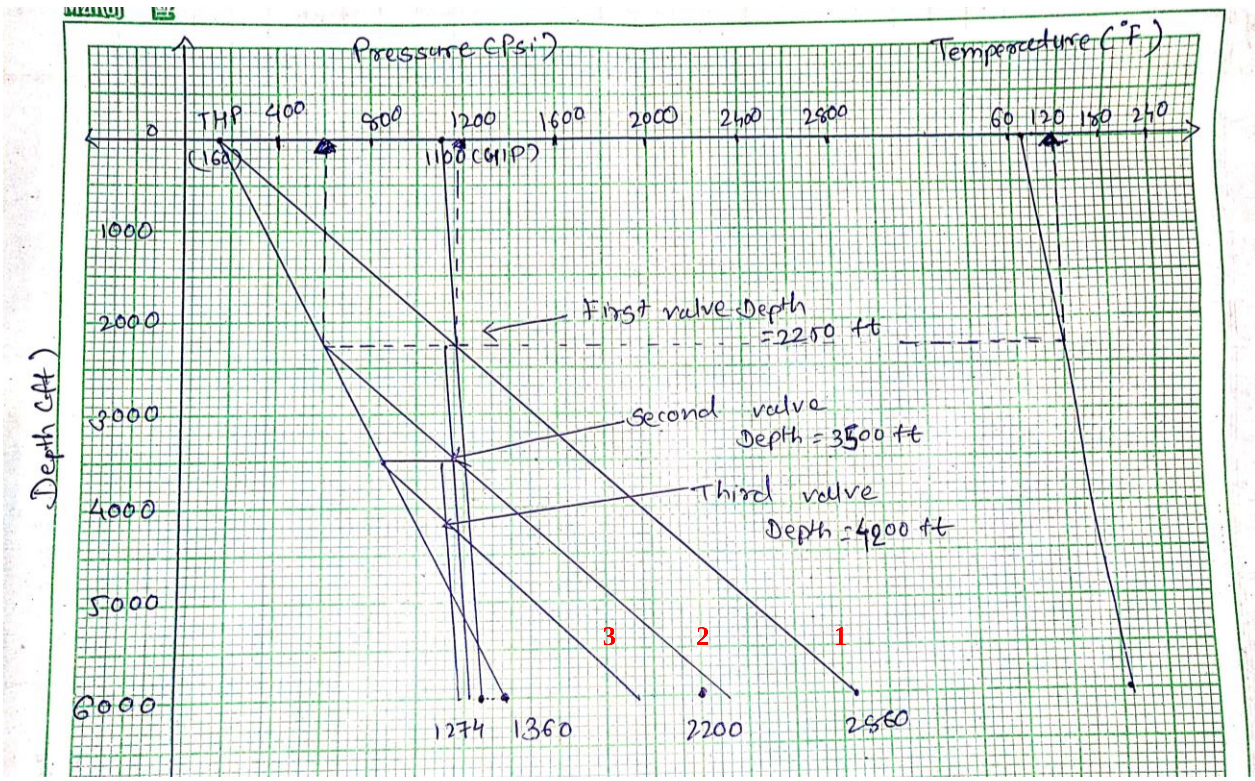

Figure 19: Gas lift design of continuous system

I. Plot the all pressure and temperature points on graph and draw kill fluid gradient, reservoir fluid gradient, gas injection pressure gradient and temperature gradient.

II. Here, the pressure at bottom is 2860 psi, which is greater than 2200 psi. It means well will not flow.

III. The intersection point of gas injection pressure line and kill fluid gradient gives the depth of the first valve.

IV. Note down the corresponding temperature at that depth. It will be required while calculating dome pressure.

V. Note down the pressure on the kill fluid gradient, which indicated valve upstream pressure and the pressure at reservoir gradient indicate valve downstream pressure.

VI. Intersection point of kill fluid gradient and reservoir fluid gradient is known as equilibrium point. Below this depth the gas lift valve can not be placed.

VII. Now, from the first intersection point find the point on the reservoir fluid gradient. Draw the straight line from that point to the bottomhole depth with the same gradient as kill fluid gradient. Here, again the pressure is greater than reservoir pressure. So, more gas lift valves are required.

VIII. Second intersection point gives the depth of second valve. For the second valve reduce the gas injection pressure by 50 psi and draw the gas injection pressure gradient line

IX. Repeat the procedure until the bottomhole pressure is less than the reservoir pressure.

Step 5: Calculate Gas rate

$$\text{Gas rate Qcalculated} = \frac{1500\ \text{bpd} \times 1500\ \text{scf/bbl}}{1000} = 2250\text{Mscf/d}$$

To find the gas rate at required depth, the temperature correction is required. Temperature at the first valve depth is 120 degree F

$\text{Qcorrected} = \frac{\text{Qcalculated}}{0.054 \times \sqrt{0.65 \times (120+460)}} = 2250\text{Mscf/d}$ = **2184 Mscf/d**

Step 6: Calculate Port size

To determine the port size, Upstream and downstream pressure of valve is required, which has been taken from the graph. Below chart is used to find the port size.

Pu: 1200 psi

Pd: 600 psi

Gas rate: 2184 Mscf/D

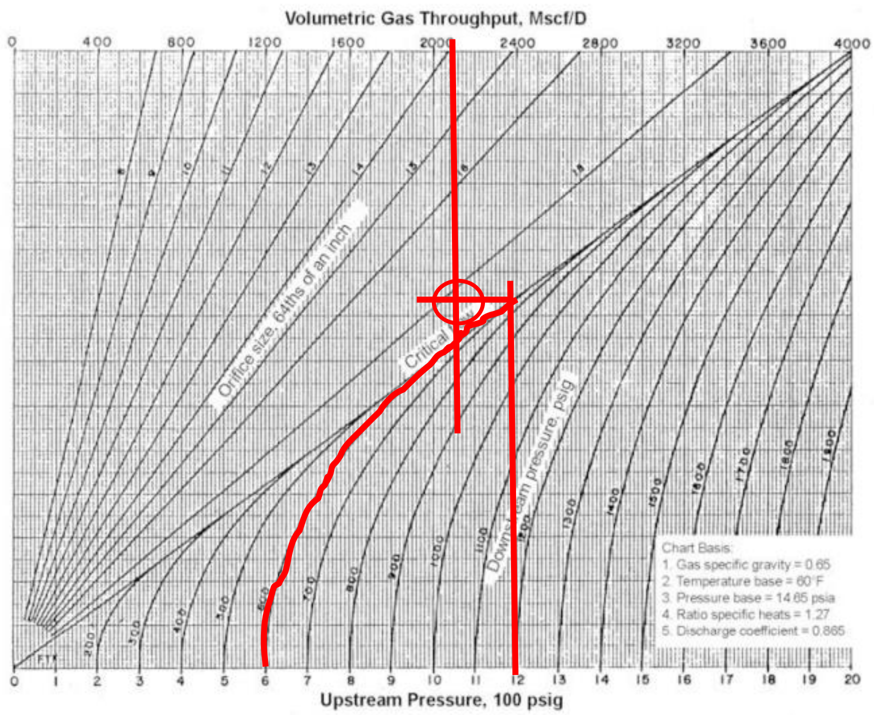

Figure 20: Port size selection chart

Port size: 18/64

Step 7: Calculate Dome Pressure

To calculate dome pressure force balance equation is used.

$P_d = P_{c^*}(1-R) + P_{t^*} R$

$= 1200\,(1-0.094) + 600\,(0.094)$

$\mathbf{= 1143\ psi}$

To charge the dome in lab condition corresponding pressure in lab condition needs to be find out. For that below chart is used.

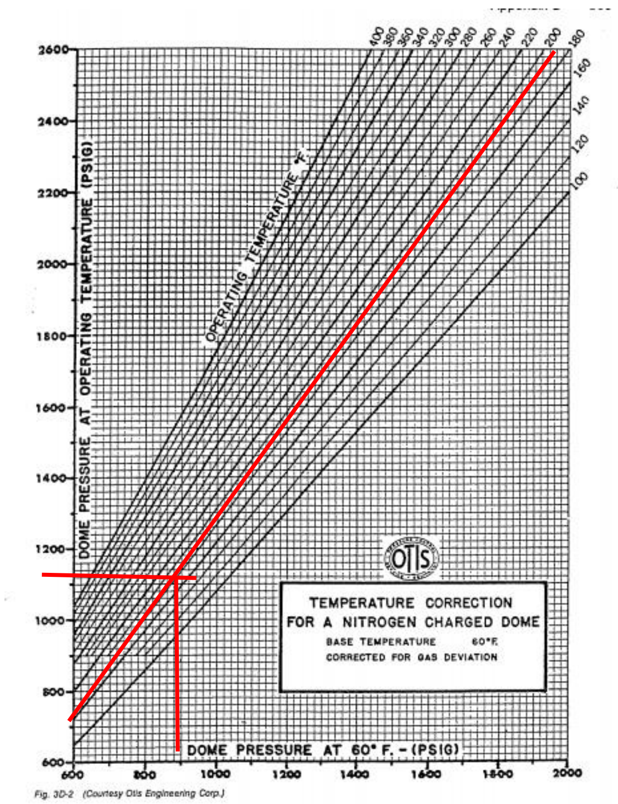

Figure 21: Test rack opening pressure chart

Pd at lab condition @ 60deg F = 890 psi

Test rack opening pressure

$$= \frac{\text{Pd @ 60°F}}{1 - \text{R}}$$

$$= \frac{890}{1 - 0.094}$$

= 982 psi

2.9.2 Design of Intermittent gas lift system

Intermittent gas lift design methodology has been explained with the help of example below.

Given data are:

1. Tubing size: 2 3/8" OD (ID = 1.995")
2. Casing size: 7"
3. Kill fluid gradient: 0.4 psi/ft

4. Surface injection pressure: 1000 psi
5. Depth of well: 7600 ft
6. Specific gravity of gas: 0.7
7. Wellhead pressure: 80 psi
8. Reservoir pressure: 1500 psi
9. Bottomhole temperature: 167 deg F
10. Surface temperature: 109 deg F
11. API = 35 deg

Step 1: Calculate the injection pressure at the depth of 7600 ft

Here GIP @surface = 1000 psi,

Calculate average temperature

1) Tavg $= \frac{109+167}{2}$

   $\therefore$ Tavg $= 138°\text{F} = 131 + 460 = 598°\text{R}$

GIP @6000 ft

2) $$Pd = Ps \times e^{\frac{SG \times D}{53.3 \times Z \times Tavg}}$$

   $$\therefore Pd = 1100 \times e^{\frac{0.7 \times 7600}{53.3 \times 0.9 \times 598}}$$

   $$\therefore \boldsymbol{Pd = 1200 @ 7600\ ft}$$

Step 2: Estimate the unloading gradient

The well test data shows that production rate 214 bbl/d is available at Pwf = 0 psi and Q= 150 bbl/d at Pwf= 750 psi

Therefore, the maximum possible production rate is 200 bbl/d. Now, to decide unloading gradient the chart given below is used. Here, the unloading gradient id **0.064 psi/ft**

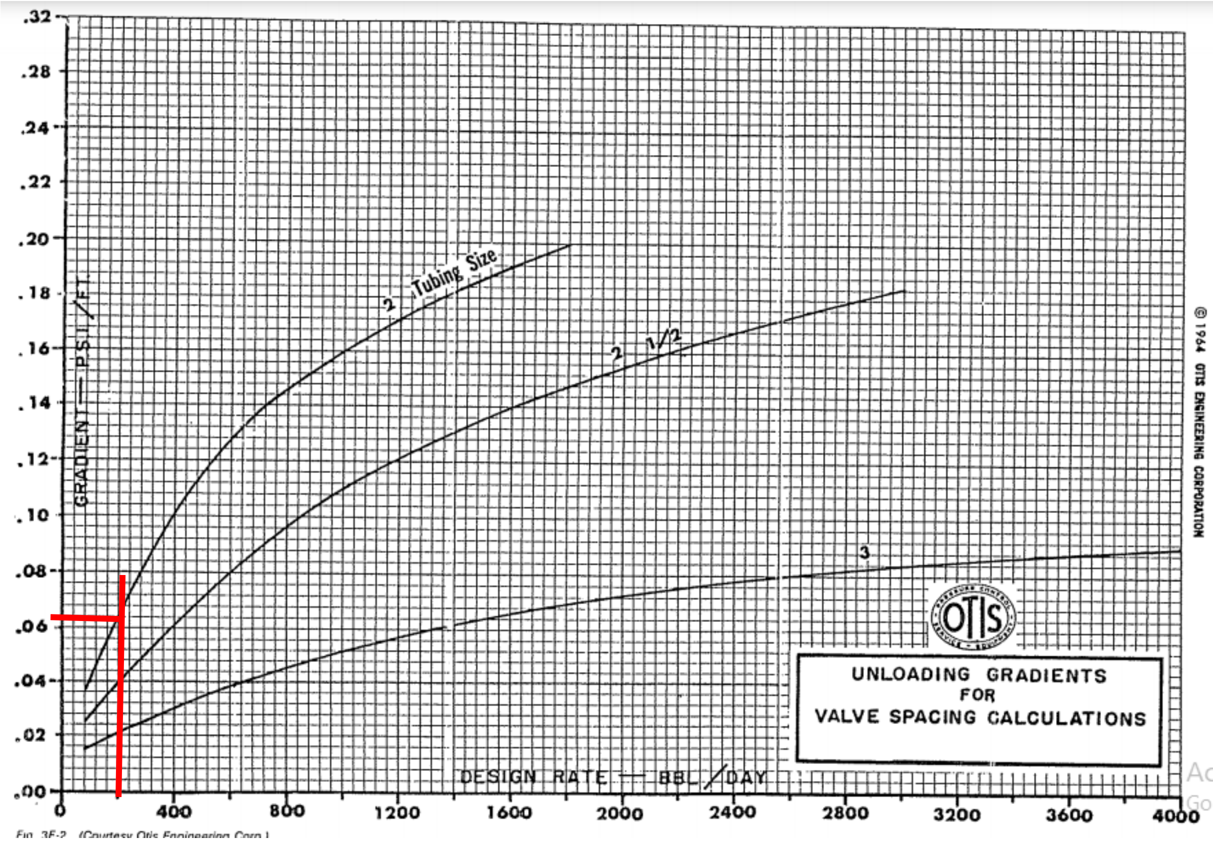

Figure 22: Unloading gradient selection chart

Step 3: Obtain bottomhole pressure for kill fluid:

BHP = 80 + 0.4*7600 = 3120 psi

Step 4: Plot the all pressure and temperature data on graph sheet:

I. Plot the all pressure and temperature points on graph and draw kill fluid gradient, reservoir fluid gradient, gas injection pressure gradient and temperature gradient.

II. Here, the pressure at bottom is 3120 psi, which is greater than 1500 psi. It means well will not flow.

III. The intersection point of gas injection pressure line and kill fluid gradient gives the depth of the first valve.

IV. Note down the corresponding temperature at that depth. It will be required while calculating dome pressure.

V. Note down the pressure on the kill fluid gradient, which indicated valve upstream pressure and the pressure at reservoir gradient indicate valve downstream pressure.

VI. In this case, the unloading gradient and injection pressure gradient will not intersect as there is very low productivity index.

VII. Now, from the first intersection point find the point on the reservoir fluid gradient. Draw the straight line from that point to the bottomhole depth with the same gradient as kill fluid gradient. Here, again the pressure is greater than reservoir pressure. So, more gas lift valves are required.

VIII. Second intersection point gives the depth of second valve. For the second valve reduce the gas injection pressure by 25 psi and draw the gas injection pressure gradient line

IX. Repeat the procedure until the bottomhole pressure is less than the reservoir pressure.

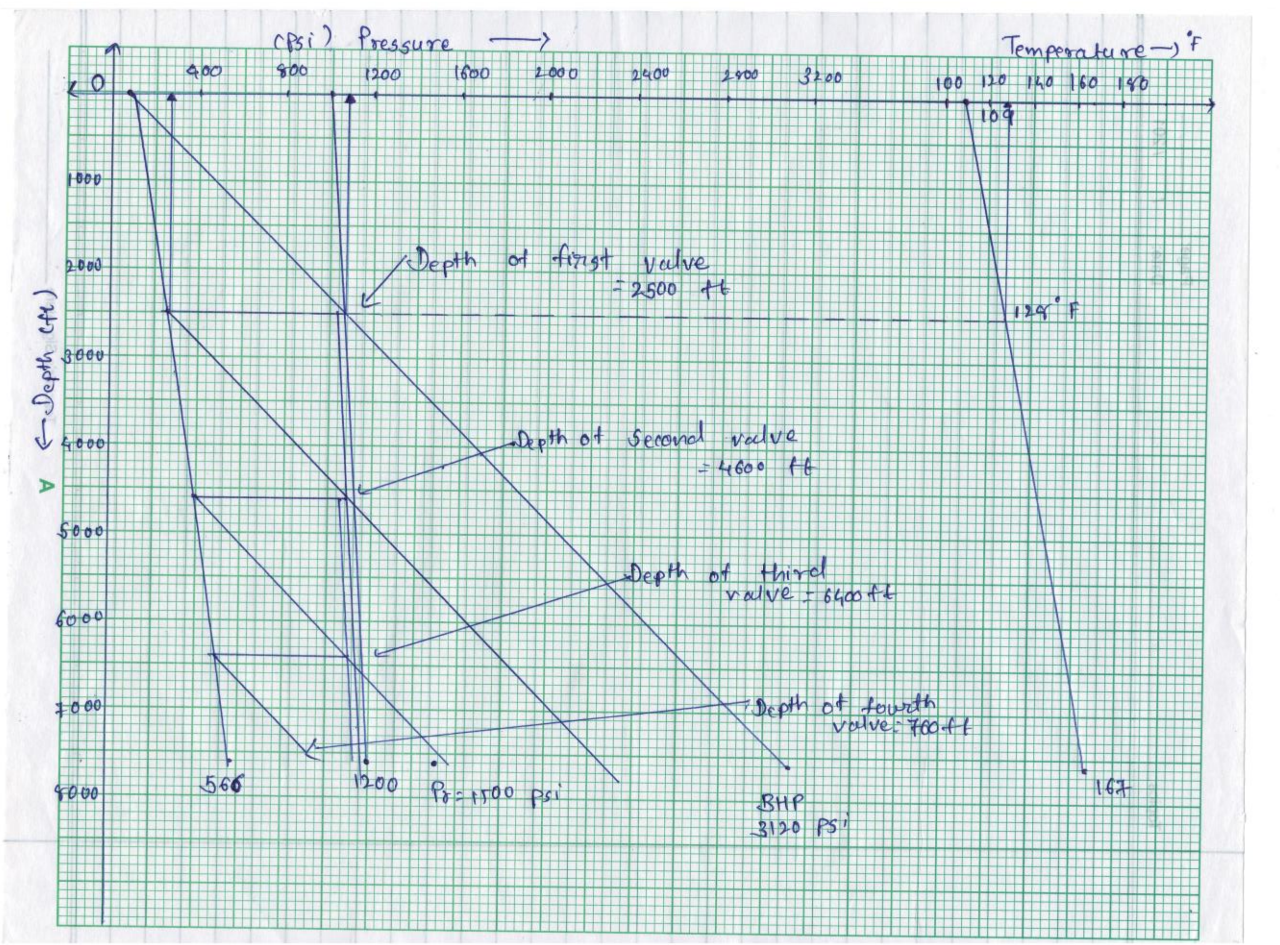

Figure 23: Design of intermittent gas lift

Step 5: Gas volume required per cycle:

For the bottommost valve surface injection pressure is 900 psi and valve opening pressure is 1080 psi at 7600 ft.

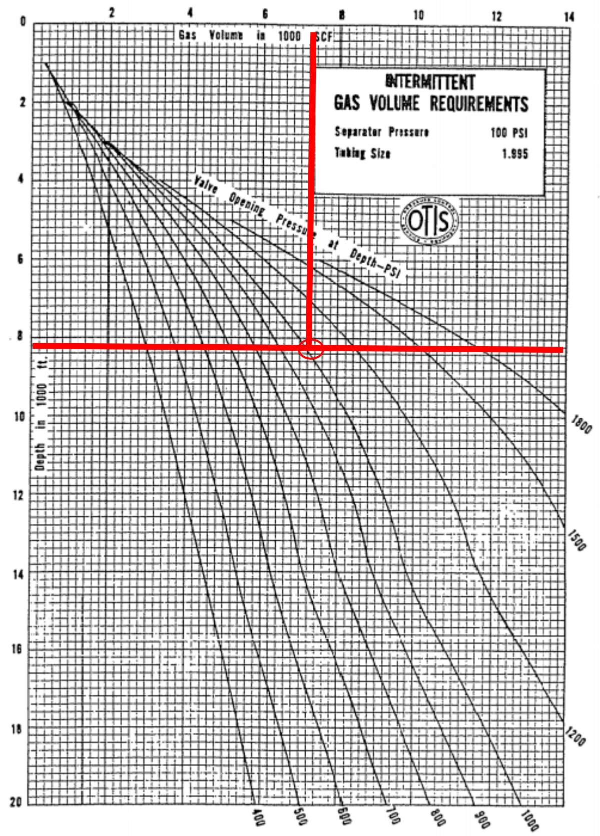

Figure 24: Gas volume per cycle selection chart

Gas volume per cycle: 7200 scf/cycle

Step 6: Calculate number of cycles and production rate per cycle:

- Total number of cycles per day = $\frac{1440*1000}{3*\text{Depth}}$ = **63 cycles per day**

- Recovered liquid per cycle = $\frac{\text{Ct}*(\text{Pt}-\text{Pwf})}{\text{Gs}}\left[1-\text{Sf}\left(\frac{\text{D}}{1000}\right)\right]$

$$= \frac{0.003866*(750-80)}{0.4}\left[1-0.07\left(\frac{7600}{1000}\right)\right]$$

= **3.03 bbl/cycle**

- Total production per day = 3.03 * 63 = **190.9 bbl/day**

Step 7: Select the port size:

Total gas injection per day = 7200*63 = 453.6 Mscf/d

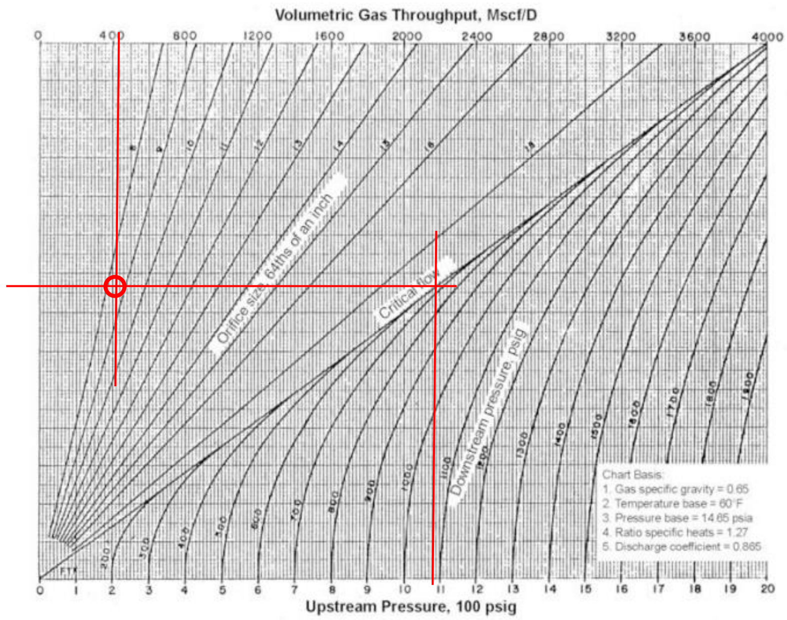

Figure 25: Port size selection chart

Port size: 5/16

2.10 Gas lift optimization

Gas Lift Optimization is a continuous process for enhancing the production, reduction in injected gas supply and thereby reducing costs (Beggs H., 2008). Well performance is continuously monitored for identification of malfunction of valves and other equipment associated with gas lift with the help of different monitoring tools. Based on gathered data and model results, suitable corrective measures have to be taken to optimize the wells and continuously maintain the system efficiency (Golan and Whitson, 1991). Thus, gas lift optimization results in following:

- Effective utilization of resources like injection gas
- Enhanced Production
- Base for performing wider optimization strategies.
- More stable well and system operation

2.10.1 Gas Lift Monitoring:

First step in optimizing of gas lift wells is to identify the wells which are flowing sub optimally i. e. to identify the wells which are not flowing as per their capacity. Major parameters which will give indication of the condition of a gas lift well are: -

- Injection Gas rate and Total Gas rate
- Gas injection pressure (Pso)
- Tubing Head Pressure (THP)
- Tubing fluid gradient
- Operating Valve Depth

An indication of the functioning of valve will be observed by the fluid gradient from the surface to the operating depth. Lighter gradient than the normal indicates more gas injection or vice-versa. Suitable corrective measures have to be taken after problem identification.

2.10.2 Gas Lift Troubleshooting:

Gas Lift problems are generally classified to two main categories: Surface problems & Subsurface problems. Surface problems again can be classified to problem associated in “Inlet” & “Outlet”. Examples of inlet problem can be related to input choke sized too large or small fluctuating line pressure, plugged choke, etc.

Outlet problems may be high backpressure due to a flow line choke, a closed or partially closed wing or master valve, or plugged flow line. Downhole problems, of course could include a cut-out valve, restriction in the tubing string. Often the problems can be found on the surface. If nothing is found on the surface, a check can then be made to see if the down hole problems are wellbore problems or gas lift equipment problems.

2.10.3 Monitoring Tools

The tools listed below are very useful to determine the trouble spots in wells:

1. Two pen pressure recorder
2. Well tests
3. Closing pressure analysis
4. Subsurface pressure and temperature traverse
5. Acoustical surveys

2.10.4 Recommended Monitoring Practices:

For Continuous Gas lift well:

Table 2.1 Recommended monitoring practices (IOGPT, ONGC)

Sl.	Monitoring Methods	Recommended Frequency
1.	Sub – surface survey	Once in a quarter
2.	Two pen recording	Once in a quarter
3.	Injection gas measurement	Once in a quarter
4.	Total gas measurement	Once in a month
5.	Well testing	Once in a month
6.	Acoustic Surveys	After unloading
7.	GIP and THP	Once in a week

For Intermittent Gas lift well:

Table 2.2 Recommended monitoring practices (IOGPT, ONGC)

Sl.	Monitoring Methods	Recommended Frequency
1.	Long Bottom Hole Pressure survey	Once in a quarter
2.	Two pen recording	Once in a quarter
3.	Well testing	Once in a month
4.	Acoustic Surveys	After unloading

2.11 Two Pen Pressure Chart Recorder

This is the device (fig.26) which tracks the pressure in casing and tubing throughout the monitoring period. In this device a circular chart having time line along its circumference and pressure value along the radial direction fitted with timer which rotates the chart accordingly and two pen-one connected with casing head and second connected with tubing head will move according to pressure in their respective regimes.

Figure 26: Two pen chart recorder device

As we have seen in chart of two pen chart recorder in Introduction section in gas lift optimization, this obtained chart will show the two drawn lines by two pens. Since casing head pressure is higher than tubing head pressure in gas lift well, the line for casing head pressure is outer side in the circular chart. The characteristics of the pressure lines are very helpful to identify any problem in the system and thus help to troubleshoot them.

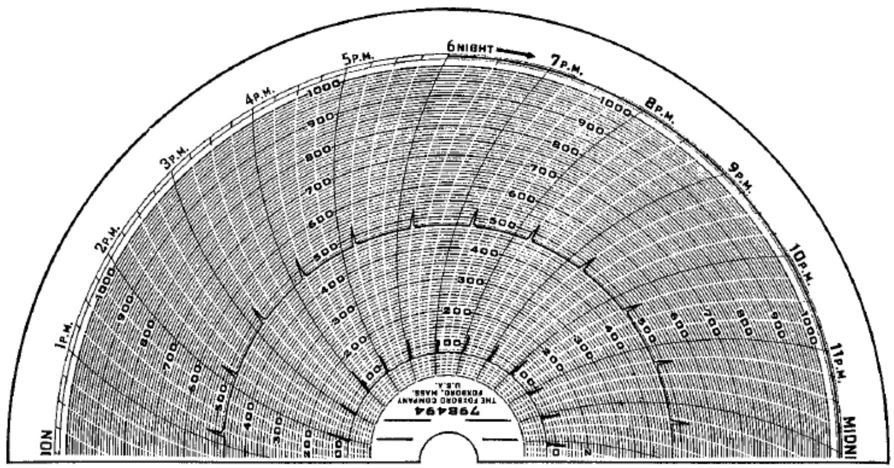

Figure 27: Two pen recorder chart of Intermittent Gas Lift installation- Time cycle controlled

From the chart shown in fig.27, one can observe that the casing pressure is increasing sudden at some points throughout the monitoring period and along with that tubing pressure line has also similar kind of peaks which shows the gas injection after a particular time period (time cycle) in the tubing which is controlled by time cycle controller. So this is the chart for 'Intermittent Gas Lift installation'.

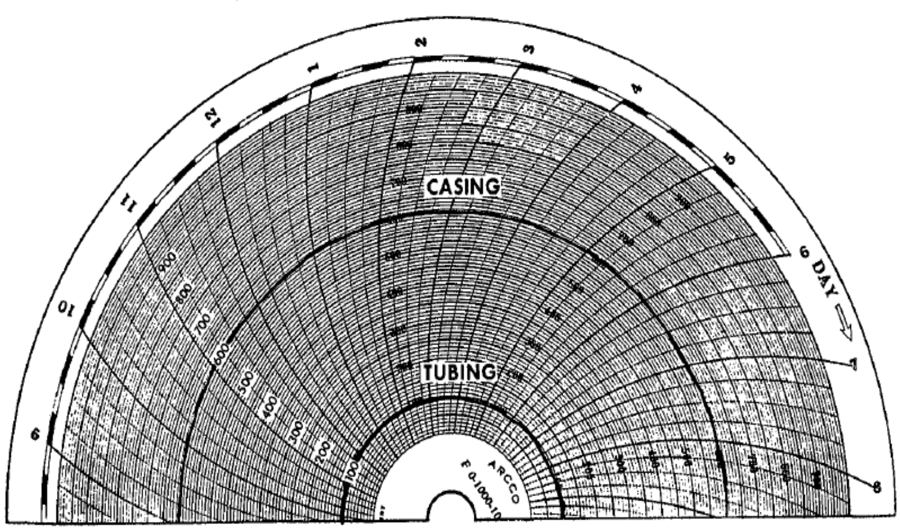

Figure 28: Two pen recorder chart showing continuous flow

Fig.28 shows the chart for continuous flow where both the pressure line are constant and making a perfect half circle.

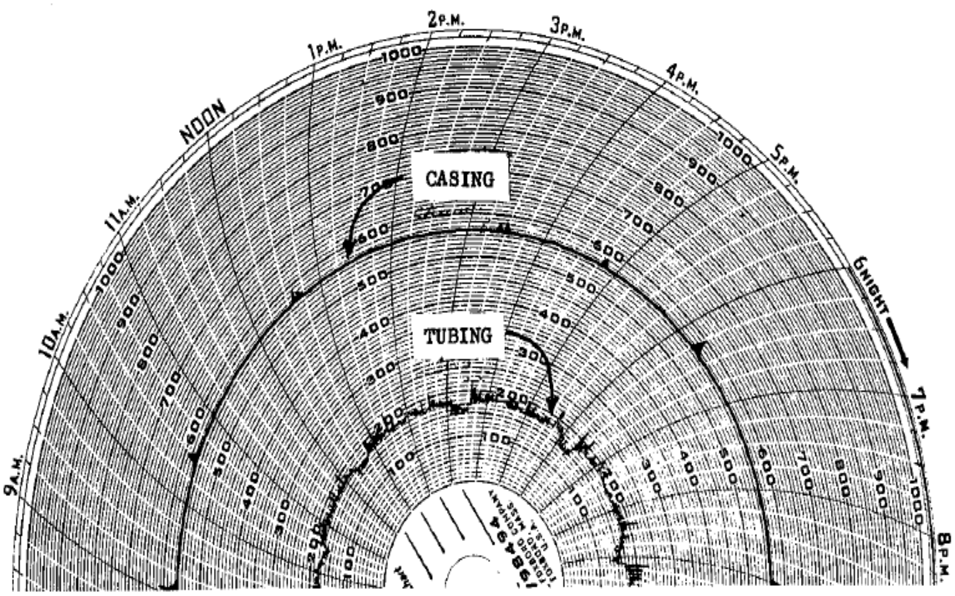

Figure 29: Two pen recorder chart showing trouble in system

In fig.29 chart, tubing pressure drops suddenly at some points periodically, this is because of the 'water loading' problem. There is a presence of tubing control element which will correct the dropped pressure in tubing by injecting gas at slightly higher pressure and this can be noticed from casing pressure line where there are small kinks / increase in casing pressure.

By the use of two pen recorder chart monitoring method, trouble in the system can be indentified and can be troubleshoot. So, this is an inevitable monitoring method for gas lift optimization.

2.12 Correlations for PVT parameters

Bubble point pressure for oil is empirically correlated to oil properties namely solution GOR, oil density, gas density and temperature.

Popular Correlations for Pb that are uses widely in industry are: Glaso (1980), Lasater (1958), Standing (1947), Vazquez (1980), Petrosky (1993), Macary (1992).

2.12.1 Glaso (1980) correlation:

Glaso has developed a correlation and nomograph for determining the bubble point pressure. He has done studies on North Sea crude oil sample and developed a correlation. The range for the data is given in the chapter 6: results and discussion. Average error for this correlation for determining the Pb is 1.28% and for Bo is -0.64%.

(i) Bubble point pressure (P_b):

$$\log(P_b) = 1.7669 + 1.7447 \log(x) - 0.3\ (\log(x)^2) \text{ ---------(1)}$$

$$x = \left(\frac{R_s}{\gamma_g}\right)^{0.816} \frac{T^{0.172}}{\gamma_o{}^{0.989}} \text{ -----(2)}$$

Where,

- Pb = Bubble Point pressure (psi)
- T = Reservoir temperature (ºF)
- γ_g = Gas sp. gravity
- γ_o = Oil sp. gravity
- Rs = Solution GOR (SCF/STB)

(ii) Solution GOR (R_s):

The bubble point equation is reversed to obtain equation for Rs.

$$R_s = \left(\frac{x\,\gamma_o{}^{0.989}}{T^{0.172}}\right)^{\frac{1}{0.816}} \gamma_g \text{ ---------(3)}$$

$$\log(x) = \frac{-b + (b^2 - 4ac)^{1/2}}{2a} \text{ -----(4)}$$

Where,

- Pb = Bubble Point pressure (psi)
- T = Reservoir temperature (ºF)
- γ_g = Gas sp. gravity
- γ_o = Oil sp. gravity
- Rs = Solution GOR (SCF/STB)

(iii) Oil formation volume factor (B_o):

For Gas saturated:

$$\log(Bo - 1) = \log(-6.58511 + 2.91329\log(y) - 0.27683\ \log(y)^2) \text{---(5)}$$

$$y = Rs\left(\frac{\gamma_g}{\gamma_o}\right)^{0.526} + 0.968\,T \text{ ----(6)}$$

Where,

- T = Reservoir temperature (ºF)
- γ_g = Gas sp. gravity
- γ_o = Oil sp. gravity
- Rs = Solution GOR (SCF/STB)

2.12.2 Lasater (1958) correlation:

Lasater has developed correlation for black oil system by extensive research on crude oil from US, Canada and South America. This model has average error of 3.8% for the calculation of bubble point pressure.

2.12.3 Standing (1947) correlation:

Standing has developed a chart for bubble point pressure calculation and then chart has been converted to equations. He used crude oil and natural gas mixture sample from California for research. It is used for both black oil and volatile oil. Average error of this model for Pb is 4.8% and for Bo is 1.17%.

(i) Bubble point pressure (Pb):

$$P_b = 18.2\left[\left(\frac{R_s}{\gamma_g}\right)^{0.83}\frac{10^{0.0009T}}{10^{0.0125\gamma_o}} - 1.4\right] \text{-----(7)}$$

Where,

- T = Reservoir temperature (ºF)
- γ_g = Gas sp. gravity
- γ_o = Oil sp. gravity
- Rs = Solution GOR (SCF/STB)

(ii) Solution GOR (Rs):

$$R_s = \left[\left(\frac{P}{18.2} + 1.4\right)\frac{10^{0.0125\gamma_o}}{10^{0.0009T}}\right]^{\frac{1}{0.816}} \gamma_g \text{ ---------(8)}$$

Where,

- P = Pressure (psi)
- T = Reservoir temperature (ºF)
- γ_g = Gas sp. gravity
- γ_o = Oil sp. gravity
- Rs = Solution GOR (SCF/STB)

(iii) Oil formation volume factor (Bo):

$$Bo = 0.972 + 1.47 * 10^{-4}\left[R_s\left(\frac{\gamma_g}{\gamma_o}\right)^{0.5} + 1.25\,T\right]^{1.175} \text{ ---------(9)}$$

Where,

- P = Pressure (psi)
- T = Reservoir temperature (ºF)
- γ_g = Gas sp. gravity
- γ_o = Oil sp. gravity
- Rs = Solution GOR (SCF/STB)

2.12.4 Vasquez and Beggs (1980):

Vasquez and Beggs correlation contains the equation for Pb, Rs, Bo, Co. This correlation is developed using the data of PVT laboratories for various oil fields all over the world.

Average error for Bo is 4.7% and for Rs is (-0.7)%. The correlation divides the data into two groups, one for oil gravity over 30 API and one at and below 30 API. It includes very complex and lengthy equations.

2.13 Multiphase flow correlations:

To understand the flow behaviour of oil and gas mixture inside the tubing, pressure loses encountered in their flow path needs to be considered. Majorly there are three types of pressure loses, frictional loses, gravity loses and acceleration loses. Flow correlations enables user to predict the liquid holdup and subsequently the fluid mixture density.

Correlations are developed for particular flow regimes and conditions. User needs to understand the particular situation and depending on that most suitable correlation should be used. In this section some most commonly used multiphase correlations are discussed.

2.13.1 Duns and Ros (Standard):

- Duns and Ros correlation is used for oil and gas mixture flowing in vertical well.
- This correlation is based on the extensive experimental work for oil and gas mixture. Around 4000 tests were conducted with pipe size ranging from 1.26 to 5.6 inch in 185 vertical pipe and pressure drop and liquid holdup were measured.

Some major observations of this correlation are:

[1]. This method cannot applied in three phase flow oil, gas and water.
[2]. It works well in bubble, slug and churn flow regime where water cut is less than 10%.
[3]. This correlation works well in high GOR wells and gas condensate well as well.
[4]. For pipe diameters 1 to 3 inch pressure drop is overpredicted.

2.13.2 Duns and Ros (Modified):

- In this correlation new transition regime has been added between bubble and slug flow and froth flow for high flow rates.
- All holdup relationships are same as Duns and Ros standard except froth flow. In froth flow slippage factor is not considered.
- For calculation of friction method proposed by Kleyweg has been used. In this method a monophasic friction factor is used instead of two phase.
- In the slug flow regime, Duns and Ros modified method gives maximum pressure drop.

2.13.3 Beggs and Brill (Standard):

- This method is developed by studying flow behaviour in horizontal and inclined smooth circular pipes.
- Beggs and Brill correlation is generally applied in horizontal and inclined wells but the drawback is it overestimates the pressure drop.
- In this method, first the holdup is calculated as if the flow is horizontal and the correction is applied for inclination angle.

2.13.4 Bess and Brill (No-slip):

- In this correlation method to calculate the holdup is different. Here, holdup is not considered as horizontal but simply no-slip holdup. There is no requirement of deviation correction.
- All the other calculation are same as standard Beggs and Brill.

2.13.5 Beggs and Brill (Modified):

The changes made in modified Beggs and Brill are as follows:

- The friction factor is calculated in same way as Duns and Rod (Modified), A monophasic friction factor is used rather than smooth pipe model.
- There is no flow regime as froth flow.

2.13.6 Hagedorn and Brown (Standard):

- This correlation is most widely used in vertical wells and it works well for bubble and slug flow regime.
- It was developed by studying the two phase flow in vertical well of 1500 ft made for study. Various pipes having different diameters inbetween 1 to 2 inch, fluids with viscosities ranging from 10 to 110 cp in 80°F in water were used in order to developed this correlation.
- In this method two phase friction factor with pipe roughness is used.

Results obtained in this method are:

[1]. Two-phase friction factor can be determined in same manner as single phase, if Raynold's number is defined in friction factor diagram.
[2]. This correlation is a generalized form without defining different flow regimes.
[3]. Change in kinetic energy pressure drop can result in change in total pressure drop, especially near top of the well.
[4]. For tubing size greater than 1.5 inch pressure drop is over predicted, but works well for 1-1.5 inch tubing sizes.
[5]. For all water cuts model accurately predicts pressure drop.
[6]. For wells with low flow rates, condensate and mist flow regime Hagedorn and Brown correlation does not give reliable results.

2.13.7 Hagedorn and Brown (Modified):

The changes made in modified Hagedorn and Brown correlation are as follows:

[1]. To calculate pressure gradient in bubble flow Griffith and Wallis correlation are used.
[2]. Acceleration pressure gradients used are Duns and Ros.

[3]. For bubble floe no-slip holdup is used and for slug flow revised holdup values are used.

2.13.8 Fancher and Brown:

- This correlation used no-slip holdup and does not account for flow regimes. Therefore, this correlation cannot be used for general purpose and also it can only be used for qualitative work.
- It is only applicable to 2 3/8 and 2 7/8 inch tubing.
- It can used only if GOR is less than 5000 scf/bbl and flow rates are less than 400 bpd.
- Independent from pipe roughness, it uses its own friction factor model.

2.13.9 Orkiszewski:

- This method is mainly applicable in vertical flow and can be applied to any flow regime.
- The major advantage of this method is pressure drop is related to flow pattern changes and geometrical distribution of oil and gas.

Major observations of this correlation are:

[1]. Method works well for tubing size 1 to 2 inch. For tubing sizes greater than 2 inch pressure drop is over predicted.
[2]. For GORs upto 5000 scf/STb model gives accurate results, beyond 5000 scf/STb it gives error more than 20%.

2.13.10 Gray:

- Gray's correlation gives very good results in gas wells for condensate ratios upto 50bbl/MMscf and high water cuts.
- It uses its own PVT model.
- For high liquid dropout wells it used Duns and Ros correlation and retrograde PVT model.

2.13.11 Mukherjee and Brill:

- This correlation was developed to give modification to Beggs and Brill method in inclined two-phase flow.
- The tests were conducted in 3.8 cm nominal id U-tube shaped pipe whose clesed end can be inclides from 0 to $\pm 91°$.
- For various gas liquid ratios around 1000 pressure drop data were recorded.

Major observations from the test are:

[1]. For upward and downward flow, this method can be used.
[2]. This method is dependent on flow patterns and each inclination angle.

[3]. For bubble and slug flow, a no-slip friction factor calculated from the Moody diagram was found adequate for friction head loss calculations.

[4]. In downhill-stratified flow, the friction pressure gradient is calculated based on a momentum balance equation for either phase assuming a smooth gas-liquid interface.

[5]. For annular – mist flow, a friction factor correlation was presented that is a function of holdup ratio and no-slip Moody friction factor.

2.14 Evolution and history of Gas Lift

(1) In 1972, the various aspects of dual gas lift installations was published b Jerry B. Daviset.al . This discussion included types of installations, types of valves, installation design, control and operation. (Davis, J. B., & Brown, K. E, 1972)

(2) In 1974,optimization of gas lift using surface facilities parameters and rock properties was developed by J. David Redden et.al. With help of this many wells were optimized. (Redden, J. D. et al, 1974)

(3) In 1974, gas lift optimization for low pressure deep wells was developed by E. E. DeMoss et.al. In this optimization AVC (Automatic Vent Chamber) was used. (DeMoss, E. E. et al., 1974)

(4) In 1984, A hydrodynamic model was developed for intermittent gas lift by Zelimir Schmidt et.al. the study has shown that by increasing the injection pressure, a higher recovery can be achieved more rapidly, but only at the pressure, a higher recovery can be achieved more rapidly, but only at the expense of increased gas injection. (Schmidt, Z., Doty et al., 1984)

(5) In 1988, two flow stability criteria for gas lift were developed by Harald asheim which were very useful. Flow instability can be occurred due to heading. (Asheim, H. , 1988)

(6) In 1992, the model to predict the gas rate through “Nitrogen Charged Gas lift valve” by H.G Acuna, Exxon Production Research Co. et.al. This research was proven to be very helpful for the gas lift optimization.

(7) In 1992, “Blowout Risk Analysis of Gas-Lift Completions” by D.D. Grasslck, SPE et.al. The research has provided Insight into the effect of critical components and operations on the overall well safety.

(8) In 2001, Ali Hernandez, SPE had studies and developed a new “Gas lift pilot valve which has increased the efficiency of gas lift. With this new 1” gas lift valve the several benefits has been observed like:

- It has been found that the fall back losses increase as the injection orifice diameter decreases.

- ➢ The required time for the injection of a certain volume of gas might be increased to a point that the daily production of the well might fall. This is especially true for wells requiring a high cycle frequency.

(9) In a relatively recent study (2002) a new concept has been introduced by S.Betancourt, Schlumberger that is “Natural gas lift”. It can be implemented on contiguous oil reservoir or even in depleted oil reservoir with a great ease unlikely conventional gas lift. Here, author has talked about remote control of natural gas of gas reservoir and has use for oil column lifting.

(10) K.S.Adiyodi, SPE, R.Sujith Kumar, SPE, Rajiv Singh, SPE / ONGC Ltd. Has done extensive study on “Probe testing” this is to evaluate and analyse the characteristics of the Bellows, termed as the heart of a gas lift valve, to predict various flow regimes, to design a gaslift system more accurately and proper monitoring of gas lift operation. The conclusion of this study was like this:

- ➢ The maximum stem travel and bellow load rate of a valve has significant improvement in the performance of a gas lift valve.
- ➢ The results indicated that interchangeability of port sizes is no longer advisable.
- ➢ The flow regimes under various injection pressures can be predicted with the aid of probe test results.
- ➢ When the operating injection pressure is in the throttling pressure range, the valve may close below a certain tubing pressure even though injection pressure is higher than valve dome pressure. The tubing pressure at which a valve may close can be predicted also.
- ➢ The flow performance of a gas lift valve can be predicted with acceptable accuracy without doing dynamic testing.
- ➢ Enough difference between casing pressure and dome pressure for operating valves should be ensured for achieving expected gas flow.

Probe test results can be effectively used for proper monitoring of gas lift wells. So today in ONGC this probe testing is used quite often for ‘Quality Assurance for Gas Lift’.

(11) In 2004, “Soft Sensing for Gas Lift Well” by H.H.J. Bloemen et.al. The research was proven helpful in understanding of Extended Kalman filtering as a soft sensing technique for Gas Lift wells.

(12) In 2007, “Subsea Gas Lift in Deepwater Applications” by Dennis Denney. The review was proven helpful in understanding of subsea gas completion and performance in deep water.

(13) In 2014, “Smart Gas Lift Valve Eliminate Multiple Sickline Trips in Gas Lift Operation” by Zhiyue Hu et.al. The research was proven helpful in understanding of Well performance of gas lift using Smart Gas Lift valve.

(14) In 2015, “Rethinking Gas Lift Intervention” by Donald Mitchell, SPE, Wireline Engineering. The review was proven helpful in understanding of a new means of improving the efficiency of gas lift intervention by Advanced Kick over Tool(AKT).

(15) Gas-lift inert system (GLIS), an alternative method of introducing a gas lift to existing wells and modification done to running procedures were proposed in SPE annual Caspian Technical Conference & Exhibition (2015) held in Baku, Azerbaijan by Fazira Aliveyaet.al.,BP. GLIS has proved itself as quick alternative for conventional gas lift retrofit that can be installed in 7-11 days versus 30+ days of the rig time for the conventional retrofit. The experience acquired from GLIS installation jobs has been appropriated and will be applied in future installations.

(16) In 2016, new smart gas lift systems were proposed by Abdel BenAmara, Silverwell, at SPE middle East artificial lift conference and Exhibition, which could help bridge technology gap compared to other artificial lift (SRP, ESP, PCP) and allowing it for a wider use of gas lift across oilfields, facilitating gas lift systems integration into the digital oilfields and resulting in an improved system efficiency, higher reliability, and reduction of HSE risks. (A. BelAmara & Silverwell2016)

(17) In 2017, R.E Moffett and S.R. Seale, Weatherford have used electronic instruments on gas lift control system and made and ‘Real time System’. They say this can be a best alternative to timer based Intermittent Gas Lift because in general this system improve the production by receiving increased attention and correction of potential issues in real time.

2.15 Economic Analysis of Gas Lift System

Countries around the globe may have adapted different Petroleum Legal Arrangement (PLA). Broadly PLA can be classified in to two systems: (1) concessionary system and (2) Contractual system. India has contractual PLA and under HELP regime India has updated Production Sharing Contract (PSC) to Revenue Sharing Contract (RSC). These contracts have their own feature like given exploration period, royalty rate, profit petroleum, incentives etc., which are affecting the company’s decision for investing in that country and also affects the implication of projects like gas lift system installation.

By taking care of several aspects of RSC model, we have made an excel model where by putting the value of different parameter like oil price, gas compression cost, gas injection rate, royalty rate, and revenue percentage shared with government a graph of net revenue to company Vs. time can be obtained for net revenue generated in case of naturally flowing well and gas lift well. So, one can easily compare these both cases from the graph and measure net revenue generated in respective case and determine that whether to go for gas lift or not by approximation capital cost needed for gas lift installation.

In model, royalty is taken as 5%, revenue sharing with government is 40%, and gas compression cost is \$0.5/MMSCF. Gas injection rate is to be taken form gas lift performance curve and here 5 MMSCF/D is taken as a optimum value. The timeline selected is from 2000-2010 and oil price is considered to be \$50/STB constant throughout the 10 years of timeline.

[Table: 1 Case of constant oil price]

Year	Oil Price	Natural Flow Prod. rate	GL Prod. rate
2000	50	1500	1650
2001	50	1400	1600
2002	50	1300	1550
2003	50	1200	1500
2004	50	1100	1450
2005	50	1000	1400
2006	50	900	1350
2007	50	800	1300
2008	50	700	1250
2009	50	600	1200
2010	50	500	1150

Net revenue = Gross Revenue * (1-Royalty)* (1-Revenue sharing)---------(1)

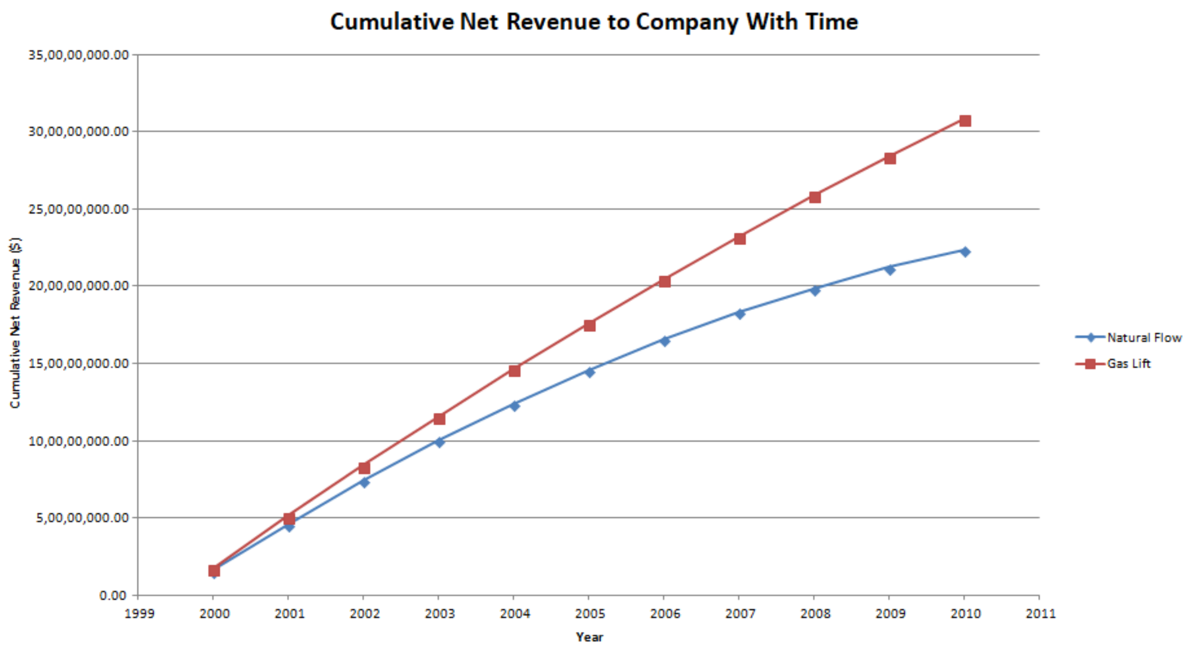

Figure 30: Comparison of net revenue in case of natural flow and gas lift flow in constant oil price

dollars. 84 million dollar is the difference between the net revenue of these cases. So if the gas lift installation capital cost is well below than this difference then obviously it would be good decision to go for gas lift installation.

As seen in the COVID-19 phase that oil price was going well below zero dollars/STB in April, 2020 and on 28th April, 2020 it touched the record lowest value of -40 dollars/STB in history. So in such cases by putting different values easily one can predict the beneficial decision.

[Table: 2 Case of fluctuating oil price]

Year	Oil Price	Natural Flow Prod. rate	GL Prod. rate
2000	50	1500	1650
2001	20	1400	1600
2002	50	1300	1550
2003	60	1200	1500
2004	100	1100	1450
2005	28	1000	1400
2006	-20	900	1350
2007	-40	800	1300
2008	10	700	1250
2009	50	600	1200
2010	62	500	1150

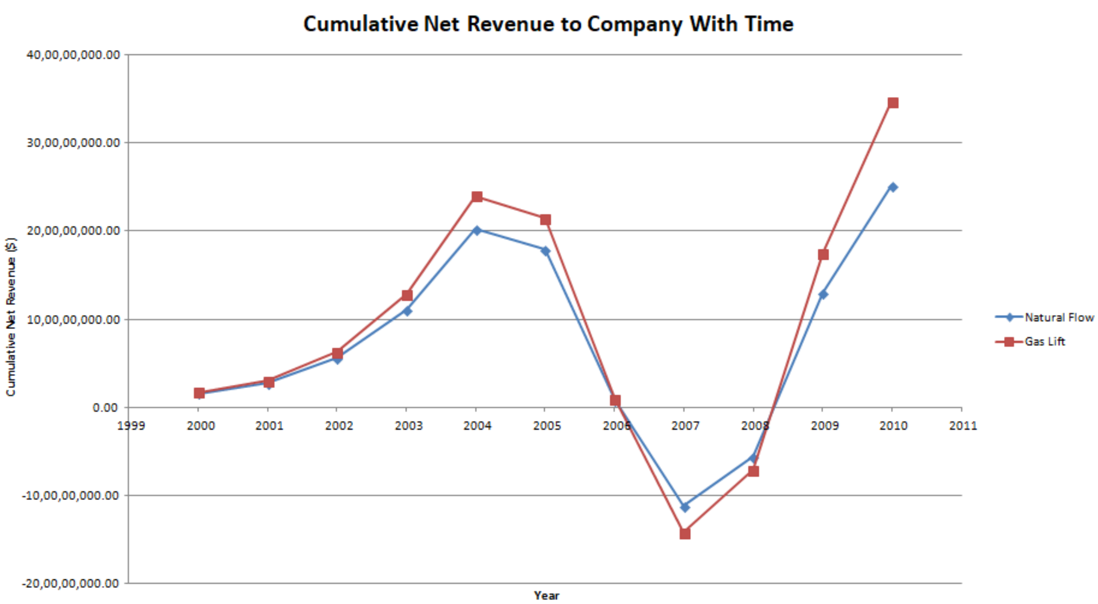

Figure 31: Comparison of net revenue in case of natural flow and gas lift flow in fluctuating oil price

Chapter 3: Scope & Methodology

3.1 Scope

Decreasing prices of oil, demand of quality products, safety regulations and environmental constraints have put on many challenges in oil and gas industry. Therefore, it has become necessary to develop a regulating and monitoring system that can optimize the field operations and reduce the operational costs. (M. Campos et al, 2017)

Success of the Gas lift system largely depends on the surveillance tools, monitoring system and the operator personnel of the system. The good optimized system can save the compression cost of compressor and reduces the risks associated with system bottleneck if wrong well mix is selected. However, the challenges and efforts associated with gas lift optimization are huge, but the gain is noteworthy. Gas lift system should be analyzed for each and every well to know whether the system is working properly and the design is proper or not. This valuable information not only helps to improve the particular well system but also provide the guidance for future gas lift installations.(Kermit Brown, 1980)

3.2 Gas Lift Monitoring System:

Gas Lift Monitoring system is Programmable Logic Controller (PLC) or Personal Computer based monitoring system which provides automatic real time measurements of gas lift wells. With the use of this technology pressure and flow rate is measured with the use of transmitters and sent to the PLC in form of analog signals and then converted into digital signals. At last signals are fed into PC for necessary processing and display. The parameters measured includes gas lift flow rate, pressure for gas lift headers and gas lift flow rate, tubing head pressure, production casing pressure for each gas lift wells. (Y.C. Chia, 1999)

The Gas Lift Monitoring System has following advantages over conventional three pen recorder.

Gas Lift Monitoring System	Three Pen Recorder
Provides Intuitive data display.	Needs some interpretation and calculation.
All gas lift wells can be displayed at the same time.	Can display only one well at a time.
Stores 8 days of data without human intervention.	Every 24 hours chart needs to be changed.

Remote monitoring is possible.	Only provides on-site monitoring.
In addition to casing and tubing pressure also displays gas lift gas rate.	Production casing and tubing pressures are displayed only.

3.3 Gas Lift Challenges:

Due to reservoir characteristics and surface facilities many challenges faced during Gas Lift optimization.

3.3.1 Dual Completion Gas Lift Operation:

As the new technologies are being developed in oil and gas industry the dual completion is being very famous to produce from multiple reservoirs. In the dual completion gas lift system few challenges are faced during unloading and operating stage because the gas lift gas needs to be shared between two tubings through same production casing.

Unloading stage:

While unloading stage the process in one tubing can interfere with the other tubing due to the drop in annulus pressure independent from whether the both strings are being unloaded or not. To mitigate this problem, the tubing pressure operated valves are used istead of casing pressure operated valves.

Operating stage:

Since the both the tubings share the gas lift gas it is quite difficult to know the precise gas lift gas rate in the individual tubing. One approach to solve this problem can be to bring one tubing online during initial stage. For example if tubings are named as A and B, then $q_{glA} = q_{gtA} - (GOR_A * q_{oA})$ and $q_{glB} = q_{glt} - q_{glA}$.

The limitation of this method is that the GOR is taken as constant which can not be true for all cases. The wells which are prone the change in GOR change with time can be misinterpreted with this approach. As a result, it becomes scope to find the individual gas lift gas rate in dual completion system. (Y.C. Chia, 1999)

3.3.2 Tight Dummy Valve Retrieval:

In the new wells during completion the gas lift mandrels are equipped with tubing. The gas lift valves are pre-installed in mandrel or the dummy valves are installed. When the gas lift valves are needed to be placed this dummy valves are retrieved with the use of kickover tool or wireline. However, in some cases it is observed that the tight dummy valves are difficult to retrieve. The pulling tools are broken into pieces or it becomes difficult to grip the valve.

Several attempts have been made in past to overcome this situation. The high strength wireline was used, but since the wireline and pulling tool both have high strength than kickover arm the arm was broken. The wells have treated with certain chemicals but no significant improvement was observed. In the later stages the modified fishing tools were used and they came out with satisfactory results since the grater pull force could be applied.

However, the exact cause of the tight dummy valve is still need to be identified and it provides challenge to provide more efficient tool to retrieve tight dummy valve. (Y.C. Chia, 1999)

3.3.3 Emulsion and Sand Production:

Sometimes well with emulsion & high sand production can have harmful effect on Gas Lift operation.

Emulsion:

In the gas lift system the gas lift operation may invite emulsion formation or the emulsion may negatively impact the gas lift operation. As the gas enters the tubing, with the flow stream countercurrent to formation liquid stream it can create the turbulence which result in emulsion formation. At the same time gas lift system can have harmful effect due to emulsified flow which can create extra pressure drop.

Sand Production:

The main objective of the gas lift is to lighten the fluid column within the well which increases the drawdown. The increased drawdown can also result in sand production if it exceeds the certain value. Therefore, it is very crucial to optimize the gas lift system such that it can not result in high sand production. (Y.C. Chia, 1999)

3.4 Methodology:

(1) Literature Review:

This section includes reviewing the papers and books foe getting more idea about the gas lift designing and optimization.

(2) Data collection:

This section includes getting actual data from field performing artificial lifting process. If we could not find the actual data, then we will use imaginary data for gas lift optimization.

(3) Modelling:

To model our project, we will be using well flow software.

Chapter 4: An introduction to software: WELLFLO

WELLFLO is well monitoring and design software owned by Weatherford. WELLFLO software models naturally flowing and artificially lifted oil and gas wells. It can be used to analyze the each and every phase of the production cycle. With monitoring and data from WELLFLO software we are able to predict the performance of the well.

To get the most from the well it is very important to accurately design and decide well operating point. Through better tuning of well the operating expenditure comes down and more revenue is generated. WELLFLO software provides powerful and easy-to-use window to design, model, predict, troubleshoot and optimize the naturally flowing or artificially lifting wells to flow at the best conditions.

WELLFLO software used nodal analysis technique to determine reservoir inflow and well outflow. Software provides the very important functions to analyze the wells, which are listed below:

- **Design:**

  It creates the different well configurations and completions, artificial lift completions etc.

- **Model:**

  This function models well configuration based on requirement and for all type of completions. It helps to know the behaviour of reservoir fluid through well configuration and surface facilities, pipelines.

- **Predict:**

  This function generates vertical lift performance curves for reservoir simulators.

- **Adjust:**

  This function is very helpful in order to monitor the reservoir, well and pipelines with temperature and pressure conditions. This data increases effectiveness of design and optimization process.

- **Troubleshoot:**

  It helps to determine any kind of issues occurring in well.

- **Optimize:**

To get optimal production, it continuously fine tunes operating parameters.

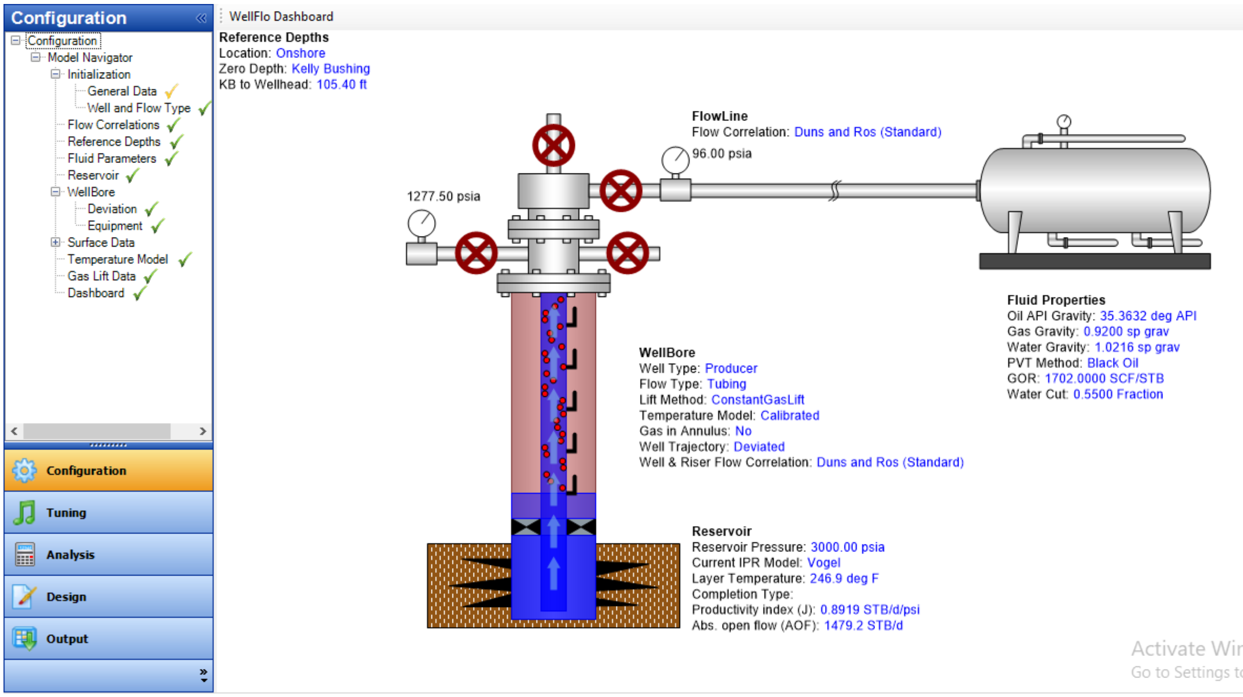

Figure 32: Dashboard of WELLFLO software

WELLFLO software has some additional applications other than production analyzes.

Reservoir inflow performance modeling

- Multiple completion and perforation models
- Inflow control device models
- Multiple fractured-zone models
- Detailed skin analysis

Fluid pressure/volume/temperature (PVT) modeling

- Compositional, equation-of-state-based PVT models for all fluid types
- Black oil PVT models for oil and gas
- PVT model tuning using laboratory data

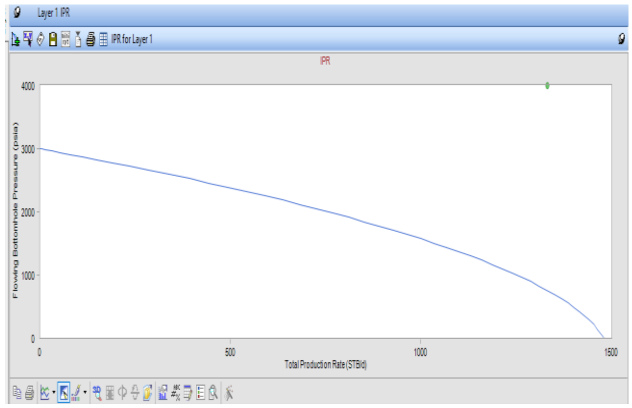

Figure 33: IPR curve

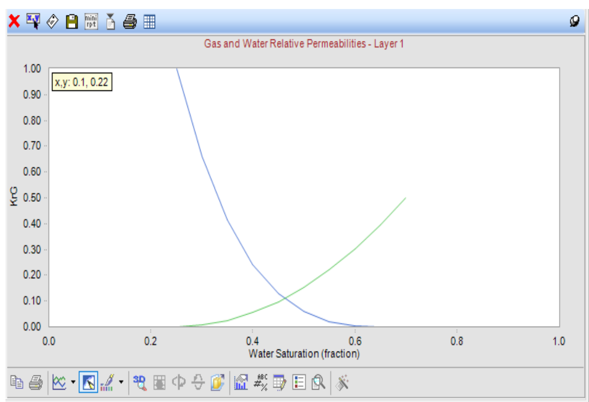

Figure 34: Relative permeability curve

Here, some major applications of the WELLFLO software are listed:

I. Inflow and completion modeling
II. PVT modeling
III. Flow assurance
IV. Pressure traverse and temperature calculations
V. Well model tuning
VI. Gas lift design and analysis
VII. ESP design and analysis
VIII. Reciprocating rod lift design
IX. Progressive cavity pump analysis
X. Jet pump design and analysis

In this project, gas lift system design and analysis tool has been utilized to analyze the well. All the data related to reservoir, reservoir fluid, well and completions, surface facilities, perforation, gas lift system related data, PVT models, flow models, well inclination and deviation have been inputted in software in order to decide the most optimum condition for the well to flow.

With the help of various tools available in the software like design, analyze, tuning etc the effect of gas lift parameters on well performance have been investigated. Results and analysis obtained from the software has been shown in the result and discusstion section.

Chapter 5: Results and Discussion

Here, two wells have been analyzed in order to understand the effect of various parameters associated with gas lift. General information about reservoir, fluid properties and well is shown below.

(i) Fluid Parameters:	
Oil specific gravity	0.8480
Gas specific gravity	0.9200
Water Salinity	32540 ppm
R_s	736.59 SCF/STB
B_o	1.5173 bbl/STB
B_g	0.0058 ft^3/SCF
B_w	1.0538 bbl/STB

(ii) Reservoir Data:	
Pressure	3000 psia
Temperature	246.9 ºF
MidPerf depth	15413 ft
Water cut	0.55
Gas-oil ratio	1702 SCF/STB

Well 1(Deviated well)

(iii - a) Wellbore Data: Well 1		
Measured depth (ft)	**True vertical depth (ft)**	**Deviation from vertical (deg)**
0	0	0
1000	1000	0
3474	3448	8.3139
6995	5993.01	43.7131
9808	7989	44.8009
11774	9504.01	39.5917
13053	10418	44.3885
13906	10986	48.2497
14695	11506	48.7716
15004	11703.87	50.1816
15413	11967.27	49.9085

Well 2 (Vertical well)

(iii - 2) Wellbore Data: Well 2	
Measured depth (ft)	**True vertical depth (ft)**
0	0
1000	1000
3448	3448
5993.01	5993.01
7989	7989
9504.01	9504.01
10418	10418
10986	10986
11506	11506
11703.87	11703.87
11967.27	11967.27

Here from given data for a well, Petrosky and Farshad (1993) correlation is selected for calculating PVT properties Pb, Rs, and Bo. Reason for selection of this correlation is that, it has least average error for PVT property calculation than any other calculation. The comparison with other correlation model is provided in Table 1.

[Table: 3 Comparison of different correlations for PVT properties]

Authors	Property	Average error %	Nature of correlation using R_s as basis
Glaso (1980)	P_b	1.28	Black-volatile oil
	B_o	-0.43	
Standing (1947)	P_b	4.8	Black-volatile oil
	B_o	1.17	
Lasater (1958)	P_b	3.8	Black-volatile oil
Vasquez & Beggs (1980)	Pb	-	Black-volatile oil
	Bo	4.7	
	R_s	-0.7	
Petrosky & Farshad (1993)	P_b	-0.17	Black oil
	B_o	-0.01	
	R_s	-0.05	
Macary & Batanony (1994)	Pb	0.52	Black oil
	B_o	0.521	

Petrosky and Farshad (1993) correlation has least average error for all the given properties. This correlation works with this great accuracy in a particular range of fluid properties which is given in table 2

[Table: 4 Data parameters and ranges for Petrosky and Farshad (1993)]

PVT property	Range
Oil FVF at bubble point (bbl/stb)	1.1178-1.6229
Bubble point pressure (psia)	1547-6523
Solution GOR (scf/stb)	217-1406
Reservoir temperature (ºF)	114-288
Oil API gravity (ºAPI)	16.3-45.0
Gas relative density (air = 1)	0.578-0.852

For the viscosity of oil, Beggs and Rebinson (1975) correlation works best with the error lesser than any other correlation.

[Table: 5 Comparison of oil viscosity correlations]

Authors	**Average error%**	**Nature of correlation using R_s as basis**
Beal (1946)	24.5	Black oil
Beggs & Rebinson(1975)	-0.64	Black oil
Petrosky & Farshad (1995)	-3.48	Black oil

For gas viscosity, there are two major correlations (1) Carr (1954) and (2) Lee (1966). Carr (1954) correlation has an advantage over Lee (1966) correlation as it includes correction for inorganic material present in the gas unlike Lee (1966) correlation.

Here, we have taken two cases for the same well data: (1) Deviated well profile case and (2) Vertical Well profile case. In the following tables, well 1 and well 2 data represent deviated well profile case and vertical well profile case respectively.

We will analyze the effect of different parameters like Tubing Head Pressure (THP), Gas injection rate, Injection gas gravity, Depth of gas injection, and Port size of valve, and will determine the suitable optimum conditions.

5.1 Effect of Tubing Head Pressure (THP)

[Table: 6 & 7 showing variation in production rate with THP for deviated profile case and vertical profile case respectively]

Table 6 & 7 data derived for conditions:
Gas injection rate = 1.2 MSCF/d
Injection gas gravity = 0.7430 (air =1)

Well 1 (Deviated case)			
THP(psi)	**Qliq (STB/d)**	**Qoil(STB/d)**	**Qgas(MMSCF/d)**
50	1111.7	500.3	0.85
60	1059.3	476.7	0.81
70	1023.2	460.4	0.78
80	986.9	444.1	0.76
90	952.1	428.5	0.73
100	919	413.6	0.7
110	888	399.6	0.68
120	858.1	386.1	0.66

Well 2 (Vertical case)			
THP(psi)	**Qliq (STB/d)**	**Qoil(STB/d)**	**Qgas(MSCF/d)**
50	1132.2	509.5	0.87
60	1078.4	485.5	0.83
70	1041.6	468.7	0.8
80	1005	452.2	0.77
90	970.4	436.7	0.74
100	937.4	421.8	0.72
110	906.2	407.8	0.69
120	875.7	394.1	0.67

From the table 4 &5 we can analyze that as THP increases the production rate decreases, because higher THP will impose more back pressure to the bottom-hole in the tubing and Pwf will increase and effective drawdown pressure will decrease and eventually production decreases.

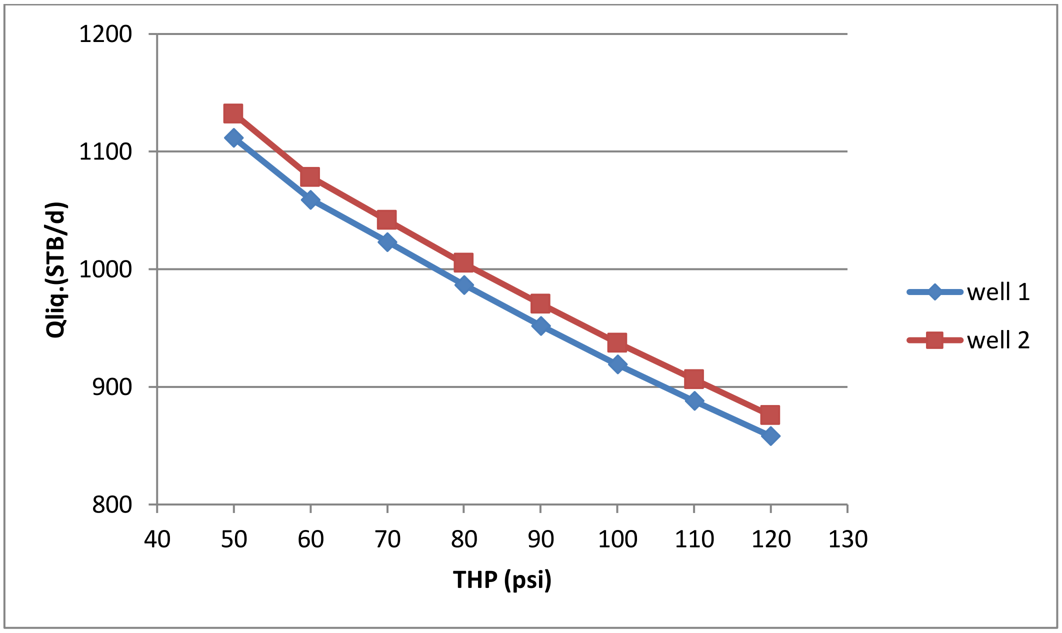

Figure 35: Graphical presentation of liquid production rate vs. THP data of well1 and well 2

From fig.35 one can depict that, vertical profiled well production rate is slightly higher than deviated profiled well. In wellbore flow performance, Pressure drop calculation plays a vital role. The pressure drop over the length L of pipe can be gained by solving the mechanical energy balance equation, which can be written in differential form as equation 1.

$$\frac{dP}{\rho} + \frac{u\,du}{g_c} + \frac{g}{g_c}dZ + \frac{2f_f u^2 dL}{g_c D} + dW_s = 0 \qquad \text{.............................(1)}$$

This equation 1 can be integrated and equation 3 can be obtained.

$$\frac{dP}{dZ} = \left(\frac{dP}{dZ}\right)_{PE} + \left(\frac{dP}{dZ}\right)_{KE} + \left(\frac{dP}{dZ}\right)_{Friction} \qquad \text{..................(2)}$$

$$\Delta P = P1 - P2 = \frac{g}{g_c}\rho\Delta Z + \frac{\rho}{2g_c}\Delta u^2 + \frac{2f_f\rho u^2 L}{g_c D} \qquad \text{..............(3)}$$

Here, L is equal to measured depth (MD) in case of deviated well which is certainly higher than the vertical well and that is why the pressure loss due to friction losses will be higher and also due to deviations and turns in the path increases the hindrance for slow and increases the pressure losses. Hence the production rate from deviated well is lesser than the vertical well.

5.2 Effect of Gas injection rate

[Table: 8& 9 Effect of lift gas injection rate on production rate for well 1 and 2]

Table 8 & 9 data derived for conditions:
THP= 96 psi, Gas injection rate= 1.2 MSCF/d

Well 1			
Injection rate	**Qliq (STB/d)**	**Qoil(STB/d)**	**Qgas(MSCF/d)**
1	868.5	390.8	0.67
2	1078.6	485.4	0.83
3	1171.9	527.4	0.9
4	1232.3	554.6	0.94
5	1239.8	557.9	0.95
6	1231.6	554.2	0.94
7	1217.9	548	0.93
8	1200	540	0.92
9	1179.5	530.8	0.9
10	1158.6	521.4	0.89

Well 2			
Injection rate	**Qliq (STB/d)**	**Qoil(STB/d)**	**Qgas(MSCF/d)**
1	886.5	398.9	0.68
2	1098.4	494.3	0.84
3	1190.3	535.6	0.91
4	1252.7	563.7	0.96
5	1260.8	567.4	0.97
6	1253.8	564.2	0.96
7	1240.8	558.4	0.95
8	1224.1	550.8	0.94
9	1204.3	541.9	0.92
10	1183.4	532.5	0.91

Here one can analyze that, initial increase in gas injection rate increases the production performance of the well but after a certain point, increase in gas injection rate will adversely affect the production performance and production rate starts to decrease. This point from where the trend changes, is called as “Reversal point”.

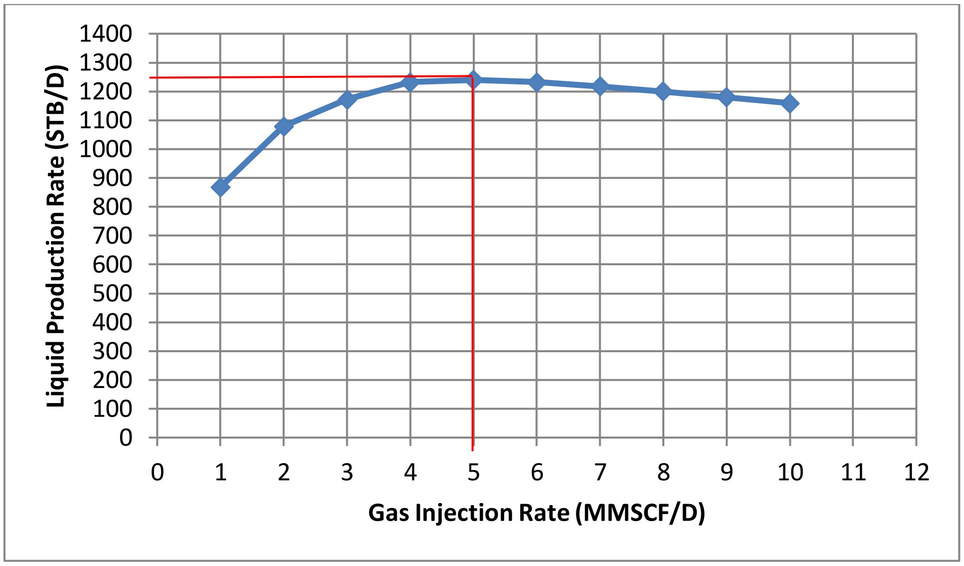

Figure 36: Gas lift performance curve for well 1

At this reversal point, the reduction in average fluid density in the tubing due to increase in the gas injection rate is being exactly counterbalanced by the increased frictional pressure losses due to the greater mass of fluid flowing in the tubing. Further increases in the gas flow rate will result in the friction term increasing relatively faster than the hydrostatic head reduction term. This is the “technical optimum gas injection rate” at which the well production is maximized.

5.3 Effect of Injection gas gravity

[Table: 10 & 11 Effect of lift gas gravity on production rate for well 1 and 2]

Table 10 & 11 data derived for conditions:
THP= 96 psi
Gas injection rate= 1.2 MSCF/d

Well 1			
Injection gas gravity	**Qliq (STB/d)**	**Qoil(STB/d)**	**Qgas(MSCF/d)**
0.6	945	425.3	0.72
0.65	940.6	423.3	0.72
0.7	935.9	421.1	0.72
0.75	930.9	418.9	0.71
0.8	928.3	417.7	0.71
0.85	922.8	415.2	0.71
0.9	916.9	412.6	0.7
1	907.1	408.2	0.69
1.1	896.7	403.5	0.69
1.2	881.2	396.5	0.67

Well 2			
Injection gas gravity	**Qliq (STB/d)**	**Qoil(STB/d)**	**Qgas(MSCF/d)**
0.6	963.3	433.5	0.74
0.65	958.8	431.5	0.73
0.7	954.1	429.3	0.73
0.75	949.1	427.1	0.73
0.8	946.8	426	0.73
0.85	941.4	423.6	0.72

Low density (sp.gravity) gas can make the aerated liquid column lighter and lift the liquid column with better flow rate and this gives higher production rate. From the above table 8 and 9 shows that as the sp. gravity of gas increases the production decreases as the injected gas havig slightly higher density can increase pressure gradient in the tubing and cause reduction in flow.

So, it is advisable to use gas having 0.7 sp. gravity (air=1) in our case to get production optimally.

5.4 Effect of Depth of gas injection

[Table: 12& 13 Effect of depth of injection on production rate for well 1 and 2]

Table 12 & 13 data derived for conditions:
THP= 96 psi
Gas injection rate= 1.2 MSCF/d
Injection Gas density = 0.7430 (air=1)

Well 1 (Petrosky, Beggs, Carr)			
Depth of injection	**Qliq (bbl/d)**	**Qoil(bbl/d)**	**Qgas(MMSCF/d)**
2660.92	0	0	0
5084.32	606.8	273	0.46
7118.2	796.6	358.5	0.61
8501.81	884.6	398.1	0.68
9417.87	931.6	419.2	0.71

Well 2 (Petrosky, Beggs, Carr)			
Depth of injection	**Qliq (bbl/d)**	**Qoil(bbl/d)**	**Qgas(MSCF/d)**
3002.64	0	0	0
4887.97	671.8	302.3	0.51
6265.85	833.6	375.1	0.64
7174.19	912.2	410.5	0.7
7734.19	949.8	427.4	0.73
8294.19	985.4	443.4	0.75
8854.19	1018.1	458.2	0.78
9414.19	1047.7	471.5	0.8

As deep we inject the gas, more length of liquid column can be aerated and higher volume of fluid can be lifted. So we need to select depth for mandrel which can be deepest technically, for optimum production rate. This depth is obtained while designing the gas lift valve depth.

In our case the deepest depth possible and which is optimum is 9417.87 ft in well 1 and 9414.19 ft for well 2.

5.5 Effect of Port size

[Table: 14& 15 Effect of port size of valve on production rate for well 1 and 2]

Table 14 & 15 data derived for conditions:
THP= 96 psi
Gas injection rate= 1.2 MSCF/d
Injection Gas density = 0.7430 (air=1)

Well 1		
Port size	**Qliq (STB/d)**	**Qgas(MSCF/d)**
8	NA	NA
16	NA	NA
24	1036.5	4.2584
32	1125.1	7.4127
40	1115.5	10.2516
48	1081.5	12.4596
56	1046.8	13.9641
64	1026.8	14.8248

Well 2		
Port size	**Qliq (STB/d)**	**Qgas(MSCF/d)**
8	NA	NA
10	NA	NA
12	1156.4	1.951
16	844.12	2.0405

Increase in port size of valve allows more gas to flow through and eventually increase the gas flow rate through valve. This will lift the liquid column efficiently and increase the production rate. However, increase of port size after certain limit will increase flow rate such that frictional losses surpass the energy level needed to lift column and also more gas flow will bypass the oil without holdup and making single gas phase flow in tubing. So this can reduce the production performance of a well after a “reversal point”.

5.6 Most optimum condition

To decide the most optimum condition for well to flow, all the above parameters are important to study. With the use of all above parameters, most optimum condition for both the wells have been analyzed.

Well 1:

THP=50 psi
Gas injection rate= 6 MSCF/d
Injection Gas density = 0.6 (air=1)
Port size 32/64

Qliq	1263 STB/d
Qoil	568.3 STB/d
Qgas	0.97 MSCF/d

Well 2:

THP=50 psi
Gas injection rate= 2 MSCF/d
Injection Gas density = 0.6 (air=1)
Port size 16/64

Qliq	1302.6 STB/d
Qoil	586.2 STB/d
Qgas	1 MSCF/d

In conclusion, tubing pressure needs to be as low as practically possible and with accordance with reservoir management strategy. Gas injection rate should be economically optimum and should not surpass the value of reversion point; the same point is also right for port size of gas lift valve. Injection gas gravity needs to be preferably low and quality of gas should be such that it does not deteriorate the production performance. Depth of injection is obtained from the designing calculation of gas lift system. Depth of injection should be the deepest point but not below the 'equilibrium point'.

Chapter 6: Conclusion

Gas lift is most used artificial lift system in the offshore. In USA, gas lift dominates the artificial lift sector by occupying 51% share of total artificial lift being used (Production Technology-II, 2011). So, gas lift has much significance in the total oil recovery throughout the life of oil field. In this project ‘Gas lift design and optimization’, extensive study and analysis is done covering topics from the fundamentals of gas lift and other artificial lift techniques to the sensitivity analysis of gas lift using software ‘Well-Flo’.

Literature survey study done for this project includes detailed information of gas lift installation, equipments that are inevitable for gas lift system, different types of gas lift valves, different types of gas lift completion and installation, Continuous gas lift and its design, Intermittent gas lift and its design, unloading sequences, gas lift monitoring and troubleshooting techniques which incorporate the use of many different methods including two pen pressure chart recorder and gas lift optimization. Moreover, literature survey encompasses ‘the evolution of gas lift system’ which gives sound knowledge regarding the chronological development of gas lift system. However, this evolution study is not limited to older days of evolution; it also focuses on how digitization of the system can bring the gas lift to next level. Correlations for PVT parameters and multiphase flow parameters are discussed in the project study and comparison between correlation is made in results and discussion chapter, which is very helpful for deciding the most accurate correlation according to given scenario and this is shown while undergoing sensitivity analysis for gas lift in software.

An Introduction to WellFlo software is described in form of new chapter which gives insights on different features and applicability of this software. Gas lift design is done with the help of WellFlo software and various factor affecting efficiency of the system is analyzed and accordingly optimized which is discussed in chapter results and discussion in detailed way and here one can notice that how important is this study and how greatly this study helps to improve oil recovery. Economics of the project is the first matter of concern to any company and in any industry. So, it becomes unavoidable for our study to extend till ‘economics of gas lift’ study, wherein the Revenue Sharing Contract (RSC) Model is taken and an excel model is made for analysis of net revenue generated in case of naturally flowing well and gas lift well. So, by this information one can quickly decide that whether to go for gas lift system installation or not under prevailing contract and oil price conditions.

This project can be as a standard reference for systematic way for designing and optimizing the gas lift theoretically as well as with WellFlo software. By performing this project, we have suggested optimum values for parameters like gas injection rate, tubing head pressure, injection gas gravity, depth of injection and port size by which oil recovery from that well will increase significantly in both case (Vertical and deviated well). So, this is indeed an important project to be considered by industry and the outcomes of the project and its applicability have a great potential to increase oil recovery and to improve the financial status or worth of company. Also it can be very helpful to oil industry since it is also containing economic analysis and providing the means to trade off between natural flowing well and gas lift well installation.

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