Gas Lift Optimization for a Sudanese Field

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ABSTRACT- Gas lift is mainly used to decrease bottom hole flowing pressure resulting from fluid hydrostatic pressure and rapid decrement in reservoir pressure. Available gas amount and compressors capacity are the main limitations to this method, thus optimization in each well is the key for the highest recovery. In this study the problem of allocating limited gas to wells network was addressed, the under-study field suffers from production deferment due to gas injection instability which is 40% of the total field production. A commercial multiphase simulator was used to model the field wells and coupled with the nonlinear weighted incremental gradient equations and simulated several scenarios for gas injection limitation for the total network. the multiphase flow correlations were considered, Begs and Brill was found to be the most accurate correlation for this field. The optimization resulted in several changes in the lift gas for each well; total injection rate incrimination was not affecting the overall oil production rate. Optimum gas injection rate is 7 MMscf\D which is 1 MMscf\D less than the current situation and the oil rate is 8% increased. Some wells cannot benefit from the optimization due to their high water cut and low reservoir pressure. Finally, the economic analysis showed that the 7 MMscf\D optimized injection rate is suitable for this field with 12% income in a daily rate.

Keywords - Production optimization, Injection rate allocation, Network Modeling, Key field

المستخلص- تستخدم تقنية الرفع بالغاز بشكل أساسي لتقليل ضغط الجريان في اسفل البئر الناتج عن الضغط الهيدروستاتيكي للمائع والانحدار السريع في ضغط المكمن. تعد كمية الغاز المتاحة وقدرة الضواغط المؤثر الرئيسي لهذه الطريقة ، وبالتالي فإن تحسين كل بئر هو المفتاح لتحقيق اعلي انتاج.في هذه الدراسة ، تمت مناقشة مشكلة توزيع كميات محدوده من الغاز في شبكة من الآبار ، حيث يعاني الحقل قيد الدراسة من نقصان الانتاج نتيجة لعدم استقرار حقن الغازحيث تشكل نسبة الانتاج بالرفع بالغاز 40% من انتاج الحقل الكلي. تم استخدام برنامج محاكاة تجاري للسريان متعدد الاطوار لنمذجة آبار الحقل إلى جانب معادلات التدرج والترجيح غير الخطية وتمت محاكاة العديد من السيناريوهات لعمليه حقن كميات محدوده من الغاز للشبكة الكلية. اخذ في الاعتبار تصحيحات الجريان متعددة الاطوار ،ووجد إن معادلة Begs وBrill هي الانسب والأكثر دقة لتمثيل هذا الحقل. أدى التحسين إلى العديد من التغييرات في الغاز المستخدم للرفع في كل بئر ؛ ووجد ان زياده إجمالي معدل الحقن لا يؤثر علي معدل الانتاج الكلي للزيت. معدل الحقن الأمثل للغاز هو 7 مليون قدم مكعب لكل يوم وهو أقل ب مليون قدم مكعب لكل يوم من الوضع الحالي ومعدل الزيادة في انتاج الزيت هو 8 ٪. بعض الآبار لا يمكن أن تستفيد من التحسين بسبب ارتفاع محتواها من المياه وانخفاض الضغط في المكمن. أخيرًا ، أظهر التحليل الاقتصادي أن معدل الحقن المحسّن 7 مليون قدم مكعب لكل يوم مناسب لهذا الحقل مع زيادة في الدخل 12 ٪ يوميا.

INTRODUCTION :

Gas lift is a form of artificial lift used mainly to increase the oil production rate of low-pressure reservoirs [1]. It is a method of lifting fluids from bottom hole of a well by injecting pressurized gas continuously to enhance the reservoir energy so that the reservoir pressure is able to lift the oil column and then forces the fluid out of the wellbore (continuous flow), or by injecting gas underneath an accumulated liquid slug for a short period to move the slug to the surface (intermittent lift). The injected gas moves the fluid to the surface by one or a combination of the following: reducing the fluid load pressure on the formation because of decreased fluid density, expansion of injected gas, and displacing the fluid [2,3].

Gas lift is the most desirable artificial lift method especially when the gas required for injection is available. Gas lift is low-priced compared with rod pumps, easy to put into operation, very effective in the wide range of operation conditions, requires

less maintenance and maximum liquid production could be achieved [4].

The goal of gas lift is to supply the fluid to the top of the wellhead while keeping the bottom hole pressure low enough to provide high pressure drop between the reservoir and the bottom hole. Decrease of bottom hole pressure due to gas injection will normally increase fluid production rate because gas injection decreases the density of the fluid column, therefore larger amounts of fluid flow along with the tubing.

However, injecting too much amount of gas increases the bottom hole pressure which decreases the oil production rate. This happens because the high gas injection rate causes slippage, where the gas phase moves faster than liquid, leaving the liquid phase behind. In this condition, less amount of liquid will flow along with the tubing.

Hence, there should be an optimum gas injection rate and optimum gas injection point for maximum oil production which is could be shown by continuous gas lift Performance curves [5,6]. A successful design was achieved in [7] by modifying the size of the orifice to optimize available pressure and gas required to open the closed wells and still sustain other gas lifted wells connected to the same gas lift manifold.

The estimation of pressure drop for multiphase flow in oil wells is one of the most complex problems in oil field practice which can affect the gas lift design and calculations. For instance, an evaluation for three of the most used correlations; the Hagedorn and Brown, Duns and Ros, and Orkiazewski methods were performed [8]. The accuracy of these correlations was determined against multiphase flow pressure drop data from 44 wells.

Orkiazewski correlation was found to be most accurate for engineering design usage and was the only correlation that could evaluate a three-phase flow condition. In this study, we will follow the same methodology to determine the most usable correlation for the field under study. In some cases, the influence of the water cut in the gas lift optimization process will require combining the statistical data from producer wells with multiphase flow correlations to estimate the uncertainty in the production variables. A mathematical optimization model such as the Mixed Integer Linear Programming Technique (MILP) could be used for linearizing the oil well performance curves [9].

Several studies were established for gas lift design and the problem of allocating injected gas in a network of wells. An optimization strategy was presented that iteratively adjusted gas-lift allocation and solve the full network until a minimum lift efficiency was achieved at all wells. This strategy was developed using a linear programming model to scale the gas-lift and production rates and to satisfy network flow rate constraints. In general, the computational cost of this method is significantly higher, as a large number of full network solutions may be needed for optimization calculations [10].

A different and more efficient optimization scheme was proposed, this scheme finds the optimal distribution of the available gas to maximize a benefit function and its subjected to surface pipeline network rate and pressure constraints, this procedure was formulated as a nonlinearly constrained optimization problem solved by the Generalized Reduced Gradient (GRG) method. The values of benefit function, constraint functions, and derivatives needed for optimization can be evaluated through solving the full-network equations using Newton iteration, which considers the flow interactions among wells [11].

An intelligent genetic algorithm was utilized recently [12], it has been developed to simultaneously optimize all the factors affecting the gas lift allocation such as gas injection rate, injection depth and, tubing diameter which will lead the maximum oil production rate with the water cut and injection pressure as the restrictions of the equations.

For big fields that consist of hundreds of strings, gas lift injection system uses Integrated Operation (IO) models that is updated continuously using live data feed and automated technical workflow, this could establish numerous cases from different scenarios to identify production bottlenecks via simulated network models for providing various optimization scenarios for gas lift [13].Also, some workflows comprises a reservoir and flow assurance simulators, achieving more accurate responses compared to regular workflows[14].

About the Field:

Keyi Oil field is located on the western escarpment of Fula Sub-basin in Muglad Basin which has been subdivided into three main structures (Keyi North, Keyi Main and Keyi South) and has been put on production since September 15th, 2010 and producing from five formations which are Ghazal, Zarqa, Aradieba, Bentiu and Abu Gabra. Table 1 describes the OOIP for the mentioned formations.

This field consists of 39 wells, 7 wells in Keyi North, 26 wells in Keyi Main and 5 wells in Keyi South **Figure 1**.

TABLE 1 OOIP FOR KEYI FIELD

Formation	Ghazal +Zarqa	Aradeiba +Bentiu	Abu Gabra	Total
STOIIP (MMSTB)	40.626	14.45	34.97	90.05

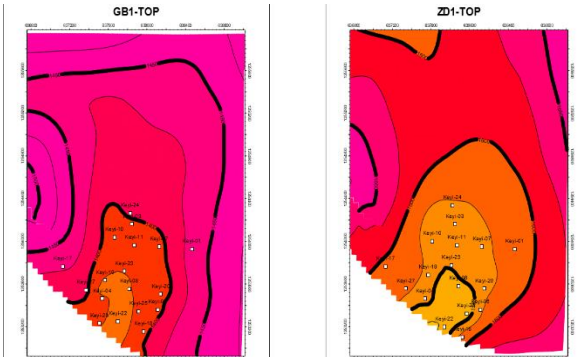

Figure 1 Formation tops for Keyi Main

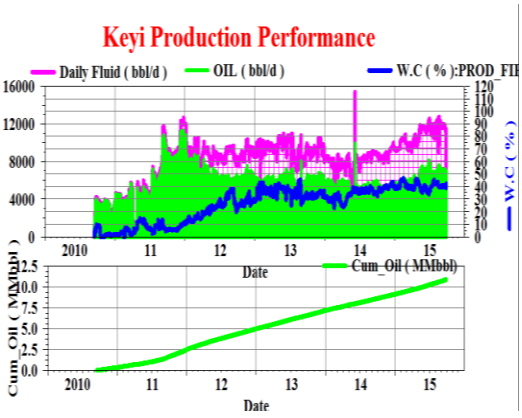

Figure 2 Keyi field production performance

15 wells are producing by the gas lift with an oil rate of almost 2500 STB/D. **Figure 2**, currently the field is suffering from instabilities in the gas lift wells due to the lack of gas and the increment in water production which is decreasing the total productivity of the field, in this study the problem of allocating limited gas to wells network will be addressed.

Materials and Methods:

A network model was created for the gas lift wells to estimate the optimum gas injection rate and the better distribution for the limited gas source using Network Simulation Software, all the data for wells (reservoir, completion, gas lift, flow line and well location data) were implemented in the model and also to estimate the productivity index for the wells with high uncertainty and no accurate reservoir data **Figure 3**.

The created model was encountered for each component of the production system separately which contributes to overall performance, and then allows verifying each model subsystem by performance matching. In this way, the program ensures that the calculations are as accurate as possible.

Once the system model has been tuned to real data, the simulator was used to model the network in different scenarios and to make forward predictions of the reservoir pressure based on surface production data.

Productivity index (J or PI) of a well measures the capability of the sand face to deliver liquid at a rate corresponding to a certain pressure drop from the static reservoir pressure to the flowing bottom hole pressure and it could be described as:

$$J = \frac{ck_{avg}H}{\beta_O \mu_{avg} \ln(\frac{r_o}{r_w})} \quad (1)$$

Where c is a constant, K is the reservoir permeability, H is the reservoir thickness, Bo is the oil formation volume factor, μ_{avg} is the average viscosity r_o and r_w are the reservoir and the wellbore radiuses respectively.

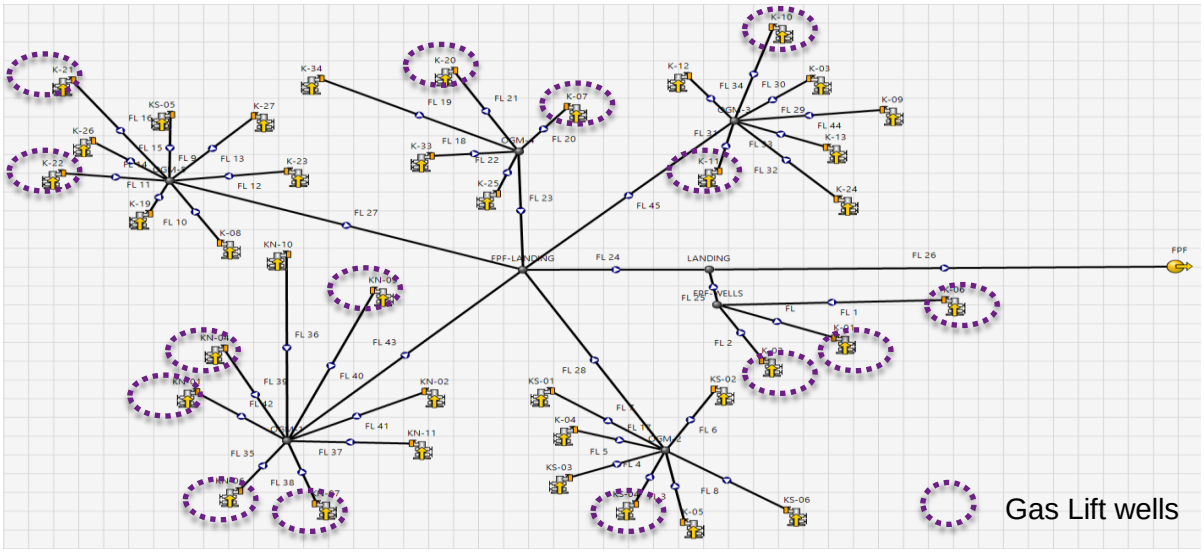

Figure 3 Keyi field Network model

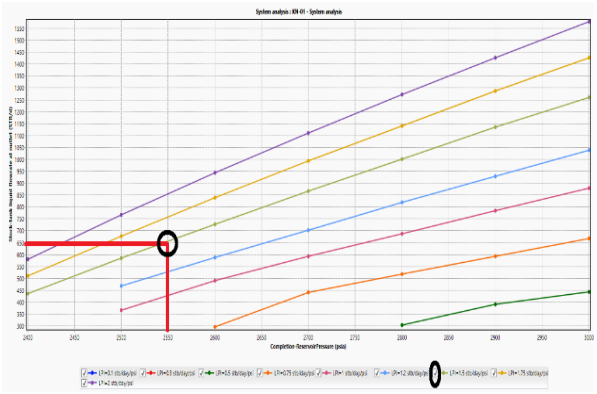

Figure 4 Sensitivity analysis for PI between 0.1 to 2 STB/D/PSI

Therefore, the oil rate increases as the productivity index increases for the same pressure drop. A sensitivity analysis was done for all wells to determine the acceptable productivity index. The productivity index for all wells was not available but the test results with other reservoir parameters estimated the PI for all the field wells to be between 0.1 and 2 STB/D/psi. **Figure 4.** The problem of gas lift allocation could be described mathematically as:

$$F(x)=Q_o R_o + Q_g R_g - Q_w R_w \quad (2)$$

where, Q_o, Q_g, Q_w, Q_{glift} are the total volumetric flow rate of oil phase production, gas phase production, water phase production, and gas-lift injection at surface condition, respectively; R_o is the unit value of the oil phase; R_g is the unit value of the gas phase; R_w is the unit processing cost of water phase; and R_{glift} is the unit operating cost of gas-lift [15]. this nonlinear equation could be solved by different approaches, but a commercial simulator was used here for the modeling accuracy and the ability to optimize different scenarios.

It's important to identify suitable vertical lift performance (VLP) correlation because it is a critical factor in gas lift calculations. This identification affects directly the number and distribution of valves and the measurements of the injected gas. Investigation on the VLP has been done, Four VLP correlations have been tested in selected wells for different formations.

Table 2 shows the least percentage deviation from the field data for selected wells along with the corresponding correlation.

TABLE 2: EMPIRICAL CORRELATIONS COMPARISON RESULTS FOR A SAMPLE WELL K-N-01

Empirical Correlation	Tuned RMS
Begs and brill	33
Duns and Ros	47
Orkiazewski	39
Hagedorn and brown	40

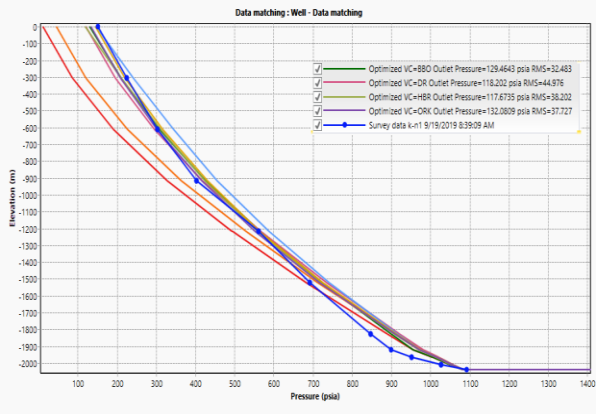

Figure 5 Multiphase flow correlation comparison sample well K-N-01

Begs and brill found to be applicable in 3 types of formations and this result was consistent in several wells **Figure 5**.

Finally, the model was tuned for the most accurate multi-phase flow correlation; and the network simulator was used to handle the gas lift optimization tasks.

The optimization procedures started with dividing the lift gas supply into discrete increments of uniform size and examine the effect of increasing lift gas to each well by one increment. The well's weighted incremental gradient was calculated, then examined the effect of reducing lift gas to each well by one increment.

The well's weighted decremented gradient also was calculated and finally added lift gas to the well as long as its weighted incremental gradient larger than the minimum economic gradient. **Figure 6.**

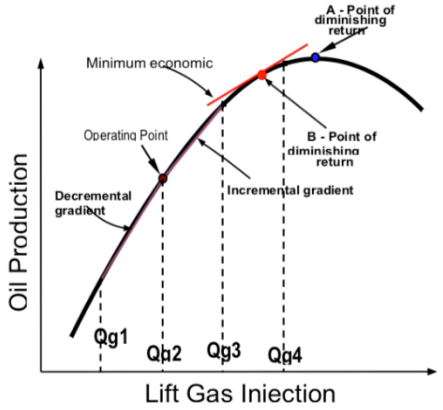

Figure 6 injection rate optimization for single well

Whenever a lift gas increment is added or subtracted, a weighted incremental gradient and weighted decremented gradient must be recalculated for all the wells in the field because the change in Q affects THPs of other wells in the network.

Each time-weighted incremental gradient and weighted decremented gradient were recalculated, the total network was rebalanced and the computation time proportional to the square of the numbers of wells multiplied by numbers of lift gas increments added or subtracted. **Figure 7.**

Results and Discussion

After completing the network model was, it was essential to calibrate it and do a history matching to the actual field production data in order to make it representative of the actual production network. The history match process involves reproducing actual measurements of flow rates and pressures by simulating the model with consideration of the production constraints.

The gas lift performance curves for all the wells were generated for a range of gas lift injection rates from 0 to 1 MMscf/D for all the wells to compare the network results and allow the gas lift optimization solver to select the optimum for each well.

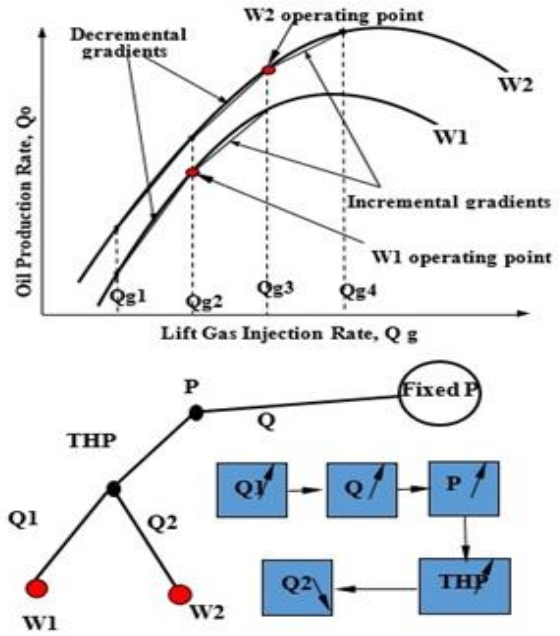

Figure 7: injection rate optimization for Multiple wells in a network

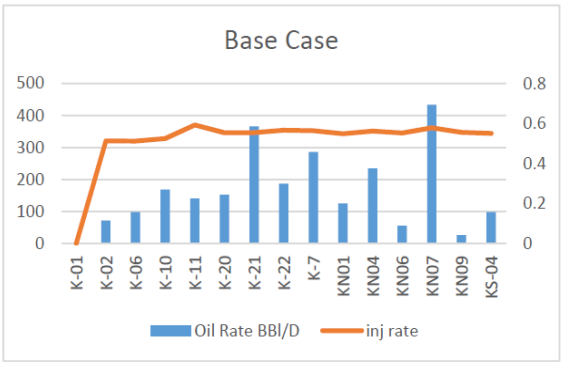

Figure 8: Base Case Scenario Injection rate 8 MMscf/D

The network was solved for a base case to test the current condition and calculate the total gas required along with the fluid produced, the optimization process started for different cases with the assumption for limited gas injection with a maximum of 8.5 MMscf/D with is the maximum amount that could be supplied by the gas compressors. the increment in oil production was calculated for each 0.5 increments in gas injection rate. The injection rate distribution is illustrated in **Figurers** 8 to 12, the base case scenario has been simulated through the simulator network solver and then its result used for the optimization for comparison purposes.

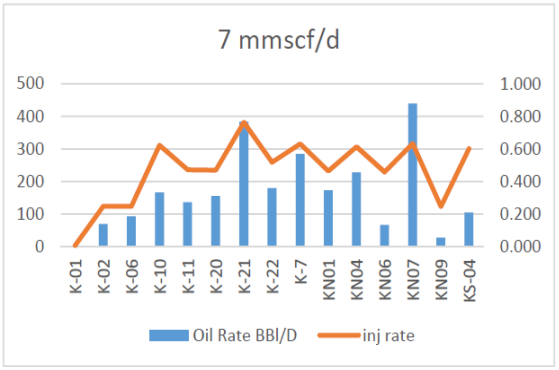

Figure 9 Optimized Total Gas injection rate=7 MMscf/D

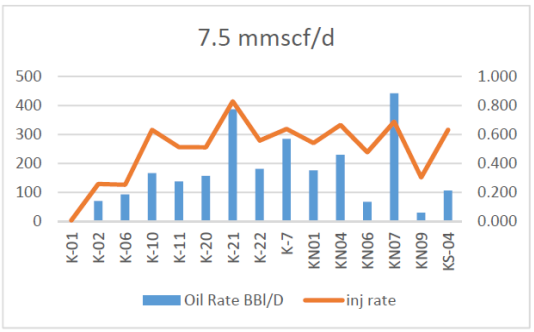

Figure 10 Optimized Total Gas injection rate=7.5 MMscf/D

The results showed that the optimization process could add over 200 STB/D by redistributing the currently available gas injection rate. **Table 3**.
The optimization resulted in several changes for the lift gas for each well, the total injection rate incrementation was not affecting the overall oil production rate. the optimum gas injection rate is 7 MMscf/D which is 1 MMscf/D less than the current situation and an 8 % increase in oil rate.

There are some wells cannot benefit from this optimization such as Keyi-01, KN-06, and KN-09 and that's due to their high water cut and low reservoir pressure.
Finally, an economic analysis was conducted to evaluate the total process and determine the feasibility of increasing the injection rate from the optimized base case, the rate of 25 $/BBL and 2.08 $/MMBtu was used as the current price for

the oil and gas, if the increased gas treated as an extra cost and deducted from total income it will decrease the total income as a result of increasing the injection rate, this prove that the 7 MMscf/D optimized injection rate is the suitable for this field and with 12 % more income in daily rate than the base case with no optimization. **Table 4.**

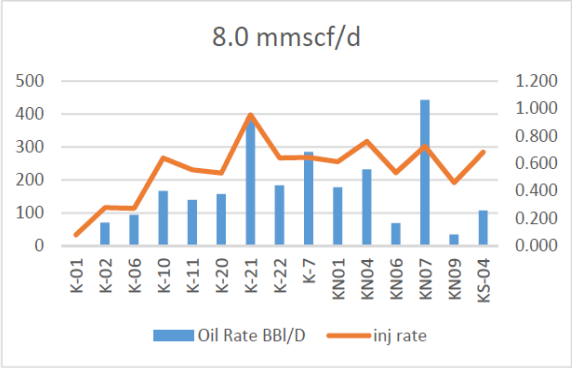

Figure 11 Optimized Total Gas injection rate=8 MMscf/D

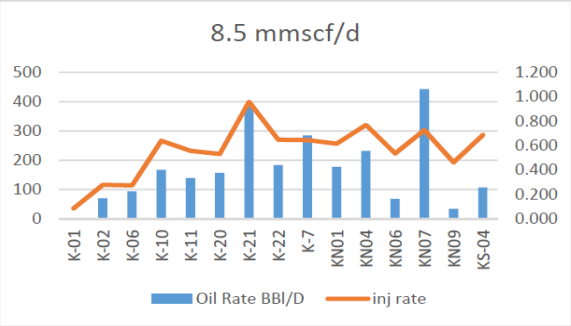

Figure 12 Optimized Total Gas injection rate=8.5 MMscf/D

Table 3: Final optimization results

CASE	GAS LIFT RATE	TOTAL GAS RATE	LIQUID RATE	OIL RATE	WATER RATE	WATER CUT	GOR SCF/STB	OIL INCREASE
BASE CASE	8.0	9.18	4553	2444	2109	46	3756	-
7 MMSCF/D	7	7.27	4670	2650	2020	43	2743	206
7.5 MMSF/D	**7.50**	**7.77**	**4806**	**2661**	**2145**	**45**	**2921**	**217**
8 MMSF/D	7.93	8.20	4895	2680	2215	45	3225	236
8.5 MMSCF/D	8.42	8.69	4899	2681	2218	45	3243	237

Table 4 : Economic analysis for different injection rates

INJ-RATE MMSCF/D	INCOME $/D	0.5 MMSCF GAS PRICE $	TOTAL INCOME $/D	DECREMENT $/D
8 (BASE CASE)	61,100	2080.00	59,020	(7230)
7	66,250	-	66,250	-
7.5	66,525	1,040.00	65,485	(765)
8	67,000	2080.00	64,920	(1330)
8.5	67,025	2600.00	64,425	(1825)

Conclusions and Recommondations

In this research, a network-based model was created to test the gas lift system in Keyi field, the production test results and pressure surveys data were used to calibrate the model and ensure the accuracy alongside the calibration of the multiphase flow correlations. Gas lift optimization analysis was performed for deferent gas injection rates, and the results showed that if the gas injection rate increase there will be some incrementation in the oil production but with limitation to the economic factors.

The optimum injection rate was selected according to economic analysis, the main conclusion of this study is that optimizing the current inject gas rate could benefit the field total recovery.

There are some wells such as K-01 couldn't benefit much from the optimization due to their high water cut and the recommendation here is to shut them and transfer them into another type of artificial lift wells.

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