Sudan University Of Science & Technology
College Of Petroleum Engineering
Department Of Petroleum Engineering

Reevaluate of Gas lift system for a heavy oil well

case study Fula north

اعادة تقييم نظام الرفع بالغاز لبئر ذو خام نفطي ثقيل
تطبيق حقلي : الفوله الشمالي

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الاستهلال

بِسْمِ اللَّهِ الرَّحْمَنِ الرَّحِيمِ

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Abstract

Gas lift is one of the best method of artificial lift which achieves the economic goals which achieve the country and company policies. The aim of the study is minimizing the viscosity of the oil by reaching the dilution stage for the well fula north 66 that located in Block 6,by using PIPESIM software to design the gas lift model.

The data has been collected and the model has been designed , several injection rates are entered to accomplish the dilution stage (1, 1.5 ,2 ,2.5 ,3,4,5 mmscf/day) and the highest viscosity diminution is happened with the injection rate (3 mmscf/day) as the suitable one ,therefore, the production rate will increase as a result of viscosity diminution.

The study shows that the viscosity has been decreased from (3863.63 cp) to (1700 cp) which means the study is successful.

التجريد

الرفع بالغاز احد افضل طرق الرفع الصناعي حيث يحقق كل من المطالب الاقتصادية والسياسية للشركة والبلد المطبق فيه. الهدف من هذه الدراسة هو تقليل الكثافة العالية للخام النفطي عن طريق الوصول لمرحلة التخفيف للبئر (66) في حقل الفولة الشمالي الواقع في المربع (6) في السودان ,باستخدام برنامج PIPESIM لتصميم نموذج الرفع بالغاز.

تم جمع البيانات, وتصميم النموذج, تم ادخال عدة قيم لمعدلات الحقن من اجل الوصول لمرحلة التخفيف (1,1.5,2,2.5,3,4,5 mmscf/day) وتم ملاحظة اعلى انخفاض للزوجه عند معدل الحقن (3 mmscf/day) كأمثل معدل حقن, سيرتفع معدل الانتاج بأنخفاض لزوجة الخام.

الدراسة توضح بأن اللزوجة انخفضت من المقدار (3863.63 cp) الي المقدار (1700 cp) وهو دليل علي نجاح الدراسة.

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CHAPTER 1

INTRODUCTION

1.1 Artificial lift:

Artificial lift is a method used to lower the producing bottomhole pressure (BHP) on the formation to obtain a higher production rate from the well.

This can be done with a positive-displacement downhole pump, such as a beam pump or a progressive cavity pump (PCP), to lower the flowing pressure at the pump intake. It also can be done with a downhole centrifugal pump, which could be a part of an electrical submersible pump (ESP) system. A lower bottomhole flowing pressure and higher flow rate can be achieved with gas lift in which the density of the fluid in the tubing is lowered and expanding gas helps to lift the fluids. Artificial lift can be used to generate flow from a well in which no flow is occurring or used to increase the flow from a well to produce at a higher rate. Most oil wells require artificial lift at some point in the life of the field, and many gas wells benefit from artificial lift to take liquids off the formation so gas can flow at a higher rate (Brown KE, 1984).

- **Types of artificial lift:**

The major forms of artificial lift are:

1. Sucker-rod (beam) pumping.
2. Electrical submersible pumping (ESP).
3. Gas lift systems.
4. Reciprocating and jet hydraulic pumping systems.

5. Plunger lift.
6. Progressive cavity pumps (PCP).

1.1.1 Sucker-rod pump:

Beam pumping, or the sucker-rod lift method, is the oldest and most widely used type of artificial lift for most wells. A sucker-rod pumping system is made up of several components, some of which operate aboveground and other parts of which operate underground, down in the well. The surface-pumping unit, which drives the underground pump, consists of a prime mover (usually an electric motor) and, normally, a beam fixed to a pivotal post. The post is called a Sampson post, and the beam is normally called a walking beam (Brown KE, 1984).

This system allows the beam to rock back and forth, moving the downhole components up and down in the process. The entire surface system is run by a prime mover, V-belt drives, and a gearbox with a crank mechanism on it. When this type of system is used, it is usually called a beam-pump installation. However, other types of surface-pumping units can be used, including hydraulically actuated units (with and without some type of counterbalancing system), or even tall-tower systems that use a chain or belt to allow long strokes and slow pumping speeds. The more-generic name of sucker-rod lift, or sucker-rod pumping, should be used to refer to all types of reciprocating rod-lift methods.

Linked rods attached to an underground pump are connected to the surface unit. The linked rods are normally called sucker rods and are usually long steel rods, from 5/8 to more than 1 or 1 1/4 in. in diameter. The steel rods are normally screwed together in 25- or 30-ft lengths; however, rods could be welded into one piece that would become a continuous length from the surface to the downhole pump. The steel sucker rods typically fit inside the tubing and are stroked up and down by the surface-pumping unit. This activates the downhole, positive-displacement pump at the bottom of the well. Each time the rods and pumps are stroked, a volume of produced fluid is lifted through the sucker-rod tubing annulus and discharged at the surface (Brown KE, 1984).

1.1.2 Electrical submersible pumps:

The electrical submersible pump, typically called an ESP, is an efficient and reliable artificial-lift method for lifting moderate to high volumes of fluids from wellbores. These volumes range from a low of 150 B/D to as much as 150,000 B/D (24 to 24,600 m3/d). Variable-speed controllers can extend this range significantly, both on the high and low side.

The components are normally tubing hung from the wellhead with the pump on top and the motor attached below. There are special applications in which this configuration is inverted.

As area in which ESPs are applied extensively, THUMS Long Beach Co. was formed in April 1965 to drill, develop, and produce the 6,479-acre Long Beach unit in Wilmington field, Long Beach, California. ESPs have been the primary method of lifting fluids from the approximately 1,100 deviated wells from four man-made offshore islands and one onshore site (Brown KE, 1984).

1.1.3 Hydraulic pumping:

Hydraulic pumping is a proven artificial lift method that has been used since the early 1930s. It offers several different systems for handling a variety of well conditions. Successful applications have included setting depths ranging from 500 to 19,000 ft and production rates varying from less than

100 to 20,000 B/D. Surface packages are available using multiplex pumps ranging from 15 to 625 hp. The systems are flexible because the downhole-pumping rate can be regulated over a wide range with fluid controls on the surface. Chemicals to control corrosion, paraffin, and emulsions can be injected downhole with the power fluid, while fresh water can also be injected to dissolve salt deposits. When pumping heavy crudes, the power fluid can serve as an effective diluent to reduce the viscosity of the produced fluids. The power fluid also can be heated for handling heavy or low-pour-point crudes. Hydraulic pumping systems are suitable for wells with deviated or crooked holes that can cause problems for other types of artificial lift. The surface facilities can have a low profile and may be clustered into a central battery to service numerous wells. This can be advantageous in urban sites, offshore locations, areas requiring watering systems (sprinkle systems), and environmentally sensitive areas (Brown KE, 1984).

There are two primary kinds of hydraulic pumps:

- Jet pumps
- Reciprocating positive-displacement pumps

1.1.4 Plunger lift:

Plunger lift has become a widely accepted and economical artificial lift alternative, especially in high-gas/liquid-ratio (GLR) gas and oil wells.

Plunger lift uses a free piston that travels up and down in the well's tubing string. It minimizes liquid fallback and uses the well's energy more efficiently than does slug or bubble flow. As with other artificial lift methods, the purpose of plunger lift is to remove liquids from the wellbore so that the well can be produced at the lowest bottomhole pressures.

Plunger lift commonly is used to remove liquids from gas wells or produce relatively low volume, high GOR oil wells. Plunger lift is important and, in its most efficient form, will operate with only the energy from the well (Brown KE, 1984).

1.1.5 Progressing cavity pump (PCP) systems:

Progressing cavity pumping (PCP) systems derive their name from the unique, positive displacement pump that evolved from the helical gear pump concept first developed by Rene Moineau in the late 1920s.

Although these pumps are now most commonly referred to as progressing cavity (PC) pumps, they also are called screw pumps or Moineau pumps. They are increasingly used for artificial lift, and have been adapted to a range of challenging lift situations (e.g., heavy oil, high sand production, and gassy wells, directional or horizontal wells) (Brown KE, 1984).

1.1.6 Gas Lift:

Gas lift is an artificial-lift method for enhancing crude oil recovery from a reservoir. This method works by injecting the optimum amount of natural gas into the production tubing which transports crude oil from reservoir to the surface. The gas injected in the oil column reduces the effective density of oil in production tubing, thus reducing the hydrostatic pressure of the oil column in the well. The reduced pressure of the oil column above the reservoir allows the reservoir fluids to enter the oil well bore at a higher flow rate, thus enhancing the oil recovery from reservoir.

Usually the natural gas recovered along with the crude oil is used for the gas-lift. This gas is typically conveyed down the tubing-casing annulus surrounding the production tubing which contains the crude oil column flowing upwards (Brown KE, 1984).

Lift gas flows through the annulus around production tubing and enters the production tubing through gas-lift valves located in the gas-lift mandrel. The gas lift valves control the gas injection rate which has to be fixed based on wellbore conditions and properties of reservoir fluids (petrowiki).

Gas Lift types:

1. . Continuous Gas Lift
2. Intermittent Gas Lift

1.2 Fula Field Background:

Fula Field is located in Block 6 of Sudan; it contributes with reasonable amount of production in block 6.

There are three producing formation of Fula field which are Bentiu and Aradeiba formation (Heavy oil) and Abu Gabra formation (Light oil), Fula Field was put into production since November, 2003, it's consist of 146 producing wells, 138 are pumping wells, 5 are flowing wells and 3 gas producing wells, 15 oil gathering manifold (OGM), 12 OGMs are for heavy oil production wells and 3 for light oil production wells in addition to the gas gathering distribution manifold (GGDM) which is use to gather the gas from producing wells and redistribute it for different use such as; Gas lifting wells, power station, compressors etc…, Most of producing wells are used Progressive Cavity Pump (PCP).

The total fluid production about 26000bbl/d, with water cut about 70%.

1.3 Problem statement:

The well FN66 contains heavy oil that means low productivity with viscosity that reaches 3863.63 cp, which makes it difficult to be produced, using PCP and the beam pump previously wasn't sufficient because of their low production rate, therefore, another method must have hand in.

1.4 Research objectives:

1. Minimize the high viscosity by using gas lift and determine the effectiveness of the system by reaching the dilution stage.
2. Determine the optimum injection rate to achieve optimum production rate by using PIPESIM software.

CHAPTER 2

Literature review

2.1 History of Gas Lift :

During its almost 150-year history, gas lift is considered as the most efficient artificial methods that may be effectively applied in the oilfields. The initial laboratory experiments using compressed air to lift liquids were conducted by Carl Loscher in Germany, 1797.

This method was later used to lift water from pit swing. In this technique, air was injected into liquid at the bottom of tubing through a valve. Gas lift operation is a single point injection. It has been documented that in 1864 the concept was applied in the oil industry, called a ‘well blower’ (Brantly JE, 1961) .

Cockford, an American engineer, used compressed air to lift produced oil from wells in Pennsylvania. According to Cloud, Cockford’s system consisted of an air-filled pipe connected to the tubing to decrease hydrostatic pressure by reducing oil density, allowing the well produce more (Cloud WF , 1937).

Cockford’s technique continued to be used until 1920. Between 1920 and 1929, for safety reason, natural gas was tested to be used instead of compressed air. Due to successful test results, this method was then applied in the Seminole field Oklahoma. Initially, gas was injected unrestrainedly into the bottom of the well. Due to low achievable injection pressures, gas lift application was limited to shallow wells. Downhole equipment used in the gas-lifted wells underwent a great evolution and early open installations utilizing a tubing string, were gradually replaced with installations including a packer and standing valve. Spring-operated differential GLV was invented in 1930s. This valve gets opened if the injected pressure (casing pressure) becomes greater than tubing pressure.

Running GLV and other downhole devices became easier and more cost effective by deploying wire line retrievable equipment in the 1930. Another GLVs model, which mechanically operated from the surface, was developed by Brown in1980 (Brown KE, 1984).

These valves are run in the well using tubing string, and if they need to be replaced, the whole tubing string has to be pulled out of the well. Due to the difficulty and unreliability of tubing retrievable GLVs, wire line retrievable GLVs were introduced. In the case of failure, wire line retrievable valves are replaced without pulling out the entire tubing string. Gas lift is not the best option for low production wells; therefore newer lifting methods such as chamber and plunger lift were introduced to produce from the wells with low liquid capacities.

2.2 Gas Lift System:

Not all the oil wells start producing fluid naturally right after they put back online due to low Bottom Hole Pressure (BHP) which is insufficient to lift the fluid to the surface. At some point, the reservoir energy will not be sufficient to bring the reservoir fluid up to the surface because its energy is depleted. One way to help a well flow is to energize the reservoir fluid with a lighter fluid as the carrying fluid. In that case, the overall fluid density will drop which results in larger lift capability of the reservoir.

Gas lift is the form of artificial lift that most closely resembles the natural flow process. It may be treated as the extension of the natural flow process. In a naturally flowing well, as the fluid travels upward toward the surface, the fluid column pressure is reduced causing the gas to expand and move faster upward. Injected gas will help carrying some diluted liquid to the surface; however, if the gas velocity is not high enough, some liquid may start to fall off at some point near surface. Gas lift is frequently used in lifting water for the purpose of gas deliquefication. In this approach, a high-pressure gas is injected into the fluid column to reduce the flowing pressure gradient. In other words; gas lift is the process of supplementing additional gas (from an external source) to increase the gas-liquid ratio (GLR) resulting in reducing the flowing fluid density. This process considered an expansion of natural flow phase. Figure (2.1) shows the schematic of a typical gas lift system. Compared to the other artificial lift methods, gas lift is simpler, more adaptable, and more efficient at wide ranges of fluid production there are two types of gas lift systems: continuous flow and intermittent flow. In both gas lift systems, high pressure natural gas is injected from the surface to lift formation fluid. Continuous flow gas, which is very similar to the natural flow, is the most common gas lift method in the industry. In this technique, injecting gas 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 a lower bottomhole pressure. Lower bottomhole pressure improves wellbore productivity index.

Intermittent gas lift operation is achieved by injecting gas at sufficient volume and pressure into the tubing at the point below the fluid column to lift the liquid to the surface. Intermittent flow is periodic displacement of liquid from the tubing by injection high pressure gas into the wellbore. The advantage of intermittent flow gas lift over the continue gas lift is periodic need of high pressure gas. On the other hand, since gas is injected intermittently over specific period of time, this method is not capable of producing at high volume rate compared to continuous flow gas lift.

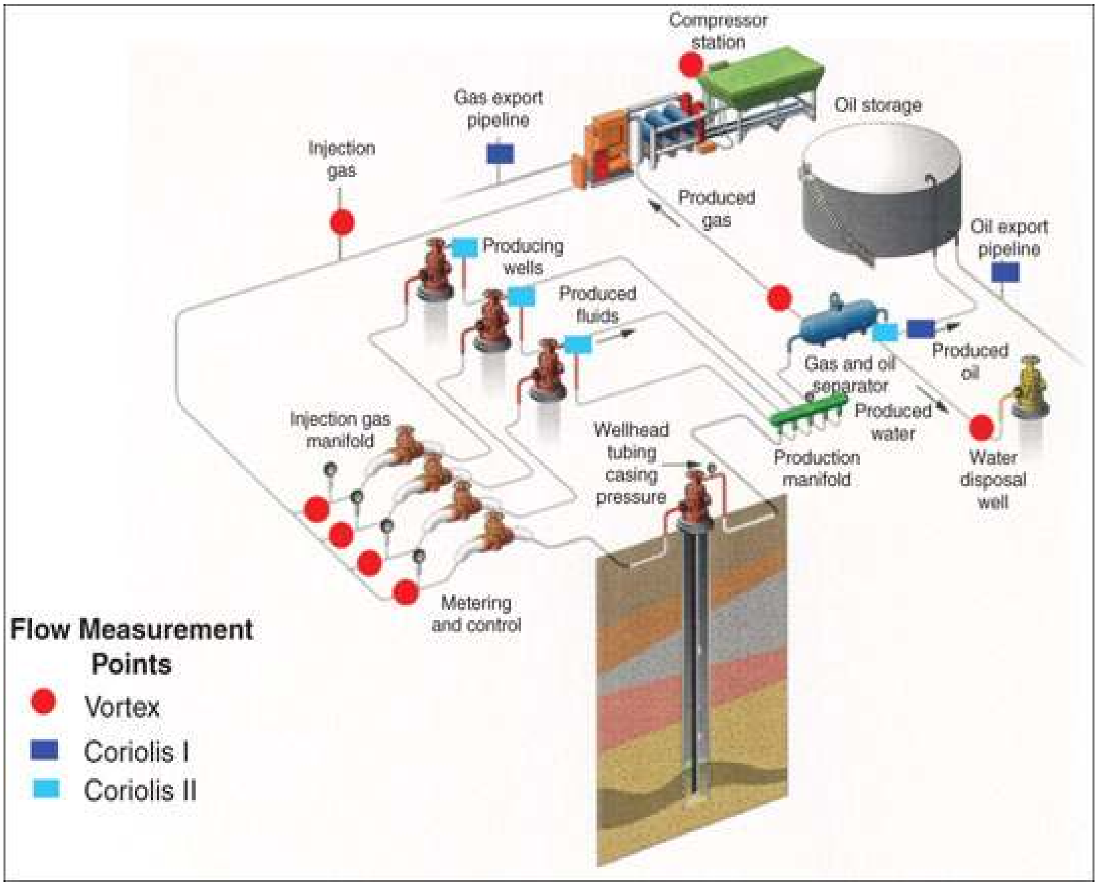


Figure (2.1) Typical Gas Lifts System (Fathi Elldakli, 2017)

Gas lift system is a closed system which requires a high pressure source of gas, surface controls, subsurface equipment, flow lines, separation and storage equipment, compressors, and GLVs. The effectiveness of a gas lift system depends on appropriate design of all these components. To achieve an efficient operation and to ensure that the suitable amount of gas is injected at all times, gas entry must be controlled by utilizing a downhole device. In modern practice, gas lift valves are used for downhole gas injection control. Because of its importance, various gas lift valves have been developed over the years.

Gas lift system may be used to resume production from a well since the primary production ceases until its abandonment. Also, it may be used to increase the production from low producing wells. Initially, continuous gas lift may be used to produce at high liquid rates up to 50,000 STB/D (Shahri MA, 2011).

Later, as both formation pressure and liquid rates gradually declined; replacing it with an intermittent gas lift system ensures that production goals are met.

Gas lift system is the only form of artificial lift system that does not need downhole pump. However, this system is unable to significantly reduce BHP. The minimum required pressure gradient is approximately 0.22 psi/ft and rarely goes below 0.15 psi/ft as suggested by Pablano, & Fairuzov (Pablano E et al, 2002).

Therefore, gas lift system is a good candidate for projects where the BHP is constant. The higher production rate may be attained when the bottom GLV installed at the deepest point. Before starting gas injection, the required injection pressure has to be calculated based on the hydrostatic pressure inside the tubing at the depth where the valve will be installed.

The location of first valve must be determined for kick off. The high pressure gas in the annulus forces the liquid out of the tubing through U-tubing. Figure (2.2) demonstrates the point of injection.

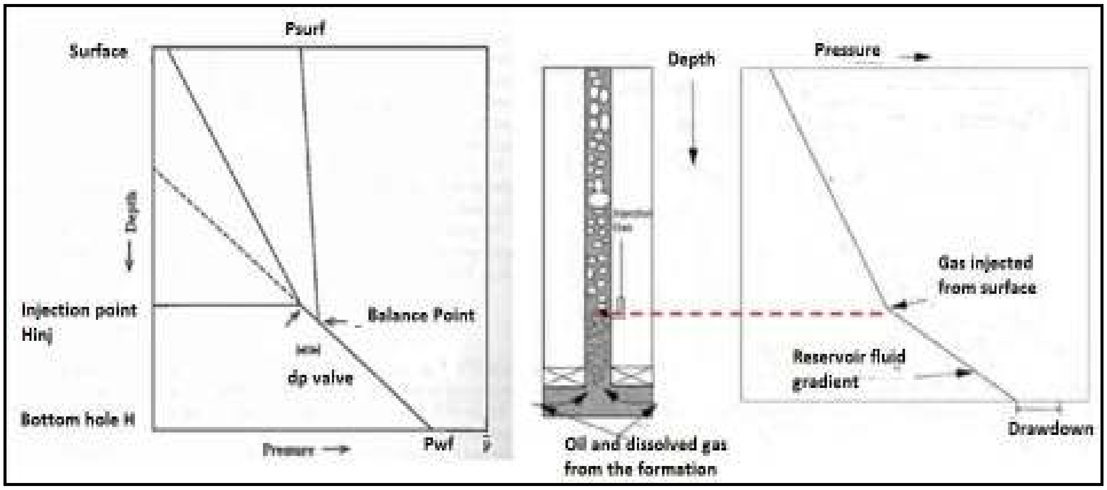


Figure (2.2) Single-injection gas lift installation (Fathi Elldakli, 2017)

Instability in the gas lift operation may frequently occur. It mainly occurs when the tubing pressure changes and the injection pressure is not high enough to keep the valve open. When the injection pressure reaches the critical pressure, any change of the tubing pressure will not affect the process and the operation stays stable. According to Bellarby to avoid gas lift instability, the exact orifice port size needs to be selected (Bellarby J, 2009).

Multiple injection points are required to unload deep wells. Figure (2.3) shows different injection points. To achieve a higher drawdown and to avoid liquid falloff while lifting, multiple GLVs may be needed to be installed.

As Shahri reported, at some wells with high productivity index, GLV may not needed and simply a large orifice choke may be used to inject required amount of gas to lift the liquid from the bottom hole (Shahri MA, 2011).

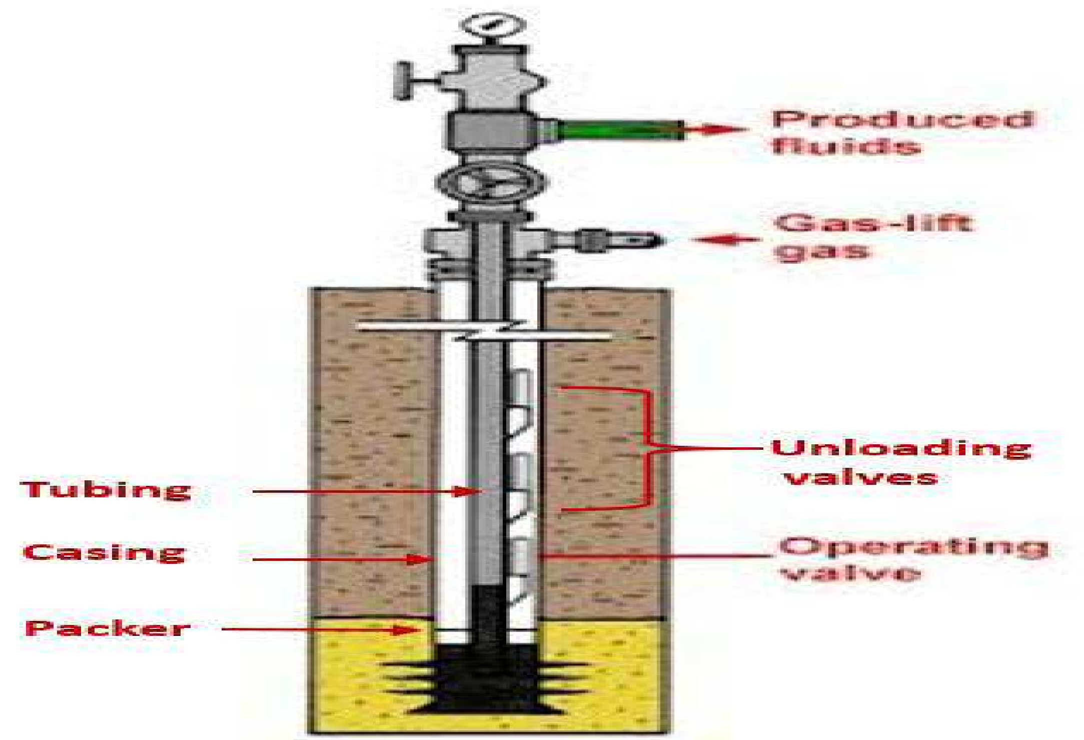


Figure (2.3) Well with multiple GLV at different depths (Fathi Elldakli, 2017)

Installing GLVs at deep depths is vitally important, and depends on the valve design, and its opening and closing pressures. The order of GLVs installation is of great importance in the lifting process. If the installation is not in the correct order, the gas lift system will fail. In a gas lift system design, the valves' operating pressures drop as it gets deeper. Therefore, as the injection pressure drops, the upper valve operating at a higher injection pressure closes and lower valve starts to unload the well and so forth. Usually the lowest GLV is an open orifice plate, which is open all the time. In the Figure (2.4), the gas is injected from the casing and the reservoir fluid is produced through the tubing. Figure (2.4) demonstrates the valve depth determination with respect to the flowing tubing pressure.

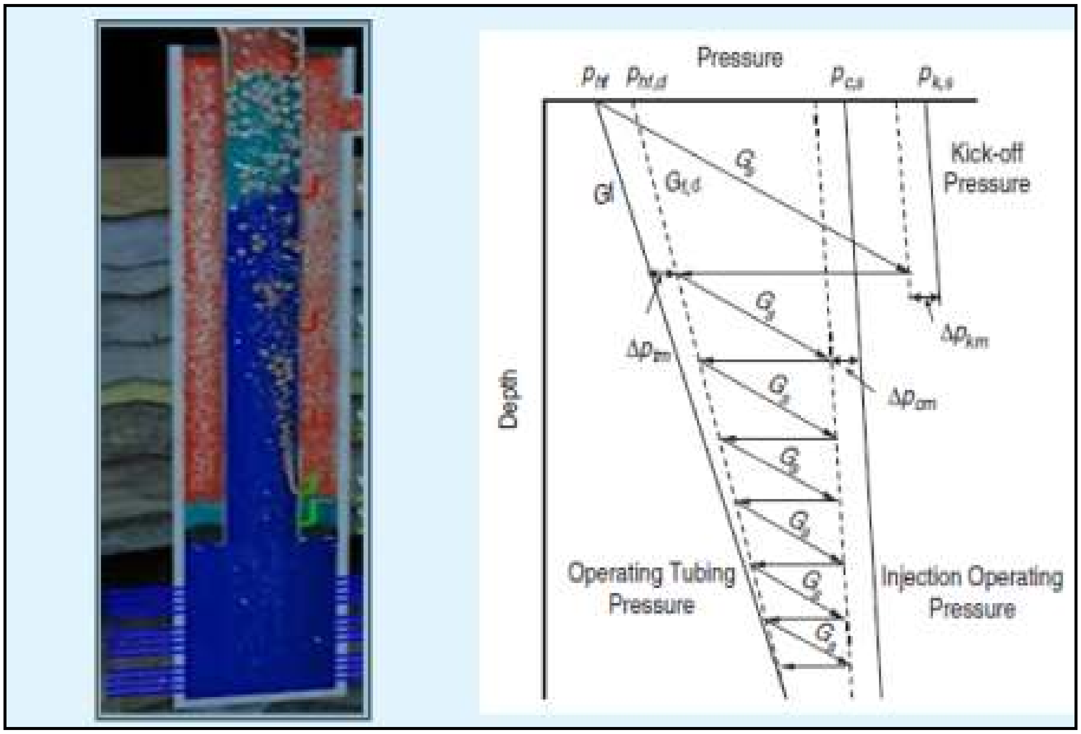


Figure (2.4) String design for GL system and the depth of the valves (Fathi Elldakli, 2017)

2.3 Advantages of Gas Lift :

In terms of production rate ranges and depth of lift, the gas lift system is flexible and can rarely be matched by other artificial lift methods if required injection gas pressure and volume are existed. Gas lift is one of the most flexible artificial lift techniques which even unappropriated design will still lift some fluid. Highly deviated wells with high formation GLR and sand production are good candidates for gas lift when artificial lift is needed.

2.4 Limitations of Gas Lift:

Large well spacing for onshore wells and limited offshore platforms space for compressors may restrict the gas lift application. Gas lift is rarely applicable to single well installation and not appropriate for widely-spaced wells due to the difficulty of locating the power system centrally. Gas lift is not the option for viscous crude oil, super-saturated brine or emulsion fluid. In addition, the gas lift system does not work well for old casing wells, or long flow lines with small inside diameter (ID). As Fleshmanand Lekic and Osuji pointed out, gas lift process is limited to the BHP and fluid properties such as scale formation, existence of paraffin and corrosion because these properties may increase the friction in the tubular (Fleshman R, Lekic HO, 1999) (Osuji LC , 1994).

2.5 Gas Lift Valve (GLV) :

GLV is the heart of a gas lift system because of controlling production rates. The GLV is a backpressure regulator which functions based on the differential pressure between the injection gas pressure and the production fluid pressure (Winkler HW, Camp GF, 1987).

The GLV regulates the pressure on its upstream side to its downstream. The architectural design of each GLV is as important as the depth of installation and number of GLVs used in each installation. Poor designs may result in installing dozens of GLVs to unload well that may not to be necessary.

Therefore, calibrating each GLV to achieve the best performance at the wellbore is vital to the artificial lift cycle of each well. Because a GLV consists of many movable mechanical compartments, achieving synergy between all those compartments should result in the best performance.

The performance of a GLV affects both the technical and economic aspects of fluid lifting process. The main duty of a GLV is to allow the required amount of injected gas enter the wellbore to unload the well. If the designed parameters such as pressure column, water cut, GLR and well deliverability change, the GLVs may be installed at different depths to adjust the gas lift system accordingly. Figure (2.5) demonstrates the GLV at different depths.

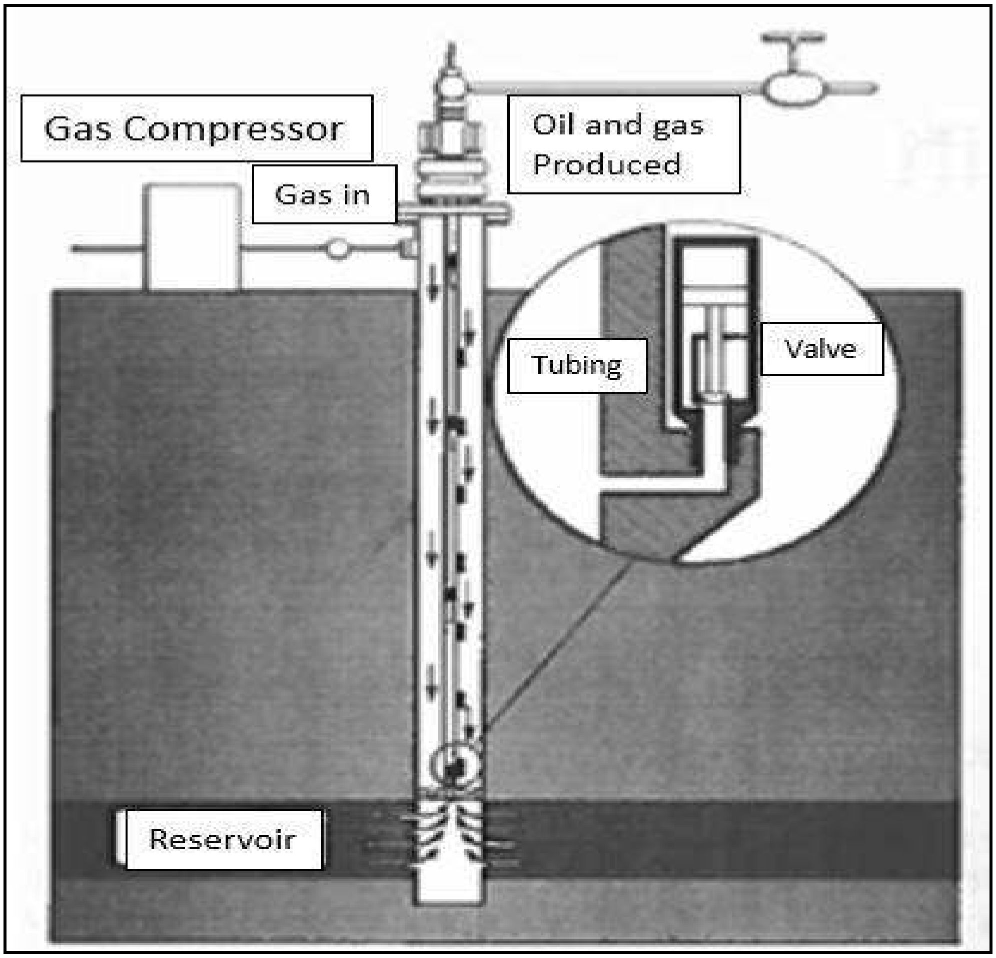


Figure (2.5) GLVs in vertical well (Fathi Elldakli, 2017).

Before 1944 and prior to introducing bellows-charged GLVs, the most common GLV was the differential valve. The differential pressure between the injecting gas in the casing and the fluid inside the tubing controlled the operation of the valve. The differential valve, however, had some shortcomings in the unloading process and the differential valves had to be spaced closely together, little surface control was possible, and the valve was bulky and difficult to transport. Since then, better GLVs designs for better unloading of wells were developed. King patented the first GLV with single element, and charged bellows (King W , 1944).

Today's pressure operated gas lift valve has been modified little since King's original valve.The King's valve was designed to lift a low volume of liquid as it has a small chamber attached to its end section. The success of the King valve is the evidence that the basic principles used in the design were quickly adopted by almost all GLV manufacturers and are still used with little modification. Brown describes four types of GLVs: casing pressure operated valve, throttling valve, fluid operated valve, and combination valve (Brown KE, 1984).

The pressure operated valve is used in most gas lift installations. The gas lift valve has a loading element, which is a spring, a nitrogen charged bellows, or a combination of the two. The loading element provides the downward closing force in a gas lift valve.

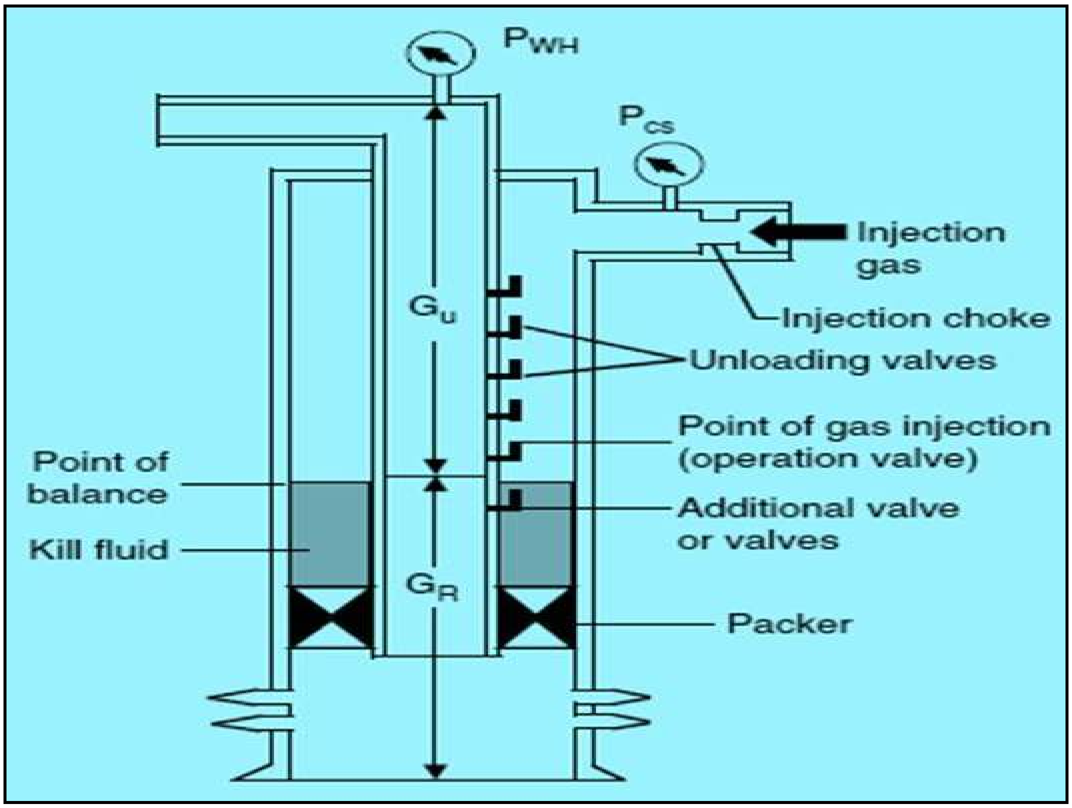
2.6 Gas Lift Mode:

There are mainly two modes of gas lift production including continuous gas lift and intermittent gas lift, intermittent gas lift includes conventional intermittent gas lift, plunger gas lift and cavity gas lift etc..

2.7 Continuous Gas Lift:

Continuous gas lift method is used typically to continuously maintain efficient production rates by enhancing the oil recovery by lowering the hydrostatic pressure of crude oil column in production tubing.

Continuous-flow gas lift is recommended for high-volume and high-static BHP wells in which major pumping problems could occur with other artificial lift methods. It is an excellent application for offshore formations that have a strong water drive, or in water flood reservoirs with good PIs and high gas/oil ratios (GORs). When high-pressure gas is available without compression or when gas cost is low, gas lift is especially attractive. Continuous-flow gas lift supplements the produced gas with additional gas injection to lower the intake pressure to the tubing, resulting in lower formation pressure as well.



Fig(2.6) continuous gas lift

2.7.1 Advantages:

- Gas lift is the best artificial lift method for handling sand or solid materials. Many wells produce some sand even if sand control is installed. The produced sand causes few mechanical problems in the gas-lift system;

whereas, only a little sand plays havoc with other pumping methods, except the progressive cavity pump (PCP).

- Deviated or crooked holes can be lifted easily with gas lift. This is especially important for offshore platform wells that are usually drilled directionally.
- Gas lift permits the concurrent use of wireline equipment, and such downhole equipment is easily and economically serviced. This feature allows for routine repairs through the tubing.
- The normal gas-lift design leaves the tubing fully open. This permits the use of BHP surveys, sand sounding and bailing, production logging, cutting, paraffin, etc.
- High-formation GORs are very helpful for gas-lift systems but hinder other artificial lift systems. Produced gas means less injection gas is required; whereas, in all other pumping methods, pumped gas reduces volumetric pumping efficiency drastically.
- Gas lift is flexible. A wide range of volumes and lift depths can be achieved with essentially the same well equipment. In some cases, switching to annular flow also can be easily accomplished to handle exceedingly high volumes.
- A central gas-lift system easily can be used to service many wells or operate an entire field. Centralization usually lowers total capital cost and permits easier well control and testing.
- A gas-lift system is not obtrusive; it has a low profile. The surface well equipment is the same as for flowing wells except for injection-gas metering. The low profile is usually an advantage in urban environments.

- Well subsurface equipment is relatively inexpensive. Repair and maintenance expenses of subsurface equipment normally are low. The equipment is easily pulled and repaired or replaced. Also, major well work over occur infrequently.
- Installation of gas lift is compatible with subsurface safety valves and other surface equipment. The use of a surface-controlled subsurface safety valve with a 1/4-in. control line allows easy shut in of the well.
- Gas lift can still perform fairly well even when only poor data are available when the design is made. This is fortunate because the spacing design usually must be made before the well is completed and tested.

2.7.2 Disadvantages:

- Relatively high backpressure may seriously restrict production in continuous gas lift. This problem becomes more significant with increasing depths and declining static BHPs. Thus, a 10,000-ft well with a static BHP of 1,000 psi and a PI of 1.0 bpd/psi would be difficult to lift with the standard continuous-flow gas-lift system. However, there are special schemes available for such wells.
- Gas lift is relatively inefficient, often resulting in large capital investments and high energy-operating costs. Compressors are relatively expensive and often require long delivery times. The compressor takes up space and weight when used on offshore platforms. Also, the cost of the distribution systems onshore may be significant. Increased gas use also may increase the size of necessary flowline and separators.
- Adequate gas supply is needed throughout life of project. If the field runs out of gas, or if gas becomes too expensive, it may be necessary to

switch to another artificial lift method. In addition, there must be enough gas for easy startups.

- Operation and maintenance of compressors can be expensive. Skilled operators and good compressor mechanics are required for reliable operation. Compressor downtime should be minimal (< 3%).
- There is increased difficulty when lifting low gravity (less than 15°API) crude because of greater friction, gas fingering, and liquid fallback. The cooling effect of gas expansion may further aggravate this problem. Also, the cooling effect will compound any paraffin problem.
- 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.

2.8 Intermittent Gas Lift:

Intermittent gas-lift method for enhancing crude oil recovery is typically used for wells with low productivity to allow build up of oil in the wellbore by lowering the oil column hydrostatic pressure.

- The intermittent gas-lift method typically is used on wells that produce low volumes of fluid (approximately < 150 to 200 B/D), although some systems produce up to 500 B/D. Wells in which intermittent lift is recommended normally have the characteristics of high productivity index (PI) and low bottomhole pressure (BHP) or low PI with high BHP. Intermittent gas lift can be used to replace continuous gas lift on wells that have depleted to low rates or used when gas wells have depleted to low rates and are hindered by liquid loading.
- Gas-lift systems can be classified in another way based on the reuse of injection gas.

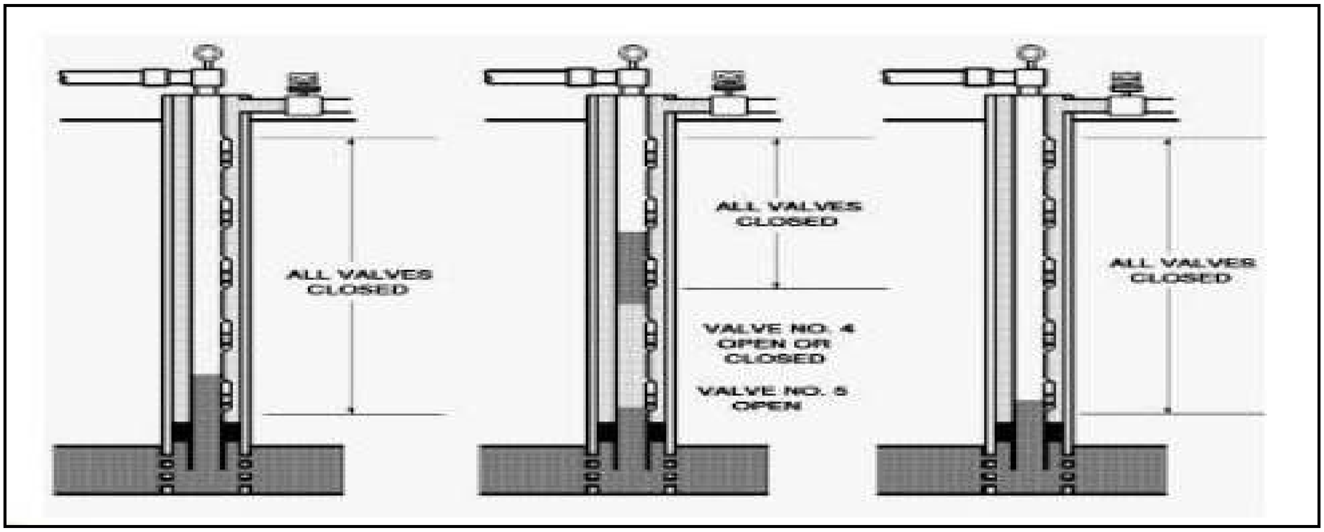


Fig (2.7) intermediate gas lift (Brown KE, 1984).

2.8.1 Plunger gas lift:

Plunger gas lift is a type of intermittent gas lift. In process of intermittent gas lift, plunger is used as a fixed interface between liquid column and lifted gas for sealing to prevent gas channeling and decrease slip loss. Plunger gas lift is mainly suitable in well of low bottom hole pressure and low productivity or high bottom hole pressure and low productivity. Plunger gas lift can also be used for displacing water to produce gas in gas well. Surface device of plunger gas lift is more complicated than other gas lift mode, there is a certain difficulty for management of operation and a larger pressure fluctuation in production is easy to be formed in surface gathering network.

2.8.2 Cavity gas lift:

Cavity gas lift is a closed intermittent gas lift. There is a cavity in lower part of cavity gas lift string. Because capacity of cavity is larger than the capacity of tubing with the same height, therefore, when a certain volumetric liquid is located above the standing valve of cavity gas lift device, its pressure head is obviously lower than the pressure head formed in conventional intermittent gas lift device with the same volumetric liquid, which can decrease the resistance of fluid entering into bottom hole from pay zone to be minimum. Cavity gas lift is a method used for production of depleted low pressure well using gas lift mode and is particularly suitable for low productivity well and low pressure well, high productivity well.

2.8.3 Advantages:

- Intermittent gas lift typically has a significantly lower producing BHP than continuous gas-lift methods.
- It has the ability to handle low volumes of fluid with relatively low production BHPs.

2.8.4 Disadvantages:

- Intermittent gas lift is limited to low volume wells. For example, an 8,000-ft well with 2-in. nominal tubing can seldom be produced at rates of more than 200 B/D with an average producing pressure much below 250 psig.
- The average producing pressure of a conventional intermittent lift system is still relatively high when compared with rod pumping; however, the producing BHP can be reduced by use of chambers. Chambers are particularly suited to high PI, low BHP wells.

- The power efficiency is low. Typically, more gas is used per barrel of produced fluid than with constant flow gas lift. Also, the fallback of a fraction of liquid slugs being lifted by gas flow increases with depth and water cut, making the lift system even more inefficient. However, liquid fallback can be reduced by the use of plungers, where applicable.
- Fluctuations in rate and BHP can be detrimental to wells with sand control. The produced sand may plug the tubing or standing valve. Also, pressure fluctuations in surface facilities cause gas- and fluid-handling problems.
- Intermittent gas lift typically requires frequent adjustments. The lease operator must alter the injection rate and time period routinely to increase the production and keep the lift gas requirement relatively low.

2.9 Selection of gas lift injection:

The main types of gas lift production can be divided into two types: annular space gas injection and tubing production; tubing gas injection and annular space production. The main difference of these two modes is selection of production path. Production path size of annular space production is usually larger than that of tubing production. Generally, tubing gas injection and annular space production is suitable for the well of larger production, or is used in producer with small casing and large pumping rate. When tubing production can fit development of oilfield, usually recommend using annular space gas injection and tubing production mode.

2.10 Field layout and well design:

Consideration of gas lift operations should be a prime factor in sizing the hole for the desired oil well tubular. This is particularly true in offshore wells where all of the downhole gas lift equipment, except the valves, is installed during the initial completion. In on-shore fields, gas lift affects the size and location of gathering lines and production stations. Artificial lift should be considered before a casing program is designed. Casing programs should allow the maximum production rate expected from the well without restrictions. Skimping on casing size can ultimately cost lost production that is many times greater than any savings from smaller pipe and hole size. The same is true in flowline size and length. Production stations should be relatively near the producing wells. In most cases, increasing the size of the flowline does not compensate for the backpressure generated by the added pipe length. Any item of production equipment that increases backpressure at the wellhead, whether it be wellhead chokes, small flowlines, undersized gathering manifolds and separators, or high compressor suction pressure, seriously impacts the operation of a gas lift system.

2.11 Injection-gas pressure:

Choosing a proper injection-gas pressure is critical in a gas lift system design. Several factors may affect the choice of an injection-gas pressure. However, one primary factor stands out above all others. To obtain the maximum benefit from the injected gas, it must be injected as near the producing interval as possible. The injection-gas pressure at depth must be greater than the flowing producing pressure at the same depth. Any compromise with this principle will result in less pressure drawdown and a less efficient operation. High volumes of gas injected in the upper part of the fluid column will not have the same effect as a much smaller volume of gas injected near the producing formation depth because the fluid density is reduced only above the point of gas injection.

Major factors that have an effect on choosing the most economical injection-gas pressure:

Only the basic conditions that must be met to ensure the most efficient injection-gas pressure to maintain operating pressure for a given well have been discussed. A variety of other factors can affect the selection of the most efficient surface injection-gas pressure. These may include:

1. Pressure/volume/temperature (PVT) properties of the crude
2. Water cut of the producing stream
3. Density of the injected gas
4. Wellhead backpressure
5. Pressure rating of the equipment
6. Design of the well facility

Calculating the effect of injection-gas pressures on surface production facilities:

The selection and design of compression equipment and related facilities must be closely considered in gas lift systems because of the high initial cost of compressor horsepower and the fact that this cost usually represents a major portion of the entire project cost. In most instances, the injection-gas pressure required at the wellhead determines the discharge pressure of the compressor. Higher injection-gas pressures increase the discharge pressure requirement of the compressor, which is translated into a related increase in the compressor horsepower required for a given volume of gas. However, if the gas lift system is designed properly, the related decrease in gas volume requirements will result in an improvement in overall operating efficiency.

2.12 Gas volume:

The total injection gas required for a continuous-flow gas lift well may be determined by well-performance prediction techniques. Well-performance calculations are discussed later in this chapter, but they are typically obtained by simultaneously solving the well inflow and well outflow equations. Well inflow, or fluid flow from the reservoir, can be simulated by either the straight line pressure drawdown (PI) or the inflow performance relationship (IPR) methods. Likewise, well outflow, or fluid flow from the reservoir to the surface, is typically predicted by empirical correlations such as those presented by Poettmann and Carpenter, Orkiszewski, Duns and Ross, Hagedorn and Brown, Beggs and Brill, and others. Once typical gas volume requirements for individual wells are determined, totals for the entire field can be calculated.

CHAPTER 3

METHDOLOGY

INTRODUCTION OF PIPESIM:

PIPESIM is built & innovated by Schlumberger, it's a way use to simulate individual well and network models. PIPESIM combines best-in-class science with an unparalleled productivity environment to enable engineers to optimize production systems from the reservoir to the sales point. These release notes describe the most significant enhancements and known limitations.

The PIPESIM steady-state multiphase flow simulator offers complex production and injection networks analysis. the well, pipeline, and flow assurance capabilities are all within a shared common environment, powered by the most rigorous field wide solver.

The solver is suitable for networks of any size and topology, including complex loop structures crossovers .by modeling the entire production or injection system as the network interdependency of wells and surface equipment can be accounted for, and the deliverability of the system can be determined.

PIPESIM network simulation and optimization capabilities enable users to:

1. Design the best well, pipeline, and facilities design.
2. Identify production bottlenecks and constraints.
3. Optimize production from complex networks.
4. Handle multiple system constraints.

5. Quickly identify locations in the system most prone to flow assurance.
6. Issues such as erosion, corrosion, and hydrate formation.
7. Quantify the benefits of adding new wells, compression, pipeline, etc.
8. Determine optimal locations for pumps and compressors.
9. Design and operate water or gas injection networks.
10. Analyze hundreds of variables such as pressure, temperature and flow assurance parameters through Complex flow paths.
11. Evaluate benefits of loops and a crossover to reduce backpressure.
12. Calculate full field deliverability to ensure contractual delivery Rates can be met.
13. Optimize the allocation of lift gas amongst wells.

3.1 Model Design procedures:

In this case study the system was designed by the following procedures:

3.1.1 Collection of inserted Data:

The first step in the design process is to gather information for the application of interest; fluid properties, reservoir parameters and production data from testing reports:

Table (4.1) Parameters

Parameter	Well data
Casing (ID) (in)	7
Casing depth (ft)	7217.848
Tubing(ID) (in)	4.5
Tubing Depth (ft)	3937.008
Initial Reservoir Pressure (psi)	2030.528
Reservoir temperature (˚F)	147.2
Oil gravity (API)	14
Gas specific gravity	0.89
Perforation Depth (ft)	4593.176
GLI Depth (ft)	3937.008
NA Depth (ft)	4593.176

3.1.2 Define the physical component of the model by the following steps:

Step 1: General data

From the workspace screen of pipesim select the option create new network and select well type (production or injection) and well name.

Step 2: Tubular data:

Choose the well description mode (simple or detailed), insert the measured depth and the inside diameter of casing and tubing.

Step 3 : Deviation survey:

Select the survey type (vertical or horizontal) and enter the bottom hole depth.

Step 4: Heat transfer data:

From this window insert the ambient temperature, total measured depth and bottomhole temperature.

Step 5: Completion data:

Select the perforation depth and choose the inflow performance relationship model (well PI) and insert its data (reservoir pressure and temperature, IPR basis (liquid or gas).

Step 6: Surface equipment:

Insert its outlet pressure and temperature and fluid parameters in fluid mode.

(P/T pro Step 7: Run model in pressure / temperature file): To show the natural production of the well.

The node is chosen in the bottomhole; therefore the system is divided into two sections to determine the node pressure:

The inflow to the node:-

$$Pr - \Delta P(resistance) = Pwf$$

The out flow from the node:-

$$Pwh + \Delta P(tubing) = Pwf$$

Effect of water cut:

While water cut is zero there is no effect.

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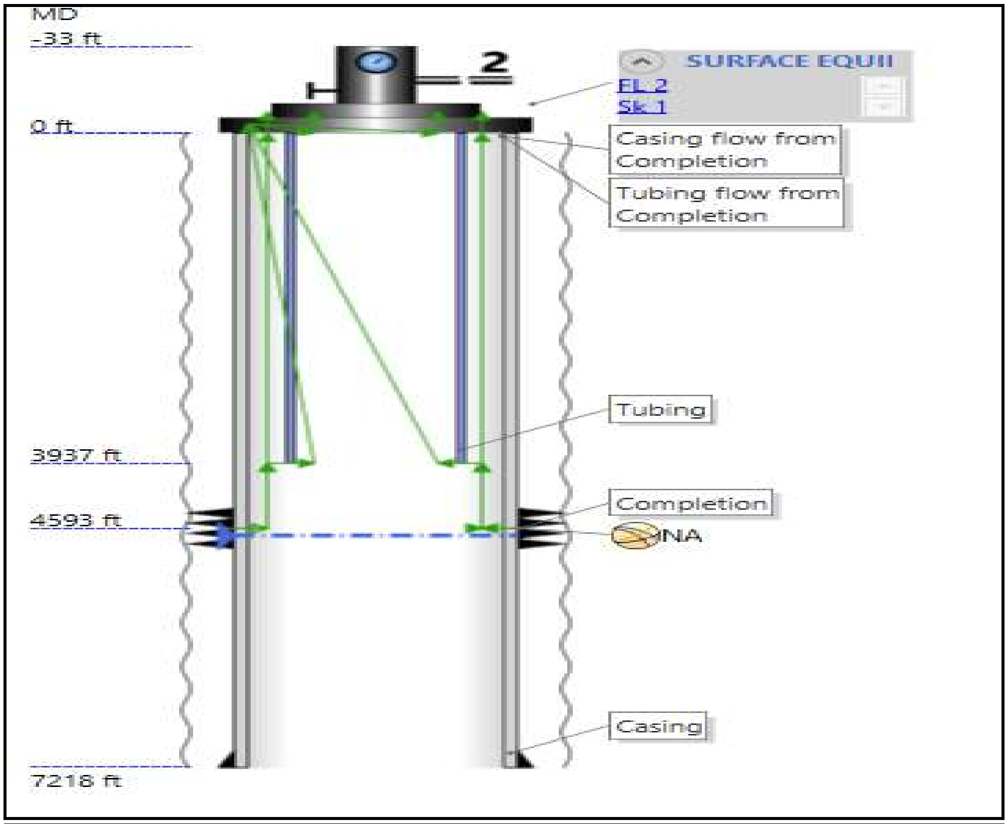

Chapter 4

RESULTS AND RECOMONDATION:

Result and discussion:

Liquid Flowing Viscosity:

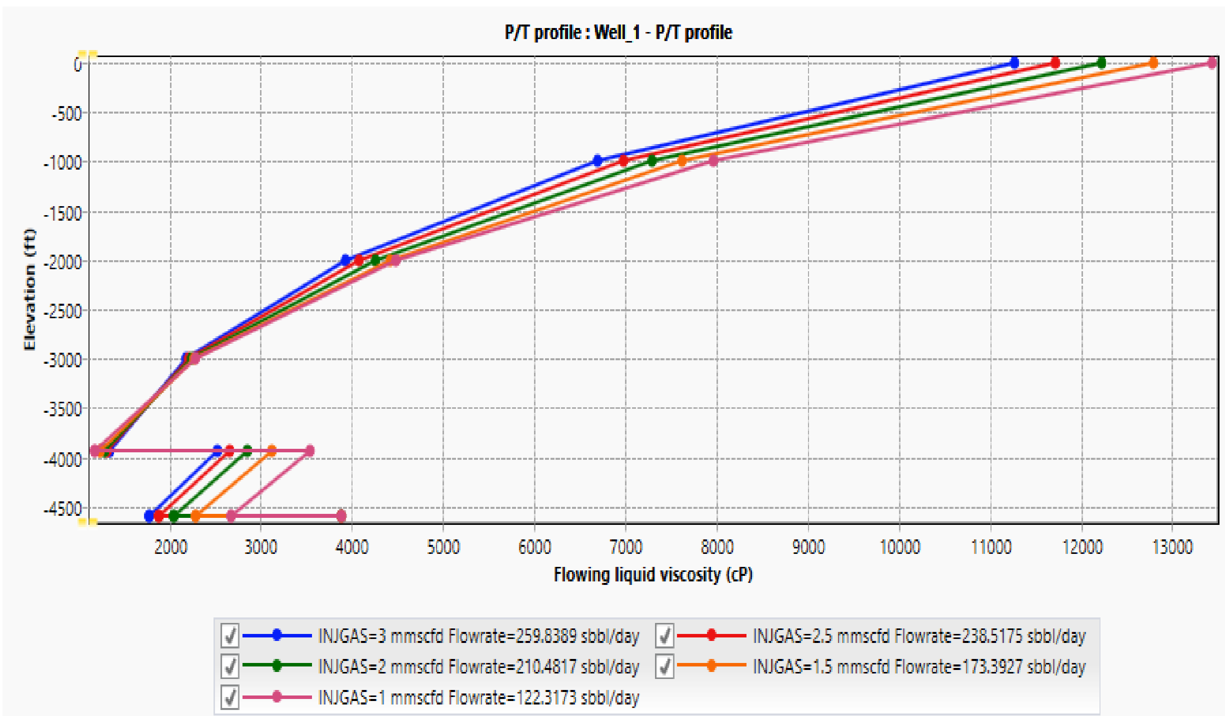

figure (4.1) Liquid flowing viscosity

From fig (4.1) it is clearly showing that the dilution occurs at depth of (4000-4500 ft) this due to the effect of flowing temperature.

Erosional Velocity Rate:

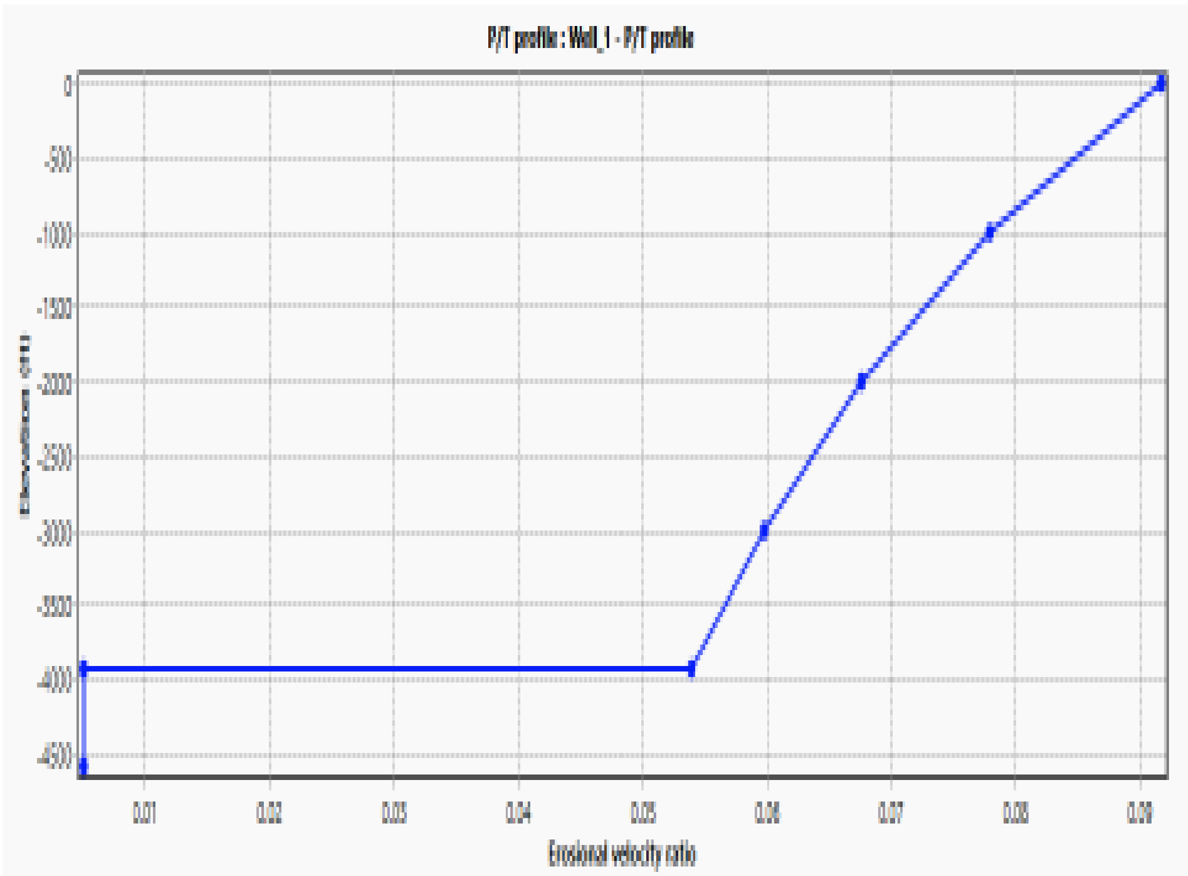

Figure (4.2) Erosional Velocity Rate

The Fig (4.2) confirms that gas lift can be used effectively for heavy oil especially at depth (4000-4500 ft) and depth proper results and erosional velocity ratio must be less than 1.

GLI-Gas Rate vs. Liquid flow rate at outlet:

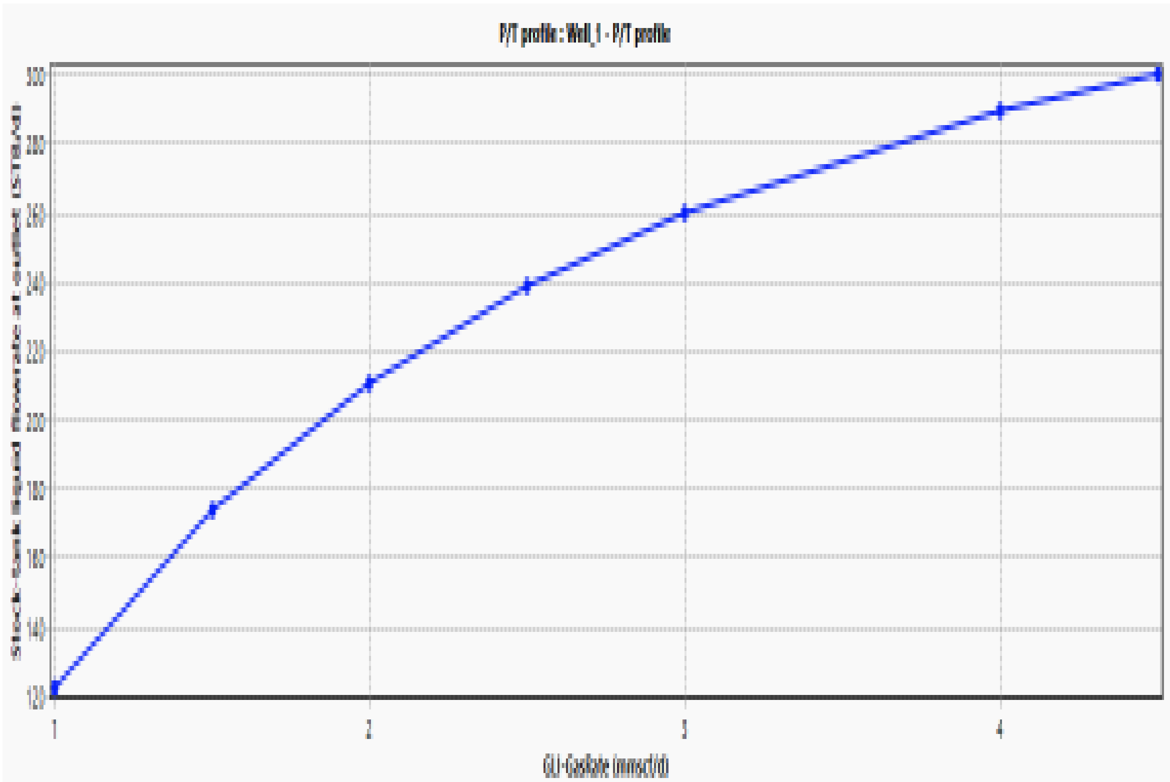

Fig (4.3) GLI-Gas Rate vs. Liquid flow rate

From fig (4.3) it should be noted that the gas bypass will accrue at any injection rate that equals or more than 5 mmscf/day, there for the optimum injection rate ranges between (1) to (4) mmscf/day.

The injection rate (3 mmscf/day) is chosen as the optimum injection rate.

Gas Superficial Velocity:

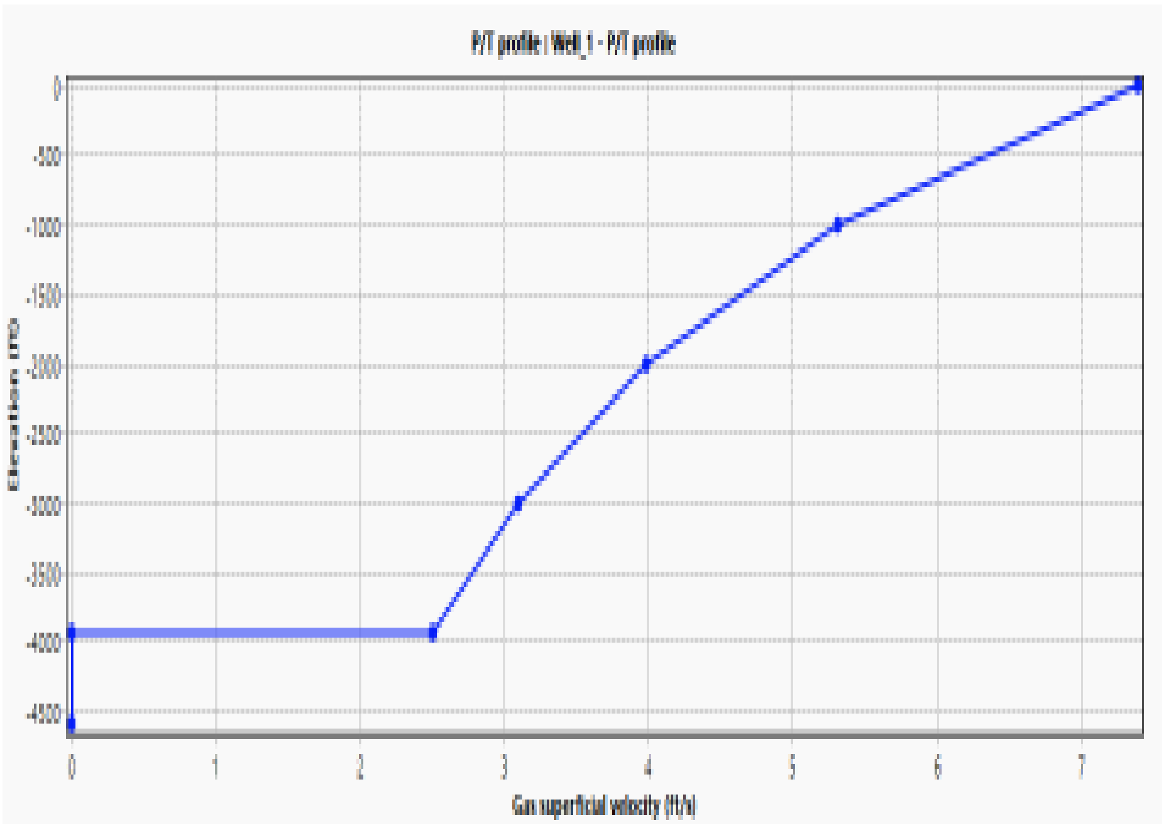

Figure (4.4) Gas Superficial Velocity

Gas Superficial Velocity must be low to ensure that the injected gas is compatible with the crude oil.

As we go to the surface the gas superficial velocity increases due to the effect of temperature.

Elevation vs. Pressure:

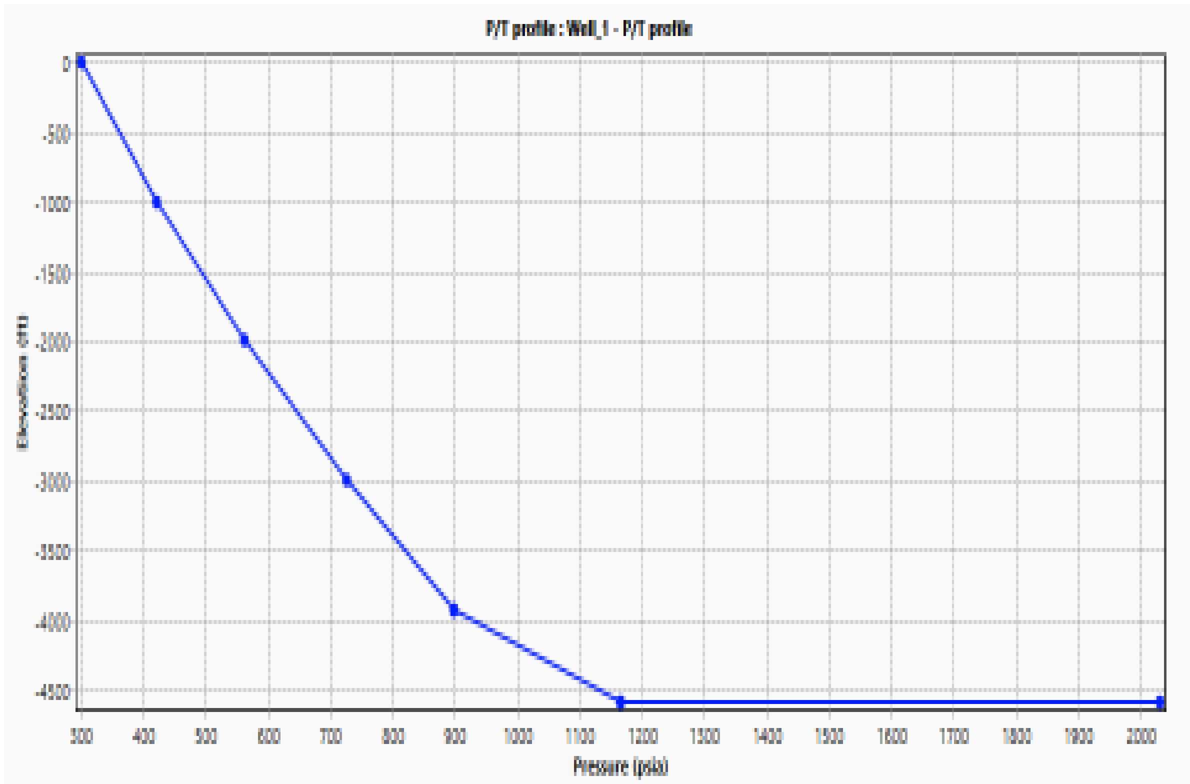

Figure (4.5) Elevation vs. Pressure

The Fig (4.5) shows that the pressure will increase according to the depth increment.

Flowing Liquid Density:

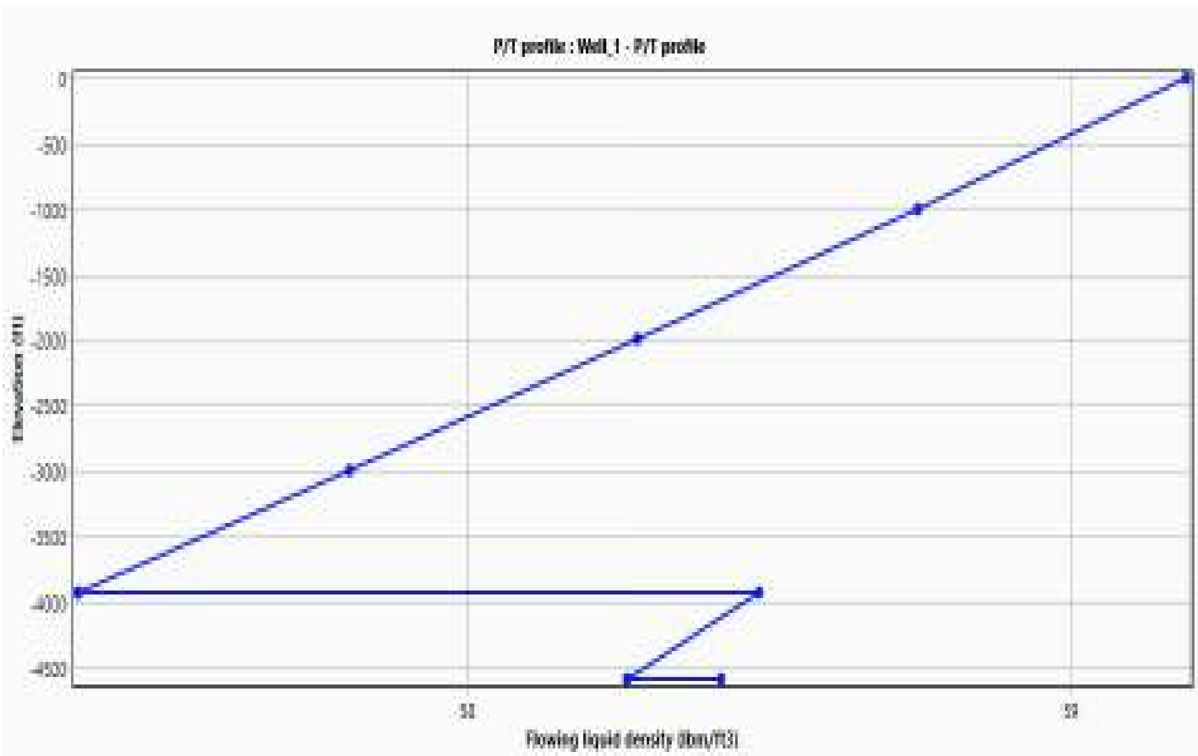

Figure (4.6) Flowing Liquid Density

The fig (4.6) shows that the density of the oil is decreased with small value between (58.5-57) pound / cubic feet.

PVT Diagram for the well:

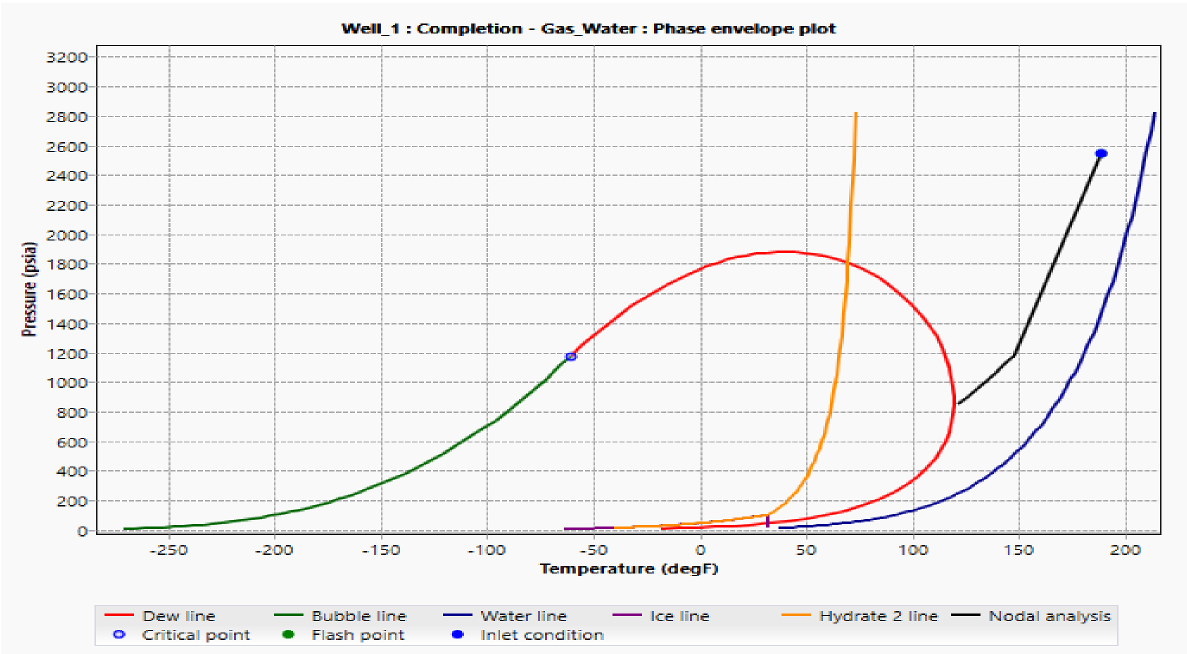

Table (4.1) Liquid Gas Map

Equipment	G-L pattren	case
GLI Tubing	Liquid Undefined Slug	INJGAS=3 mmscfd Flowrate=259.8389 sbbl/day
GLI Tubing	Liquid Undefined Slug	INJGAS=2.5 mmscfd Flowrate=238.5175 sbbl/day
GLI Tubing	Liquid Undefined Slug	INJGAS=2 mmscfd Flowrate=210.4817 sbbl/day
GLI Tubing	Liquid Undefined Slug	INJGAS=1.5 mmscfd Flowrate=173.3927 sbbl/day
GLI Tubing	Liquid Undefined Slug	INJGAS=1 mmscfd Flowrate=122.3173 sbbl/day
GLI Tubing	Liquid Undefined Slug	INJGAS=4 mmscfd Flowrate=289.0516 sbbl/day
GLI Tubing	Liquid Undefined Slug	INJGAS=4.5 mmscfd Flowrate=299.7944 sbbl/day

Chapter 5

Recommendations and conclusion

5.1 Conclusion:

- Gas lift model for Fulla north 66 has been successfully constructed .
- The model has proved that the process is completely effective and economical.
- According to the results the erosion velocity ratio is less than (1) which means the process is safe and no damage expected to happen.
- This study confirms that modeling gas lift design can help to increase the production rate by minimizing the viscosity of oil as a result of the dilution process.

5.2 Recommendations:

- While all the artificial lift methods including gas lift have a problem of sand production especially in Sudanese fields this problem must be considered.
- According to the study the injection rate (4 mmscf/day) causes the optimum production rate, however, (3mmscf/day) is chosen as suitable injection rate for the economical impact due to the huge amount of injected gas between the two injection rates.

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