Design Consideration for Smart In-Situ Gas Lift

by

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CERTIFICATION OF APPROVAL

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Approved by,

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September 2014

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CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

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MOHD HAFIZUDDIN BIN MAHUSIN

ABSTRACT

A smart in-situ gas lift is the latest emerging technology in the oil and gas production. This intelligent system requires the reservoir to have high amount of gas supply either from reservoir's gas cap itself or another gas formation. The aim of this study is to select the design consideration for smart in-situ gas lift. Theoretical analysis, simulation and also field applications have been critically reviewed to notice their effects on the field development and production strategy. Compared to conventional gas lift design, four main design factors have been addressed namely interval control valves (ICV), well selection, valve setting depth and valve opening. To further validate the effectiveness of the smart in-situ gas lift, the design has been applied on a well which is located in L-Field. The application of smart in-situ gas lift show great improvement to the productivity of the well when the natural production rate has increased up to 27% compared to the impact of conventional gas lift on natural production rate which has increased about 11% from natural production rate. Plus, the implementation of smart in-situ gas lift has maximized the production of oil from reservoir that characterize by large gas cap size. This paper generally endorses the fact that in situ gas lift method gives big advantage in extending the well life even at high water cut and reducing the high cost of installing expensive gas lift infrastructures in the conventional gas lift system.

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NOMENCLATURES

A_A = Area of annulus (ft^2)

A_B = Bellows area (ft^2)

A_T =Area of tubing (ft^2)

C_T = Temperature correction factor

D_d = Datum depth

DP_C = Injection pressure difference from surface to valve depth

$D_{v(n)}$ = depth of gas lift valve, n=1, 2, 3…

D_v = Spring differential pressure $(psia)$

g_{gio} = static injection gas pressure at depth gradient, psi/ft

g_{ls} = static load fluid gradient

g_{pfa} = unloading flowing pressure at depth gradient above the point of gas injection

G_s = Dead-liquid unloading gradient

K = Permeability (md)

L_1 = Depth to the first valve (ft)

L_s = Depth of static-fluid level (ft)

L_2 =Distance between valve 1 and valve 2 (ft)

`

P_c = Surface casing injection pressure $(psia)$

P_D = Dome pressure ($psia$)

P_{io} = injection gas pressure at surface, psia

P_{iod} = injection gas pressure at depth, psia

P_{pfD} = pressure of flowing production

PI = Productivity index $(\frac{stb}{d}/psi)$

P_{ko} = surface kick off pressure

P_{pd} = Flowing production pressure at valve depth

Pr = Reservoir pressure $(psia)$

P_s = Back pressure at the tubing well head $(psia)$

P_{sc} = Surface closing pressure of valve

P_T = Tubing pressure $(psia)$

P_{vcd} = Valve closing pressure at depth

P_{vcd} at T_{sc}= Dome pressure at test rack temperature

P_{vod} = Valve opening pressure at depth

P_{vo} = Test rack opening pressure

P_{wf} = Bottom hole flowing pressure $(psia)$

P_{wfu} = unloading wellhead pressure

q_{giu} = maximum unloading injection gas rate, MSCF/D

q = gas flow rate $(MMscf/d)$

q_{lt} = liquid production rate,B/D

R_{glu} = Maximum unloading GLR, scf/STB

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CHAPTER 1

INTRODUCTION

1.1 Background

The production stage plays an important role in producing oil and gas. Once a reservoir starts to produce, it will flows naturally for some period of time. Oil wells that are flow naturally by natural energy are called flowing wells. This natural energy is provided by the pressure differential between reservoir and wellbore to lift the fluids to the surface. In order for the fluid to be lifted from the bottom of a well to the surface facilities, sufficient energy must be required to overcome the friction losses in the system (Osuji, 1994)

When the producing well continuously consumes this energy and reaches at some point, it will encounter pressure drop naturally and the reservoir is depleted when the natural flow started to cease (McAfee, 1961; Tutschulte, 1945). By this time, the reservoir's production tends to be fall from expected volume of oil and gas that can be produced. This happens because there is insufficient pressure differential between the reservoir and wellbore to cause the well to flow (Fotouh, Eissa, & Al Gharabawy, 1999; Takacs, 2005).

One of the types of artificial lift is gas lift. According to Institute (1992), gas lift is the only type of artificial lift that does not use mechanical pump in order to lift the fluid from bottom of a well to the surface. Gas lift always is a preferable choice when a reservoir has readily natural energy stored in it. The availability of gas either as dissolved gas or outsource gas makes the gas lift method as a better choice among other artificial methods. Gas lift is applied in the oil well to lift fluids from well by continuous injecting high pressure gas in tubing string at certain depth in order to

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reduce the density of fluid column and lightening the hydrostatic column to lift the oil to the surface (Kirkpatrick, 1959) .This type of gas lift is called continuous flow gas lift.

The second method of gas lift is called intermittent gas lift where high instantaneous rate of gas is injected to a well to increase the potential energy of the liquid slug (Hernandez et al., 1999). The slug will accumulate at the bottom of the well and the high rate of gas is injected below the slug to cause it to lift to the surface (Pittman, 1982). In contrast to other artificial lift method, gas lift system has flexibility in few aspects such as in production, high gas oil ratio (GOR) and water oil ratio (WOR), high temperature wells and compatibility with sand production makes gas lift as preferable choice among operators around the world (Kumar, 2005).

In this paper, the rare case of gas lift design is discussed briefly which is in-situ gas lift design. In-situ gas lift used gas from its own producing gas zone without injecting the outsource gas into the well (Vasper, 2008). This means that the well will use its own gas from gas cap to lift the oil from producing zone. This is different from the conventional gas lift where predetermined amount of gas is injected from surface into the tubing string to increase the production rate on the depleted or dead well. In-situ gas lift use flow control valve which allows the gas to flow inside the tubing at a controlled flow rate. The oil production in the tubing will commingled with the natural lift gas that is flowing from the gas cap in order to lighten the density of produced fluid and increase the inflow of oil from oil producing zone by lowering the hydrostatic head in the production fluid (Limbachiya et al, 2010).

Furthermore, in situ gas lift method give big advantage in reducing high cost of installing expensive gas lift infrastructure especially at the offshore platform. By reducing the needs of gas lift facilities at the surface, the platform load requirement and space limitation on the platform can be reduced. This in situ gas lift system can be a great achievement in replacing the conventional gas lift system.

1.1.1 Field Description

For this project, L-Field is chosen to apply the application of in-situ gas lift and to study the impact of smart in-situ gas lift implementation on the field's production.

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The field is characterized by large gas cap volume and thick oil zone which are about 750ft thick and 143 ft respectively. The estimated Gas Initially in Place (GIIP) was about 497 BCF and oil production recorded in January 2002 was 43 MMSTB. The reservoir contains light and saturated oil reservoir (45° API) and has low water cut (2%). The porosity and permeability of the reservoir range from 13% to 20% and hundreds mD to ten Darcy respectively at bubble point of 1620 psia (Yaliz, Chapman, & Downie, 2002).

The structure of this field is faulted and rollover anticline on the hanging wall of the Formby Point Fault. The east part of L-Field is tilted fault block while at the western part of the field shows no faulting and gently dips toward other direction. The water oil contact recorded is at 3400 ft TVDSS and gas oil contact is at 3257 ft TVDSS. The reservoir contains dry gas with a gas ratio of 3 stb/mmscf with the gas expansion factor of 125 scf/rcf.

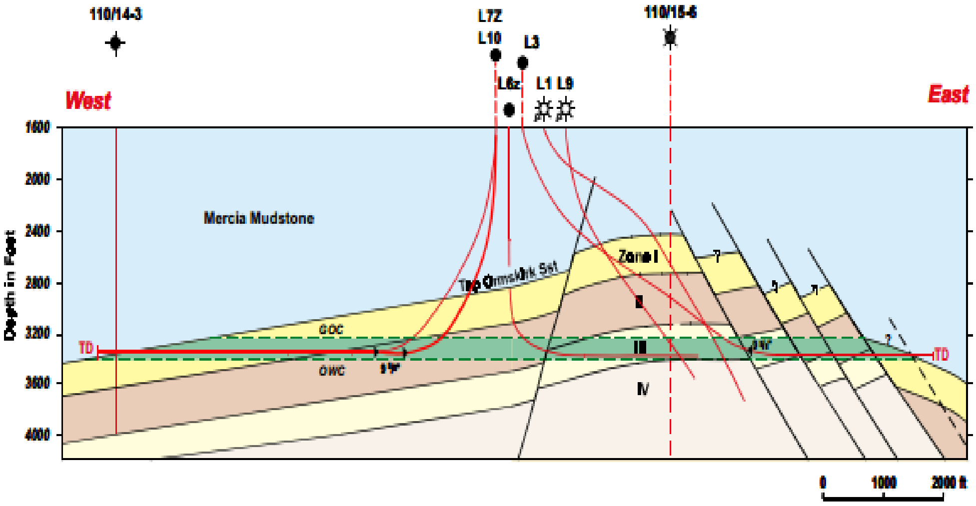

Figure 1: Reservoir cross section of L-Field (Yaliz et al., 2002)

1.2 Problem Statement

1.2.1 Problem Identification

In the oil and gas field development, there is a situation where a potential well is located at far distance from the main processing platform due to some reasons. This

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potential well is characterized by large gas cap size that can be used to supplement the natural energy to increase the production of the well.

The problem arises when the operators want to install facilities such as pipeline for gas transportation or for artificial lift purpose due to space restriction and big investment needed to install those facilities. The main concern is to increase the production of the well by utilizing the gas cap.

A case study was conducted on a well located in L-Field. This well has large gas cap above the oil producing zone .The abundant amount of gas from the gas cap zone can be used as a lift medium in order to increase the oil production in that well.

Unfortunately, this well is isolated from other wells and located far distance from central processing platform. Large amount of moneys need to be invested if the artificial lift facilities want to be installed at the platform of the well. Plus, the space limitation on the platform makes the installation of other surface facilities for artificial lift purpose is quite difficult for the operators.

1.3 Objective and Scope of Study

The objectives in conducting this project are:

- **i.** To identify design consideration for smart in-situ gas lift system
- **ii.** To predict the production and well performance after implementing smart in-situ gas lift system.

The scope of study cover by this project is predicting well performance by doing simulation. The simulation can be done by using Wellflo software in order to analyse the inflow and outflow performance and production of well after in-situ gas lift system. Plus, the depth of injection point, numbers of gas lift valves needed, and the gas flow rate can be estimated by performing this simulation

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CHAPTER 2

LITERATURE REVIEW

Artificial lift will be useful in helping a flowing well to increase the production rate or to help a dead well to start the production again. There are a few methods of artificial lift that are commonly used which are sucker rod or beam pumping, gas lift, electric submersible pumping, and hydraulic pumping (Beggs, 2003). The selection of artificial lift system must depends on several factors such as depth of well, availability of gas, production rate required, hole deviation, etc.

Plus, artificial lift is needed to provide the additional energy and to increase the fluid flow required by well to lift the fluids to the surface (McAfee, 1961). The artificial lift is used to reduce the flowing bottom-hole pressure of the well. When the bottom-hole flowing pressure decreases, the production rate of a well will increase.

In order to sustain the production of oil, artificial lift method plays crucial part in continuously producing the oil as the oil fields mature. Factors such as decreasing in reservoir pressure and increasing water cut cause the natural flow of wells come to the end. By implementing in-situ gas lift, the availability of gas from gas bearing formation can sustain the production of a well by continuously flow the gas at controlled rate. In addition, the high cost of gas handling and gas compression facilities can be cut since the in situ gas lift design does not require those surface facilities. Besides, the life of a well can be extend by operating the in-situ gas lift since this method help high water cut wells to become active wells and start produce the oil (Warren et al., 2009).

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2.1 Artificial Lift

In the early stage of oil productions from a flowing well, the reservoir fluids being lifted from the bottom of a well to the surface by means of natural energy (Takacs, 2005). According to API Gas Lift Manual (1994), the pressure differential of reservoir and producing facilities on the surface cause the oil to be produced from a well. As the time goes and the oil fields become mature, the reservoir pressure will depletes and the well will have insufficient energy to lift the oil to the surface (Fotouh et al., 1999).

The artificial lift methods help to kick off the dead wells to start reproduced again and to increase the fluid flow rate from the bottom of well to the surface (Tutschulte, 1945). By implementing the artificial lift methods, the abandonment well can be produced again. The artificial lift methods need to be choose wisely and depends on many factors which includes reservoir pressure, depth of well, potential of well and type of the produced fluid (Naguib, Shaheen, Bayoumi, & El-Emam, 2000). Improper selection of artificial lift methods can lead to the reduction of production and cause high operating cost. Brown (1982) discussed in details about the design of artificial lift systems.

There are two main considerations in designing the artificial lift system which are the inflow and outflow performance relationship. The inflow performance relationship (IPR) represents the ability of reservoir to push the fluids into the wellbore. The inflow performance of a reservoir can be determined by plotting well production rate against bottom-hole pressure (BHP).

According to Beggs (2003), pressure maintenance or secondary recovery can be the best ways to keep the inflow performance of well high after the well is stimulated. The outflow performance or Vertical Lift Performance (VLP) describes the fluid flow inside the tubing up to surface by considering pressure losses (McAfee, 1961).

The outflow components such as tubing string restriction, safety valve, chokes, tubing string, separator, flowline, flowline restrictions and artificial lift mechanisms need to be considered when doing the analysis and designing of artificial lift system (Brown, 1982).

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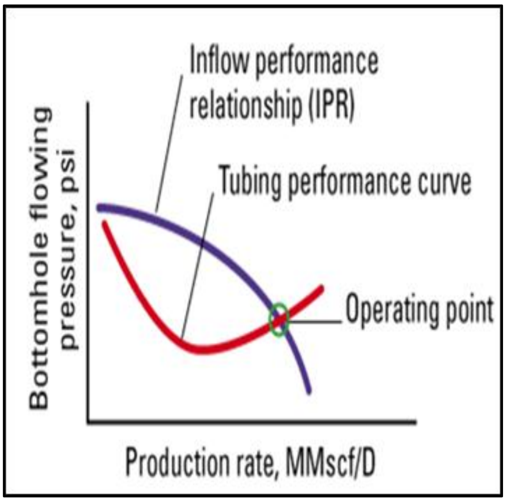

Figure 2: IPR and VLP Curve (Beggs, 2003)

Wan & Chen (1986) discussed the needs of artificial lifting when there is an increasing of water cut on crude output. When the water cut increase, the borehole fluid gradient will increase. The increment of flowing pressure cause the production pressure differential to drop and lead to the declination of crude output. This problem can be solved by reducing the flowing bottom-hole flowing pressure (Pwf) using artificial lift method to increase the producing pressure differential. This statement is supported by Duncan and Beldring (2002) in which increasing water cut can cause the reservoir pressure to cease and the artificial lift is needed to increase fluid production rate.

2.2 Conventional Gas Lift

The production of flowing wells is done by the natural energy from reservoir in the early life of the wells. During that time, the pressure in the wells is highly enough to push the reservoir fluids into the wellbore and rise up to the surface. However, as the well become matures, the reservoir energy depletes and the well needs artificial lift such as gas lift to perform the production process (Fotouh et al., 1999). Pittman (1982) explained that the movement of fluid from the wellbore up to surface facility reduced the potential energy of the well. This phenomenon will reduce the flow rate of fluids and the fluid will be unable to flow to the surface.

Gas lift is one of the artificial lift methods that are widely used in the production technology nowadays (Nishikiori, Redner, Doty, & Schmidt, 1989). About 111

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producing oil wells in the Teak, Samaan and Pouio oil fields of Trinidad applying gas lift method (Laing, 1989). While Cedeno and Ortiz (2007) mentioned that about 4500 wells in Lake Maracaibo are using gas lift method. Conventional gas lift method used outsources gas supply to continuously inject the well. Gas lift method is the extension of natural flow since this method needs the continuous injection of natural gas (Winkler, 1987). The only requirement for the gas lift to be applied on a well is the availability source of injection gas (Blann & Williams, 1984; Kirkpatrick, 1959).

According to Gilbertson, Hover, and Freeman (2013), gas lift being used to increase the production rate in the flowing naturally wells and to produce the oil from the dead wells. Besides, Kirkpatrick (1959) mentioned in his article that the injection of gas on the vertical wellbores help to lift the fluids to the surface. Basically, gas lift is applied by the injection of natural gas through the gas lift mandrel and valves into the tubing at some downhole point. The gas will mixes with the produced fluid and lighten the density of the fluids (Decker, 2007; Duncan & Beldring, 2002; Tutschulte, 1945) . This will reduce the weight of the fluid column and gas will lift the fluids to the surface (Blann & Williams, 1984; Cedeno & Ortiz, 2007). At this point, the bottom-hole flowing pressure (Pwf) will reduce and create required drawdown or pressure differential between the reservoir and wellbore for production of a well. The equation below shows the relationship of productivity index (PI) with pressure drawdown.

$$Q = PI(Pr - Pwf)$$

As the pressure drawdown increases, the production flow rate (Q) increases.

The gas lift method can be applied in two ways which are continuous flow and intermittent gas lift. The first method of gas lift which is continuous gas lift is much more similar to the naturally flowing wells since the gas is injected from surface into the tubing continuously (Duncan & Beldring, 2002). While Kirkpatrick (1959) mentioned in his article that this type of gas lift is suitable for most of flowing wells that have good productivity index (PI) and bottom-hole pressure maintenance. The gas lift valves being set at fixed depth to allow the injection gas to pass through the unloading valve to unload all the kill fluid inside the wellbore and continuously

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injected at operating valve. The injection gas then mixes with the producing fluid to increase gas liquid ratio (GLR).

As gas liquid ratio increases, the hydrostatic pressure gradient in the tubing will decrease and cause reduction on bottom-hole flowing pressure (BHFP) (Blann & Williams, 1984; Mach, Proano, Mukherjee, & Brown, 1983). Beggs (2003) explained that the gas lift valve can be set at any depth and depend on the availability of injection pressure. According to Duncan and Beldring (2002), the higher the pressure injection available, the deeper the injection can be done. For the deeper injection point, less amount of injection gas is required to achieve the same bottom-hole flowing pressure of the well and increase oil production rate (Mukherjee & Brown, 1986).

When the reservoir pressure decline, the typical gas lift method must be replaced with other method since the wells are incapable to continuously producing the oil. Intermittent gas lift is applied by injecting large volume of gas periodically under the formation of a column or slug of liquid at the bottom of the well. The high instantaneous rate of injection causes the slug to move up to the surface (Pittman, 1982). The injection of gas in the intermittent gas lift is done by cycle process in which a new column of liquid needs to build up again at the bottom of well before the gas injection can be done (Takacs, 2005). However, the intermittent gas lift method cause the well to be an abandoned well or other artificial lift must be applied to keep the well producing because the intermittent lift no longer profitable (Hernandez et al., 1999).

2.3 Conventional Gas Lift Design Consideration

The design of gas lift system and installation is an important factor for a well to have an efficient gas lift system. One of the main design consideration that need to be considered when designing gas lift system is effect of gas injection pressure on gas lift well (Decker, 2007; Jones & Brown, 1971; Mukherjee & Brown, 1986; Takacs, 2005).

In addition, valve design and spacing also are the main factors for contributing to the success of gas lift system (Beggs, 2003; Jones & Brown, 1971; Pittman, 1982). Other

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than that, a good gas lift design also must specify the tubing and flowline size to optimize the production of well (Mukherjee & Brown, 1986).

Besides, one of the design consideration that need to pay attention in designing gas lift system is the well performance (Beggs, 2003; Hepguler, Schmidt, Blais, & Doty, 1993). Meanwhile, (Mach et al. (1983); Mukherjee and Brown (1986)) stated that the differential pressure at the gas injection point also is an important design criteria for gas lift system.

Furthermore, the effect of water cut also need to be considered when designing gas lift system (Blann & Williams, 1984; Mukherjee & Brown, 1986).

From the design consideration that has been discussed above, the main consideration for designing gas lift are gas injection pressure, valve spacing, tubing and flowline size, differential pressure at the point of gas injection, well performance, and water cut.

2.3.1 Gas Injection Pressure

The first design consideration is the effect of gas injection pressure on depth (Blann & Williams, 1984; Kanu, Mach, & Brown, 1981; Mach et al., 1983; Mukherjee & Brown, 1986; Redden, Sherman, & Blann, 1974). According to Mukherjee and Brown (1986), the depth of injection can be control by the amount of gas injected.

While Mach et al. (1983) explain that the flowing bottom hole pressure can be reduced by amount of gas to be injected and depth of injection point can be controlled by changing the differential pressure.

The lower the pressure differential will lead to the lower injection point before the bottom-hole injection. As more gas is injected into the well, the density of gas liquid ratio decreases (Tutschulte, 1945). This cause reduction in the weight of the column produced fluid and less volume of gas is needed for the fluid to be lift to the surface (Blann & Williams, 1984).

Somehow, higher pressure of gas need to be injected as the injection depth increase (Pittman, 1982). As more volume of gas is injected into the tubing, the production of oil increases (Lo, 1992). When additional amount of gas is injected beyond

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minimum gradient, flowing bottom hole pressure will increase as a result of friction loss effect (Cedeno & Ortiz, 2007).

However, (Redden et al. (1974); Saputelli (1997)) mentioned that excessive amount volume of gas injection beyond maximum production rate can cause production to be decline.

Factors such as suitable injection gas quantity, pressure of injected gas and depth of gas injection point are very important in order to get optimum production from a gas lift well (Adiyodi, Kumar, & Singh, 1999).

2.3.2 Valve Spacing

Gas lift valve is an important element in the gas lift system in which injected gas from the surface will flow from annulus into the tubing through valve located in mandrel (Beggs, 2003; Cedeno & Ortiz, 2007; Jones & Brown, 1971; Kirkpatrick, 1959; Walker, 1929). Adiyodi et al. (1999) mentioned that the quality of gas lift valve have major impact in achieving maximum efficiency of a gas lift system and to make sure the production of oil and gas run smoothly. The equation below shows the gas lifts design equation for static force balance when the gas lift valve start to open to allow the gas flow.

$$(Pd \times Ab) = [Pt \times Ap + (Ab - Ap)]$$

$(Pd \times Ab)$ represent the closing force while $[Pt \times Ap + (Ab - Ap)]$ represent the opening force. As the valve start to close, the static force balance equation can be referred as below.

$$Pc = Pt = Pd$$

The design of spacing and pressure setting in any gas lift well must be able to lift the liquid downwards from the casing to the predetermined depth. In addition, the design also must allow any valve under producing operation to be open without letting the above valve to open. According to Blann and Williams (1984), very close valve spacing is needed for a well that have low gas injection pressure and high wellhead back pressure due to less amount of pressure differential between produced fluid and injection gas pressure

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The differential pressure is directly proportional to the maximum valve spacing, as the differential pressure increase, the larger the valve spacing is needed (Mach et al., 1983).

According to Kirkpatrick (1959), the position of first valve in the well completion can be determined from equation below when the static-fluid level of the well is near the surface and the well is to unload into the pit.

$$L_1 = P_c/G_s$$

or, if unloading into the separation, the equation will be represented as per below.

$$L_1 = (P_c - P_s)/G_s$$

When the static fluid starts to decrease in the wellbore, the spacing of the first valve can be determined using equation below.

$$L_1 = L_s + \frac{P_c}{[1 + \left(\frac{A_A}{A_T}\right)]} \times G_S$$

The following spacing of valves can be determined by equation below.

$$L_2 = \frac{D_v}{G_s}$$

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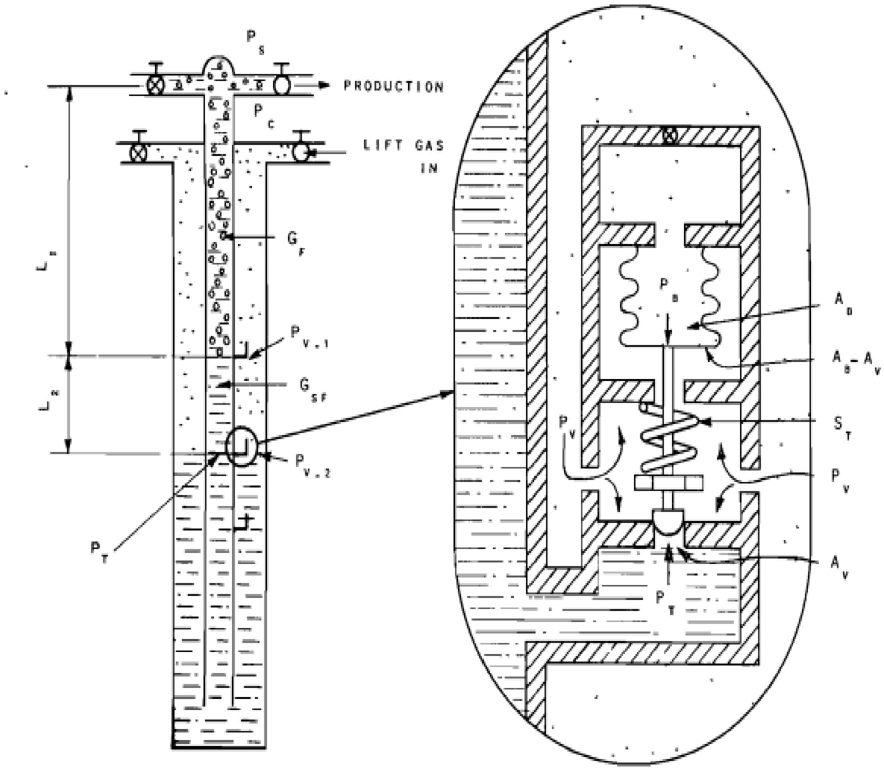

Figure 3: Valve Spacing (Kirkpatrick, 1959)

2.3.3 Tubing and Flowline Size

According to Mukherjee and Brown (1986), sizing of tubing and flowline are important factors in desigining gas lift system and flow well design. While Jones and Brown (1971) explained when larger size of tubing is selected for gas lift design, lower flowing bottom-hole pressure (FBHP) will be created, hence the production of oil increased and the reservoir is expexcted to produce more longer time. This is supported by Gunawan and Dyer (1996) in which suitable selection size of tubing can maximize economic reserve recovery from depleted gas drive reservoir. This can be prove by the equation below.

$$\Delta P = \frac{1}{2}\frac{\rho v^2 l}{D}$$

The production rate increases as the pressure decreases due to increase in size of tubing. Besides, the vertical pressure gradient changes as the tubing size change since there is a different in the liquid removal efficiency and frictional losses

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(Greene, 1983). By plotting an outflow performance curve, the effect of changing tubing size on well performance can be predicted.

The selection of suitable tubing size can prevent the problem of well load up with liquid. This is because too large size of tubing will cause well to load up and dies. Turner, Hubbard, and Dukler (1969) mentioned that there are two methods in identifying when well will load up and dies which are Nodal Analysis and physical model based on reservoir inflow performance and two phase flow correlations. According to Turner et al. (1969), well will not load up with the accumulated liquid and continue to flow if the velocity in the tubing is high enough to lift the liquid to the surface.

The formation of slug at the bottom of well must be consider when selecting the tubing and flowline size since it will reduce gas lift efficiency. This is supported by Slupphaug, Hole, and Bjune (2006) in which slug instabilities can cause operational challenges and need proper reservoir management to handle it. Duncan and Beldring (2002) discussed in their paper about slugging effect in gas lift well and can be solved by injecting more gas into the tubing to increase the velocity of superficial gas and stabilized the fluid flow in flow regime.

2.3.4 Differential Pressure at the Point of Gas Injection

According to Mach et al. (1983), one of the important consideration in completing the continuous flow gas lift design is the differential pressure at the point of gas injection and since production and valve spacing is based on differential pressure. Low pressure differential wells means the well are producing with high production rate.

The differential pressure between casing and tubing indicates the need of additional energy into well and for the condition of gas to be injected into the tubing, the casing pressure must be greater than tubing pressure. (Mukherjee & Brown, 1986).

While Blann and Williams (1984) explained that in order to create a pressure differential, sufficient amount of gas injection pressure must be greater than the flowing production pressure at well depth and zero differential pressure means no injection gas is required.

`

2.3.5 Well Performance

Performance of well is one of the design factors that need to be considered when designing gas lift well (Beggs, 2003). According to Gunawan and Dyer (1996), inflow performance relationship (IPR) is a relationship between gas production rate and bottom-hole flowing pressure. This formulation can be illustrated as equation below:

$$PI = \frac{Q}{(Pr - Pwf)}$$

The equation above only can be used for single phase oil flow (Camacho V & Raghavan, 1989). However Bendakhlia and Aziz (1989) explained that when it comes for multiphase phase flow of oil and gas in the reservoir, the IPR curve can be generated from equation below:

$$\frac{q}{q_{max}} = 1 - 0.2\left(\frac{Pwf}{\bar{P}}\right) - 0.8(\frac{Pwf}{\bar{P}})^2$$

A curve graph will be plotted in the graph of bottom hole pressure versus flow rate. The graph in Figure 4 illustrated the IPR curve plotted from the equation above.

Nodal analysis system is used to determine the gas lift well performance. In order to find optimum gas rate, pwf is used a node location. The inflow and outflow can be described as equation below.

Inflow

$$Pwf = Pr - \Delta Pres$$

Outflow

$$Pwf = Psep + \ \Delta Pflowline + \Delta Ptubing$$

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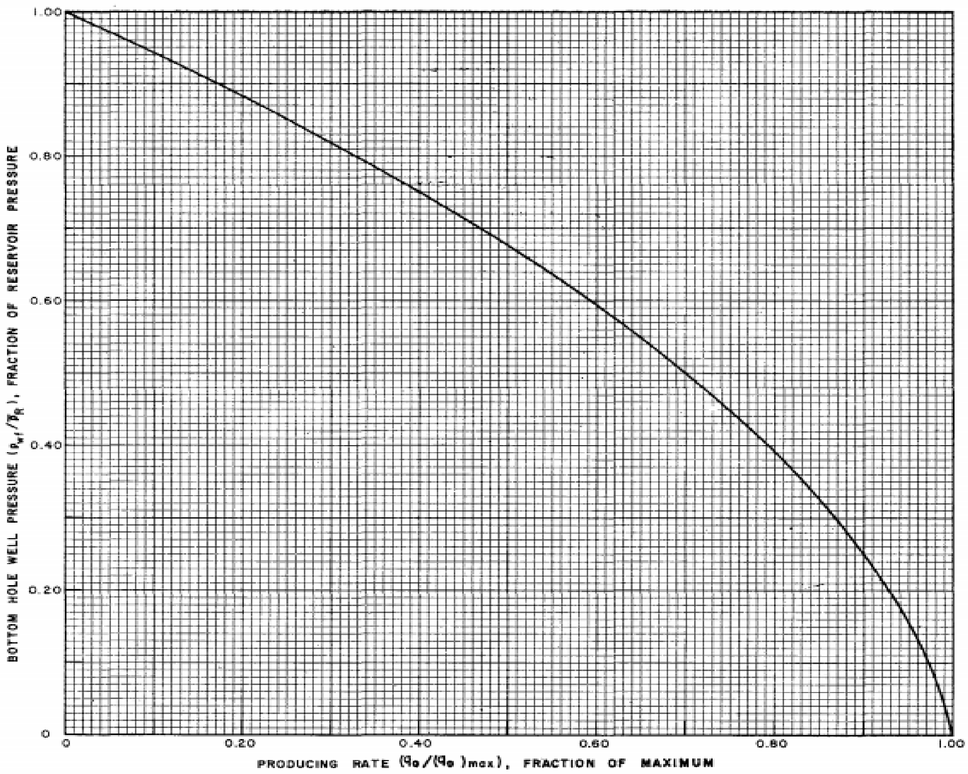

Figure 4: Vogel's IPR Curve (Vogel, 1968)

In addition, Winkler (1987) mentioned that initial installation design of gas lift wells should have reliable inflow well performance in order to determine accurate gas injection point in deep wells. While Decker (2007) stated that inflow and outflow analysis can predict the depth of operating point and production rate of a well. Greene (1983) explained in his article that the performance of gas well can be analysed by referring to the equation below:

$$q = C(Pr^2 - Pwf^2)^n$$

While Gunawan and Dyer (1996) mentioned that the inflow performance curve for pseudo-steady state gas flow can be constructed by using the equation below:

$$q = \frac{0.000703\; k\; h\; (\,Pr^2 - Pwf^2)}{T\; \mu\; z\; [\ln\left(0.472\;\frac{r_e}{r_w}\right) + s + Dq]}$$

According to Vogel (1968), as the reservoir pressure decreases in solution gas drive reservoir, the productivity index (PI) decreases due to higher gas saturation which cause high resistance to oil flow.

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2.3.6 Water Cut

(Cedeno and Ortiz (2007); Kanu et al. (1981)) stressed out the importance of considering water cut when conducting gas lift since water cut can affect gas allocation and total gas liquid ratio.

Blann and Williams (1984) mentioned that the higher amount of gas needed to be injected to create higher pressure drawdown. The higher pressure drawdown needed to overcome the wells that have high water cut since the wells will have small amount of gas to lift the formation oil to the surface.

The depletion of reservoir cause by influx in water drive reservoir increases water cut which lead to the problems such as increase in the density of produced fluid and formation oil-water emulsion due to increase in the viscosity of the produced fluid may occur and will reduce the production rate of well. (Mukherjee & Brown, 1986).

2.4 Smart In-Situ Gas Lift

Smart in-situ gas lift is a gas lift design that fully utilizes the natural energy from gas cap or gas formation to lift oil to the surface (Konopczynski, 2007; Peringod et al., 2011; Vasper, 2008). This means no outsource gas is injected from the surface unlike the conventional gas lift system. This is supported by Al-Otaibi, Al-Gamber, Konopczynski, and Jacob (2006) in which smart well technology application used in Abqaiq field utilize free energy from overlying gas cap in order to produce low productivity and high water cut wells. While Al-Kasim, Synøve, Jakobsen, Tang, and Jalali (2002) mentioned that excessive pressure from gas cap can be fully utilized for smart in-situ gas lift and gas influx is allowed to flow into wellbore for liquid lifting process.

Konopczynski (2007) stated that the smart in-situ gas lift system is a system whereby the gas producing from reservoir is commingled with oil production zone to decrease the hydrostatic pressure of producing fluid and eliminate the effect of water cut to increase the production rate. This statement is supported by Warren et al. (2009) in which high water cut well can still producing oil by implementing smart in-situ gas lift. The primary objective of smart in-situ gas lift is to increase oil production by utilizing the natural energy from the reservoir's gas cap itself (Betancourt, Dahlberg, Hovde, & Jalali, 2002; Peringod et al., 2011; Vasper, 2008).

While Jin, Sommerauer, Rahman, and Yong (2005) explained the concept of smart in-situ gas lift which is source for internal gas lifting can be used from a reservoir that has sufficient amount of energy and reserve. Plus, the life of a well can be extended by eliminating the effect of high water cut. Betancourt et al. (2002) explained the continuous flow of gas into the well can eliminate high water cut.

According to Vasper (2008), flowing gas from gas formation is let to flow into the tubing by flow control valve and the valve's opening can be control at the surface. Application of smart in-situ gas lift have been installed at many wells such as in the Panna field (India), North Sea, Egret field (Brunei), Abqaiq field (Saudi Arabia), Norne field (Norway), Troll oil field (Norway) and Oman (Al-Kasim et al., 2002; Al-Otaibi et al., 2006; Betancourt et al., 2002; Jin et al., 2005; Konopczynski, 2007; Peringod et al., 2011; Warren et al., 2009).

2.5 Smart In-Situ Gas Lift Design Consideration

A smart completion system such as in-situ gas lift was designed to utilize the downhole smart choke and in-situ gas lift valve (Jin et al., 2005). The design of in-situ gas lift is very important in order for the system to be operated successfully. This is supported by Konopczynski (2007) in which the design of in-situ gas lift should takes into account of possible range of uncertainties that is related to reservoir and well performance.

Parameters such as oil and gas zone productivity index, fluid composition of oil and gas zone and reservoir pressure of oil and gas zone should be considered in designing process since these parameters represent of both reservoir uncertainties and expected to change throughout the life of a well (Al-Otaibi et al., 2006; Konopczynski, 2007).

One of the main factors that need to be considered when designing in-situ gas lift is interval control valve (Al-Kasim et al., 2002; Al-Otaibi et al., 2006; Gilbertson et al., 2013; Jin et al., 2005; Warren et al., 2009).

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While (Konopczynski (2007); Peringod et al. (2011); Warren et al. (2009)) discussed in their paper that selection of well can be important factor in designing in-situ gas lift well.

In addition, setting depth for smart in-situ gas lift well also plays a major role in producing a good in-situ gas lift system (Al-Otaibi et al., 2006; Vasper, 2008). Meanwhile, (Al-Kasim et al. (2002); Vasper (2008)) stated that the opening of valve can affect the performance and production rate of in-situ gas lift well.

From the view of many experts, the main design consideration for smart in-situ gas lift system are interval control valves (ICV), well selection, setting depth and valve opening for smart in-situ gas lift well.

2.5.1 Interval Control Valve (ICV)

One of the main considerations for designing smart in-situ gas lift system is in-situ gas lift valve or specifically called interval control valve. In-situ gas lift system is much different from conventional gas lift system in term of flow of gas injection where gas from gas cap will flow into the tubing through a remotely down-hole flow control device (ICV) that is connected by control line at surface (Al-Otaibi et al., 2006). The design of in-situ gas lift system must have hydraulic control line that connects the control line at surface and down-hole operating valve. By having this feature, the gas injection rate can be easily control by hydraulic or electric activation or both of the combinations (Betancourt et al., 2002).

Interval control valve (ICV) is highlighted as one of the important design consideration for in-situ gas lift since ICV will be a medium to allow the fluid or gases to communicate between the production tubing and annulus inside the wellbore (Shaw, 2011). This ICV can be in different shapes and designs such as ball valve, sliding sleeve and can be offset which looks similar to side pocket mandreal.

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Figure 5: Interval Control Valve (Youl, Harkomoyo, & Finley, 2010)

The ICV is designed to adapt to the changes of reservoir condition, pressure and temperature. Plus, the ICV have special ability to handle condensate, water and small particles that are produced in the producing fluids which come from the formation (Rahman, Allen, & Bhat, 2012).

The ICV or downhole choke which is used to control the flow at the bore or targeted producing zone has the sensors (pressure and temperature) for data acquisition purposes (Davies & Ebadi, 2006).

For the number of valve, it may be varies depending on flow selection either discrete or continuous flow that is determined at the flow control system. Continuous flow may have infinite position and numbers of valves, while discrete flow signifies the fixed numbers of valves ranging from 6-10 valves needed in the in-situ gas lift system (Betancourt et al., 2002).

2.5.2 Well Selection

Besides, the good selection of well for the in-situ gas lift implementation can sustain the smart in-situ gas lift well. According to Peringod et al. (2011), the existence of continuously gas injection can be a good selection for in-situ gas lift well.

While Konopczynski (2007) stated there are three condition for a well to be completed with in-situ gas lift which includes the pressure of gas reservoir must higher than the hydrostatic pressure of the column of fluid in the tubing, gas reservoir

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must have high production rate and the volume of gas reserve must be large enough to maintain the productivity of the well though different producing conditions.

Other than that, a reservoir with small producing oil zones, having a gas cap on top of oil layer and equipped with aquifer layer underneath of oil layer can be regarded as a natural candidate for implementation of in-situ gas lift system. In addition, the in-situ gas lift also can be applied to the depleted reservoirs that have some access for source of gas from nearest well within the reservoirs (A.K., 2010).

One of the type of well that can be considered to implement with in-situ gas lift system is high water cut well since the well need some sort of energy which is gas from gas producing zone to achieve the production rate required (Betancourt et al., 2002).

According to Warren et al. (2009), the in-situ gas lift performance can be represented by the equation below:

From the oil zone to the injection point:

$$P_{inj} = P_{wf,oil} - \Delta P_{Friction,oil} - \Delta P_{Hydrostatic,oil}$$

From the gas zone to the injection point:

$$P_{inj} = P_{wf,gas} - \Delta P_{Friction,gas\ annulus} - \Delta P_{Hydrostatic,gas\ annulus} - \Delta P_{Orifice}$$

From surface to the injection point:

$$P_{inj} = WHP + \Delta P_{Friction,gas\ column} + P_{Hydrostatic,gas\ column}$$

For $P_{wf,oil}$, Vogel equation is used to represent the oil rate that can be produced from the reservoir:

$$Q_{oil} = Q_{max,oil}\,(1 - 0.2\left(\frac{P_{wf,oil}}{P_{e,oil}}\right) - 0.8\left(\frac{P_{wf,oil}}{P_{e,oil}}\right)^2$$

For $P_{wf,gas}$,back pressure equation is used to represent gas rate that can be produced from the reservoir:

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$$Q_{gas} = Q_{max,gas}\,(1 - \left(\frac{P_{wf,gas}}{P_{e,gas}}\right)^2)^{0.5}$$

2.5.3 Setting Depth for Smart In-Situ Gas Lift Valve

The concept of pressure differential on the ICV makes the fluid column to be unloaded from the wellbore by allowing sufficient amount of gas to pass through the valve during static condition. In order to kick off the well from a static condition, a large amount of pressure differential such as 200 psi needed by locating the ICV at 500ft above the oil column (Al-Qahtani, Warren, Al-Shahri, & Muhaish, 2009).

According to Davies and Ebadi (2006), the ICV should be placed on top or bottom of the oil zone if the reservoir produced under gas cap drive mechanism. For the vertical well producing from depletion drive mechanism, the valve should be placed in top of the reservoir. The higher number of ICV installed will create better control and reduce of loss in oil zone when other valve was closed. The ICV also best to be placed at the region of high permeability thickness and the division of zones for ICV placement shall be equal to reduce uncertainties.

For the conventional gas lift, gas lift mandrel will give some limitation for setting depth of gas lift valve such as the maximum setting angles of conventional gas lift valve cannot exceed 60°. This is different from smart in-situ gas lift system in which the ICV can be set at deepest point of injection and not limited to any installation angle or trajectory angle, so that the production can be fully optimized (Youl et al., 2010).

The determination of valve setting depth for smart in-situ gas lift is quite similar to the conventional gas lift and can be determined from following equation:

To find the maximum unloading GLR,

$$R_{glu} = \frac{q_{giu}}{q_{lt}}$$

To calculate unloading flowing pressure at depth gradient above the point of gas injection,

$$g_{pfa} = \frac{P_{pfD} - P_{wfu}}{D_d}$$

`

In order to calculate the static injection gas pressure at lower end of production fluid,

$$g_{gio} = \frac{P_{iod} - P_{io}}{D_d}$$

To calculate depth of gas lift valve,

$$D_{v(n)} = \frac{P_{ko-}P_{whu}}{g_{ls}}$$

Besides, the valve should be located between the two packers because the zones of oil and gas must be isolated (Al-Otaibi et al., 2006). This valve also is positioned at the zones that capable for gas breakthrough, so that the gas from gas cap can be easily reached and supplied into the production tubing (Rahman et al., 2012).

2.5.4 Valve Opening

The design of in-situ gas lift valve must have optimum slot width and must be small enough to prevent from backflow of high pressure gas into oil zone and large enough to have maximum gas flowing into production tubing (Al-Kasim et al., 2002; Vasper, 2008).

The ICV can be divided into three types of control which are two position valve either open or close, infinitely variable valves and multiple step valve. This valve will be operated based on the nature of the reservoir which represented by choke application (Davies & Ebadi, 2006).

Meanwhile Warren et al. (2009) mentioned that ICV have various setting that can control gas production which related to the gas trim application and the opening of ICV is controlled by a shifting piston. Other than that, ICV needs to have check valve in order to prevent the back flow of fluid into the annulus (Jin et al., 2005).

The main principle to operate the ICV is pressure in which metal-to-metal seal will be unlocked by minimum pressure differential of 250 psi to open up the ICV at desired opening and it can be closed by applying pressure on the closed line (Youl et al., 2010).

The injection gas pressure can be determined by equation below:

$$P_{ioD(n)} = P_{io} + g_{gio}[D_{v(n)}]$$

`

In case of gas coning or gas breakthrough, the well is said to be uneconomical since the gas influx will occur in the well and oil production start to decline. Somehow, the ICV can be used in efficient way to handle this problem by controlling the opening of the valve, so that the gas coning problem can be used to optimize the reservoir's production (Leemhuis, Belfroid, & Alberts, 2007).

2.6 Application of Smart In-Situ Gas Lift

Conventional gas lift and in-situ gas lift has much difference in term of its applications and designs. From Figure 4, in term of source of gas, typical gas lift used outsource gas injected from the surface into the unloading and operating valve located in side pocket mandrel. While in-situ gas lift used gas from gas cap injected through interval control valve (ICV). The opening of ICV can be controlled at the surface to avoid from reservoir pressure depletion.

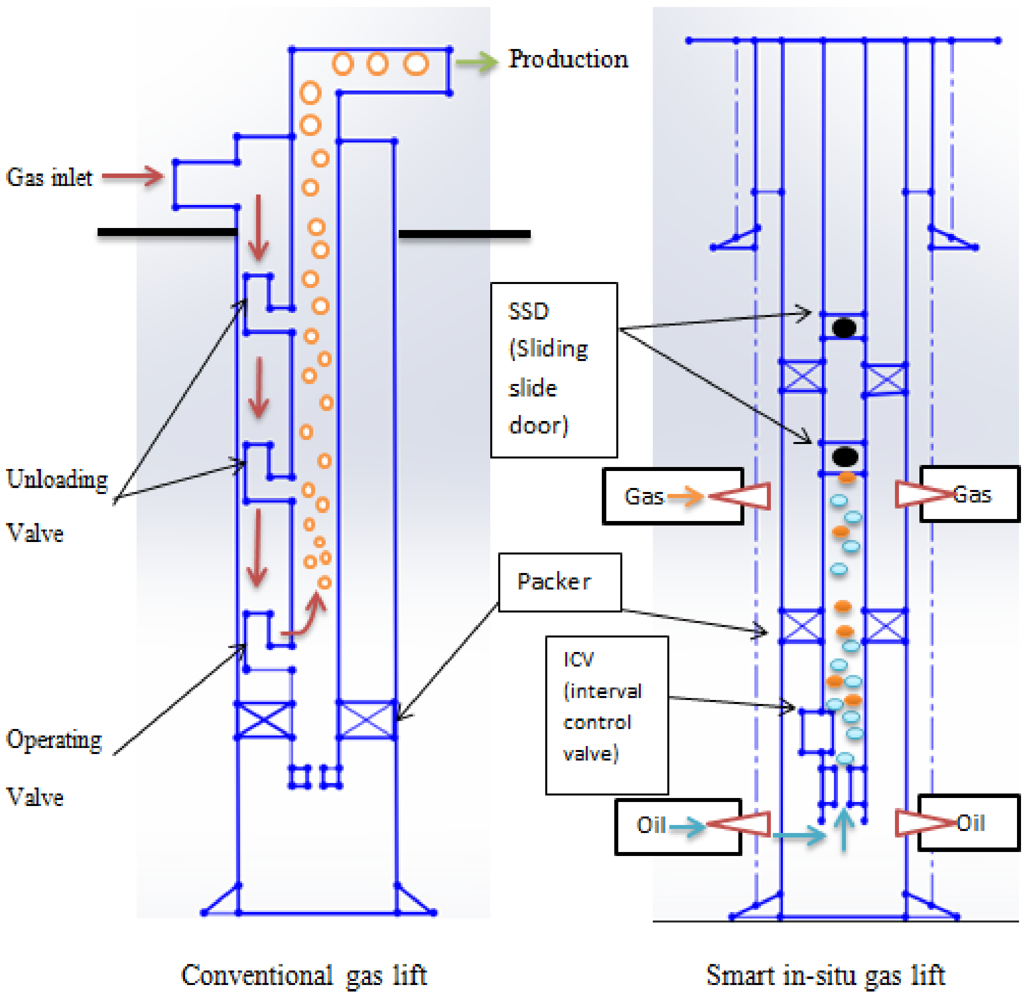

Figure 6: Example of conventional gas lift and smart in-situ gas lift system

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The application of in-situ gas lift gives various advantages to the oil and gas industry. According to Al-Kasim et al. (2002), application of in-situ gas lift can save 3-4 rig days and increase liquid production rates. Plus, in-situ gas lift design reduces the platform load requirement and replaces the conventional gas lift equipment with much more simple setup, thus reducing the operating cost (Al-Otaibi et al., 2006; Vasper, 2008). By using this method, the capital expenditure (CAPEX) can be reduced and prove to be a cost effective artificial (Konopczynski, 2007; Peringod et al., 2011).

In economic point of view, Jin et al. (2005) mentioned that by having a smart technology like in-situ gas lift, the liquid recovery can be maximized by producing from small oil rim. In addition, in-situ gas lift prove to be a smart system which can extend the life of a well by allowing the continuous production from a high water cut well (Warren et al., 2009).

(Peringod et al. (2011)) also highlighted the advantages of using in-situ gas lift which includes stability of production rate, less time taken for a well to start-up after plant shutdown, superior well integrity and reduction of footprint. The comparison between the conventional gas lift and in-situ gas lift application can be summarized in Table 1.

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Table 1: Comparison between conventional gas lift and smart in-situ gas lift

Criteria	Conventional Gas Lift	Smart In-Situ Gas Lift
Economic	High cost and maintenance of gas compression facilities, gas transport pipeline and artificial lift infrastructure	Eliminate the cost of gas compression facilities and gas transport pipeline and
	High capital expenditure (CAPEX) and operating expenditure (OPEX)	Low capital expenditure (CAPEX) and operating expenditure (OPEX)
	Installation of conventional gas lift infrastructure takes longer time	Installation in-situ gas lift save 3-4 days of rig time
Design	Require outsource gas to be injected from surface	Use natural energy from gas cap or gas producing zone
	Need annular safety valve in gas lift system	Eliminate the need of safety annular valve
	Valve need to take out from downhole for resizing purpose	Flow area or opening of valve can be controlled at surface
	Required lot of well intervention	Less well intervention required

CHAPTER 3

METHODOLOGY

3.1 Gantt Chart

Table 2 : Gantt chart (FYP1)

Activities	Week No.													
	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Selection of Project Topic														
Introduction -Identify the problem & objectives						●								
Literature Review -Conventional gas lift -In-situ gas lift							●							
Submission of Extended Proposal								●						
Proposal Defence									●					
Simulation (Wellflo)												●		
Submission of Interim Draft Report													●	
Submission of Interim Report														●

Table 3: Key milestone (FYP 1)

KEY MILESTONE	
Week 6	Completing the introduction part
Week 7	Completing writing methodology
Week 8	Submission of extended proposal
Week 9	Proposal defence presentation
Week 12	Data collection and start doing simulation
Week 13	Submit the draft for interim report
Week 14	Submit interim report

Table 4: Gantt chart (FYP 2)

Activities	Week No.														
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Conduct Simulation in Wellflo					●										
Completion of Data Analysis - Analyse the result						●									
Submission of Progress Report							●								
Writing Draft for Final Report									●						
Pre-SEDEX										●					
Submission of Draft Final Report											●				
Submission of Dissertation (Soft bound)												●			
Submission of Technical Paper													●		
Viva														●	
Submission of Project Dissertation (Hard Bound)															●

Table 5: Key milestone (FYP 2)

KEY MILESTONE	
Week 5	Completing simulation work by using Wellflo
Week 6	Complete the data analysis obtained from simulation
Week 7	Submission progress report
Week 9	Completing draft for final report
Week 10	Preparation for Pre-SEDEX
Week 11	Submission of draft final report
Week 12	Submission of dissertation (soft bound)
Week 12	Submission of technical paper
Week 14	Completing Viva
Week 15	Submission of project dissertation (Hard bound)

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3.2 Flow of Process

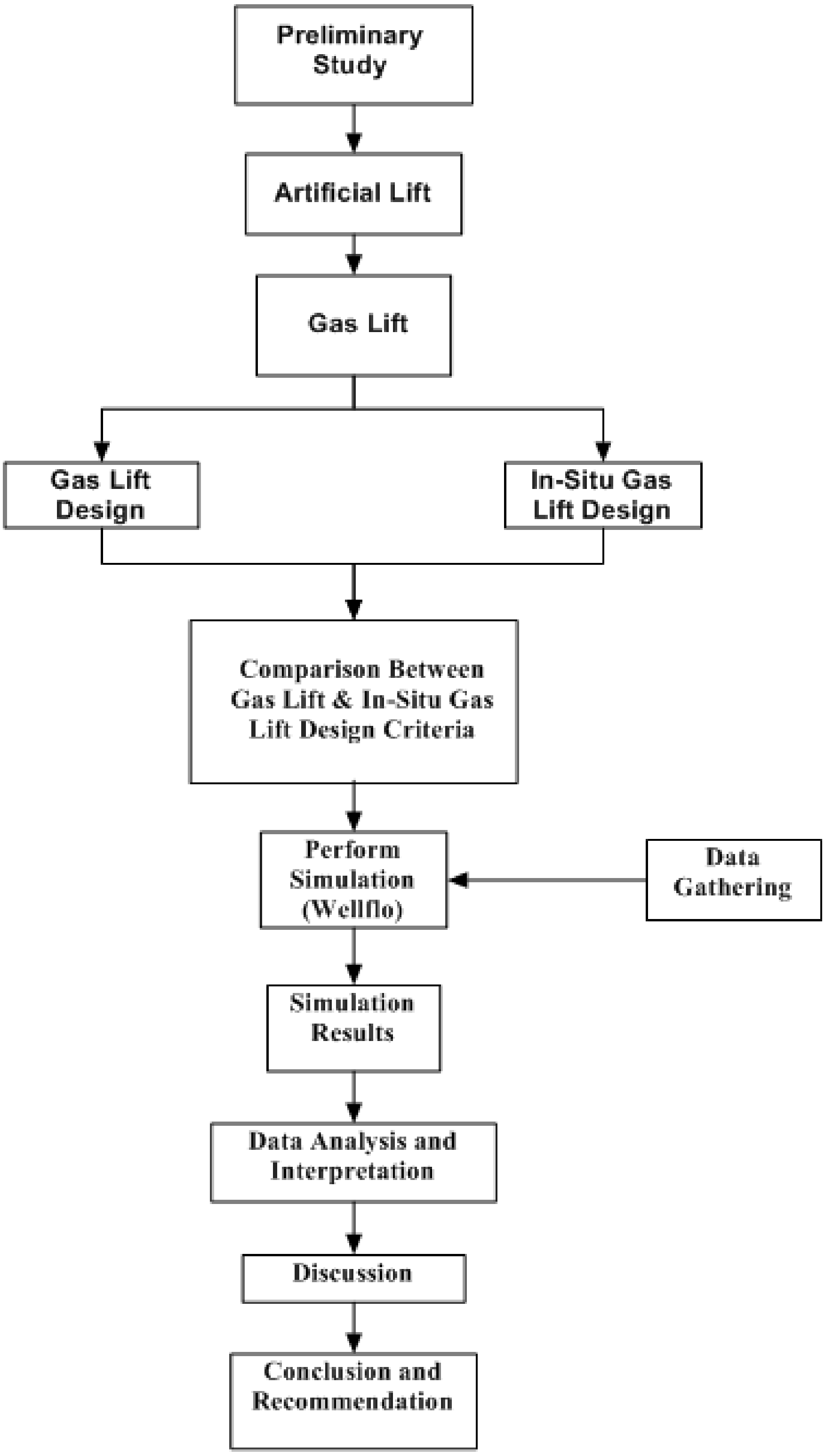

Figure 7: Flow of Process

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The flow of process for this project can be divided into three main phases which are preliminary study, simulation work and discussion of results.

3.2.1 Preliminary Study

In this part, the project started by focusing on the project planning and literature review about the topic which includes the understanding the concept of artificial lift, gas lift and in-situ gas lift. Plus, selection of design criteria for gas lift and in-situ gas lifts also being studied and shortlisted in the report. From this point, the comparison of the design for both of gas lift and in-situ gas lift are drawn to get more understanding on both design considerations. The main interest of this research will be the determination of design consideration for in-situ gas lift and prediction of well performance and production evaluation after performing in-situ gas lift system.

3.2.2 Simulation Work

After that, the work project continues with the gathering set of data for simulation purpose. The Wellflo software is used for modelling and simulation by using Nodal analysis method. By using this software, production optimization and forecasting of well performance can be done. In order to perform in-situ gas lift design in Wellflo, a model must be built and perform diagnostic analysis. Plus, the depth of injection point, numbers of gas lift valves needed, and the gas flow rate can be estimated by performing this simulation.

The in-situ gas lift well can be modelled in the software by specifying the components such as gas lift valve, tubing size, etc. The software will provide all gas lift calculation after the sensitivity variables such as amount of gas injection being inserted in the software. Once the in-situ gas lift model has been designed and inserted with real data, Wellflo can accurately analyse the inflow performance, predict the optimum injection point and injection pressure needed for gas lift system.

The set of data needed for simulation includes well data, fluid parameters, PVT data, inflow parameters, gas lift data, production information and test data.

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3.2.3 Result and discussion

By performing simulation using Wellflo, the design consideration of smart in-situ gas lift system can be applied in the software. From this application, the results obtained in the can proved that all the design consideration listed for smart in-situ gas lift system as discussed in the literature review are true and the production of the well is expected to increase.

From the result obtained using software, the comparison and discussion will be made based on three types of well conditions which are natural flow well, conventional gas lift well and smart in-situ gas lift well. From this comparison study, the analysis of smart in-situ gas lift well to the normal well and conventional gas lift well can be made clearly.

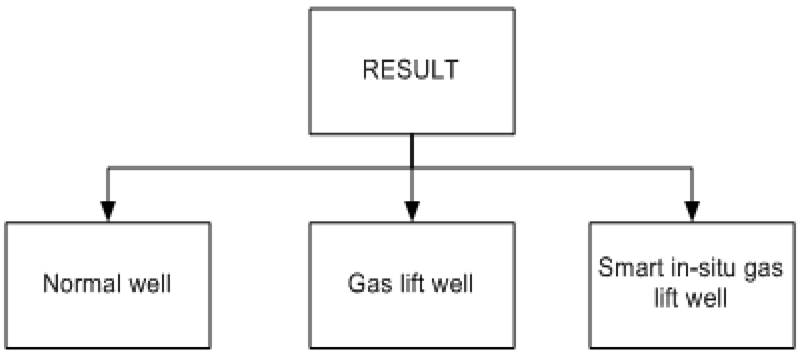

Figure 8: Flow of result

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CHAPTER 4

RESULT AND DISCUSSION

After done with simulation work, the results obtained are divided into several main components which includes of inflow/outflow performance curve, gas lift design and smart in-situ gas lift design.

4.1 Inflow/ Outflow Performance Relationship

Vogel was chosen as IPR model because the reservoir is classified as saturated reservoir since reservoir pressure is below bubble point pressure. As shown by vogel's IPR plot in figure 10, the productivity index recorded for this well was 8.5 STB/d/psi with absolute open flow (AOF) of 7486.4 STB/d.

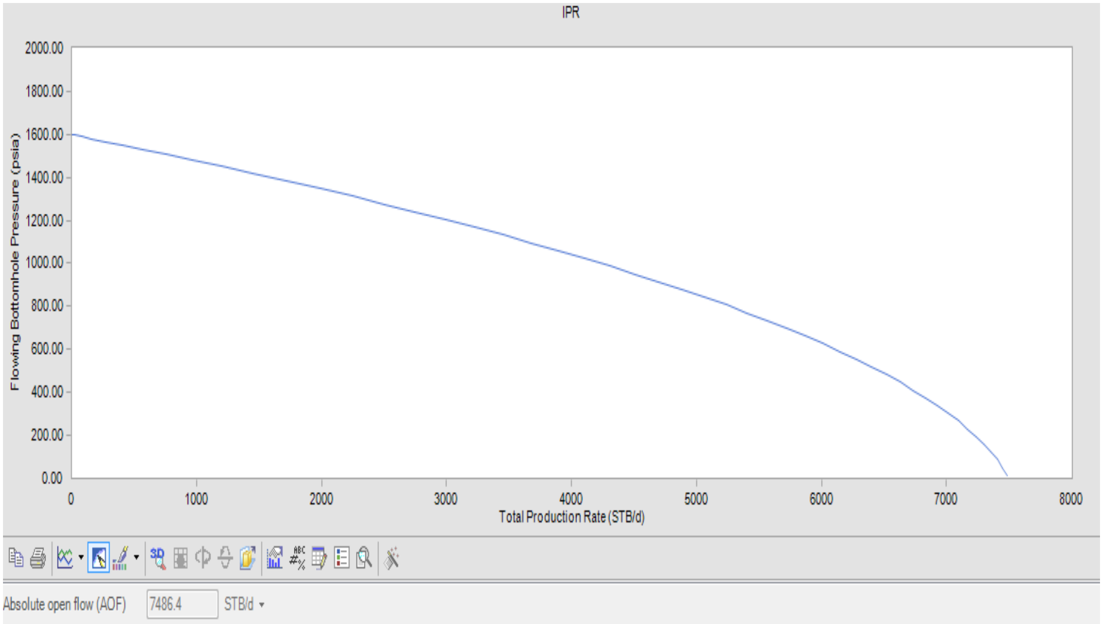

Figure 9: Vogel's IPR curve

The simulation for three different cases was done in Wellflo. The first case/ base case represented the natural flow well, the second case represented the well with

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conventional gas lift and the third case represented the well with smart in-situ gas lift. The optimum tubing size of 3.5 inch and optimum gas injection rate of 2.01 MMSCF/d were selected to be used for that well.

For the base case, the performance of the well without installing any artificial lift or produce naturally was well described by the plot of inflow and outflow performance curve in figure 10. The well was capable to produce liquid rate of 3974 STB/d with oil rate of 3895 STB/d and formation gas rate of 2.53 MMSCF/d. Meanwhile, the produced GOR recorded was 650 SCF/STB. However, the production rate depleted as the reservoir pressure decrease with time.

From figure 10, the operating point of the well can be seen at the intersection between the inflow performance relationship (IPR) curve and vertical lift performance (VLP) curve where the operating pressure was 1080 psia and the operating rate was 3780 STB/d.

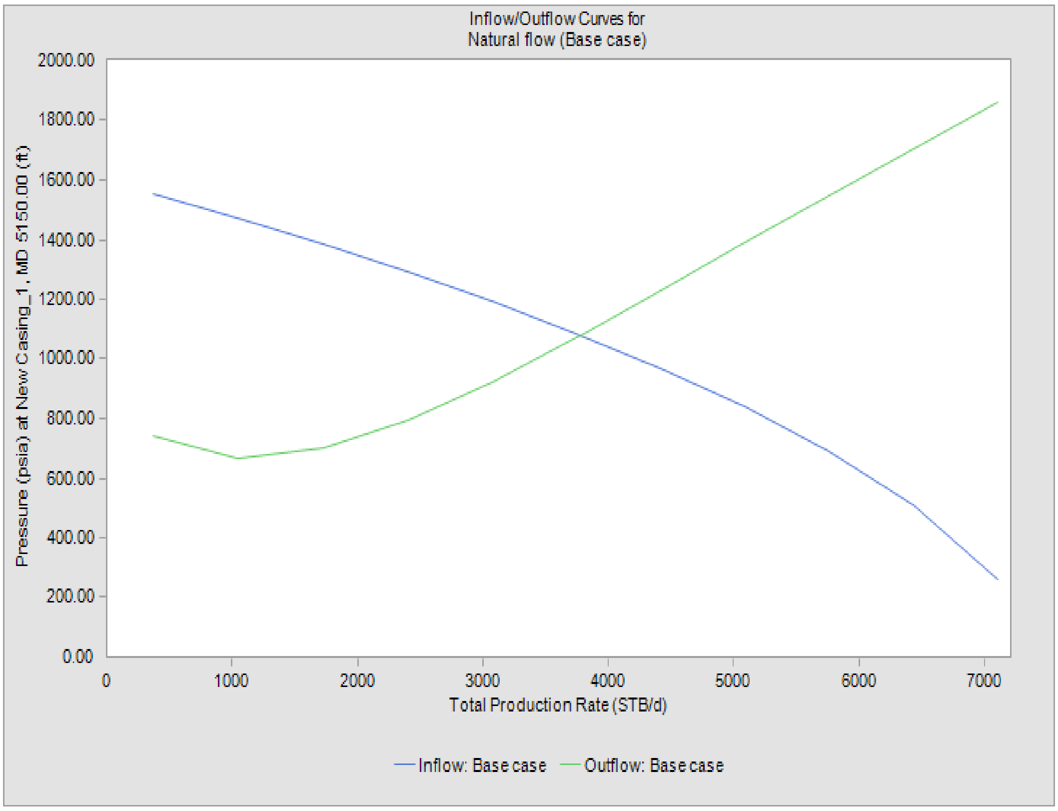

Figure 10: Inflow/outflow performance curve for naturally flowing well

The second case was represented by figure11, by installing the conventional gas lift, the oil production rate of this well increased to 4326 STB/d by injecting gas at rate of

2.01 MMSCF/d. The injection gas rate has reduced the fluid average density, so that the available reservoir energy can cause inflow and ease the process of lifting oil to the surface.

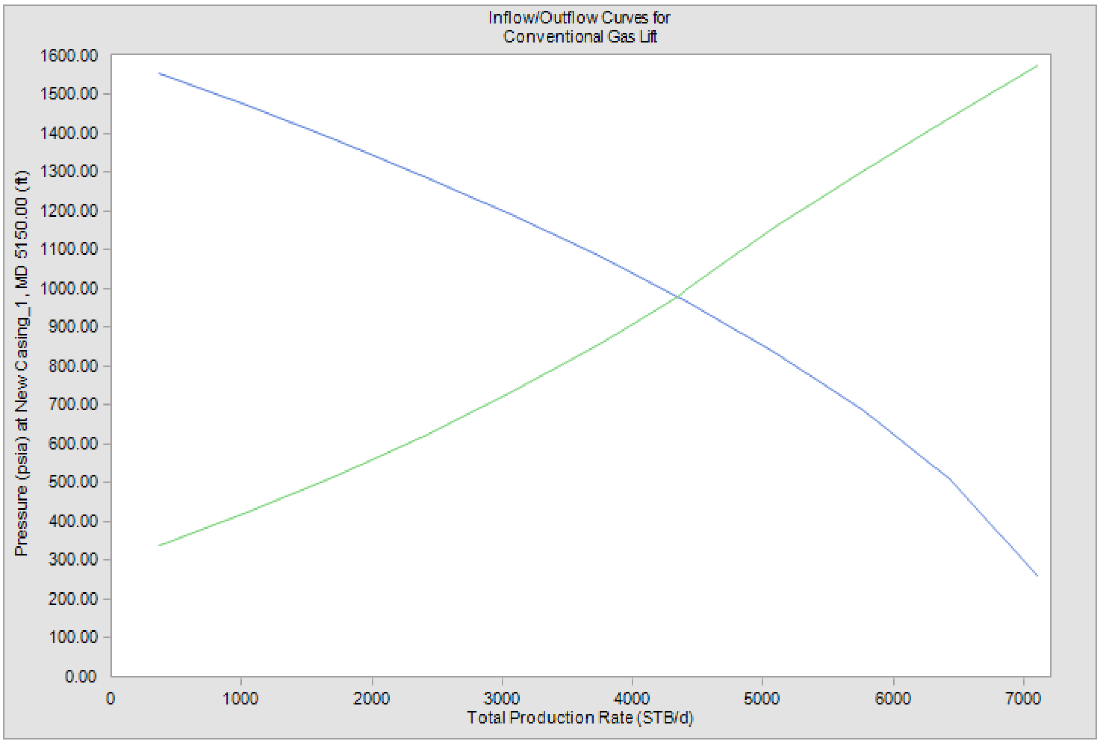

Figure 11: Inflow/Outflow Performance Curve for Gas Lift Well

Besides that, the operating point has decreased after conventional gas lift was implemented in this well (Figure 11). The operating pressure and rate recorded for conventional gas lift well were 968 psia and 4414 STB/d respectively. Plus, the injection of outsource gas into the well has caused the produced GOR increase to 1115 SCF/STB.

Lastly, for the smart in-situ gas lift application on the well, the performance of the well throughout the production time which was shown in figure 12 proved to be much better than using the conventional gas lift system. The implementation of smart in-situ gas lift system in the well has caused the total liquid production increased to 5031 STB/d compared to naturally flowing well (3974 STB/d) and conventional gas lift well (4350 STB/d). The oil production rate for smart in-situ gas lift well has improved about 26 % from natural production well due to help from gas cap zone.

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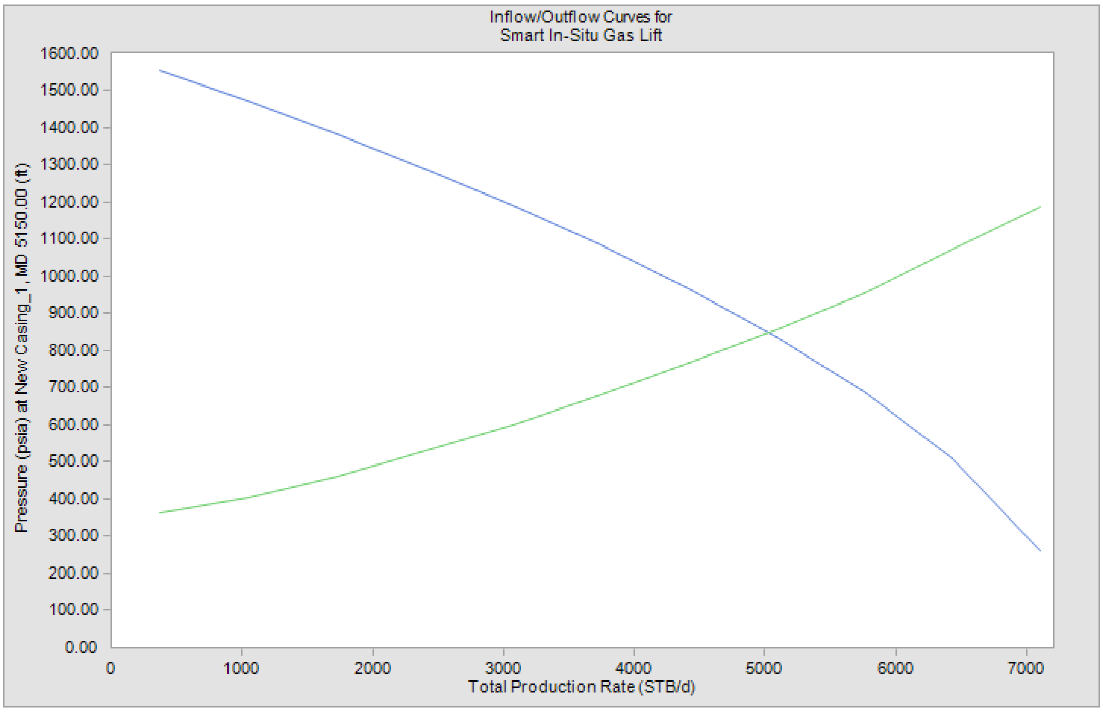

Figure 12: Inflow/Outflow Performance Curve for Smart In-Situ Gas Lift Well

The summary of inflow and outflow performance for the well is represented in figure 13. Through this figure, it can be conclude that the installation of conventional gas lift gave little improvement to the well performance compared to the impact of smart in-situ gas lift on the well.

The implementation of smart in-situ gas lift has allowed gas from gas cap zone to commingle with produced fluid and lightened the fluid density to ease of oil lifting process to the surface.

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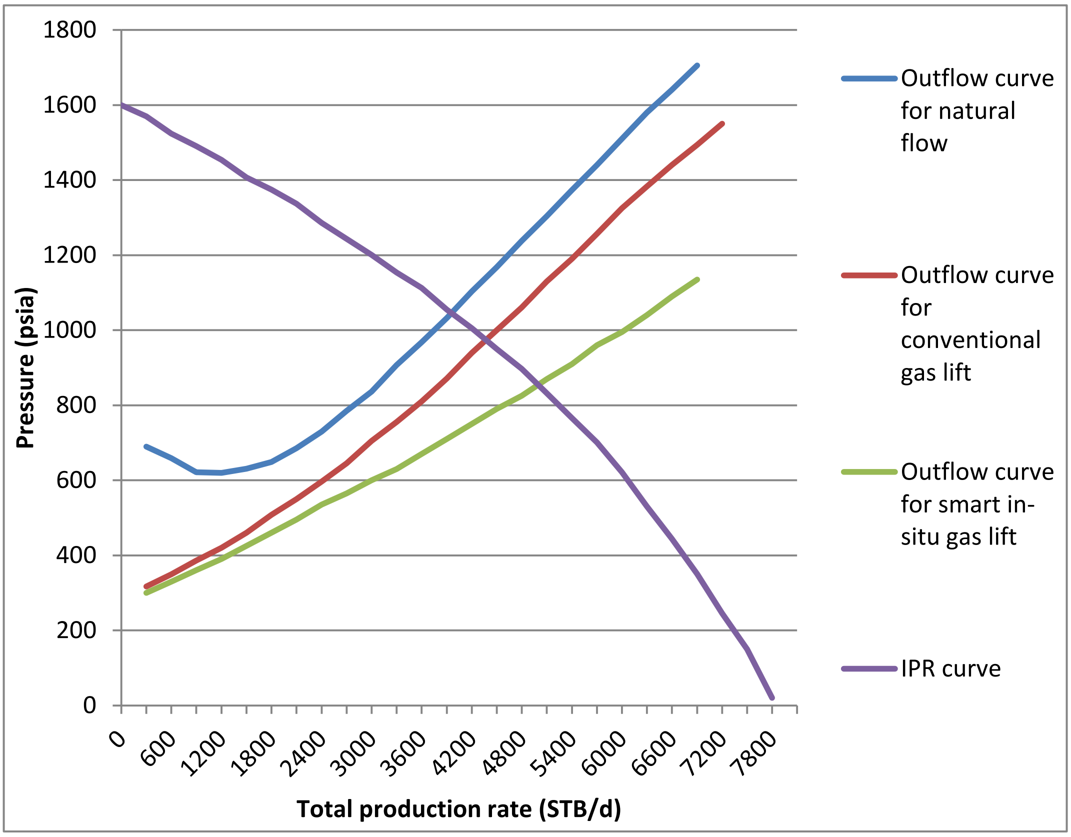

Figure 13: Summary of inflow and outflow performance curve for the well

4.2 Gas Lift Design

4.2.1 Conventional Gas Lift Valve Design

For conventional gas lift system, the total number of valve required was two unloading valve and one operating valve. The top valve was placed at depth of 2318 ft TVD and the second unloading valve was located at 3031 ft TVD. Meanwhile, the operating valve was located at the possible deepest position which was at 3331 ft TVD.

The valves design for conventional gas lift can be referred in the Table 6 and Figure 14. The valve used was injection pressure operation (IPO) type and the orifice was used as operating valve to continuously inject the gas into the well.

Table 6: Conventional gas lift valve design

Valve #	Depth TVD	Depth MD	T_v	C_T	Port Size	R	DP_c	P_{pd}	$P_{pd}R$	P_{sc}	P_{vcd}	P_{vod}	P_{io}	P_{vcd} at T_{sc}	P_{vo}
1	2318.70	2944.30	86	0.9453	20.0000	0.2474	53	631	156	859	911	1010	950	861	861
2	3031.85	4502.72	86	0.9449	20.0000	0.2474	78	854	211	890	968	1013	930	915	915
3	3331.00	5000.00	86	0.0000	32.0000	0.0000	0	937	0	0	0	967	880	0	0

In the Wellflo, the maximum deepest point of injection for operating valve was set at any deepest injection depth according to the conventional method of placing the valve. The valve differential pressure used was 30 psi and the calculated minimum valve spacing was 88 ft.

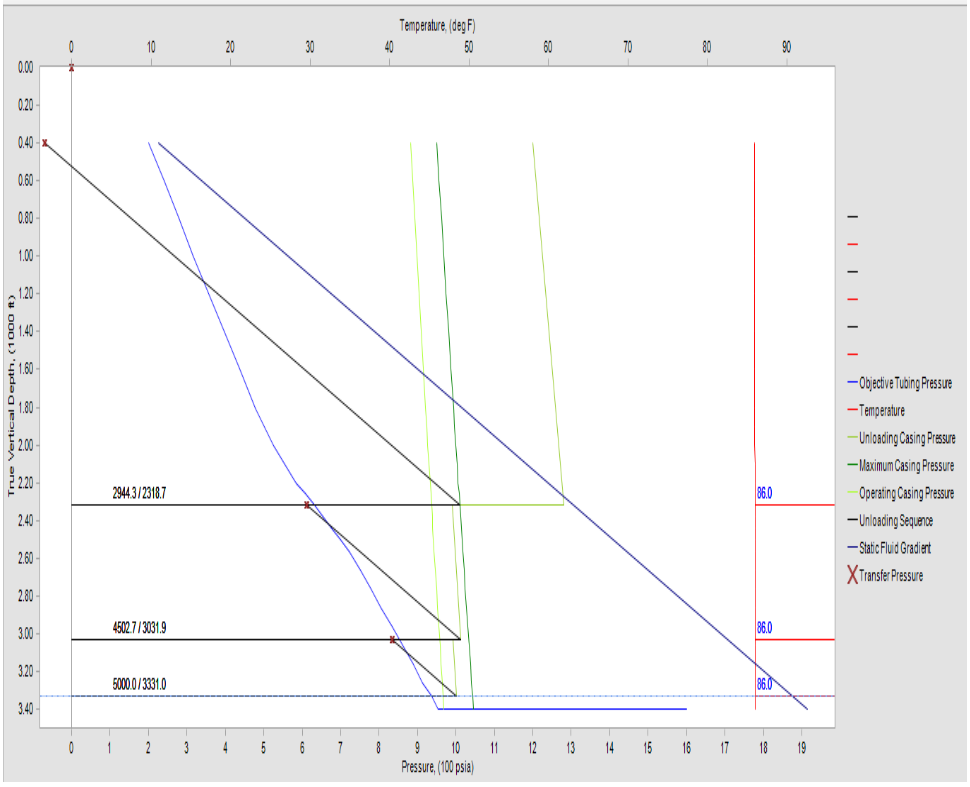

Figure 14: Conventional gas lift valve plot

4.2.2 Smart In-Situ Gas Lift Valve Design

While for the smart in-situ gas lift, one ICV was required to allow the gas from producing cap to enter the casing. From the gas lift plot in Wellflo, it was assumed that the ICV could be placed at the deeper depth to replace the orifice. Bases on the graph of gas lift design plotted in figure 15, the ICV was set at depth of 3120 ft TVD.

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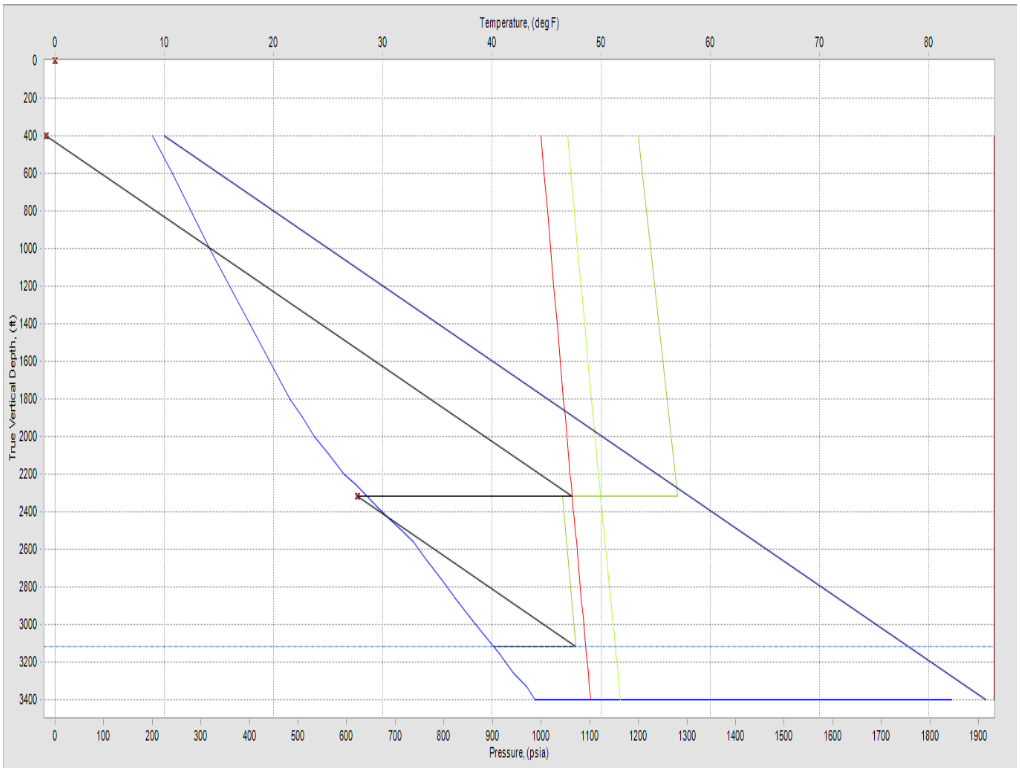

Figure 15: Smart in-situ gas lift valve plot

The smart in-situ gas lift design can be referred in figure 15. Based on the literature review, the interval control valve should be located at the top or bottom of oil zone if the reservoir is operating under gas cap drive mechanism or the valve should be placed at 500 ft above oil column (Al-Qahtani et al., 2009). Therefore, in the Wellflo, the valves were designed to be placed at any depth above oil column to meet the design criteria. From figure 15, the result shown that the deepest ICV can be placed at 3120 ft TVD.

Besides, the valve differential pressure is one of the factors needs to be considered when designing smart in-situ gas lift valve. From the literature study, in order to kick off the well from the static condition, large amount of valve differential pressure is required (Al-Qahtani et al., 2009). In the Wellflo, the valve differential pressure was set at 200 psi, so that the requirement to design the ICV could be met.

4.3 Advanced Smart In-Situ Gas Lift Valve Modeling

In addition, the true performance of interval control valve (ICV) with sensitivity to port size, gas injection rate and tubing pressure was done in the Wellflo. To perform this simulation, various port sizes were selected which includes of 12, 16, 20, 24 and 28 (64^{th} in) at the injection pressure of 750 psia. The plot of valve performance based on the well performance can be referred in the Figure 16.

Based on the graph plotted in the Figure 16, it can be concluded that the rate of gas entering the valve increases as the port with bigger size is used.

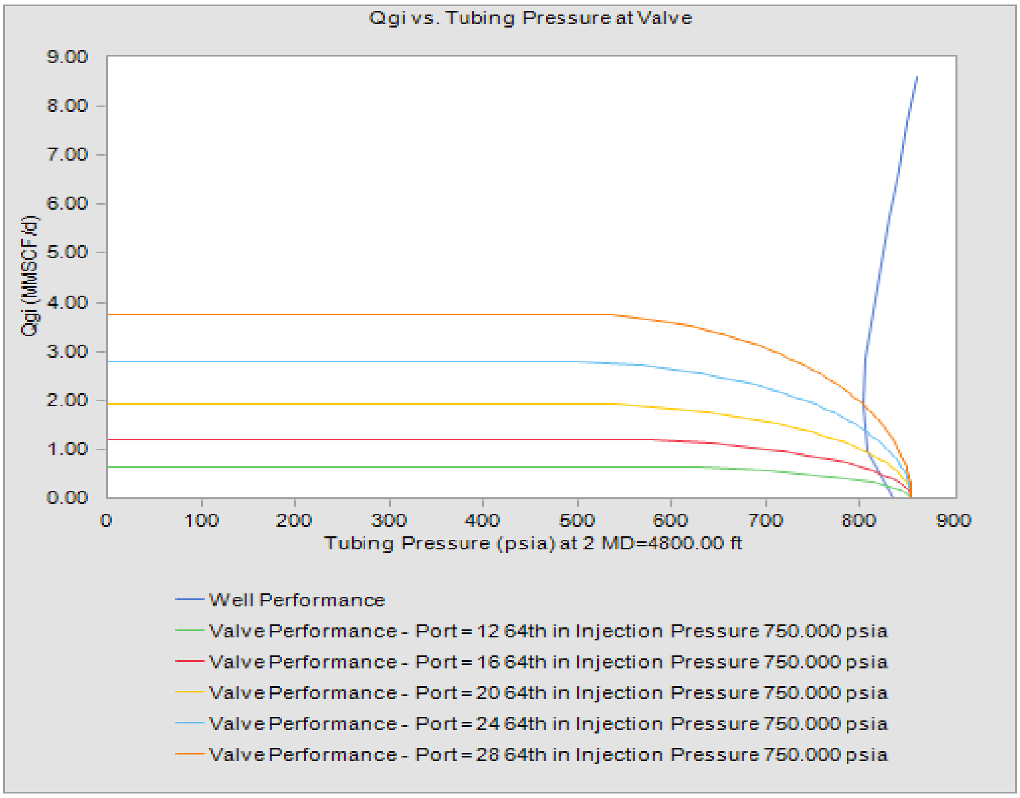

Figure 16: Valve performance curve for interval control valve (ICV)

4.4 Sensitivity Analysis

After done with designing the smart in-situ gas lift system, the overall well performance need to be analyzed based on several sensitivity parameters. The objective of running this sensitivity study is to determine and predict how the performance of smart in-situ gas lift well affected by comparing with different sensitivity cases. In order to evaluate the well performance before and after implementing smart in-situ gas lift system, sensitivity parameters such as water cut, lift gas injection rate and valve differential pressure were done. The sensitivity

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analysis will be compared between the naturally flowing well, gas lift well and smart in-situ gas lift well.

4.4.1 Water cut analysis

Sensitivity analysis for water cut was run in the Wellflo with different values of water cut which ranging from 10% until 80% were used to measure the effect of water cut to the inflow and outflow performance of the naturally flowing well, conventional gas lift well and smart in-situ gas lift well. The analysis of water cut to the three different cases of well was listed in the figure 17, 18, 19 and table 7, 8, 9.

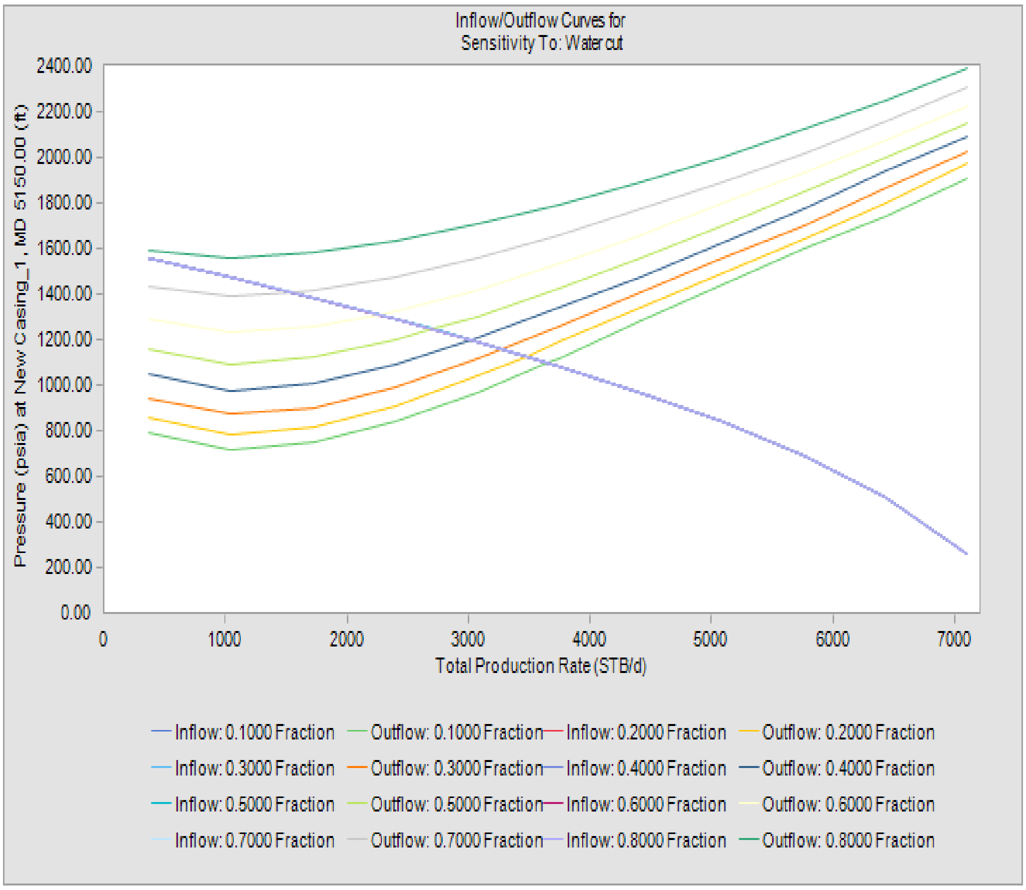

Figure 17: Water cut analysis for natural flow well

Table 7: Oil production rate with different water cut values for natural flow well

Water cut (%)	10	20	30	40	50	60	70	80
Qo (stb/d)	3291	2786	2289	1812	1355	904	470	-

For the base case, the well was economically to be produced if the water cut was below than 80%. When the water cut reached 80%, no oil production recorded from the well.

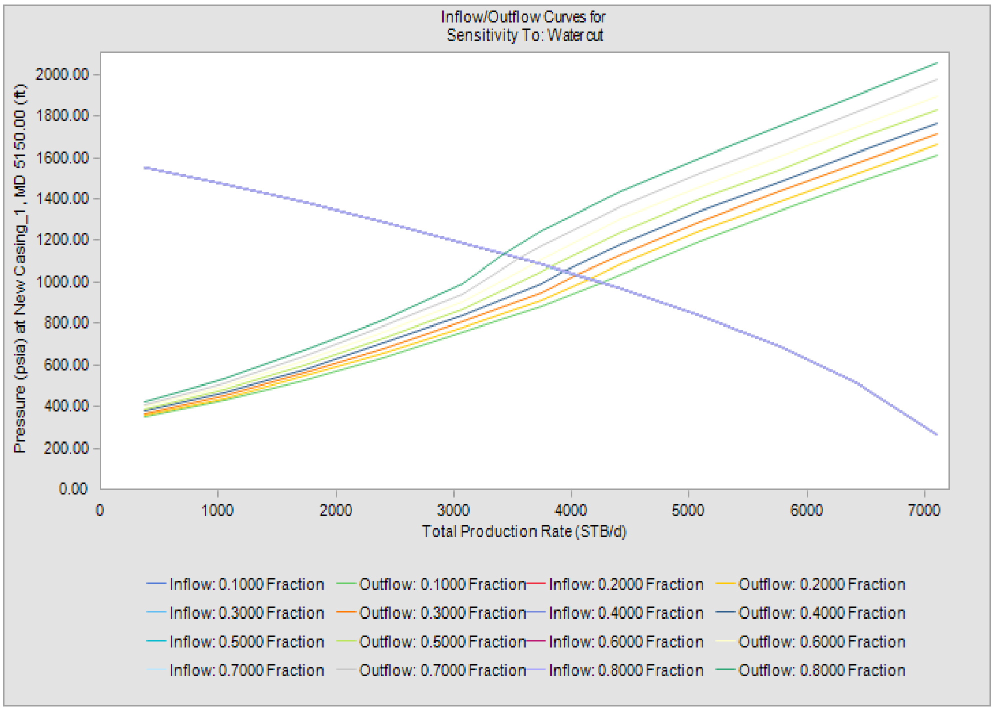

Figure 18: Water cut analysis for conventional gas lift well

Table 8: Oil production rate with different water cut values for conventional gas lift well

Water cut (%)	10	20	30	40	50	60	70	80
Qo (stb/d)	3838	3323	2831	2361	1908	1477	1069	685

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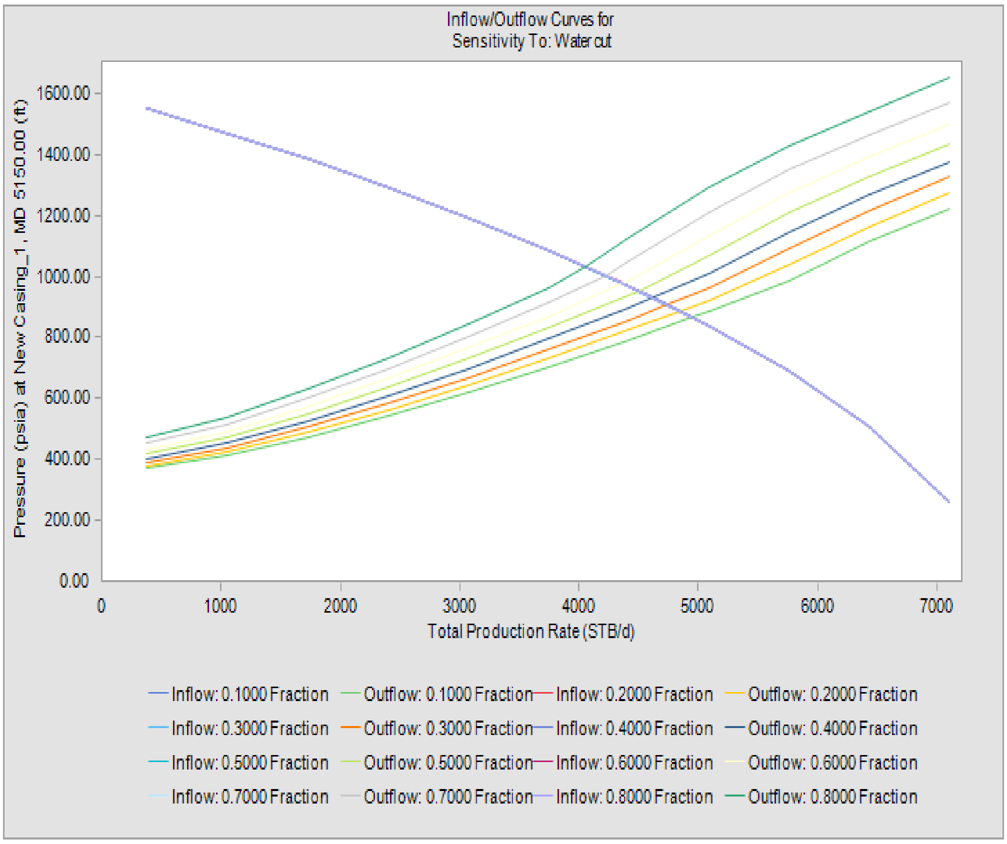

Figure 19: Water cut analysis for smart in-situ gas lift well

Table 9: Oil production rate with different water cut values for smart in-situ gas lift well

Water cut (%)	10	20	30	40	50	60	70	80
Qo (stb/d)	4457	3880	3318	2772	2251	1748	1269	812

From the figures 17, 18 and 19, it can be concluded that as water cut increases, the total liquid production rate will be decreases. This was proved when the value of water cut was at 60%, the total oil rate produced decreased to 904 STB/d for naturally flowing well, 1477 STB/d for conventional gas lift well and 1748 STB/d for smart in-situ gas lift well. From this observation, the smart in-situ gas lift well still can be produced at higher rate even at high amount of water cut.

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4.4.2 Valve differential pressure analysis

Valve differential pressure is one of the main design considerations for constructing smart in-situ gas lift system. The sensitivity analysis to valve differential pressure was conducted to identify the ideal pressure used to kick off the well from static condition.

To perform the sensitivity analysis in Wellflo, six different values of differential pressure which includes of 0, 200, 400, 600, 800 and 1000 psia were analysed on both type of gas lift valve.

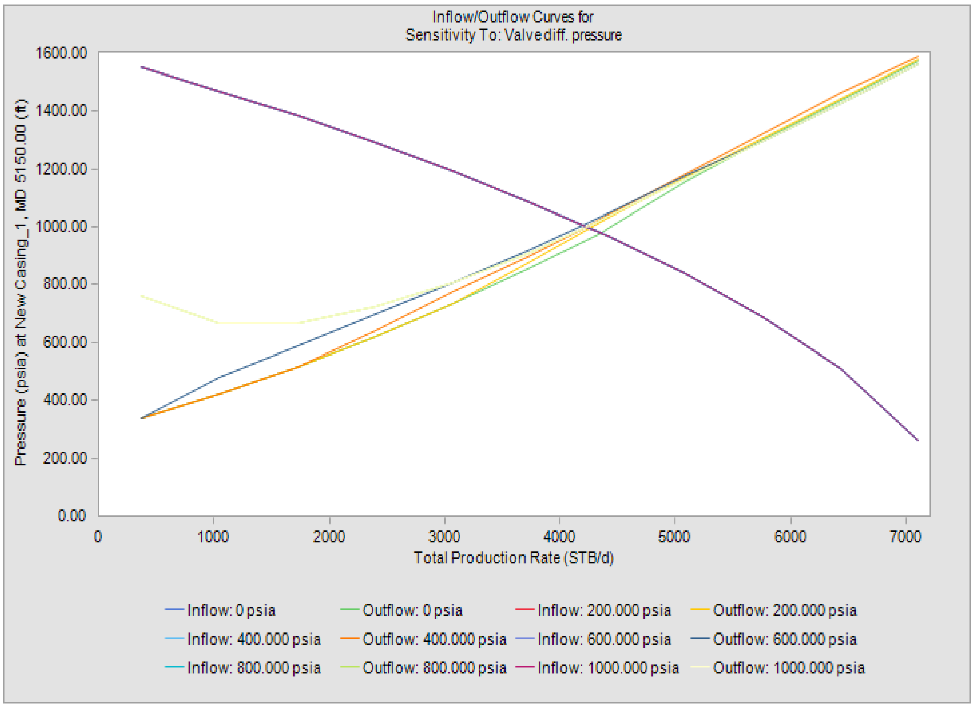

Figure 20: Valve differential pressure analysis for conventional gas lift well

From the analysis in figure 20, for the conventional gas lift, the valve can be set at differential pressure range from 0 to 200 psi which is the optimum differential pressure since the maximum liquid production recorded at this pressure was 4200 STB/d. Further increment in the valve differential pressure will cause the oil production rate to drop.

Meanwhile, figure 21 shows the valve differential pressure analysis for the smart in-situ gas lift well. The optimum valve differential pressure for this well can be set at range of pressure from 100 to 400 psi. If the valve is set at differential pressure

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greater than 400 psi, the injection gas rate will become unstable and production decreased rapidly.

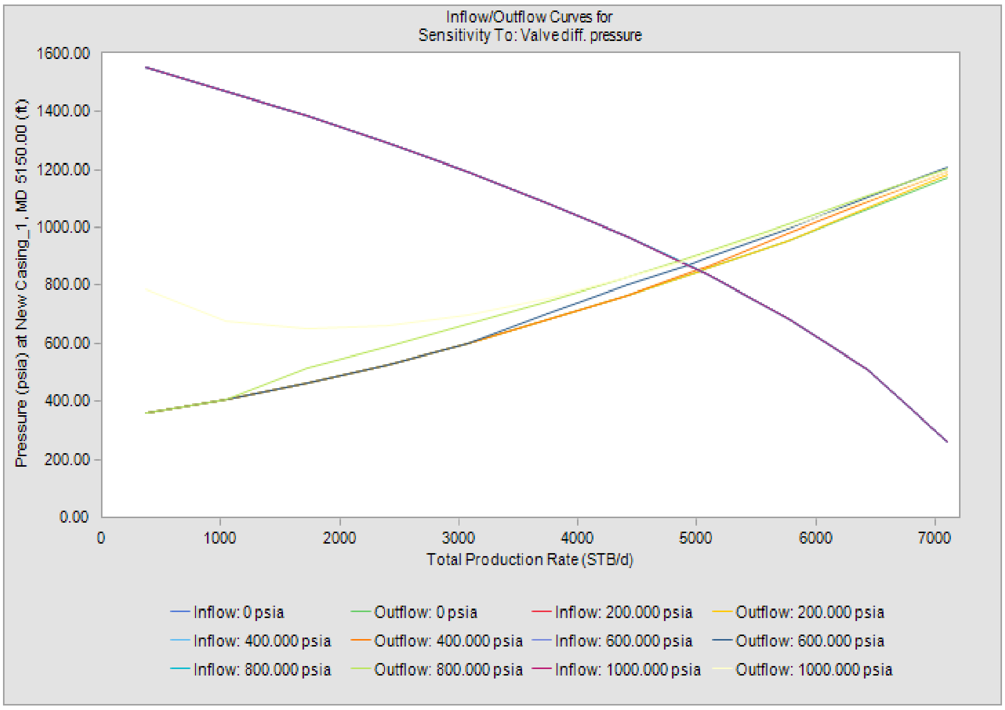

Figure 21: Valve differential pressure analysis for conventional smart in-situ gas lift well

The large valve differential pressure design generated from Wellflo meets the requirement of design consideration for ICV design which needs the valve to be set at high differential pressure such as 200 psi.

4.5 Smart In-Situ Gas Lift Production Forecast

By using spread sheet calculation, production forecast model for oil can be determined. This was done in order to estimate the amount of oil that can be produced during the life of reservoir. Figure 22 shows the graph of oil production rate against time. Initially, after the smart in-situ gas lift was implemented, the oil production increased after the gas from gas producing zone has helped the oil lifting process to the surface.

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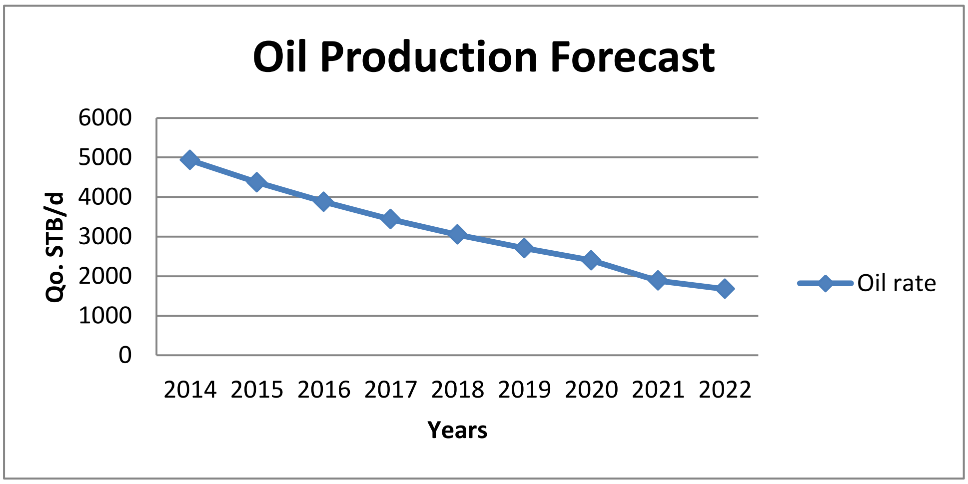

Figure 22: Oil production forecast

After one year, the production started to decrease due to concern of reduction in reservoir pressure. However, the interval control valve is capable to adjust the rate of gas flow entering the well can help in maintaining the reservoir pressure. From the estimated total oil production rate, the well is expected to continue produce the oil under the smart in-situ gas lift for more than 10 years.

The summary of production forecast for the well after the implementation of smart in-situ gas lift is represented in the table 10. The well is expected to continue produce after ten years of production.

Table 10: Smart in-situ gas lift well production forecast

Year	2014	2015	2016	2017	2018	2019	2020	2021	2022
Oil production (STB/yr)	4931	4373	3879	3440	3051	2706	2400	1888	1675

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Table 11: Summary of comparison between natural flow, conventional gas lift & smart in-situ gas lift

Type of well / Parameter	**Natural Flow (Base Case)**	**Conventional Gas Lift**	**Smart In-Situ Gas Lift**
Oil production rate (STB/d)	3895	4326	4931
Percentage increase of oil production based on base case (%)	-	11	27
Gas production rate (MMSCF/d)	2.53	2.81	3.21
Water rate (STB/d)	79.5	88.3	100
Minimum valve spacing (ft)	-	88	355
Valve differential pressure (psia)	-	50	200
Deepest injection point (MD)	-	3331	3120

To summarize the performance of the well, the comparison was made between the condition of the well in the state of natural flow, conventional gas lift and smart in-situ gas lift. By referring to table 11, the oil production rate increase by 11% from the base case if the well was operating under conventional gas lift. Meanwhile, the smart in-situ gas lift gave big impact to the productivity of the well when this method managed to increase about 27% from the production of natural flow well. Besides, the smart in-situ gas lift method which allowed the flow of gas from gas producing zone into the well show highest gas production rate compared to natural flow and conventional gas lift.

Despite the advantages show after the smart in-situ gas lift was applied in the target well, there was a concern about this method in which the reservoir pressure was expected to be depleted faster than the well in natural flow and conventional gas lift. This problem was handled by having intelligent valve (ICV) and downhole chokes which controlled the injection gas rate from gas cap into the well.

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CHAPTER 5

CONCLUSION AND RECOMMENDATION

At the end of the project, the objectives of this project which were to identify the design consideration of smart in-situ gas lift and to predict well performance after the smart in-situ gas lift system being applied at the target well has achieved. From the simulation and analysis that have been done using Wellflo, the smart in-situ gas lift injection method had improved the productivity of the tested well. The oil production rate has increased up to 27% from the natural production rate that can be produced. Meanwhile, the implementation of conventional gas lift can only lift up the production rate up to 11% from the normal production rate of the well.

From this project, the smart in-situ gas lift which was designed to replace the conventional gas lift provide the financial advantage over the conventional method by eliminating the needs for high cost of traditional gas lift facilities. Moreover, this method also provides the solution for the space restrictions that eliminate the needs of conventional gas lift facilities such as gas compressor facilities. Plus, the capability of smart in-situ gas lift to deliver the production in high water rate environment give a great advantage to optimize the production from the target well.

For the recommendation, it is hoped that the project can be done in more details and critical ways by having the real gas lift data from the field. Plus, critical analysis shall be done on the valve performance in order to know more details about the optimum gas injection rate and pressure to pass through the valve. Besides, the cost analysis for the smart in-situ gas lift well shall be performed, so that it can be compared with the application of conventional gas lift.

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