Romanian Journal of Petroleum & Gas Technology
VOL. IV (LXXV) • No. 2/2023

GAS LIFTING FOR PRODUCTION OPTIMIZATION USING EXTRA-HIGH-PRESSURE (XHP) GAS FROM NATURAL GAS WELLS WITHOUT COMPRESSION

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DOI: 10.51865/JPGT.2023.02.03

ABSTRACT

Artificial lift techniques are used when reservoir pressure drops below the fluid hydrostatic column weight in the well. A compressor station supplies high-pressure gas for the gas lift system, which includes a gas distribution manifold, gas lift lines to the well heads, and gas lift valves. Gas lift has many benefits, but the source of gas and the number of compression stages needed to lift reservoir fluid to the surface are major drawbacks. This paper critically examined this drawback and found a steady source of high-pressure gas that eliminates the need for compression. This study used PROSPER to determine the depths at which gas lift valves will be installed, the maximum gas injection rate of 0.81761 MMscf/day, the maximum oil production rate of 1183.4 STB/D, and the best valve type. Although the extra-high pressure gas (XHP) gas pressure needed to be reduced to properly aerate the fluid hydrostatic column as the gas lift valves (GLVs) opens, this pressure reduction (gas expansion) caused gas cooling/freezing, which is a critical concern on the lift gas path. Therefore, a heat exchanger and water bathe heater preheated the XHP gas to reduce the J-T phenomenon and ensure flow.

Keywords: artificial lift, XHP gas, compression, gas lift valve

INTRODUCTION

Once discovery is made, the reservoir is evaluated further to know the areal extent, the initial volume of the producible hydrocarbon, the production potential, and the required action to take for development (Field development) and production. The accumulation of hydrocarbon mixture and the reservoir's trapping system-caprock that prevents vertical migration and the underlying aquifer that prevents lateral migration—put oil in the reservoir under pressure [1]. After a well is drilled into the target formation and completed, a pressure differential drives hydrocarbon fluid to the surface, producing "the first oil". This pressure differential refers to the pressure difference between the reservoir and the production (surface) facilities. If for any reason, this differential does not exist, there would be no flow and, ultimately, no production. Although, a period in the life of the reservoir is reached where the pressure of the reservoir begins to decline, and the energy is no longer sufficient to force the fluid to the surface; hence, other methods of recovering the hydrocarbon fluids are employed. Some of these oil recovery methods include primary recovery, specifically, artificial lift method; the most known are sucker rod pumps, gas lift, progressive cavity pumps, electric submersible pumps, hydraulic jet pumps [2, 3], secondary recovery and tertiary recovery. Artificial lift is required when a well will no longer flow or when the production rate is too low to be economical [4].

The gas lifting system helps to reduce the backpressure in the well induced by fluid in the pipeline, thus increasing the injection and production efficiency of the well [5, 6]. It is a form of artificial lift that might be seen as an extension of the natural flow process due to its great similarity with a natural flowing well. Gas lifting, a type of artificial lift, requires gas to be compressed before use, so fields that want to use it must buy and operate compressor stations, which are expensive. Many researchers have considered the factors responsible for selecting the type of artificial lift system employed for a given well [7, 8]. Szucs *et al*. [9] and Ayatollahi *et al.* [10] studied the operations of types of gas lift systems and their applications. Factors affecting gas lift optimisation that leads to improved well performance were studied [11-16]. Using gas lift performance is a common practice to determine a well's optimum gas lift rate in a gas lift analysis involving two wells sharing a common flow line [17]. Computer modelling, simulation and optimisation program are required to model, simulate and analyse gas lift optimisation for maximum oil production [18-20]. However, based on this study, extra-high pressure (XHP) gas from gas wells was utilised for gas lifting, eliminating the need to increase the gas pressure by compression. Gas lift can be applied to wells as deep as 15000ft and can lift fluid at a rate of 50,000 STB/D. In this approach, 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 fluid density [21]. There are two types of gas lift systems: continuous gas lift systems and intermittent gas lift systems. For using XHP gas from natural gas wells, employing a continuous gas lift system for gas lifting without compression is preferable.

Despite the numerous advantages of a gas lift system, it faces a major limitation: the need for sufficient injection gas. Other limitations include the following:

- Wide well spacing.
- Unavailability of space for compressors (usually on the offshore platform).
- Poor compressor maintenance by operators.

This paper critically looked into these limitations and arrived at an alternative method by which gas lifting operation can be carried out by using extra high pressure (XHP) gas from natural gas well without the need for compression. Although, due to the J-T cooling effect on the XHP gas as a result of pressure reduction downstream of a pressure control valve (PCV), a heat exchanger and water bathe heater were installed upstream of the PCV to ensure that the gas is heated beyond the hydrate formation of the XHP consequently preventing hydrate formation as well as mitigating J-T cooling effect.

Joule-Thomson (JT) phenomenon/effect occurs due to fluid temperature changes for a given pressure change at constant enthalpy. This phenomenon explains the increase or decrease in the gas mixture, which freely expands on flowing through a restriction such as chokes and regulators [22]. This implies that as the gas pressure is reduced across a valve or regulator, the temperature, in turn, reduces, therefore, causing a freezing or cooling effect along the gas line in which it flows (with the exception of H_2, Ne, He gas which heats up on expansion). The use of heat exchangers, shown in Figure 1 and the water bath heater, shown in Figure 2, were some of the technologies employed in the prevention of the cooling/freezing effect caused by the J-T phenomenon as the XHP gas from the gas well flows through the various valves and regulators on entering the flow station.

Fig. 1 *Heat exchanger XYZ field*

Fig. 2 *Water bathe heater XYZ field*

The heat exchanger is made up of two working fluids that exchange heat by thermal contact using bundles of tubes housed with a cylindrical shell. The different fluids in the shell and tube are of different temperatures, and this temperature difference is the driving force for heat transfer (temperature exchange). The working principle of shell and tube heat exchanger is quite simple; one fluid flows into the tubes while the other fills up the shell in a counter flow motion; in this case, the fluid that flows through the tubes is the XHP gas from the gas well at 31.8°C whereas heated water at 90°C from a water bathe heater fills up the shell. As the fluid flows, heat exchange occurs; thus, cold fluid gains heat from the heated fluid. Consequently, at the heat exchanger outlet, the cold fluid (XHP gas) has now been heated – preheated stage. Further heating occurs in the water bath heater as the heated gas passes through an insulated pipeline outlet with an adjustable choke which reduces the gas pressure to 1247.325 psi. Next, the gas flows through the control valve and pressure regulator on the insulated gas line that steps the pressure down to 75 bar, then into an XHP separator which removes any condensate in the gas and finally to the gas distribution mandrel of Well-12, which supplies injected gas of 75 bar capable of opening the gas lift valve to begin continuous gas lift operation on Well-12.

METHODOLOGY

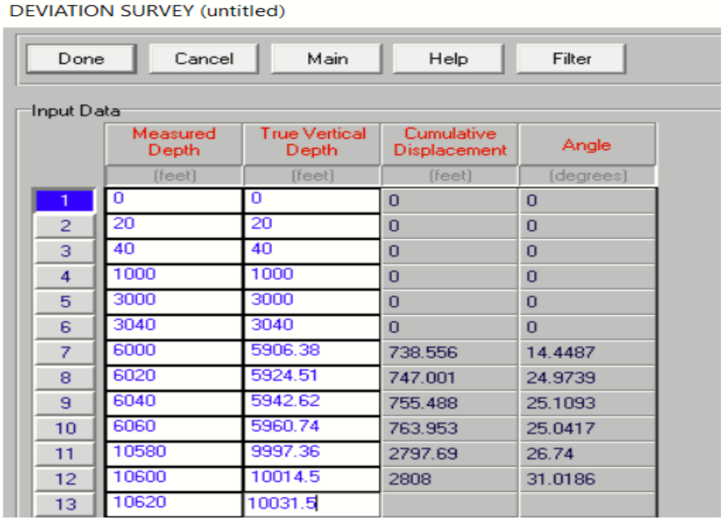
The PROSPER (Production and System Performance) analysis software developed by Petroleum Experts is used to model Well-12. The gas lift process used XHP gas from natural gas well without compression. This method determined the number of valves required (including the orifice for a well) with their respective installation depth, and the well performance was predicted before and after the mandrels' installation.

The option summary on PROSPER software sets up the model by inputting the available data, which properly describes the fluid, well, type of recovery method, calculation type, type of well completion, type of reservoir and user information. The inputted ***PVT data*** are from Table 1, consisting of solution GOR, bubble point pressure, oil formation volume factor, oil viscosity, water salinity, gas relative density, reservoir temperature and oil API gravity. Once all these must have been entered, select regression-match all parameters, which directs the software to carry out a series of calculations eventually, giving the best correlation to be used for modelling the well.

Table 1. *PVT data*

Parameters	**Values**
Reservoir temperature	200F
Oil API gravity	23API
Gas Relative Density	0.55 sp. Gravity
Solution GOR	80 SCF/STB
Bubble point Pressure (Pb)	3000 psig
Oil FVF	1.025 rb/stb
Oil viscosity and Water Salinity	0.6cp & 17000ppm

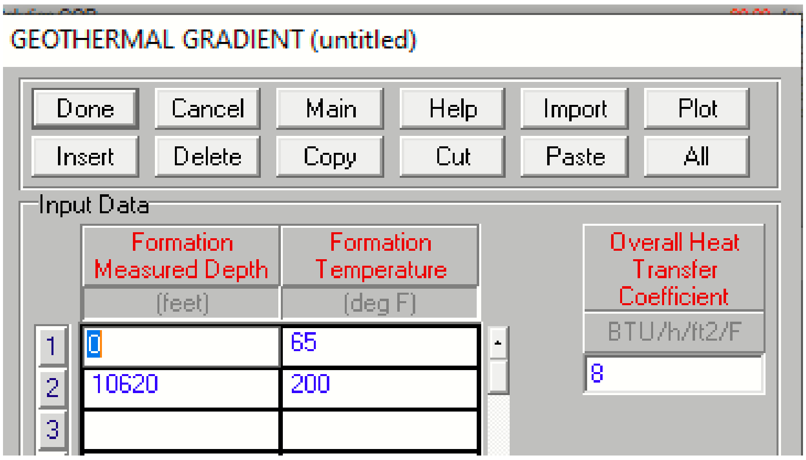
Based on the available data, the deviation survey data were inputted as shown in its given entry on Plate 1. The downhole equipment data was inputted into the necessary menu section. The data entry for the deviation survey was filled up by inserting the respective measured depth and true vertical depth of the well.



	Measured Depth (feet)	True Vertical Depth (feet)	Cumulative Displacement (feet)	Angle (degrees)
1	0	0	0	0
2	20	20	0	0
3	40	40	0	0
4	1000	1000	0	0
5	3000	3000	0	0
6	3040	3040	0	0
7	6000	5906.38	738.556	14.4487
8	6020	5924.51	747.001	24.9739
9	6040	5942.62	755.488	25.1093
10	6060	5960.74	763.953	25.0417
11	10580	9997.36	2797.69	26.74
12	10600	10014.5	2808	31.0186
13	10620	10031.5		

Plate 1. *Deviation data survey*

Subsequently, the corresponding geothermal gradient on the menu of the equipment data, as shown in Plate 2, was inputted. It includes two columns for formation-measured depth and formation temperature, which are inputted into the entry. Geothermal gradient data entry also requires introducing the overall heat transfer coefficient in BTU/h/ft^2/F.



	Formation Measured Depth (feet)	Formation Temperature (deg F)
1	0	65
2	10620	200
3		

Plate 2. *Geothermal gradient entry*

On the IPR (inflow performance relation) section, the PI entry for the reservoir model was filled with the inputted corresponding total GOR, reservoir pressure, temperature and water cut of the reservoir model data, as shown in Table 2. The model was validated and subsequently calculated and plotted the IPR graphical results.

Table 2. *Inflow performance relation data*

Parameters	**Values**
Reservoir Pressure	4000psig
Reservoir Temperature	200F
Water Cut	20%
Total GOR	80 scf/STB

The VLP/IPR matching and the estimate of the overall heat transfer coefficient "U" correlation comparison were done from the analysis summary section. The analysis summary can also be used for sensitivity analysis, which helps to figure out why a particular reservoir model is not producing or to predict likely factors (potential problems) that can influence productivity, such as pressure change and change in tubing size, effectively cater for these problems.

The well to be modelled requires continuous gas lifting; hence, the continuous gas lift data from Table 3 obtained from the XHP gas well is inputted into the system with valve information: manufacture – Camco, Type – BK-F6, Specification – Normal.

Table 3. *Continuous gas lift design data*

Parameters	**Data**
Gas lift method	Optimum depth of injection
GLR rate	Use injected gas rate
Design rate method	Calculated from maximum production
Gas lift gas gravity	0.68 sp. Gravity
Mole percent H2S	0
Mole percent CO2	0.507%
Mole percent N2	0.309%
GLR injected	2 scf/STB
Injected gas rate	1MM SCF/D
Casing pressure	1187.78 psig
Dp across valve	50 psi
Kickoff injection pressure	1087.78 psig
Operating injection pressure	1087.78psig
Maximum liquid rate	3000 STB/D
Maximum depth of injection	6000ft
Valve type	Tubing sensitive
Vertical lift correlation	Petroleum expert 4

RESULTS AND DISCUSSION

The PROSPER design was implemented using the injection pressure operated (IPO) gas-lift valve and the production pressure operated (PPO) gas-lift valve as shown in Figure 3.

In the production pressure-operated valves, the valve's behaviour is controlled by injection pressure, production pressure, or both. Gas-lift valves (GLV) are easily controlled by changing the surface injection pressure. Designing the optimum gas lift system is the most important part of gas lift design for any application, off-shore or onshore. GLVs performance must be tested to ensure sufficient gas flow enters the wellbore to lift the predicted volume of formation fluid. Failure to choose the right GLV size will result in an ineffective gas lift system. The operation mechanism of the IPO and the PPO gas-lift valve types is the same.

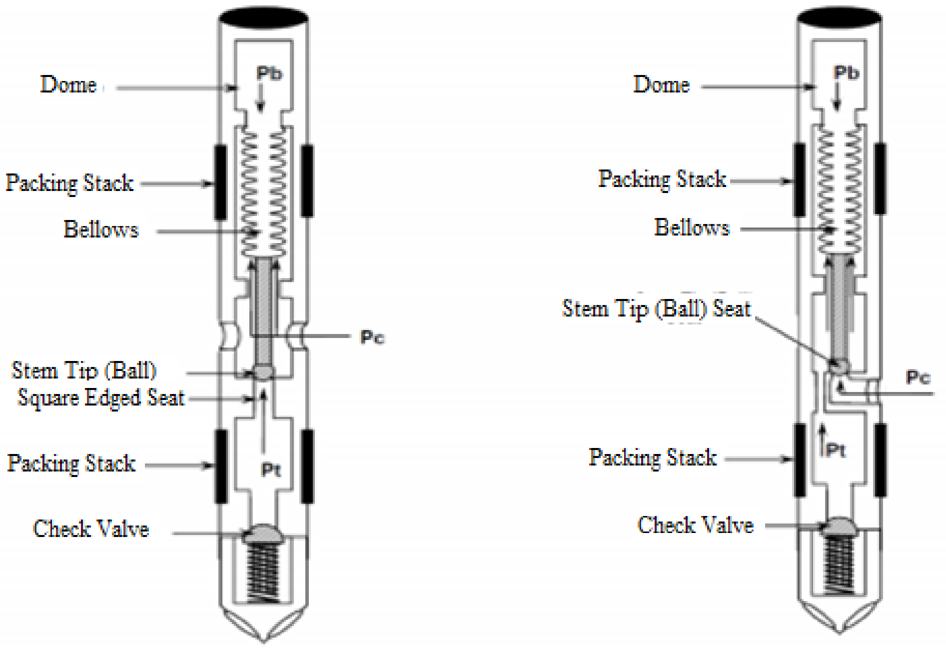


Fig. 3 *Injection Pressure Operated (IPO) gas-lift valve (left) and the Production Pressure Operated (PPO) gas-lift valve (right)*

In the IPO type of GLV, the casing pressure is acting on the larger area of the bellows. The casing pressure plays the main role in the valve operation. During the unloading process, the drop in the casing pressure results in closing the valves in order.

The advantage of the IPO valve type is that when the desired injection depth is reached, an extra casing pressure drop is made to ensure that the upper valves are closed. So, the variation in tubing pressure is unlikely to re-open loading valves.

This valve type is widely used in continuous gas lift systems. However, in the PPO GLVs, the tubing pressure acts on the larger area of the bellows making the valve primarily sensitive to the tubing pressure. As gas is being injected, the drop in the tubing pressure is used to close the valve. Since the drop in the tubing pressure is less predictable than the injection pressure, PPO usages are generally limited to dual completion wells.

Results in Table 4 and Table 5 show certain depths were determined through the system accuracy of PROSPER for the installation of various possible gas lift valves in the gas lift mandrels at specific opening and closing pressure to stimulate production of Well-12.

Table 4. *IPO valves and their respective TVDs for installation*

Gas Lift Valve (IPO)	True Vertical Depth (TVD) (ft)
Valve 1	1800.9
Valve 2	2639.11

Table 5. *PPO valves and their respective TVDs for installation*

Gas Lift Valve (PPO)	True Vertical Depth (TVD) (ft)
Valve 1	1806.15
Valve 2	2409.93
Valve 3	2804.34
Valve 4	3061.97
Orifice	3456.28

All data needed to properly model Well-12 are integrated into the system; a major factor to consider first is to ensure that PVT data are correctly matched. This is to ensure computational accuracy onward and to correctly predict fluid properties. Using the Inflow Performance PI entry, the result for the generated IPR plot relative to the production rate is shown in Plate 3. Plate 4 shows the result for the IPR v VLP Plot before Gas lift Operation in Well-12, while Plate 5 shows the result for the IPR v VLP after Gas Lift Operation in Well-12.

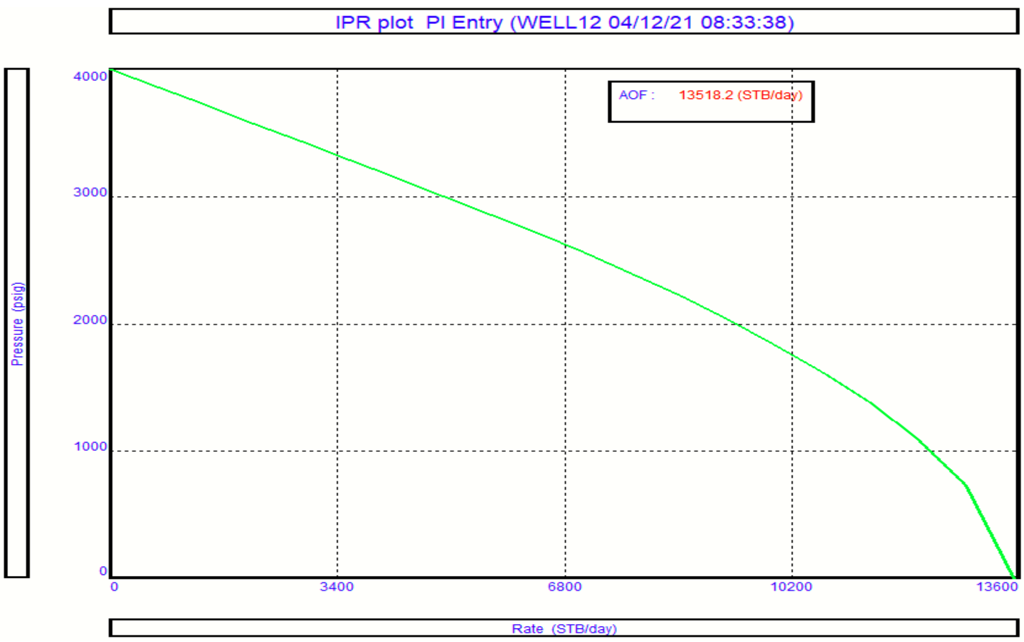


Plate 3. *IPR plot of pressure v rate*

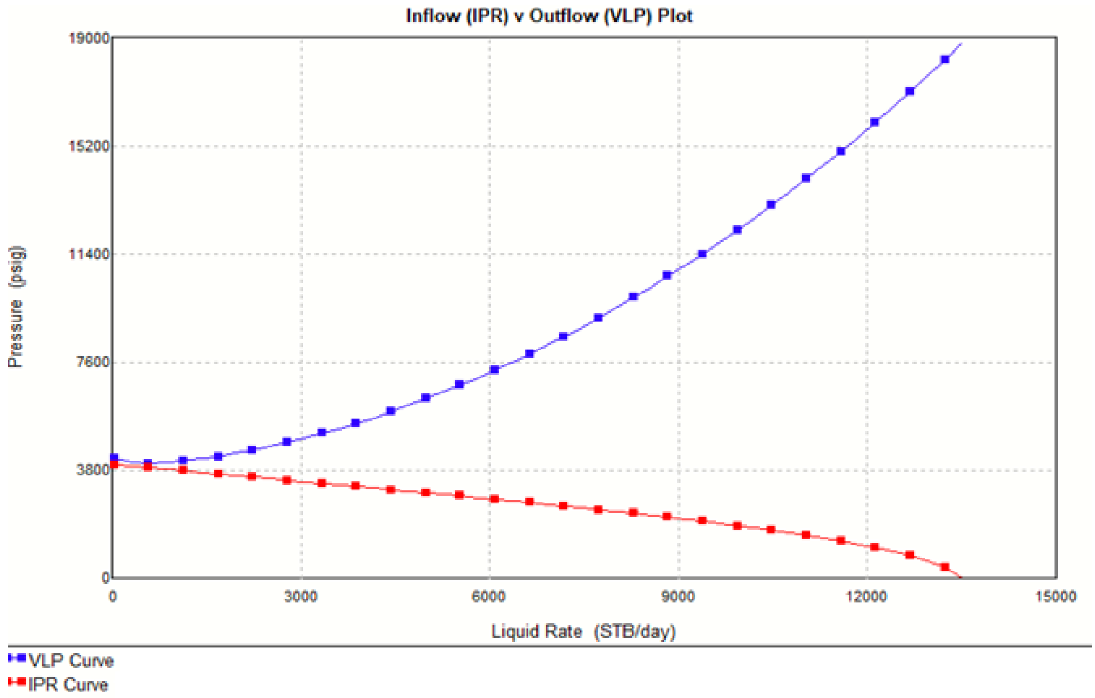


Plate 4. *IPR v VLP plot before gas lift operation in well-12*

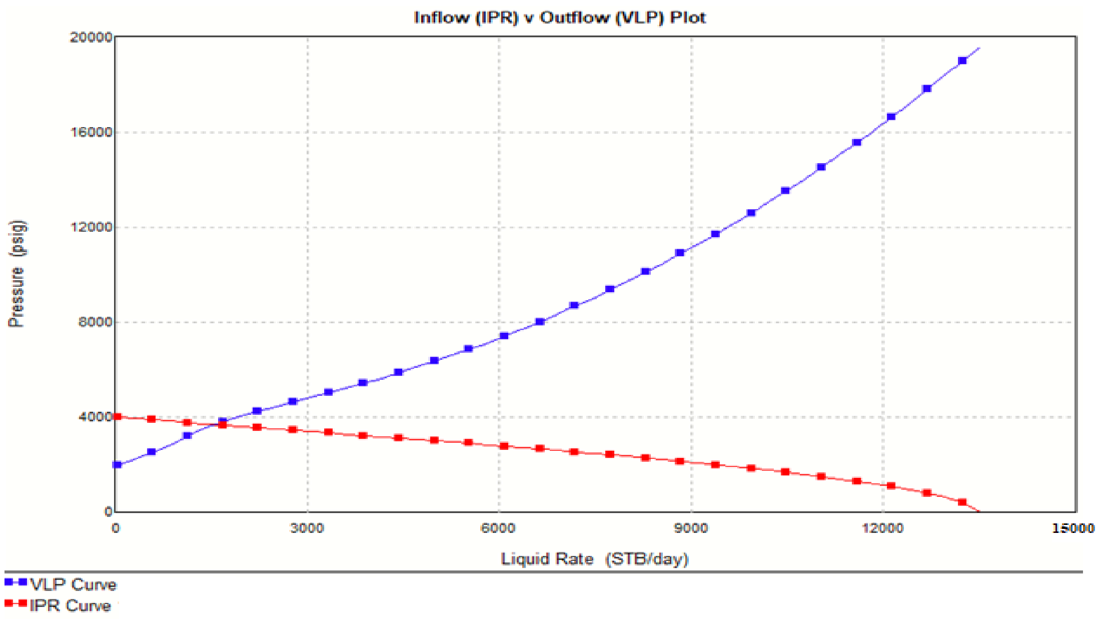


Plate 5. *IPR v VLP after gas lift operation in well-12*

ANALYSIS SUMMARY RESULT BEFORE AND AFTER GAS LIFT

Plate 4 shows that there is no fluid flow because the graph of IPR vs Vertical Lift Performance (VLP) does not intersect. Therefore, explaining the need for artificial lift, such as gas lift.

The built model of Well-12 is put on continuous gas lift with the necessary gas lift data entered into the system. As a result of this, the IPR vs VLP curve is seen to intersect in Plate 5. In addition, a gas lift performance curve in Plate 6, IPO & PPO valve types are derived in Plate 7 and Plate 8.

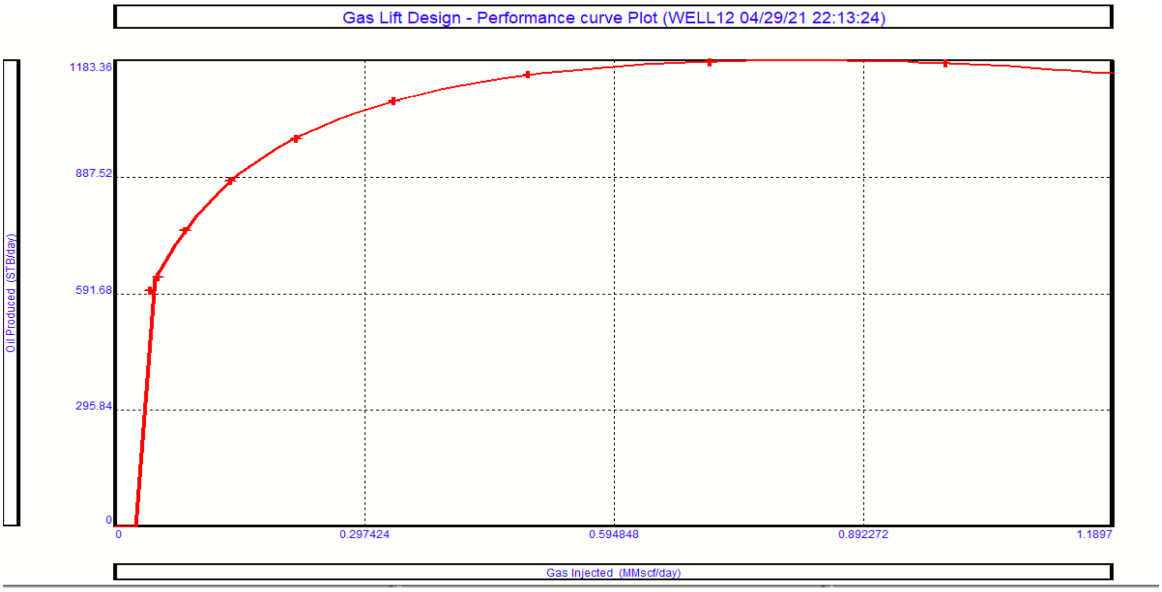


Plate 6. *Gas lift performance curve plot for well-12*

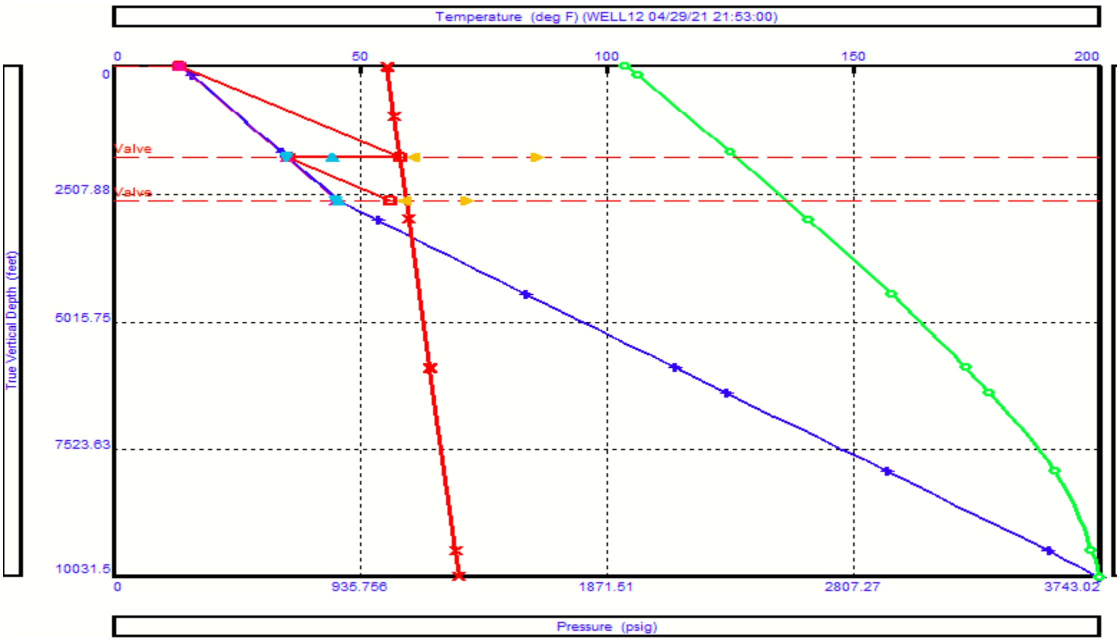


Plate 7. *Gas lift valve depth determination (IPO valve type)*

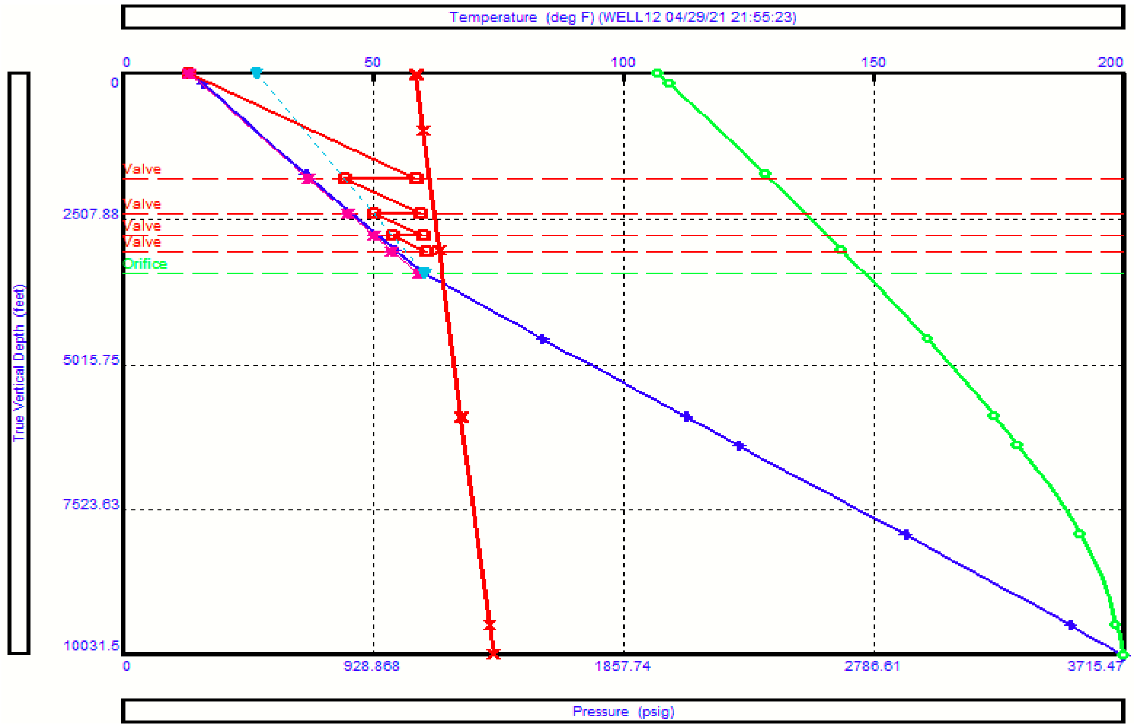


***Plate 8**. Gas lift valve depth determination (PPO valve type)*

DISCUSSIONS

i. The IPR result gave a plot of pressure (p_{sig}) vs. production rate (STB/D) as seen in Plate 3. Therefore, the system was able to compute the absolute open flow potential (AOF) to be 13518.2 STB/D**.** This is the maximum flow rate at which the modelled Well-12 would produce at the lowest possible bottom hole pressure ($P_{wf} = 0$) with a productivity index (PI) of 5 STB/day/psi.

ii. Productivity of Well-12 was tested before any external assistance for recovery was implemented; this gave an IPR vs. VLP plot (Plate 4) in which there exists no intersection between IPR curve & VLP curve thereby describing the analysis summary result without gas lift optimisation. Consequently, the reservoir fluid in Well-12 can no longer flow naturally from the reservoir to the surface.

iii. Once it was certain that the plot of IPR vs. VLP did not intersect, continuous gas lift data was incorporated system which in turn generated Plate 5 i.e. IPR vs. VLP plot intersecting with each other; thus with all assurance, the built model of Well-12 can be made to flow when optimised using continuous gas lift process.

iv. The gas lift design rate was computed by system analysis to be 0.81761 MMscf/day indicating the maximum rate of gas injection. By censoriously interpreting the gas lift performance curve in Plate 6, it is observed that as the gas injection rate increases, the operating oil production rate also increases until it gets to a peak of 1183.4 STB/D having an injection rate of 0.81761 MMscf/day then finally begins to decline due to excess gas injected.

v. Construing the plot in Plate 8, PPO valve type if installed will produce 1136.63 STB/D of oil at an injection rate of 0.61177 MMscf/D while IPO valve plot in Plate 7, if installed will produce 1027.63 STB/D of oil at injection rate of 0.67113 MMscf/D.

vi. An injection pressure restriction is often placed on IPO valves because the injection pressure must not exceed the casing collapse pressure. Although the injection pressure must not reach the tubing burst pressure for PPO valves, PPO valves tend to allow for injection at higher pressures which increases the gas lift performance. Thus in this study, the higher oil rate observed for the installation with PPO gas-lift valves, unlike the IPO gas-lift valves, was because the tubing pressure acts on the larger area of the bellows making the PPO valve largely sensitive to the tubing operating pressure. As gas is being injected, the drop in the tubing pressure is used to close the valve. When the injection pressure is insufficient to handle the closing pressure, the valve behaves in the throttling flow pattern. When the GLV behaves in the throttling flow pattern as the production pressure decreases, the gas flow rate increases due to an increase in the differential pressure across the valve seat.

vii. In addition, higher injection depths increases gas lift performance for both IPO and PPO valves. But the valves can only be installed at a depth shallower than the position of the tubing packer, thus placing a restriction on how deep gas can be injected.

CONCLUSIONS

This software study which involved the use of XHP gas for gas lifting of Well-12 without compression gave positive results through which the following conclusions where attained:

1. Gas lift optimization process was inevitable for stimulating the production of Well-2 due to the insufficient energy in the tubing. On this basis, a gas lift performance curve was generated, the best rate of injection – 0.81761 MMscf/d was obtained therefore, reservoir fluid can be produced effectively and economically.
2. Two valve types were considered IPO valves and PPO valves in which the PPO valves produced 1136.63STB/D of oil at an injection rate of 0.61177 MMscf/d while IPO valves gave 1027.63 STB/D of oil at an injection rate of 0.67113 MMscf/d. Hence, the oil production rate which is evidently higher in the PPO valves should be installed to enhance production in Well-12.

In this study, the PPO gas-lift valves had a higher oil rate compared to the IPO gas-lift valves because the tubing pressure had more sensitivity to the PPO valve due to the larger area of the bellows that it acts on. The best results are achieved when the valve operates under critical flow conditions, with high injection gas pressure compensating for downstream fluid pressure, leading to maximum production.

RECOMMENDATION

Gas lift operations can experience instability when there are changes in tubing pressure and injection pressure is not sufficient to keep the valve open. To avoid this, it is recommended to select the appropriate orifice port size. Consequently, the performance of each GLV depends on various factors such as injection gas pressure, port size, and fluid pressure. Based on the PROSPER aided modelling of Well-12, it is highly recommended that remedial action by the installation of PPO valves in the gas lift mandrels be carried out through workover operations. Also, it can be suggested and recommended that in the absence of a compressor and the presence of XHP gas from a gas well, gas lift operation is highly possible provided the pressure of the gas is regulated to the required amount needed to open the GLV and the gas to be injected is kept at temperature unable to condense free water to ensure flow assurance.

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Received: March 2023; Revised: June 2023; Accepted: July 2023; Published: July 2023