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RESEARCH ARTICLE

Evaluation of Gas Lift Deepening Design Using a Retrofit Gas Lift System to Increase Well Production in an Offshore Field: Case Study of Well S-7

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Abstract

Well S-7 is a horizontal well in the NDF Field that produces hydrocarbons from carbonate formation for over seven years using gas lift. Over time, Well S-7 has experienced a significant decline in production due to reservoir pressure along with an increase in water cut. To address this issue, a well intervention was conducted to deepen the injection point by installing Retrofit Gas Lift technology, aiming to enhance the well's production to an optimal level. This research focuses on evaluating the application of Gas Lift Deepening using Retrofit Gas Lift (RGL) in Well S-7 through well modeling methods with PROSPER software and providing recommendations for an optimal Gas Lift Deepening design. The study analyzes well modeling for Well S-7 before and after RGL installation, validated using well test data to compare production performance in both scenarios. The evaluation proceeds by identifying the parameters that influence the effectiveness of the Retrofit Gas Lift (RGL), followed by designing an optimized RGL system to enhance production performance. Based on the research, the installation of the Retrofit Gas Lift (RGL) in Well S-7 resulted in an increase in the production rate of 78.58 STB/d. Sensitivity testing identified key factors influencing the production rate, including reservoir pressure, top node pressure, gas injection rate, coiled tubing size, and coiled tubing length. Design optimization by adjusting the top node pressure to 130 psi, coiled tubing length to 2000 ft, coiled tubing size to 1.75 in, and gas lift injection rate to 1 MMSCFD resulted in an increased flow rate of 220.86 STB/d and a drawdown of 751.77 psi.

Keywords: Gas Lift, Retrofit Gas Lift, Horizontal Well, Well Modelling, Nodal Analysis

1. Introduction

Indonesia aims to achieve a production target of 1 million barrels of oil per day and 12 billion cubic feet of natural gas per day by 2030. In response to this goal, optimizing oil and gas field production can significantly contribute to increasing national energy output. Production technology development through artificial lift is one potential solution for enhancing oil and gas production. Artificial lift is a method used to add energy to the fluid flow in a well to increase the flow rate (Bellarby, 2009). This can be achieved using positive-displacement downhole pumps, such as beam pumps or Progressive Cavity Pumps (PCPs), which aim to reduce the flow pressure at the pump intake. Additionally, it can be achieved by injecting high-pressure gas through a valve near the bottom of the well (Mehran, 2022). Gas lift is one artificial lift option that has a significant impact on production increase with cost-efficiency.

Well S-7 is a horizontal production well located in the NDF Field in the Indonesian Sea. This well specifically targets hydrocarbon fluid production from carbonate formations using a gas lift artificial lift system and has been producing for over seven years. Over time, the well has experienced a substantial decline in production. This production decline can be attributed to several factors, one of which is a decrease in reservoir pressure accompanied by an increase in water cut values in the well. To address the issue of declining well production, optimization of the gas lift system installed in this well is necessary. The performance of the gas lift can be optimized in several ways, including optimizing the gas injection rate and deepening the injection point. In this case, valve replacement to deepen the injection point is no longer feasible, as the injection point in this well is already at the orifice, and the other SPM (side pocket mandrels) have dummy valves installed. Additionally, optimizing the gas injection rate by increasing the injection rate has already been attempted but has not yielded significant results. To overcome this issue, a well intervention was conducted to deepen the injection point by installing Retrofit Gas Lift technology, which aims to optimally increase well production. This technology was implemented because the conventional gas lift installed in the well could no longer deepen the injection point or change the orifice size.

This study focuses on evaluating the application of Gas Lift Deepening using Retrofit Gas Lift (RGL) on Well S-7 with well modeling methods using PROSPER software and providing a design recommendation for Gas Lift Deepening using RGL, which is expected to enhance well productivity and achieve optimal production rates. In this study, a comparison of well production results before and after applying RGL technology, as well as variables affecting the effectiveness of RGL in increasing well production, will be analyzed in depth. The study will also discuss optimal RGL design recommendations for Well S-7, allowing this technology to be implemented effectively and expected to enhance well productivity and achieve optimal production rates.

2. Gas Lift

Most oil reservoirs are volumetric, with drive mechanisms relying on dissolved gas expansion as reservoir pressure decreases due to fluid production. One way to achieve high well production rates is by enhancing production pressure drawdown, which is achieved by reducing bottom hole pressure through artificial lift methods (Guo et al., 2017). Nearly 50% of wells worldwide require artificial lift systems to produce hydrocarbons (Bellarby, 2009). Gas lift is one of the artificial lift methods that significantly boosts production efficiently. This technology works by injecting compressed gas into the lower part of the tubing through the casing-tubing annulus and an orifice installed in the tubing string. Upon entering the tubing, the gas impacts fluid flow within the tubing through the expansion energy principle, pushing oil to the surface. The gas dissolves in the oil, reducing fluid density, making it easier for the oil to reach the surface. **Figure 1** displays the various types of gas lift techniques.

2.1 Continuous Gas Lift

Continuous gas lift is a method commonly used for producing mature and depleted reservoirs that can no longer flow naturally. However, it is also often applied during the start-up phase of production wells (de Souza et al., 2010). Continuous gas lift works by injecting gas through the well annulus into the production fluid column to reduce the hydrostatic pressure of the produced fluid by decreasing its density. Advantages of continuous gas lift include its ability to produce wells with high sand content, high deviation, and high gas-to-oil ratio, which are typically not producible with other artificial lift systems (Chia and Hussain, 1999). For optimal gas lift operation, the system design should allow injection through a single valve at the deepest possible depth according to the available injection pressure. Maximum benefit from continuous gas lift can be achieved by injecting gas at the deepest point in the well, which minimizes the required gas volume to reach the desired bottomhole pressure (Beggs, 2003).

2.2 Retrievable Gas Lift

The principle of Retrievable Gas Lift (REGAL) is to add a gas lift system to produce from depleted reservoirs. REGAL has two types based on the injection location: Gas Lift Macaroni (GLM) and Gas Lift Annulus (GLA). GLM operates by inserting an injection tubing called macaroni into the wellbore to the desired gas lift injection depth. In GLM, the macaroni runs from the swab valve at the wellhead to the desired injection depth. While GLM is the basic option for REGAL, it can only be used for wells that cannot flow at atmospheric pressure (non-eruptive wells), as the upper and lower master valves cannot be closed as a safety barrier. Alternative options exist for eruptive wells, but they require A-annulus integrity checks (annulus directly to the production tubing). In cases where eruptive wells lack A-annulus integrity, GLM can be safely installed using an additional spool, which connects the gas lift line to the macaroni under the x-mass tree, allowing the master valves to remain operable (Syarafi Ashfahani et al., 2018).

Siphon string gas lift operates similarly to GLPO but has a longer pipe section, creating a new annulus for a deeper gas lift injection point. This string is generally used when GLPO cannot be installed due to annulus restrictions. Siphon string gas lift comprises a top packoff integrated with lower sealing elements. The space between these elements allows for the installation of one or more gas lift mandrels. Due to the heavier string installation, a snubbing unit is required for its setup (Shobar et al., 2019).

2.3 Retrofit Gas Lift

Installing coiled tubing can provide a solution for GLPO to achieve a deeper gas lift injection point. The coiled tubing runs down to the target injection depth in GLPO, where gas lift flows through A-annulus into the orifice and further into the siphon string to reach the target injection depth (Syarafi Ashfahani et al., 2018). This technology, known as Retrofit Gas Lift (RGL), combines the advantages of GLA and GLM. The RGL system offers a solution for reviving dead wells or optimizing production in active wells with minimal risk and lower costs. RGL is designed to enable gas injections below the existing production packer, to an optimal point in the wellbore where gas lift can maximize well performance (Al-arbi Ganat et al., 2020).

The RGL system (**Figure 2**) is a two-trip straddle injection system that consists of two packers and a crossflow diverter sub with dual flow paths. The packers clamp onto an existing gas lift mandrel or sliding side door (SSD), serving as the entry point for injected gas. The gas lift is directed to the perforations (or optimal gas lift point) through the crossflow diverter sub and into the injection string or tailpipe, which can be coiled tubing or jointed pipe. Produced fluids and gas flow to the surface through the

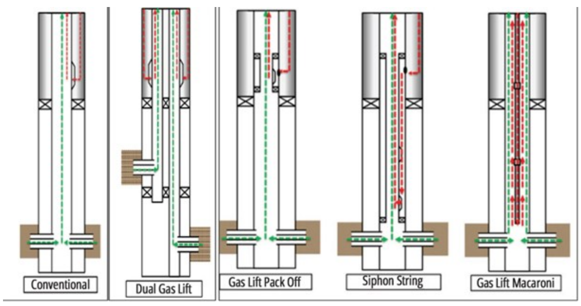


Fig 1. Gas lift type (Syarafi Ashfahani et al., 2018).

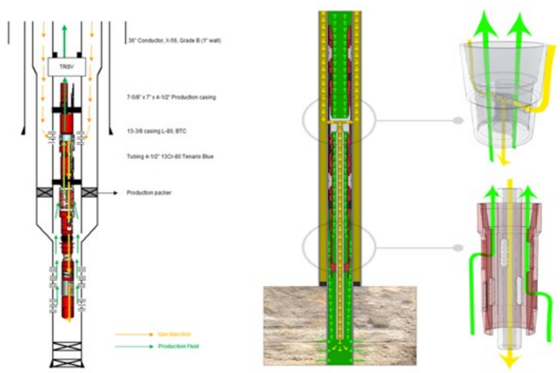


Fig 2. Retrofit Gas Lift (RGL) (Djabaruddin et al., 2016).

same crossflow diverter sub but via the annulus between the string and the production tubing. This system has three main components: the tailpipe, upper assembly, and lower assembly (Djabaruddin et al., 2016).

Conventional gas lift is generally applied in oil wells to reduce the density of the liquid phase. In contrast, gas lift applications in gas wells are rare, as gas has a much lower density and generally flows naturally. Conventional gas lift is conducted using side-pocket mandrels, typically limited to depths above the production packer. However, RGL offers several advantages, including no need for new completions, no rig requirement, relatively low cost, and the ability to place the injection point as deep as possible (Khairun Nissa and Sudibjo, 2015).

RGL is used to address liquid loading issues in wells and extend production life. Additionally, RGL extends the lowest gas lift mandrel in the well, enhancing its effectiveness by deepening the gas injection point thousands of feet below the production packer, where conventional systems cannot reach. This deeper injection point will result in greater drawdown. However, the size of the production packer remains a primary limitation for RGL development, and some trials indicate that RGL assemblies are not sand-resistant, which ultimately reduces their lifting capacity (Al-arbi Ganat et al., 2020).

3. Methodology

This study uses a quantitative approach through data processing with PROSPER software. In this research, PROSPER software is utilized to perform well modeling to evaluate the application of Gas Lift Deepening using Retrofit Gas Lift (RGL) on Well S-7 and to conduct a sensitivity analysis on parameters that significantly influence RGL design. This is aimed at creating a design that optimizes well productivity and achieves optimal production rates. There are two types of data sources in this research: primary and secondary data. The primary data includes well completion data, production data, reservoir characteristics, well test data, and artificial lift design data. The secondary data comes from literature reviews, including research journals, books, and other literature sources that support data processing in this study.

Figure 3 illustrates the research workflow for this study. In this research, well modeling analysis is conducted on Well S-7 before and after RGL installation, validated by well test data. Subsequently, nodal analysis is performed to compare production performance before and after RGL installation. The evaluation is furthered with a simulation using PROSPER software to identify parameters influencing RGL performance effectiveness. Based on the results of this parameter evaluation, the study proceeds with designing an effective and efficient RGL to achieve optimal well production performance.

4. Results and Discussion

4.1 Field Analysis

The NDF Field is an offshore oil and gas field in Indonesia. This field produces through the gamma Wellhead Platform (WHP), with a capacity of 9 wells, and the delta WHP, with a capacity of 13 wells. Hydrocarbons from both platforms are transported to a Floating Production Storage and Offloading (FPSO) unit for crude oil processing and storage, while gas from this field is transported to the Onshore Receiving Facilities (ORF), the gas sales point located 110 km from the NDF Field. The field has 16 horizontal wells serving as production wells, with 5 located on the gamma WHP and 11 on the delta WHP. These wells target the main reservoirs of the Cenderawasih Formation, producing oil, and the Kijang Formation, producing hydrocarbon gas. Additionally, hydrocarbons are produced from other reservoir zones like the Anoa, Elang, and Flamingo formations. The reservoir rocks in this field are carbonate with depths ranging from 4590-6300 ft and reservoir pressure between 1800-2700 psi. The reservoir drive mechanism is depletion drive, with a weak to moderate water drive in certain reservoir zones.

4.2 Well Analysis

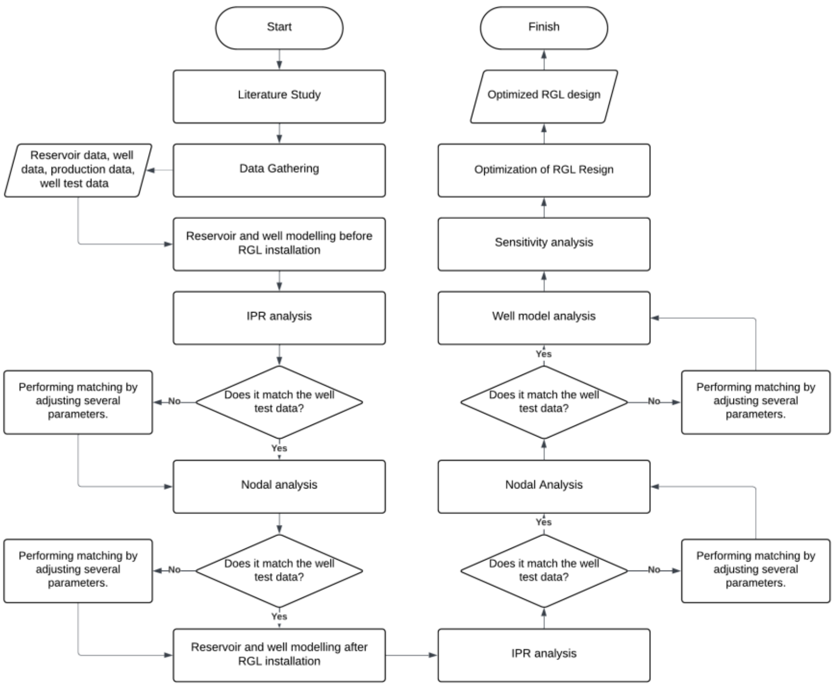


Fig 3. Research Workflow

Well S-7 is a production well in the NDF Field and is a horizontal well designed to produce fluids from the Cenderawasih Formation. As illustrated in **Figure 4**, the well has a 3415 ft horizontal open hole section with an 8-1/2" diameter. In this open hole section, a lower completion consisting of a 5-1/2” perforated liner with 12 and 6 SPF was installed to optimize fluid flow from the reservoir and maintain wellbore integrity. During installation, the lower completion encountered significant challenges as it became stuck, leading to the decision to install a liner hanger, leaving 1695 ft of open hole without lower completion.

The upper completion installed in this well is a 4-1/2” carbon steel tubing extending 6097 ft, providing structural integrity and facilitating hydrocarbon production from the reservoir. The upper completion setup includes a production packer, Sliding Sleeve Door (SSD), Chemical Injection Valve (CIV), Surface Control Subsurface Safety Valves (SCSSV), and Permanent Downhole Gauge (PDG). However, in early October 2023, a PDG malfunction was detected, preventing observation of wellbore pressure data. Additionally, the tubing setup includes 4 Side Pocket Mandrels (SPM) to support gas lift application.

Based on available data, the estimated Static Bottom Hole Pressure (SBHP) for this well is around 1245 psi at a depth of 11520 ft MD (6500 ft TVD), with a fluid level around 3768 ft TVD and a static gradient of approximately 0.38 psi/ft. Meanwhile, the Flowing Tubing Head Pressure is around 150 psi, with a maximum casing pressure of 1050 psi. Over time, Well S-7 has experienced a notable decline in production (**Figure 5**), likely due to factors such as reservoir pressure reduction and increased water cut. To maximize flow rate in this well, a well intervention was conducted to enhance gas lift performance by deepening the injection point using Retrofit Gas Lift technology.

4.3 Well Modeling Before RGL Installation

The well performance can be determined by modeling the reservoir and simulating the flow within the tubing mathematically. The Inflow Performance Relationship (IPR) is a curve that describes the analytical relationship between the wellbore pressure and production rate, formulated for a specific flow regime (Guo et al., 2007). IPR is used to evaluate reservoir deliverability, as it represents the relationship between flowing wellbore pressure and liquid production rate. The IPR curve is created using the reservoir inflow model, which can be based on theoretical or empirical foundations (Guo et al., 2007). This study models the IPR curve based on reservoir data and fluid properties data presented in Appendix. The correlation used for the IPR curve in this study is the Horizontal Well-No Flow Boundaries IPR Equation, based on the Goode and Kuchuk (1991) equation.

For nodal analysis, the IPR curve must be combined with Vertical Lift Performance (VLP). The intersection of these two curves provides the expected production rate and flowing wellbore pressure. In this study, the VLP correlation used is the Duns and Ros Modified Correlation. This equation is derived from the Original Duns and Ros correlation, which was modified by Petroleum Experts to provide greater pressure drop in oil wells for slug flow regimes. This equation was selected due to its strong agreement with the test data, exhibiting a deviation of only 0.8%. Based on well modeling using the selected correlation and input data, the nodal analysis results before RGL installation are as follows.

Based on the well modeling conducted using PROSPER software (**Figure 6**), it was found that the IPR and VLP curves intersect at a flow rate of 828 STB/d with a flowing pressure of 652.16 psi. Furthermore, the IPR curve shows that the maximum flow rate or Absolute Open Flow (AOF) of the well is 1339.8 STB/d, with a Productivity Index (PI) of 1.55 STB/d/psi. The well modeling results also show a drawdown of 594.3 psi. In terms of pressure drop in the tubing, the dominant factors causing the pressure drop in Well S-7 are gravity and friction. The pressure drops due to gravity in this well is 233.93 psi, which is likely caused by the high water cut in the well. The friction-induced pressure drop is 263.75 psi, likely due to tubing roughness caused by scale formation within the tubing. Before RGL installation, the injection point for gas lift operations in Well S-7 was located at an orifice size of 32/64 inches at a depth of 5792 feet, with a gas injection rate of 3.79 MMSCFD.

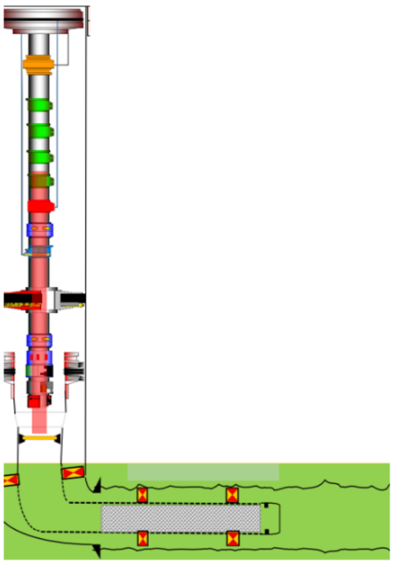


Fig 4. Well Schematic of Well S-7

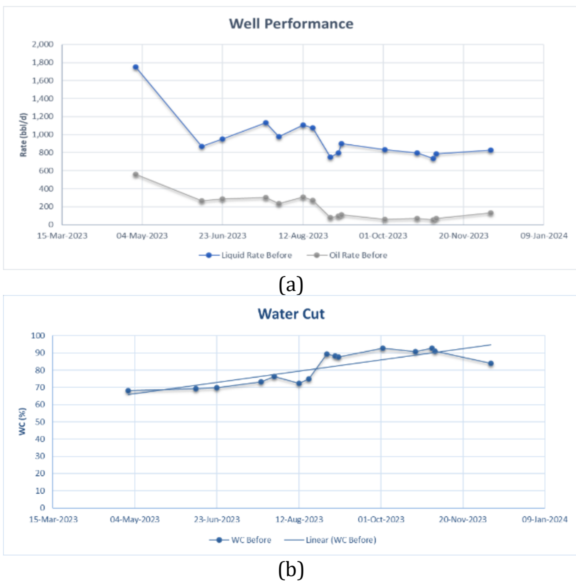
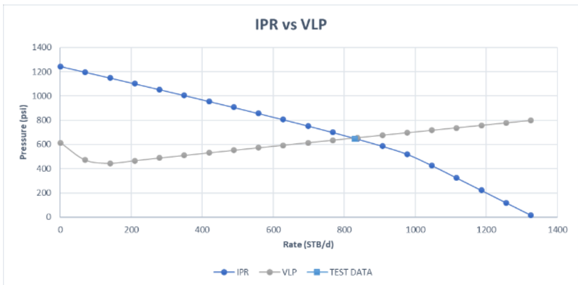


Fig 5. Production (a) and water cut profile (b) of Well S-7

4.4 Well Modeling After RGL Installation

To maximize the production rate of this well, well intervention was conducted by optimizing gas lift performance through deepening the injection point using Retrofit Gas Lift (RGL) technology. Well performance evaluation after RGL installation was performed using well modeling to represent the fluid flow pattern within the well. **Figure 7a** shows the actual flow pattern within the well after RGL installation. This figure also shows the flow path of injection gas, which flows through the annulus between the tubing and casing, enters the orifice, and then flows into the coiled tubing through the MGIM DF Mandrel, injecting at the orifice located at the end of the coiled tubing. Meanwhile, the produced fluid flows through the annulus between the coiled tubing and tubing, passes through the perforated tail joint to enter the DGL Assembly, and then flows directly into the production tubing.

To represent the complex flow in the RGL system, well modeling was performed by simulating the injection and production flow paths with equal inner and outer diameters for tubing and casing. This conceptual method was used to address software limitations in modeling fluid flow within the RGL system. As shown in **Figure 7b**, "New Tubing" represents the production fluid flow through the annulus between the tubing and RGL assembly. The annulus area is converted into a new tubing ID for the well model input. On the other hand, "New Casing" represents the injection gas flow in the coiled tubing, transformed to represent annular flow between tubing and casing with a flowing area



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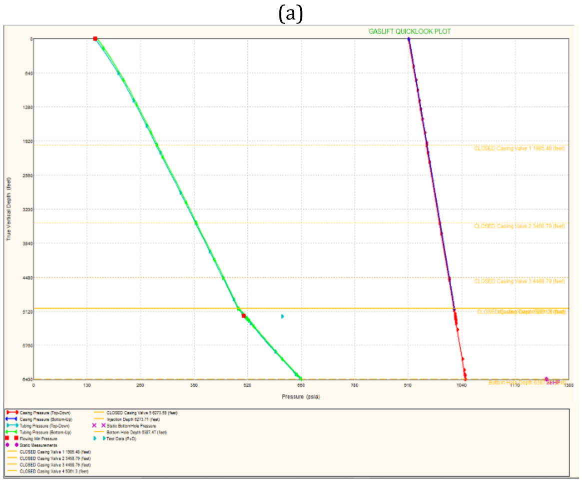
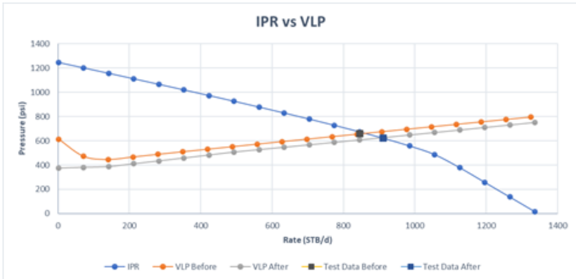


(b)

Fig 6. (a) Nodal analysis before RGL installation; (b) Tubing pressure vs. casing pressure graph before RGL installation.



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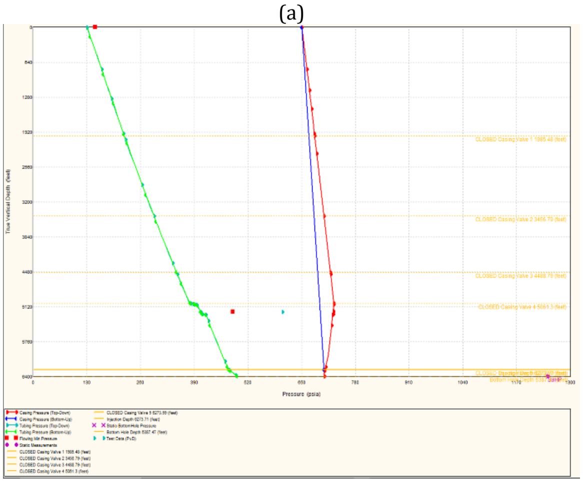
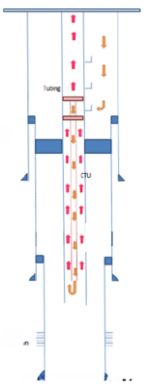


(b)

Fig 8. (a) Nodal analysis after RGL installation; (b) Tubing pressure vs. casing pressure graph after RGL installation.



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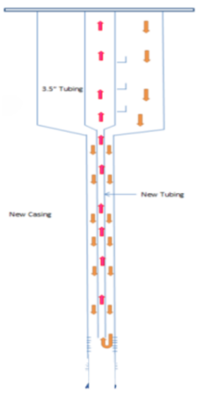


(b)

Fig 7. (a) Actual flow; (b) Well model.

Table 1. Well modeling result

Parameter	Before	After	Unit
Liquid Rate	827.9	906.6	(STB/d)
Oil Rate	124.2	199.5	(STB/d)
Injection Depth	5791	6984	(feet)
Solution Node Pressure	652.2	625.7	(psia)
dP Friction	263.8	275.7	(psi)
dP Gravity	233.9	201.8	(psi)

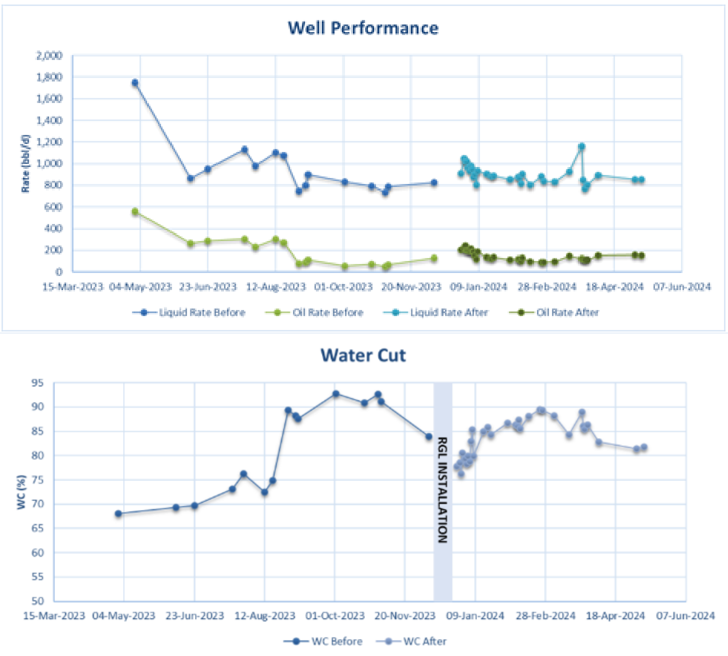
equivalent to that within the RGL assembly, achieved by adjusting the flowing area to the new tubing OD. This creates an injection flow similar to that within the coiled tubing. The calculations for equal ID and OD can be seen in **Table 7**.

Based on the well modeling conducted using PROSPER software (**Figure 8** and **Table 1**), the IPR and VLP curves in the nodal analysis intersect at a flow rate of 906.58 STB/d at a flowing pressure of 625.71 psi. The results show that the RGL installation, which deepens the injection point by 1192 feet, increases the production rate by 78.58 STB/d. Additionally, the RGL installation reduces the pressure drop in the tubing due to gravity by 32.15 psi, as it enhances injection effectiveness into the fluids column, lowering the hydrostatic pressure due to reduced fluid density from the injected gas. However, the friction-induced pressure drops increases by 12 psi due to the smaller flowing area resulting from RGL installation.

RGL installation also significantly impacts the casing pressure curve, with an increase in casing pressure as the injection gas flows through the annulus between the casing and tubing, followed by a substantial pressure drop after entering the orifice connecting the casing-tubing annulus with the RGL assembly. This anomaly is due to a notable difference in flowing area when gas enters the RGL assembly, where the RGL has a smaller flowing area compared to the annulus, creating a bottleneck effect and resulting in a pressure build-up before entering the RGL assembly, followed by a significant pressure drop upon entering the assembly.

The RGL installation also significantly impacts the production decline trend and water cut in this well. This can be seen in **Figure 9a**, where before RGL installation, the well exhibited a significant production decline with a steep and negative gradient trendline. After RGL installation, the production decline curve of Well S-7 becomes less steep, indicating that the RGL technology effectively maintains the well's production rate. Additionally, in the water cut test results shown in **Figure 9b**, it is evident that water cut increases over time. However, after RGL installation, there is an indication of a change in the water cut trend, likely due to resistance from the narrow flow area in the RGL assembly, creating a dynamic choking effect that minimizes the production of higher-density fluids such as water.

Based on the production profile and injection gas rate graphs (**Figure 10**), it is evident that the RGL installation also significantly reduces the optimum injection rate. Before RGL installation, the optimum injection rate for this well was around 3.7 MMSCFD. However, after RGL installation, the optimal injection rate is below 3 MMSCFD, as the injection depth increased, enhancing gas lift efficiency. This phenomenon demonstrates that, in addition



(a)

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Fig 9. (a) Production profile of well S-7 after RGL installation; (b) Water cut graph after RGL installation.

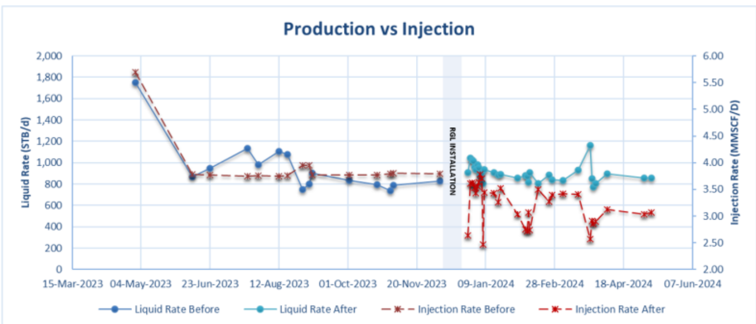


Fig 10. Graph of production flow rate and injected gas rate.

to increasing the production rate, the RGL technology also lowers the optimum injection gas rate, reducing operational costs for this well.

4.5 Sensitivity Analysis

To optimize the performance of Retrofit Gas Lift (RGL), sensitivity evaluations on various parameters affecting its effectiveness are necessary. In this study, parameters such as reservoir pressure, top node pressure, injection gas density, injection gas rate, coiled tubing size, and coiled tubing length will be tested for sensitivity. Testing these parameters is crucial to evaluate the current RGL performance and to identify parameters with a significant impact on RGL performance. By understanding the influence of these various parameters, the productivity and efficiency of the RGL in Well S-7 can be maximized.

Based on the results of the sensitivity analysis on the reservoir pressure parameter, shown in **Figure 11a**, the effectiveness of RGL has a strong correlation with reservoir pressure, where production flow rate decreases as reservoir pressure declines. However, the reduction in flow rate due to reservoir pressure is not very significant, as the gradient of the sensitivity test curve has a gentle slope, resulting in a 1:1 correlation between parameters. This means that a 10 psi decrease in reservoir pressure results in a 10 STB/d reduction in production flow rate. On the other hand, **Figure 11b** depicts the sensitivity evaluation of the top node pressure parameter, showing a correlation where the flow rate increases as the top node pressure decreases, although the change in production flow rate due to top node pressure/wellhead pressure reduction is not very significant. Sensitivity testing indicates that a 10-psi reduction in wellhead pressure increases the flow rate by 5 STB/d. Operationally, this parameter can be adjusted by modifying the choke opening or minimizing back pressure by cleaning the flowline to eliminate obstructions in the choke, flowline, and manifold during shutdown campaigns.

Figure 11c shows a sensitivity analysis graph for the casing head pressure parameter, which represents injection pressure in gas lift operations. The sensitivity test results indicate that the optimal injection pressure range is 710–775 psi. Moreover, when considering the gas injection rate aspect, as shown in **Figure 11d**, the use of RGL can minimize gas consumption, as a lower injection rate will significantly increase productivity. Sensitivity testing reveals that the optimal injection rate for Well S-7 is between 2.55 and 3 MMSCFD, indicating that the operational injection rate is already at an optimal point. The sensitivity test results also indicate a reduction in the optimal gas lift injection rate compared to the pre-RGL installation condition, a key factor with significant effects on flow rate and operational cost reduction.

Figure 12 presents a sensitivity analysis of the coiled tubing length parameter. Results show that the length of

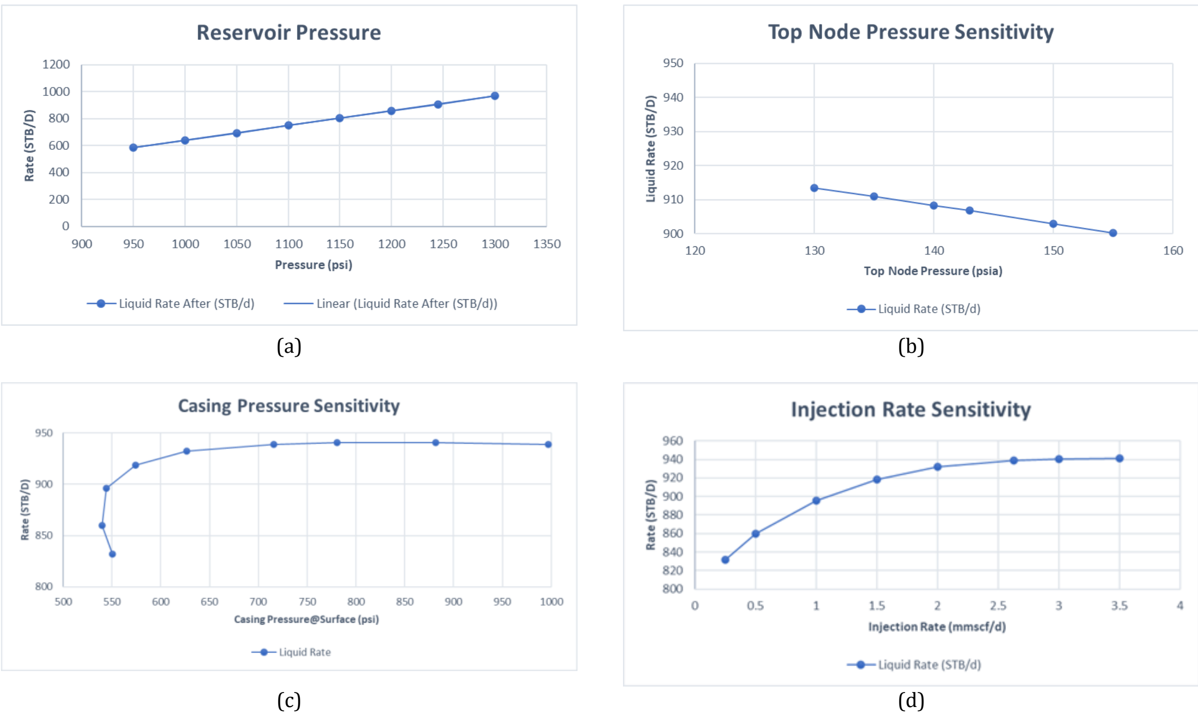


Fig 11. Sensitivity result for (a) reservoir pressure, (b) top node pressure, (c) casing head pressure, and (d) gas injection rate

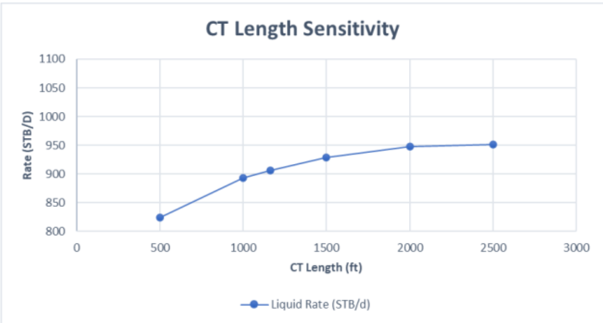
coiled tubing installed in the RGL assembly significantly affects the production flow rate; the longer the coiled tubing used, the more productivity increases. This is because a longer coiled tubing allows a deeper gas lift injection point, thus improving gas lift efficiency due to a decrease in FBHP. Sensitivity analysis indicates that the optimal coiled tubing length is 2000 ft, producing a flow rate of 947.28 STB/d. Additionally, the tubing and casing pressure curve plot shows that a longer coiled tubing results in a lower FBHP.

Sensitivity testing of the coiled tubing size parameter (**Figure 13**) shows a correlation: the smaller the coiled tubing, the higher the production flow rate. This is because the fluid produced flows through the annulus between the RGL assembly and tubing, so a larger coiled tubing diameter restricts flow due to a narrower flow area for the produced fluid. However, from the tubing and casing pressure curves, a very small, coiled tubing size results in a high pressure drop in the injection pressure, preventing gas from entering the production tubing because its pressure is lower than the tubing pressure. This anomaly in the casing pressure curve is due to a significant difference in flow area as gas enters the RGL assembly, where the RGL has a smaller flow area than the annulus, resulting in a bottleneck phenomenon with a high pressure increase before entering the RGL and a significant pressure drop upon entry.

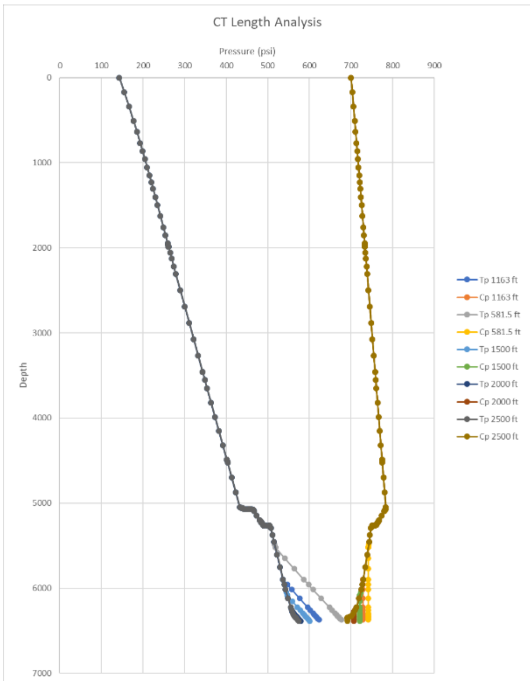
4.6 Optimization of RGL Design

After sensitivity testing on parameters affecting RGL performance in Well S-7, the next step is to optimize the RGL design. Gas lift well optimization is carried out through two approaches: determining the optimal design scenario and optimizing the gas injection rate. Sensitivity testing indicates that the optimal coiled tubing length is 2000 ft, which deepens the injection point to 7821 ft-MD. Additionally, the size of coiled tubing that provides the most optimal flow rate without significant casing pressure drop is 1.75 in, with the design using the minimum top node pressure of 130 psi in the well.

Based on the determined design, the next step is to determine the optimal gas lift injection rate using

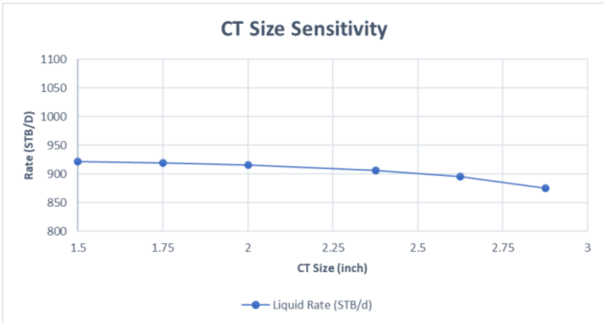


(a)

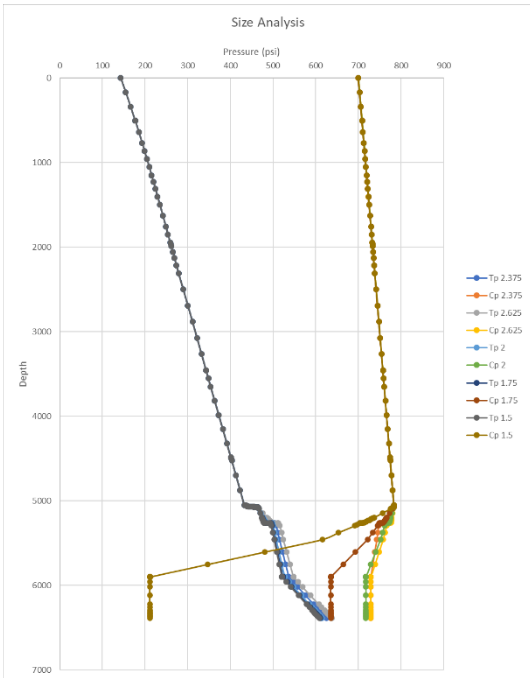


(b)

Fig 12. (a) Coiled tubing length sensitivity; (b) Tubing pressure and casing pressure for each coiled tubing length variation.



(a)



(b)

Fig 13. Coiled tubing size sensitivity; (b) Tubing pressure and casing pressure for each coiled tubing size variation.

sensitivity analysis. The sensitivity test results (**Figure 14**) show that the optimal gas injection rate is 1 MMSCFD, which is lower than before optimization, indicating that a deeper injection point can significantly reduce the optimal injection rate. This data is then used for well modeling to evaluate the optimization results.

Based on well modeling conducted with PROSPER software (**Figure 15**), the IPR and VLP curves in the nodal analysis intersect at a flow rate of 1048.86 STB/d at a flowing pressure of 494.58 psi. This flow rate is optimal, as it represents 78.28% of the Absolute Open Flow (AOF) for this well. The modeling results also show that the RGL installation, which deepened the injection point by 2030 ft, increased production flow rate by 220.86 STB/d. The well modeling further indicates a high drawdown of 751.77 psi. Additionally, the RGL installation reduces the flowing bottomhole pressure by 157.59 psi and reduces the gravity-induced pressure drop by 31.28 psi. This is due the deeper injection point enhancing injection efficiency into the fluid column, reducing the hydrostatic pressure of the fluid flowing through the tubing because of the lower density resulting from gas injected into the fluid column. Additionally, the optimized design reduces friction pressure drop by 104.1 psi as the produced fluid flows through a larger flow area due to the reduced coiled tubing size, minimizing restrictions in the tubing flow.

The optimized design has no significant impact on injections (**Table 2**), as the tubing and casing pressure curves show no indication of cross-plotting between the two curves, indicating that gas has been optimally injected at the injection point. Furthermore, examining the casing pressure parameter reveals no significant pressure drop when the injected gas enters the RGL assembly. This is due to the lower injection gas flow rate than the current condition, reducing the effect of the bottleneck caused by a smaller flow area.

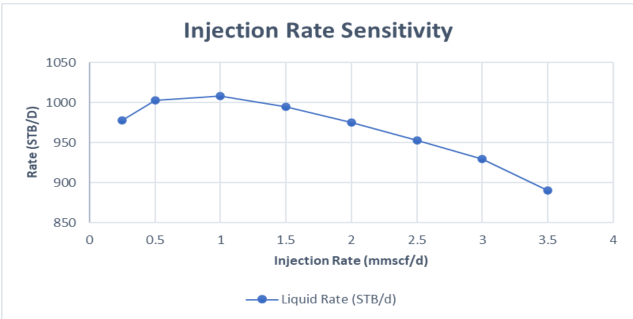
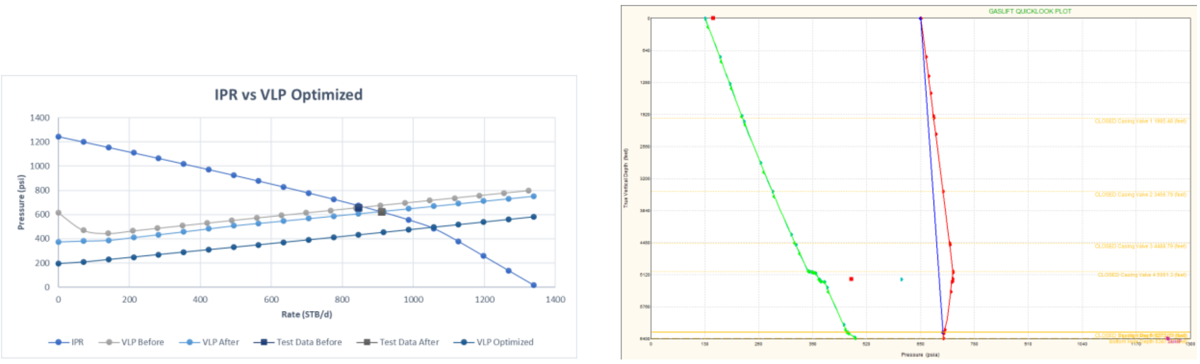


Fig 14. Gas injection rate sensitivity results after optimization



(a) (b)

Fig 15. (a) Nodal analysis after optimization; (b) Tubing pressure vs. casing pressure chart after optimization

Table 2. Well modeling results after optimization.

Parameter	Before	After	Gain	Unit
Liquid Rate	827.9	1048.9	220.0	(STB/d)
Oil Rate	124.2	230.8	106.6	(STB/d)
Injection Depth	5791.9	7821.0	-	(feet)
Solution Node Pressure	652.2	494.6	-	(psia)
dP Friction	263.8	159.7	-	(psi)
dP Gravity	233.9	202.7	-	(psi)

5. Conclusion

Based on the research, it can be concluded that the RGL installation in Well S-7 significantly increases production rates, as demonstrated by a flow rate increase of 78.58 STB/d following well modeling evaluation after RGL installation. Factors affecting production rates include reservoir pressure, top node pressure, gas injection rate, coiled tubing size, and coiled tubing length. Additionally, when considering annulus friction loss, a quick-look analysis suggests potential injection flow issues. Sensitivity testing led to design optimization by adjusting the top node pressure to 130 psi, coiled tubing length to 2000 ft, coiled tubing size to 1.75 in, and gas lift injection rate to 1 MMSCFD. The optimized design results in a flow rate increase of 220.86 STB/d and a high drawdown of 751.77 psi compared to pre-RGL installation. The study's casing pressure analysis indicates potential issues in injection flow, suggesting further research on the impact of annulus friction loss on casing pressure.

Appendix

Table 3. Reservoir Data

Properties	Value	Unit
Reservoir Pressure	1245	psia
Reservoir Temperature	222	deg-F
Water Cut	78	percent
Total GOR	2750	scf/STB
Skin	-5	
Permeability	207	md
Thickness	31.33	feet
Wellbore Radius	4.25	inches
Horizontal Anisotropy	0.071	fraction
Vertical Anisotropy	0.1	fraction
Length of Well	2132	feet
Reservoir Length	12922	feet
Reservoir Width	9389	feet
Distance from length edge to centre of well	1500	feet
Distance from width edge to centre of well	656	feet
Distance from length bottom to centre of well	12	feet

Table 4. Fluid Properties Data

Properties	Value	Unit
Solution GOR	549	scf/STB
Oil Gravity	37.3	API
Gas Gravity	0.83	
Water Salinity	25000	ppm
Mole percent of H_2S	0	percent
Mole percent of CO_2	0.77	percent
Mole percent of N_2	0.42	percent
Pb, Rs, Bo Correlation	Standing	
Oil Viscosity Correlation	Beggs et al.	

Table 5. Test Data

Properties	Before RGL	After RGL
FTHP (psi)	150	143
Flowline Temperature (deg-F)	128	136
Watercut (%)	85	78
Liquid Rate (bbl/d)	830	910
PDG Depth (ft)	5989	5989
Downhole Pressure (psia)	511	483.3
FBHP (psia)	465	583
Reservoir Pressure (psia)	1245	1245
FGOR (scf/bbl)	3707	2750
GOR Free (scf/bbl)	0	0
Gas Lift Injection Rate (MMCF/d)	3.79	2.55
Injection Depth (ft)	5792	6984
Casing Pressure (psia)	910	700

Table 6. Optimized Design Parameters

Properties	Value	Unit
Injection Rate	1	MMSCFD
CT Length	2000	ft
Top Node Pressure	130	psia
CT Size	1.75	inch
Orifice Diameter	20	/64 inch

Table 7. RGL assembly input data (production flow)

Production Flow Description	Depth	Length	Actual OD	Actual ID	Actual Tubing ID	Flow Area	Eq Tubing ID	Production Flowpath
Upper A Stop	5780.34	1.31	3.72	2.25	3.958	3.976	2.25	inside dgl
Upper Packoff	5782.09	1.75	3.72	2.25	3.958	3.976	2.25	inside dgl
Spacer 2-7/8" (1 ea)	5792.09	10	2.875	2.44	3.958	4.676	2.44	inside dgl
Stinger	5792.39	0.3	3.72	2.25	3.958	3.976	2.25	inside dgl
Receptacle	5792.69	0.3	3.72	2.25	3.958	3.976	2.25	inside dgl
Spacer 2-7/8" (1 ea)	5802.69	10	2.875	2.44	3.958	4.676	2.44	inside dgl
MGIM DF Mandrel	5803.69	1	3.72	2.5	3.958	1.35	1.311	inside dgl
Bottom Pack Off	5805.44	1.75	3.72	2.25	3.958	3.976	2.25	inside dgl
Perforated Tail Joint	5808.44	3	2.875	2.44	3.958	4.676	2.44	inside dgl
Stinger w/ Star shape	5808.74	0.3	3.71	1	3.958	1.494	1.379	ann dgl tubing
HD Receptacle	5809.74	1	3.71	1.35	3.958	1.494	1.379	ann dgl tubing
Dimple	5810.34	0.6	3.125	1.375	3.958	4.634	2.429	ann dgl tubing
CT	5970.26	159.92	2.375	2.025	3.958	7.874	3.166	ann dgl tubing
CT-SSD	*	*	2.375	2.025	3.813	6.989	2.983	ann dgl tubing
CT	5988.77	18.51	2.375	2.025	3.958	7.874	3.166	ann dgl tubing
CT-PDG	*	*	2.375	2.025	3.9	7.516	3.093	ann dgl tubing
CT	6007.48	18.71	2.375	2.025	3.958	7.874	3.166	ann dgl tubing
CT-9-5/8" PKR	*	*	2.375	2.025	3.9	7.516	3.093	ann dgl tubing
CT	6033.00	25.52	2.375	2.025	3.958	7.874	3.166	ann dgl tubing
CT-SSD	*	*	2.375	2.025	3.813	6.989	2.983	ann dgl tubing
CT	6050.34	17.34	2.375	2.025	3.958	7.874	3.166	ann dgl tubing
Dimple	6050.94	0.6	3.125	1.375	3.958	4.634	2.429	ann dgl tubing
Carsac	6052.50	1.56	2.875	1.375	3.958	5.812	2.72	ann dgl tubing
CTU Adapter	6055.25	2.75	3.1	1	3.958	4.756	2.461	ann dgl tubing
Stopper Hanger	6056.25	1	3.76	1.2	3.958	1.2	1.236	ann dgl tubing
CTU Adapter	6059.00	2.75	3.1	1	3.958	4.756	2.461	ann dgl tubing
Dimple	6059.60	0.6	3.125	1.375	3.958	4.634	2.429	ann dgl tubing
CT IN TUBING	6097.02	37.42	2.375	2.025	3.958	7.874	3.166	ann dgl tubing
CT IN LINER	6982.60	885.58	2.375	2.025	4.892	14.366	4.277	ann dgl liner
Dimple	6983.20	0.6	3.125	1.375	4.892	11.126	3.764	ann dgl liner
MGIM BF Mandrel	6984.50	1.3	3.5	2.5	4.892	9.175	3.418	ann dgl liner

*Restriction

Table 8. RGL assembly input data (gas injection input)

Production Flow Description	Actual ID (in)	Injection Area	Eq Tubing OD	Eq Casing ID	Injection Flowpath
Upper A Stop	2.25	43.269	4.5	8.68	ann tub cas
Upper Packoff	2.25	43.269	4.5	8.68	ann tub cas
Spacer 2-7/8" (1 ea)	2.44	5.812	2.875	3.958	ann dgl tubing
Stinger	2.25	1.435	3.72	3.958	ann dgl tubing
Receptacle	2.25	1.435	3.72	3.958	ann dgl tubing
Spacer 2-7/8" (1 ea)	2.44	5.812	2.875	3.958	ann dgl tubing
MGIM DF Mandrel	2.5	1.435	3.72	3.958	ann dgl tubing
Bottom Pack Off	2.25	3.976	3.256	3.958	inside dgl
Perforated Tail Joint	2.44	4.676	3.116	3.958	inside dgl
Stinger w/ Star shape	1	0.785	3.83	3.958	inside dgl
HD Receptacle	1.35	1.431	3.721	3.958	inside dgl
Dimple	1.375	1.485	3.711	3.958	inside dgl
CT	2.025	3.221	3.401	3.958	inside dgl
CT-SSD	2.025	3.221	3.231	3.813	inside dgl
CT	2.025	3.221	3.401	3.958	inside dgl
CT-PDG	2.025	3.221	3.333	3.9	inside dgl
CT	2.025	3.221	3.401	3.958	inside dgl
CT-9-5/8" PKR	2.025	3.221	3.333	3.9	inside dgl
CT	2.025	3.221	3.401	3.958	inside dgl
CT-SSD	2.025	3.221	3.231	3.813	inside dgl
CT	2.025	3.221	3.401	3.958	inside dgl
Dimple	1.375	1.485	3.711	3.958	inside dgl
Carsac	1.375	1.485	3.711	3.958	inside dgl
CTU Adapter	1	0.785	3.83	3.958	inside dgl
Stopper Hanger	1.2	1.131	3.772	3.958	inside dgl
CTU Adapter	1	0.785	3.83	3.958	inside dgl
Dimple	1.375	1.485	3.711	3.958	inside dgl
CT IN TUBING	2.025	3.221	3.401	3.958	inside dgl
CT IN LINER	2.025	3.221	4.453	4.892	inside dgl
Dimple	1.375	1.485	4.695	4.892	inside dgl
MGIM BF Mandrel	2.5	4.909	4.205	4.892	inside dgl

Table 9. Sensitivity Results

Parameter	Value	Liquid Rate (STB/D)
Reservoir Pressure (psi)	900	658.8
	950	678.2
	1000	692.9
	1050	747.7
	1100	802.3
	1150	856.9
	1245	906.7
	1300	967.9
	1350	1014.3
Top Node Pressure (psi)	135	910.8
	140	908.3
	143	906.7
	150	902.2
	155	900.1
	160	891.8
Casing Pressure (psi)	539	885.9
	544	885.9
	574	918.5
	627	932.9
	715	978.8
	781	940.7
	882	940.9
	987	939.1
	1025	881.8
Injection Rate (MMCF/d)	0.5	859.9
	1	898.9
	1.5	906.7
	2	933.0
	2.63	938.8
	3	940.7
	3.5	940.9
Injection Depth (ft-MD)	6000	824.0
	6500	885.0
	6984	906.7
	7500	936.4
	8000	950.2
CT SIZE (inch)	1.5	922.3
	1.75	918.5
	2	916.2
	2.375	906.7
	2.625	895.4

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