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Research Paper

Effective Parameters on Oil Production Rate using Artificial Gas Lift: Case Study in the One of South Iranian Oil Fields

Mojtaba Zadnorouzi[1], Seyyed Ali Faal Rastegar[1], Atefeh Hasan-Zadeh[1*]
[1] Fouman Faculty of Engineering, College of Engineering, University of Tehran, Iran

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Abstract: When the oil well pressure diminishes, production in the stock tank will decrease. One of the best methods for enhancing the production rate is an artificial gas lift. Injecting gas reduces the density of the oil column, resulting in a bottom-hole pressure. As a result, the oil comes to the surface more easily, increasing production. Accordingly, in this paper, we designed an artificial gas lift for a well in one of the south Iranian oil fields in a new method. We also carefully examined the effective parameters of oil production rate, including gas injection rate, injection depth, tubing diameter, gas specific gravity and temperature and pressure of injected gas, and water cuts. Then, to optimize the process under study, we determined the best value for each of these parameters, while studies do not optimize all parameters. Injection gas rate and pressure had an optimum point; the tubing diameter at one point had the highest output. As the specific gravity of the injection gas increased, production generally decreased. As the temperature of the injection gas rose, diminished decreased slightly. To ensure the correctness of the work, the analysis of the necessary sensitivities about the optimal effect of each parameter has been done with sufficient accuracy. The results show that gas injection will lead to a 156.4% increase in production in the reservoir which is a remarkable and thought-provoking result.

keywords: Pressure, Specific Gravity, Temperature, Tubing Diameter

Nomenclature

Symbols	Description	Unit
D	pipe diameter	ft
h	depth	ft
GOR	Gas Oil Ratio	scf/bbl
VGS	stock tank volume of the gas dissolved in oil	Scf
VG	stock tank volume of free gas	scf
H_L	liquid holdup factor	fraction
f	friction factor	dimensionless
M	total mass of oil, water and gas associated with 1 bbl of liquid flowing into and out of the flow string	lbm/bbl
q	liquid flowrate	bbl/d
R_S	solution gas-oil ratio	scf/stb
ρ_L	density of liquid phase	lb_m/ft^3
$\overline{\rho_m}$	average two-phase density of the mixture	lb_m/ft^3
ρ_g	density of gas phase	lb_m/ft^3
p	pressure	psia
v_m	two-phase mixture velocity	ft/sec
g_c	standard acceleration due to gravity	ft/s^2

* **Corresponding Author.**
Authors' Email Address: [1] **M. Zadnorouzi** (mojtabazn77@gmail.com), [2] **S. A. Faal Rastegar** (saf.rastegar@ut.ac.ir), [3] **A. Hasan-Zadeh** (hasanzadeh.a@ut.ac.ir)

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1. Introduction

Over time, as the reservoir pressure decreases, the well's production rate declines gradually. One way to obtain economical production rates of wells is to enhance the production pressure drop by lowering bottom-hole pressure using the artificial lift method. Approximately 50% of wells worldwide require artificial lift systems (Gou *et al*., 2007). The commonly used artificial lift methods include sucker rod pumping, hydraulic pumping, and gas lift, each of which has its advantages and limitations (Fakher *et al*., 2021).

In 1900, an artificial lift made by compressed air was injected through a ring or pipe where many patents had been issued, but it took nearly 20 years for the gas lift to become an acceptable method of lifting (Elbarbary *et al*., 2015). Gas lift is one of the common methods of artificial lift that can be used a lot due to the availability of gas in Iran. It is a simple, flexible, and reliable artificial lift system that covers a wide range of production rates (Elldakli *et al*., 2014; Syed *et al*., 2020).

The other advantages of the gas lift method include no problem with sandy and gassy oils, being the most cost-effective method for accessing high-pressure oil, lower flow costs than other methods, and applicability in deviated wells plus offshore operations. Limitations of this method include the necessity of having a suitable gas supply and the probability of gas hydrate formation.

In the gas lift method, the gas is injected continuously or intermittently into the lowest possible part of the oil column. This gas aerates the oil and thus reduces the effective density of the fluid. These factors diminish the oil column and the flowing bottom-hole pressures, and finally, the oil can easily move from the reservoir to the well. Also, the gas expansion energy propels the oil to the surface, which can get to the surface more easily, increasing production at the surface.

A gas lift can be done in three ways. In the first method, the gas is injected into the annulus where the fluid is produced from the tubing. In the second method, the gas is injected into the tubing, and the fluid is produced from the annulus. The third method uses two different separate tubings for injection and production (Memari et al., 2017; Sami, 2021; Al-Janabi, 2021). We chose the first method to prevent corrosion of the casing and slugging of produced fluid.

The maximum performance of a gas-lifted well is summarized to maximize oil production by keeping the gas injected into the tubing at a certain level (decided by the constraints of topside production) which may be in an unstable region. In academia and industry, efforts have been made to find optimal conditions and factors (Aamo *et al*., 2005; Eikrem *et al*., 2008; Yadua *et al*., 2020). Coltharp and Khkhar developed a computer gas lift surveillance and gas injection control system installed in Dubai (Coltharp & Khokhar, 1984). Everitt showed that optimizing the gas lift in a large mature field could reduce the gas lift requirements by 50% (Everitt, 1994).

In this paper, we have designed a gas lift system and then investigated the factors affecting the production of wells in one of the oil fields in southern Iran and obtained the optimum value of these factors. At first, the artificial gas lift method is explained, and the appropriate amount of pressure and flow rate of the injected gas is obtained. Then, the effect of injection gas flow rate and depth, the specific gravity of injection gas, tubing diameter, and temperature is investigated on good production. Other factors that influence the performance of a gas lift system, including the reservoir's life, an optimum depth of injection, injected gas pressure, gas injection rate, temperature, and specific gravity of the gas, have been examined. One of the important points of this study is the optimization of all the parameters that have not been addressed simultaneously in the above studies, and of course, the analysis of accurate sensitivities in each case. In each case, the results are visually depicted in the form of graphs.

2. Gas Lift Method

The purpose of gas lift is to have the fluids reach the top at a desirable wellhead pressure while keeping the bottom-hole pressure at a small value to provide a proper driving force in the reservoir. This pressure drawdown must not violate restrictions for sand control and water or gas coning (Economides *et al*., 2013; Nguyen *et al*., 2020).

In this method, the gas is injected continuously or intermittently with a specific pressure and flow rate into the good annulus space. It enters the tubing through the gas lift valves. One or more compressors are used simultaneously to enhance the injection gas pressure.

As displayed in Figure 1, injection gas mixes with the produced well fluid and reduces the density and, subsequently, the flowing pressure gradient of the mixture from the point of gas injection to the surface. The diminished flowing pressure gradient lowers the bottom-hole pressure below the static bottom-hole pressure, thereby creating a pressure difference that allows the fluid to flow from the reservoir into the wellbore.

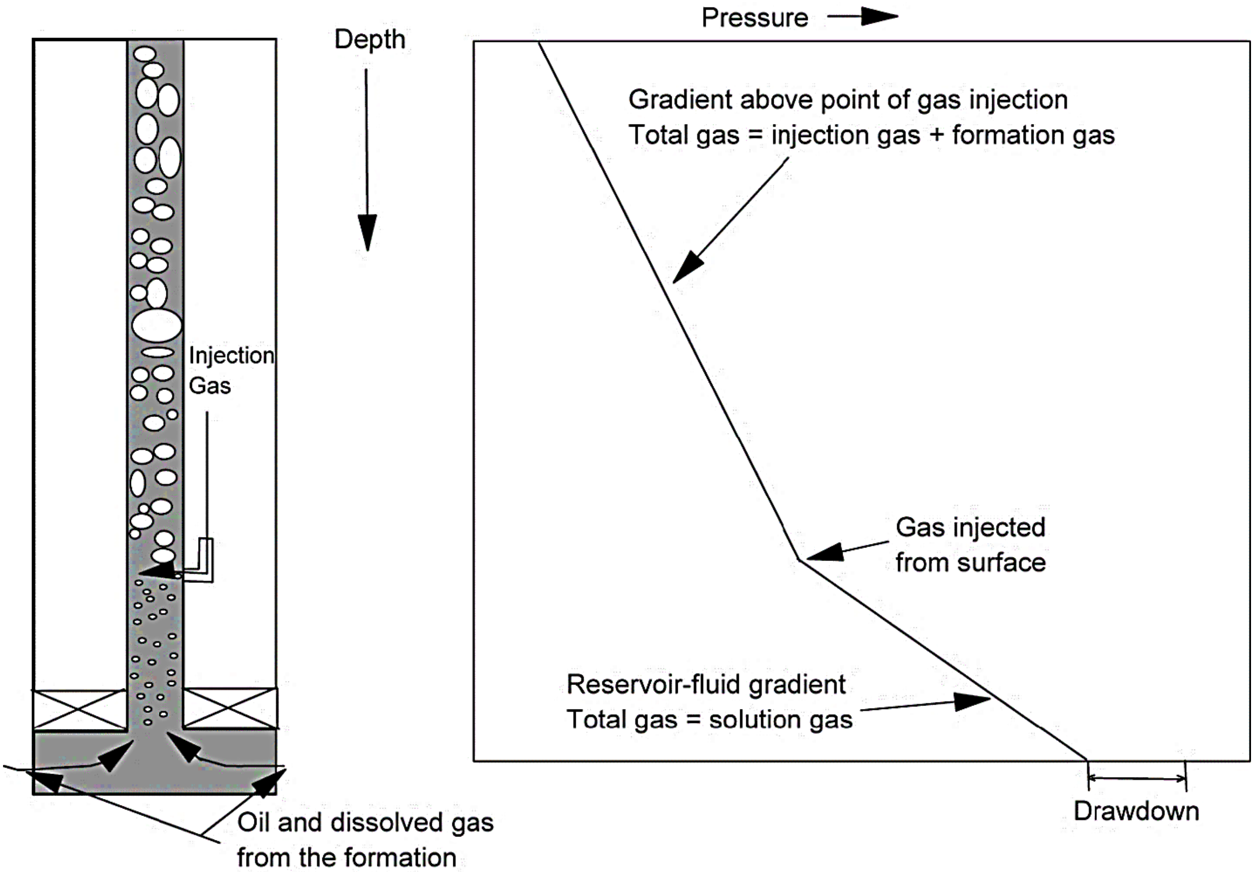

Figure 1- In the left picture, gas is injected continuously into the production conduit at a maximum depth that depends upon the injection-gas pressure and well depth. As it can be seen, the increase in the volume of bubbles is due to the combination of injection gas with well fluid, which indicates a decrease in the flowing pressure gradient of the mixture from the point of gas injection to the surface. In the right picture reducing the flowing bottom hole pressure below the static bottom hole pressure can be seen which is from the point that gas is injected (After Winkler & Blann, 2007).

There are many correlations for the vertical multiphase flow in a well (Beggs & Brill, 1973; Hagedorn & Brown, 1965; Duns & Ros, 1963; El-Moniem & El-Banbi, 2020), which we used the second one. Hagedorn and Brown is an empirical two-phase flow correlation used for pressure loss and holdup. This correlation was derived from data from a 1500-foot well which does not predict the flow pattern. In this correlation, the liquid holdup was not measured but was calculated to satisfy the measured pressure gradient after the pressure gradient due to the friction and acceleration calculated (Brill & Beggs, 1991; Nagoo & Vangolen, 2020). The heart of the Hagedorn and Brown method is a correlation for the liquid holdup (HL) which can be expressed as:

$$144\frac{\Delta p}{\Delta h} = \overline{\rho_m} + \frac{f q_L^2 M^2}{2.9652 \times 10^{11} D^5 \overline{\rho_m}} + \overline{\rho_m}\frac{\Delta\left(\frac{v_m^2}{2g_c}\right)}{\Delta h} \quad (1)$$

$$\overline{\rho_m} = \rho_L H_L + \rho_g (1 - H_L) \quad (2)$$

Where Δp is pressure traverse, Δh denotes depth increment, $\overline{\rho_m}$ is the average two-phase density of the mixture, f represents the friction factor, q_L shows liquid flowrate, M reflects the total mass associated with one bbl of stock tank liquid, D is the diameter of the tubing, v_m denotes two-phase mixture velocity, ρ_L is the density of the liquid phase, ρ_g represents the density of the gas phase, and H_L is the liquid hold-up.

The fluid type must be chosen based on the fluid reservoir. There are two models, including black oil and compositional for the fluid types, with the first one used here. Black oil fluids are modeled into three phases: oil, gas, and water. The amount of each phase is defined at stock tank conditions by specifying gas and water phase ratios, typically the gas/oil ratio (GOR) and the water cut (WCUT). Properties at pressures and temperatures other than the stock tank are determined by correlations. Water is assumed to remain in the water phase. The key property for determining the phase behavior of the hydrocarbons is the solution gas-oil ratio $R_s(P,T)$, which is used to calculate the amount of the gas dissolved in the oil at a given pressure and temperature. In this way, the stock tank volume of the gas dissolved in oil is given by:

$$V_{GS} = R_S \times V_o \qquad (3)$$

Also, for the stock tank volume of free gas:

$$V_G = (GOR - R_S) \times V_o \qquad (4)$$

Many parameters can affect the production rate in the gas lift, with the most important being injection gas flow rate and depth, the specific gravity of injection gas, tubing diameter, and temperature. To get the maximum benefit from the injected gas, it should be produced as much as possible in the production interval.

Using the optimum depth of injection, we must design the location of the injection and lift valves. Choosing the proper gas injection pressure is crucial in designing a gas lift system. Various factors influence the choice of injection-gas pressure. However, the depth of injection stands out above all others. The gas injection pressure must be greater than the flow generation pressure at the same depth. The gas injection rate should be optimized; as the injection rate increases, the production grows to a certain extent and diminishes at higher levels of production (Gou *et al.*, 2007; Hari *et al.*, 2021).

When using the gas lift method, we must also realize the reservoir's life, which declines with pressure over time. If we inject with a certain speed and pressure at the current time, we must increase the gas flow and the amount of gas injected and reduce the effect of reservoir pressure drop over time. In the next section, we introduce the well and reservoir fluid properties and then develop a suitable gas lift system.

3. Case Study: Gas Lift in the Proposed Oil Field

In this section, we intend to consider increasing the production of wells using an artificial Gas Lift design. We can find the right one by examining the different injection rates and the amount produced at the surface. We also consider the appropriate injection depth.

3.1. Well and Reservoir Fluid Properties

The site of this study has been one of the south Iranian oil fields. The reservoir range in this field included the Asmari formation, which has a 45×10 km anticline shape and considerable amounts of oil. We chose a vertical well in this field which was completed with the open-hole method. The minimum wellhead pressure required for flowing to the first separator was 700 psi. The other reservoir fluid and well properties are reported in Table 1.

Table 1. Well and Reservoir fluid properties

Properties	Value
Reservoir Temperature	186 °F
Bottom-Hole Pressure (P_{wf})	2973 psi
Well-Head Pressure (P_{wh})	283 psi
Productivity Index	2.15 Stb/Psi/Day
Water Cut (W.C)	35 %
GOR	320 Scf/Stb
Current Production Rate	500 Stb/D
Production Path	Tubing
Static Pressure (P_s)	3438 psi
Base Depth	2540 m
Tubing Diameter	2.5 in

3.2. Gas Lift Response

Here, the impact of injected gas rate changes is explored on the production at the surface. For this purpose, we assume three pressures of 800psia, 1000psia, and 1200psia and consider the range of gas injection rate variations from 1mmscf/d to 10mmscf/d. In Figure 2, the horizontal axis indicates the injection rate, and the left vertical axis reveals the level of production rate at the surface. In contrast, the right axis shows the best depth of gas injection.

It is observed that for the three different pressures, the production trend first rises and then falls. As the amount of gas injection increases, the oil becomes lighter, and the production grows. Still, from the optimal point onwards, due to the excessive increase in gas, gas produced is more than oil produced, resulting from low oil production. Considering the three graphs, we consider the green diagram and the optimum point as a better and optimal state because, due to the increase in pressure, the rise in production will be significant. Thus, we will consider the pressure of 1000psia and the injection rate of 6 mmscf/d. We have a 156.4 % increase in production in response to gas injection.

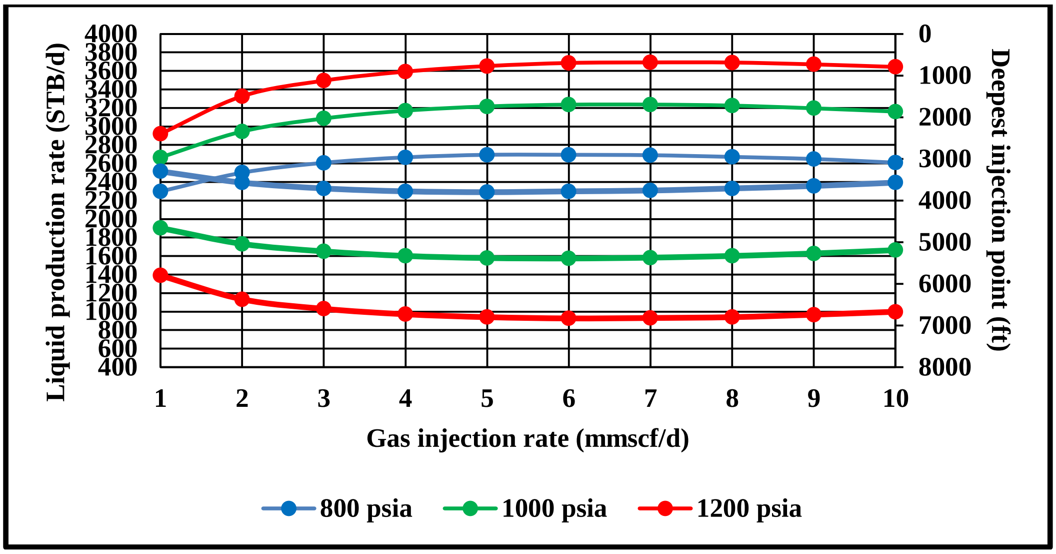

Figure 2- Liquid production rate and depth of injection point vs. gas injection rate.

3.3 Deepest Injection Point

The deepest injection point (DIP) represents the deepest location in the well where the gas can be injected under conditions of production and injection. This value indicates the optimum location of the operating valve. Using the pressure of 1000psia and injection rate of 6mmscf/d, we can obtain the deepest injector depth. The specific gravity of the injection gas is 0.64, and the temperature of the injection gas is 80 degrees Fahrenheit. According to Figure 3, the maximum depth of gas injection by the DIP indicator is 5391.2 feet.

Figure 3. The maximum injection depth is obtained with a specified injection rate and pressure. The dashed grey line specifies the maximum injection depth.

4. Sensitivity Analysis

4.1 The Effect of Tubing Diameter

One of the ways to boost the production rate is to alter the inner diameter of the tubing. Using different tubings, we will notice a change in production. We are currently examining production changes from 2.441 to 3.75 inches. The variations in production also depend on the amount of fluid flowing pressure. In Figure 4, the horizontal axis reveals the inner diameter of the tubing, and the vertical axis represents the rate of liquid produced on the surface. According to Figure 4, production has increased from 2.441-inch to 3.476-inch inner diameter and dropped from 3.476 to 3.75 inches.

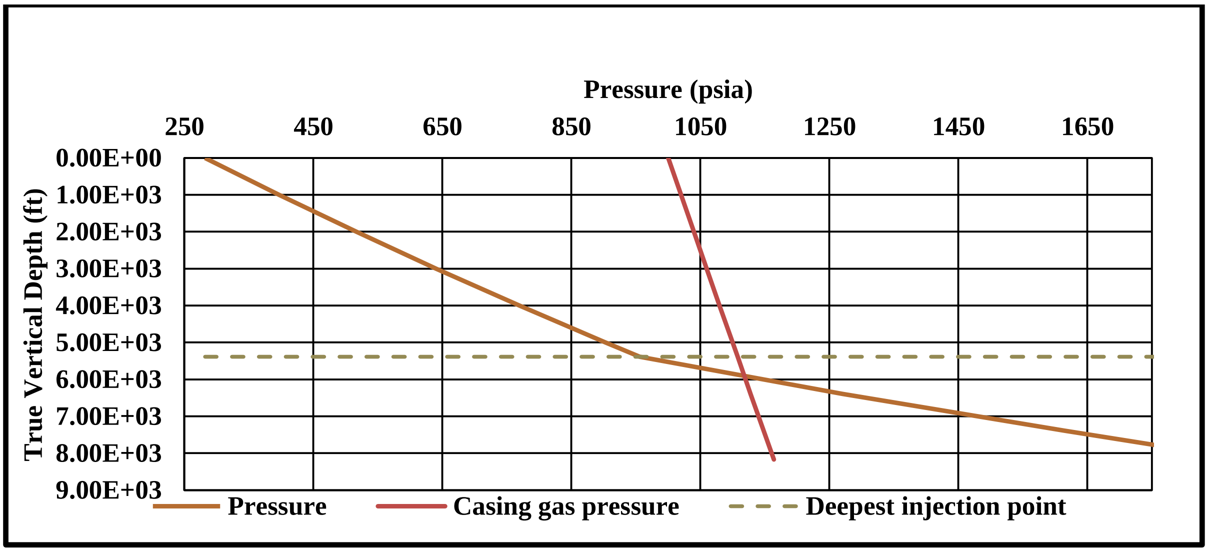

Figure 3. The maximum injection depth is obtained with a specified injection rate and pressure. The dashed grey line specifies the maximum injection depth.

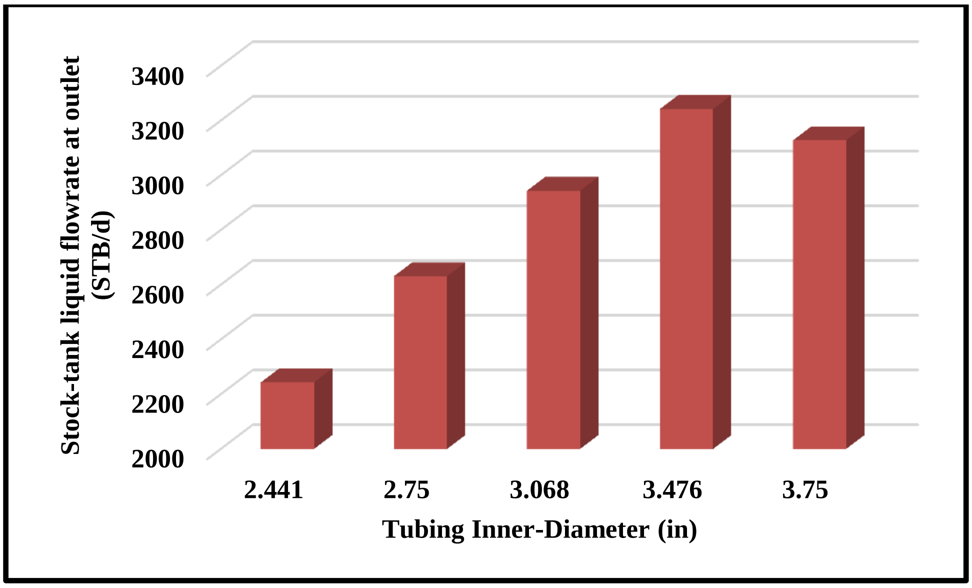

Figure 4- Stock tank liquid flowrate in terms of tubing inner diameter. We have the most production at the optimum point, which is 3.476 inches of inner diameter.

4.2 The Effect of Injected Gas Specific Gravity

In this step, we examine the specific gravity changes of the injection gas and its impact on surface production. In Figure 5, the horizontal axis indicates the injection gas specific gravity, and the vertical axis represents the production at the surface. As can be seen, the diagram has generally decreased with increasing specific gravity as the injection gas became heavier. Also, the production fluid weight has increased proportionally, so its ability to produce diminishes as it reaches the surface.

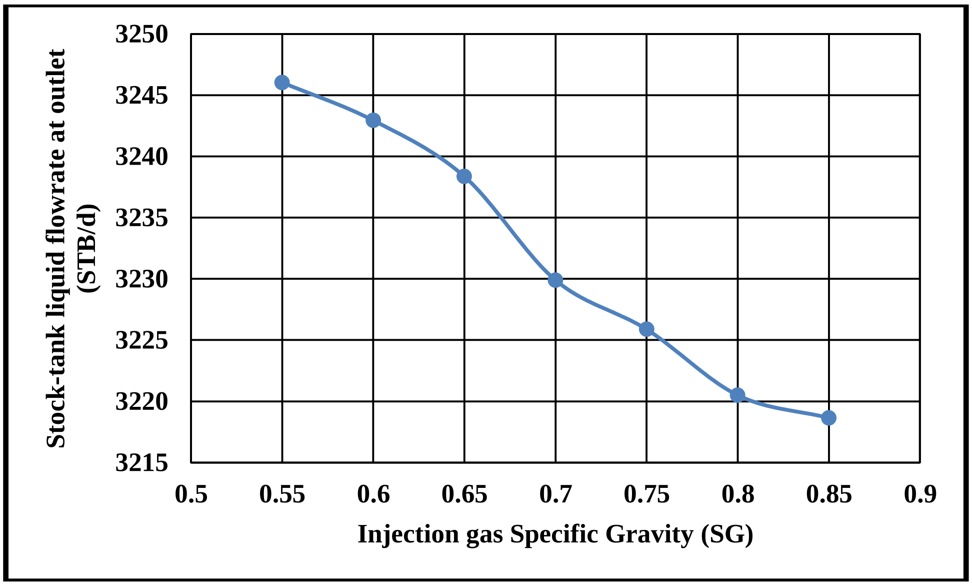

Figure 5- Stock tank liquid flowrate in terms of specific gravity of the injection gas – As it can be seen, it is generally a downward trend.

4.3 The Effect of Injected Gas Temperature

This part discusses the temperature changes of injection gas and its impact on production. For this study, we consider the range of injectable gas temperature variations from 60 degrees Fahrenheit to 400 degrees Fahrenheit. We observe the liquid production rate at the surface as the temperature rises. The horizontal axis in Figure 6 shows the temperature of the injection gas, and the vertical axis reveals the production. As can be seen, the trend line is almost descending, but the decline is minimal and not significant. As the temperature of the injectable gas increases, the amount of liquid production at the surface decreases slightly.

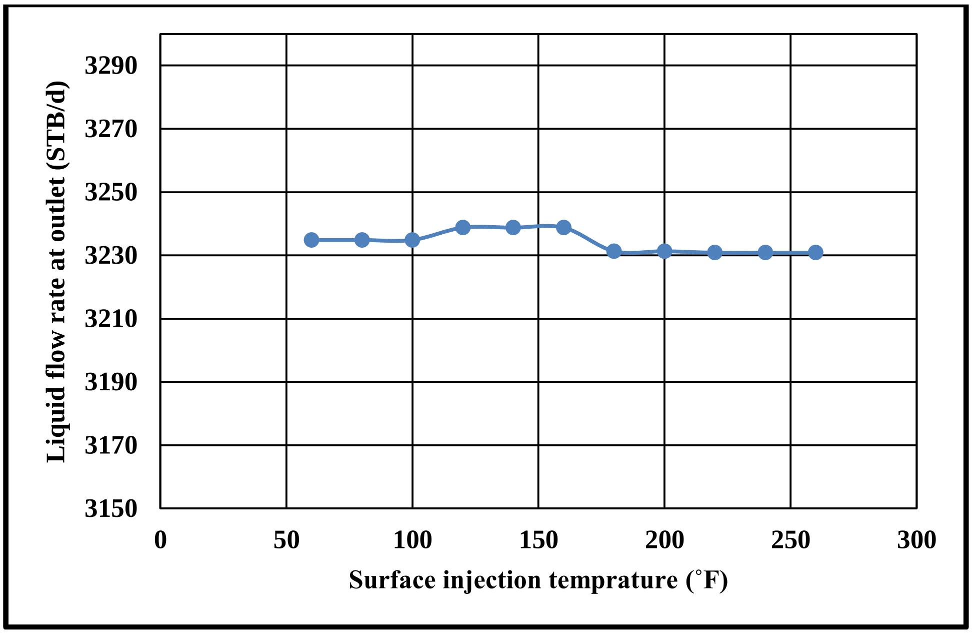

Figure 6- Stock tank liquid flowrate in terms of injection gas temperature. Generally, its impact is negligible.

4.4 The Effect of Water Cuts on Producing Flowrate

Water production is one of the most severe problems in the oil industry. Controlling water production in various ways improves oil production. Water cut is the ratio of water produced compared to the volume of total liquids produced. Increasing the water cut due to its separation at the surface increases the cost. This section investigates the effect of water cut changes on the oil flow rate. Figure 7 depicts the water cut of production fluid from 20% to 50% and the associated flow rate for each percentage. As can be seen, the production rate drops with the increase of the water cut since the ratio of water to oil grows, and oil production decreases.

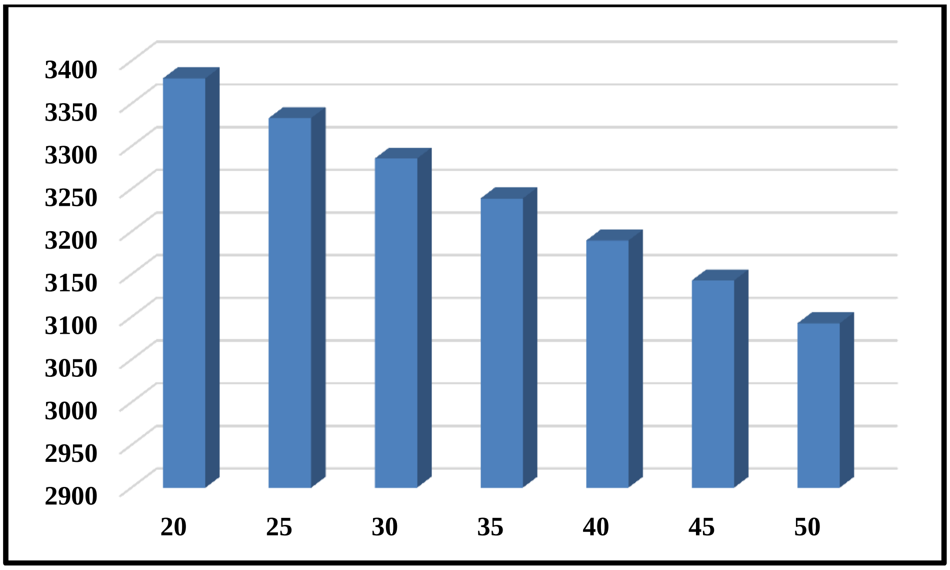

Figure 7- The effect of water cuts on oil-producing flowrate. As the water cut increases, the oil flow rate declines.

5. Conclusions

Reservoir pressure and, subsequently, oil production diminishes over time. Injection of gas to boost production is a common artificial gas lift, especially in areas with large gas availability. This study used the gas lift in a new method to enhance the good production rate in one of the south Iranian oil fields.

We investigated the effect of flow rate, pressure, temperature, and specific gravity of the injected gas and changes in the pipe diameter in oil production. Injection gas rate and pressure had an optimum point; the tubing diameter at one point had the highest output. As the specific gravity of the injection gas increased, production generally decreased. As the temperature of the injection gas rose, diminished decreased slightly. We can produce a better and more ideal product based on these conclusions, and this is one of the advantages of the optimization method used in this study. Sensitivity analysis was performed well for each parameter to obtain sufficient accuracy and reliability of the optimization process used. In response to gas injection, we achieved a 156.4 % increase in production.

In order to expand this study, by examining and analyzing the sensitivity of other properties of injected gas and also examining different chemical compounds of injected gas with different percentages, more accurate results can be obtained from the effect of other properties of injected gas on increasing oil production.

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