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The Implementation of Critical Gas Rate in Liquid Loading Well and Optimization Analysis using the Adequacy Chart

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Abstract

In the gas well, liquid loading occurs when the gas rate is insufficient to lift liquids into the surface such as water and/or condensate. This causes an accumulation of the liquid in the wellbore, supplies additional backpressure to the formation, and may completely kill the well. Meanwhile, the limited space and typically high cost of offshore operations have made a proper study for optimization selection very essential. The selected project must fulfill several requirements, namely: 1) Fit for the purpose, 2) Low risk and uncertainties, and 3) Economic. Hence, this study will describe the pilot project and continuous improvement process of lowering the gas well pressure using a wellhead compressor and a temporary separator to optimize the liquid loading. It also explains the implementation of critical gas rate in predicting the liquid loading event from the well's production history. A new analysis method utilizing the adequacy chart was proposed to verify the suitability of the available pressure-lowering system unit available in the market with the well candidates. An adequacy chart was constructed from the well's deliverability, critical gas rate, and lowering pressure unit or system capacity. These three charts will combine to generate an overlapping area, which signifies suitability for the recommended operation. The well's production data history can be used to predict the liquid loaded-up event due to the continued decline of the generated gas. Also, a combination of the critical gas rate and decline analyses can predict potential liquid loading problems.

INTRODUCTION

Liquid loading issues occur in naturally flowing gas wells because the self-lifting capacity of the gas is insufficient to raise its generated liquid to the surface (Andru Ferdian, 2011). The accumulated liquid in the wellbore creates a liquid column and supplies additional pressure to the reservoir. This results in decreased well production, which eventually ceases to flow once the sum of the hydrostatic pressure of the accumulated liquid and system pressure is equal to the reservoir pressure. Since the depletion of the reservoir pressure causes the well to experience liquid loading during the late period of its production time, reservoir gas production is the key to avoiding liquid loading.

As illustrated in Figure 1, (a) the well flows naturally and stably at the initial production. However, (b) the liquid begins to fall back to the wellbore by the time the gas production begins to decline and is unable to adequately carry it to the surface. Here, the well experiences a production drop due to the additional backpressure generated as the liquid accumulates and builds up in the wellbore, which causes the gas production to continue dropping. This results in slugging flow, as well as unstable pressure and flow rate at the surface (c). Once the hydrostatic column and reservoir pressures are equal, the well ceases to flow (d).

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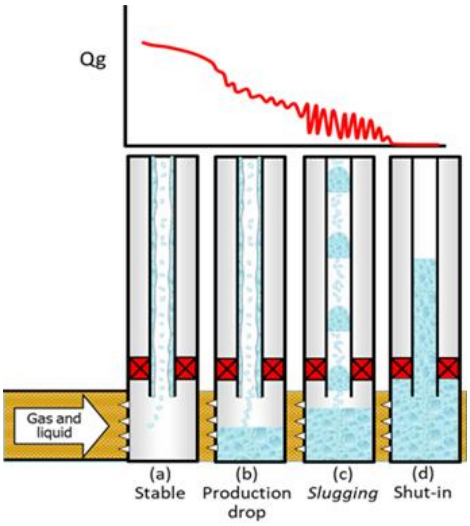

Figure 1. A typical well liquid loading sequence

Critical Gas Velocity For Continuous Liquid Unloading

The minimum gas flow rate required to lift the produced fluid to the surface is often referred to as the critical gas flow rate. A gas flow rate below this critical rate will cause the liquid droplets in the well to fall and accumulate in the wellbore.

Turner et al. (1969) developed a correlation to predict the critical gas flow rate in vertical wells via a droplet model approach. In this model, a droplet obtains two forces, where the gravity works downward, and its friction force works upwards, as in Figure 2. A balance of these two forces causes the droplet to remain stationary and move neither upward nor downward, resulting in a critical condition of the gas flow rate.

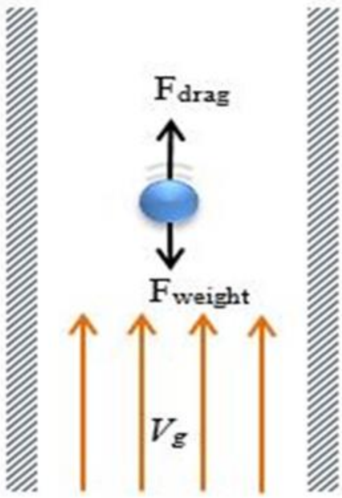

Figure 2. Illustration of critical gas rate (Source: Hernandez, (2017))

Turner's critical velocity equation,

$$V_g = 1.92\, \sigma^{1/4} \frac{(\rho_L - \rho_g)^{1/4}}{\rho_g^{1/2}} \quad (1)$$

where:

Vg = gas critical velocity, ft/sec.

ρ_L = liquid density, lbm/ft3

ρ_g = gas density, lbm/ft3

σ = surface tension liquid-gas, dynes/cm

 Journal of Earth Energy Engineering
Vol. 10 No. 3, November 2021, pp 179-191

Although Turner's equation has been tested on gas wells that mostly operate at wellhead pressures above 1000 psi, the analysis data obtained showed that it can also be applied to low wellhead pressures between 5 and 800 psi (Lea et al., 2008). In its application, the addition of a multiplier factor of 20% from the empirical equation is required to ensure all liquid droplets are lifted to the surface (Turner et al., 1969).

Assuming:

Surface tension, σ condensate = 20 dynes/cm and σ water = 60 dynes/cm

Liquid density, ρ_L condensate = 45 lbm/ft3 and ρ_L water = 67 lbm/ft3

Gas gravity, γg = 0.6

Gas temperature = 120^{O}F

$$V_g\ condensate = 4.02\ \frac{(45 - \ 0.0031\, p)^{1/4}}{(0.0031)^{1/2}} \tag{2}$$

$$V_g\ water = 5.62\ \frac{(67 - \ 0.0031\, p)^{1/4}}{(0.0031)^{1/2}} \tag{3}$$

For wells producing condensate and water, Turner suggested the equation developed for water due to its greater density and the need for a higher critical velocity.

Coleman et al. (1991) developed the critical velocity equation, which has been tested on wells with wellhead pressure below 500 psi. The equation is similar to the original Turner equation without the need for the 20% adjustment.

Coleman's critical velocity equation,

$$V_g = 1.593\ \sigma^{1/4}\ \frac{\left(\rho_L - \rho_g\right)^{1/4}}{\rho_g^{\ 1/2}} \tag{4}$$

Nosseir et al. (2000), while adopting Turner's equation for critical velocity and considering the flow regimes in the tubing, observed that the equation was suitable for turbulence flow. Li et al (2002) developed and tested another equation in China by considering the shape of liquid droplets, which reduced the critical velocity of Turner's proposition by around two-thirds. The liquid droplets, moving relative to the gas and held by their surface tension, are subjected to forces that attempt to shatter them (Hinze, 1955). Li et al. (2002) suggested that the droplets would be deformed by these forces and their shape will shift from spherical to the convex bean. The spherical droplets have a smaller efficient area, held by gas, and need a higher terminal velocity and critical rate to lift them to the surface. Conversely, the convex bean liquids have a more efficient area and are easier to carry to the wellhead.

Subsequently, this study will utilize the critical velocity equation proposed by Turner et al. (1969), as it is suitable for predicting the liquid loading event in almost all NBB Block gas wells.

Critical Gas Rate

The minimum flow rate required to self-lift the gas-produced fluid to the surface can be estimated by the equation derived by Turner et al. (1969). This equation was developed to calculate the required gas velocity produced from the formation to move the liquid droplet upward. Through the knowledge of the tubing size used on the well, the minimum flow rate required to continuously self-lift the liquid can be calculated. The resulting estimate, which is known as the critical flowing rate, depends on the tubing size and surface operating pressure, assuming the fluid surface tension, temperature, alongside liquid and gas phase density remain constant.

Critical gas rate equation,

$$q_c = 3.06\ \frac{p\, V_g A}{T\, z} \tag{5}$$

where:

qc = critical gas rate, MMscf/day

Vg = critical gas velocity, ft/sec.

p = wellhead presure, psia

A = tubing cross-section area, ft2

T = temperature, °R

z = gas compressibility factor

The critical gas rate, assuming constant temperature and gas compressibility factor and referring to the equation above, will depend on the wellhead pressure value and tubing cross-section area. Lowering the critical rate of the well is technically expected to prevent the liquid loading problem. There are two options for lowering the critical gas rate, namely reducing the tubing ID and decreasing the wellhead operating pressure, as shown in Figure 3.

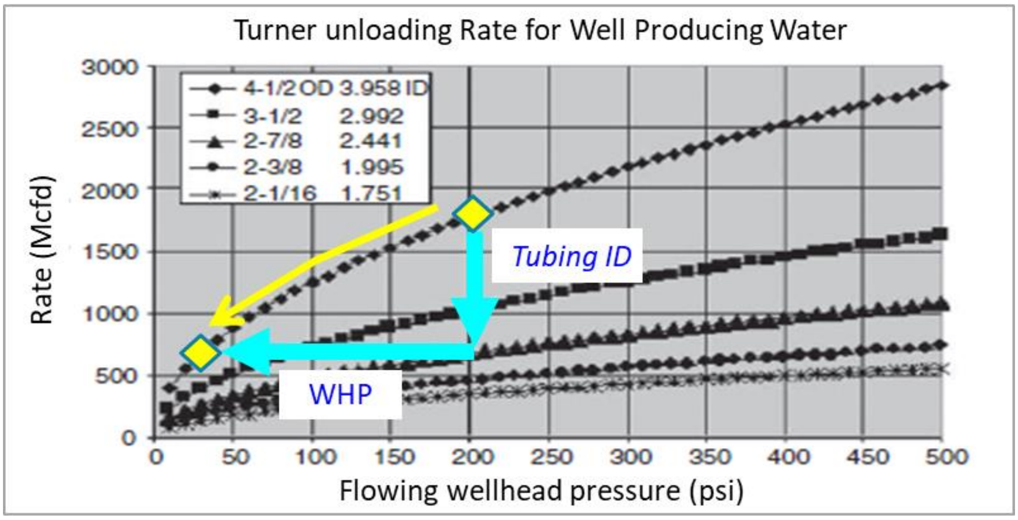

Figure 3. Simplified Turner critical gas rate chart (Source: Lea et al. (2008))

For wells located in offshore locations, the tubing replacement requires a Hydraulic Workover Unit (HWU) or rig, which is unattractive due to the high operating cost and the benefits to only one well.

Another option for offshore operations is to reduce the pressure system at surface facilities by replacing or adding a compressor unit, which will benefit all connected wells in the same production system. However, the platforms generally have limited space, and high capital costs are involved in replacing or adding a compressor unit. A small footprint and low-cost package are a good alternative to investigate the potential production from candidate wells and reduce the uncertainties before implementing more advanced pressure lowering efforts.

METHODOLOGY

The adequacy chart consists of three input values, namely the Turner critical gas rate for the investigated well, wellhead production deliverability, and the pressure-lowering unit capacity. The critical gas rate depends on the well's tubing size as well as the operating pressure, which also determines the varying production deliverability. Also, the wellhead compressor performance depends on the suction and discharge pressure, which will be assumed to be constant.

Field Data

The production history data of the well should be available as it indicates liquid loading and plays important roles, hence, the flow metering to record the data must work accordingly and properly. Figure 5 shows the well's production historical data used to predict the accumulation of liquid in the wellbore along with the decrease in the gas produced from the well.

Journal of Earth Energy Engineering
Vol. 10 No. 3, November 2021, pp 179-191

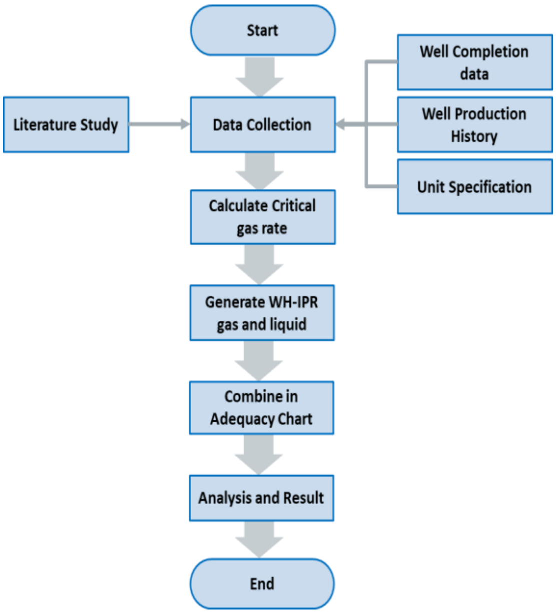

Figure 4. Flow chart for generating the adequacy chart

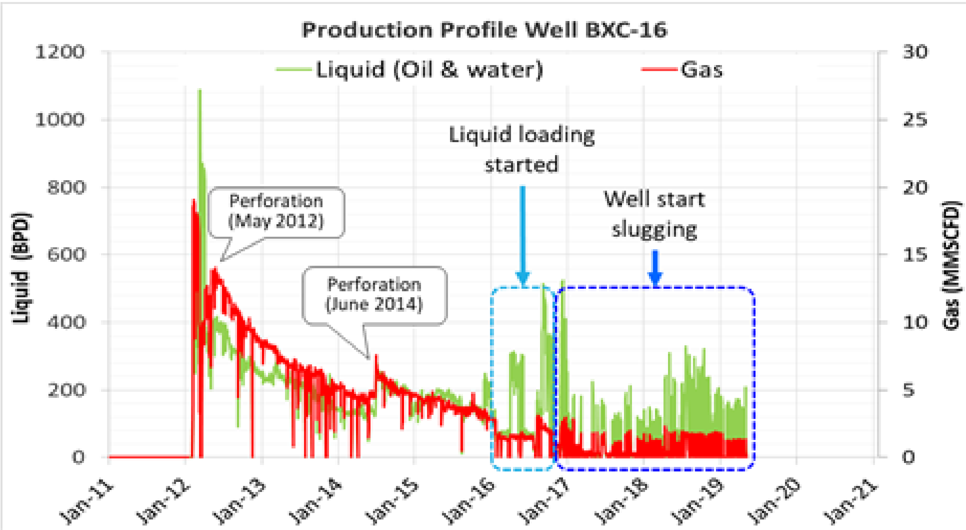

Figure 5. Well BXC-16 production history

The history indicated that well BXC-16 started experiencing liquid loading in January 2016. In January, the well produced 1.6 MMscfd at a wellhead pressure of 195 psi. According to Turner et al's calculations, the critical gas flow rate at 195 psi THP is about 1.7 MMscfd, showing that the BXC-16 well has experienced no flow condition often since January 2016, suspected to be caused by liquid loading in the wellbore. Hence, well BXC-16 was operated cyclically with the huff and puff method.

Although the huff and puff strategy was able to return the liquid loading well back to production, the next loading returns will result in production loss. Since the duration depends on the length of the shut-in period required to raise the well's pressure to the expected condition, another production strategy is required to reduce the production loss.

Wellhead Compressor Trial

The information needed for lowering the operating pressure was obtained from VICO experiences in implementing the wellhead compressor (WHC) to extend the well's life. Generally, wellhead compressors ensure the well continues flowing above the critical rate for a longer period. By 2013, VICO had implemented 46 units of wellhead compressor, in which its pilot project revealed that the unit package has a small footprint and is easy to relocate to other wells (Suhendar et al., 2013).

Also, a pilot project to further evaluate the lowering impact to the wells was conducted using a wellhead compressor unit in the NBB Block. This compressor unit was selected based on the criteria of low rental cost and space requirement, alongside the ability to reduce the wellhead pressure from 200 psi to around 15 psi. The objectives of this project were to evaluate the well's potential improvement by lowering the pressure effort, alongside understanding the wellhead compressor performance prior to establishing a longer-term rental contract. Furthermore, the pilot project was expected to be useful as a basis for other efforts to lower the pressure. One unit of wellhead compressor has a handling capacity around 0.4 MMscfd and 50 BLPD, though the actual estimate depends on suction and discharge pressure.

Figure 6. BLA-01 performance during the trial of the wellhead compressor (Source: A Ferdian (2020))

The first trial was performed on well BLA-01, which was completed with a 4-1/2" tubing, and had a normal operating wellhead pressure of 199 psi. During the trial, the wellhead compressor reduced its wellhead pressure to 15 psi, with an increase in temperature, indicating that the well was flowing. The critical gas generated at a pressure of 15 psi was 0.6 MMscfd, while the estimated well production during the trial was around 0.75 MMscfd and 5 BLPD. Consequently, the wellhead compressor performance was not smooth and frequently shut down, as the actual gas production from the well was greater than its capacity. As shown in Figure 6, the wellhead compressor unit was suspected to be unable to cope with the fluctuating mode.

The second trial was executed on well BXC-07, which was fitted with 4-1/2" tubing, operated using the huff and puff strategy, and with a normal operating wellhead pressure at 170 psi. According to the last test, the well produced 0.25 MMscfd, 129 BLPD, and 0% water cut. Then, a two-unit wellhead compressor was installed to accommodate higher liquid rates. The trial result showed that the wellhead pressure only dropped to 112 psi just before the high liquid flow received at the WHC unit, causing an interrupted functioning of the wellhead compressor and a reduced well production compared to the huff and puff mode.

Although the pilot project using the wellhead compressor unit was unable to sustain the well production, some information obtained from the trial will be useful for further optimization efforts. The pressure-lowering effort was proven to be able to revive the well with the liquid loading problem. However, the well and the pressure-lowering unit should be selected to suit each other, and the unit capacity must be sufficient to accommodate the minimum critical gas rate required to ensure the liquid loading is not occurring.

Temporary Separator Trial

Based on the lessons obtained from the wellhead compressor trial, the process was further improved by utilizing a temporary separator with a higher production handling capacity of 3 MMscfd and 1000 BLPD. The temporary separator was used to unload the well and vented into the flaring system, which is close to atmospheric pressure. As shown in Figure 7, the success of this process facilitated a further optimization plan to route the gas production back to the system by installing a small size compressor.

Journal of Earth Energy Engineering
Vol. 10 No. 3, November 2021, pp 179-191

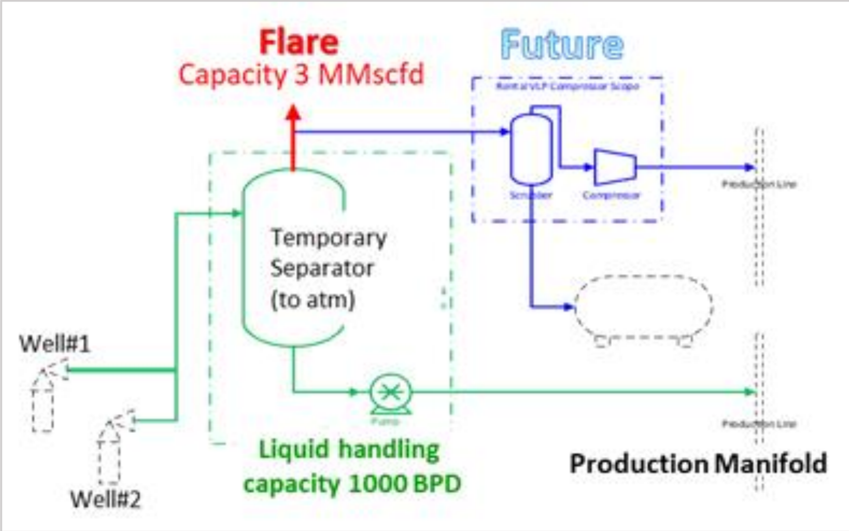

Figure 7. Temporary separator unit configuration and future compression unit (Source: Fernando et al. (2018))

Figure 5 shows that well BXC-16 was produced using huff and puff mode since August 2016 with a 3-day shut-in cycle for PBU and a 1-day flow. The average production during the flow was around 1.30 MMscfd with a 146 psi wellhead pressure. According to Turner's equation, a 145 psi wellhead pressure produces a critical gas rate of 1.50 MMscfd, which explains the frequent liquid loading in well BXC-16.

In January 2019, well BXC-16 was tested using the temporary separator and flowline. Figure 8 shows that the well flowed continuously to the temporary separator at a wellhead pressure of 120 psi, indicated by a temperature increase to 120 – 130 deg-F. Hence, the well production can be optimized by neglecting the required 3 days shut-in period for PBU. As indicated by Figure 9, a drop in the temperature caused the well to be routed to the temporary separator for unloading and back to the production system when stable. Since the flare meter was not working properly and the actual gas production rate could not be measured, only visual observation was performed by studying the flare, as in Figure 10. However, the actual gas production rate, based on the temperature parameter, should be higher than Turner's critical gas rate to facilitate continuous flow.

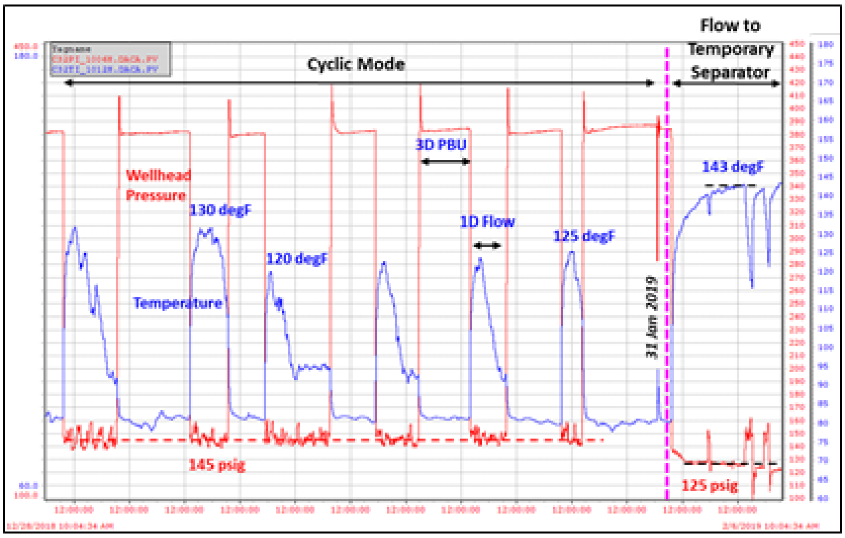

Figure 8. Well BXC-16 performance before routing the Temporary Separator (Source: A Ferdian (2020))

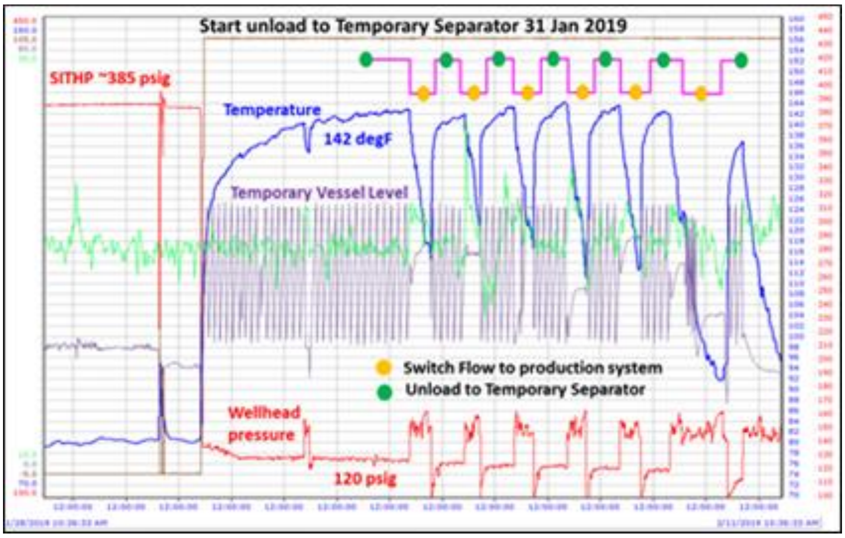

Figure 9. Well BXC-16 performance during the trial of the temporary separator (Source: A Ferdian (2020))

Figure 10. Flare tip visualization while unloading well BXC-16 to the temporary separator (Source: Fernando et al. (2018))

Adequacy Chart

Based on the experiences obtained during the pilot project using a wellhead compressor unit, a quick overview was needed to confirm the suitability of the pressure-lowering unit available in the market with the well's condition and meet the requirement to flow above its critical gas rate. By combining the curve for the minimum critical gas rate, the wellhead production deliverability, and the pressure-lowering unit capacity, an overlapping area, denoting suitability for the recommended operation, will be obtained. The well liquid to gas ratio is considered the same for all gas rate variations.

Also, the suitable recommended operating area has a higher well gas production than the critical gas rate but is lower than the unit handling capacity.

$$Q\ gas\ critical\ < Q\ gas\ production\ < Q\ gas\ unit\ handling\ capacity$$

$$Q\ liquid\ production < Q\ liquid\ unit\ handling\ capacity$$

Journal of Earth Energy Engineering
Vol. 10 No. 3, November 2021, pp 179-191

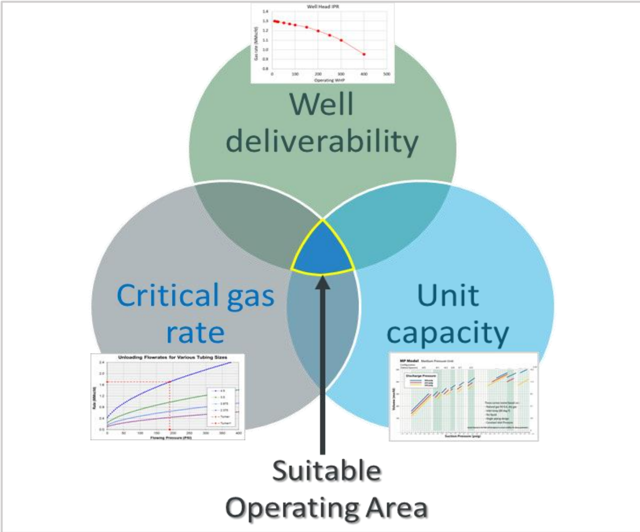

Figure 11. Illustration of the suitable recommended operating area

Generating The Adequacy Chart

The adequacy chart was built by combining the minimum critical gas rate curve, wellhead performance curve, and the lowering pressure unit capacity. Figure 12 is an example of the adequacy chart for *n* wellhead compressor units. Assuming the produced fluid could be spread properly, the total unit capacity will be equal to that of the one unit wellhead compressor multiplied by the number of units applied. The x-axis is the operating pressure at the wellhead, while the primary y-axis on the left shows the value of well gas production, critical gas rate as a function of the wellhead flowing pressure, and the total gas unit handling capacity. Conversely, the secondary y-axis on the right shows the value of the well's liquid production and total liquid unit handling capacity.

Figure 12 is an example of an adequacy chart for the type of wellhead compressor used in the pilot project. According to the chart, the well gas production must be higher than its critical gas rate to avoid liquid loading. This is indicated by the green area above the critical gas rate curve in the green line. The well gas deliverability, indicated by the red line curve, must lie above the critical gas rate curve, while the gas and liquid products must be below the unit handling capacity.

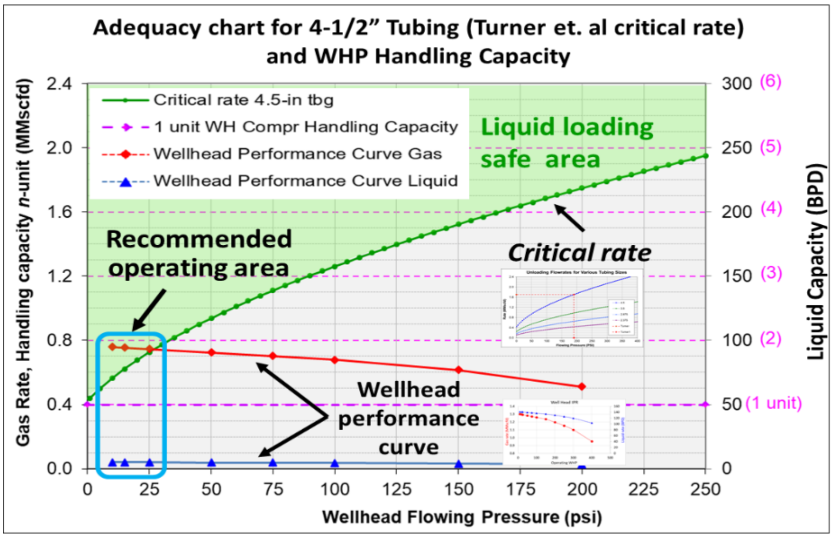

Figure 12. Example Adequacy chart for *n*-unit of wellhead compressor

RESULT AND DISCUSSION

Figure 13, showing the adequacy chart analysis developed for the two wells during the pilot project, indicates a quick review of the suitability between the well and wellhead compressor unit. The first trial on well BLA-01 shows that the gas production rate is higher than its critical rate, which in turn is greater than the handling capacity of 1-unit of wellhead compressor and the liquid rate. As shown by the illustration, a wellhead compressor of 2 units is required to suit the well BLA-01 production at 0.75 MMscfd and 5 BLPD.

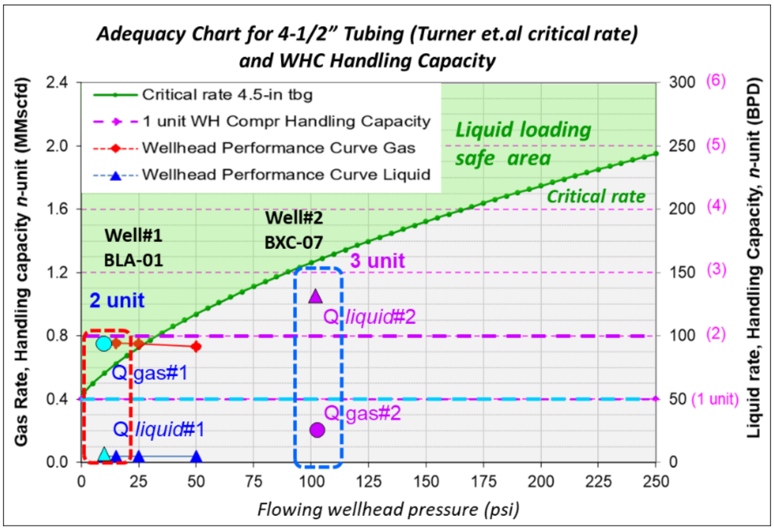

Figure 13. Adequacy chart analysis for the wellhead compressor pilot projects on wells BLA-01 and BXC-07

The second trial on well BXC-07 shows that the gas production rate is below the handling capacity, while the liquid production is above the 2-unit wellhead compressor handling capacity. Although the wellhead compressor required to suit the well BXC-07 condition is supposed to be 3 units, the well will be unable to sustain its gas production, which is below the critical rate, eventually leading to a liquid loading problem.

Further optimization was performed using a temporary separator with a bigger handling capacity, and the 3 days shut-in period was no longer needed. On indicating liquid loading, the well was routed to a temporary separator for continuous unloading, causing the production time to be higher than the huff and puff mode. Figure 14 shows the adequacy chart analysis developed for well BXC-16. On routing, the gas production was higher than its critical rate, and the well was able to sustain its production. Hence, the temporary separator had sufficient capacity to handle the gas and liquid products.

After routing to the normal system, the gas was not produced in the wellhead IPR because the number was taken by averaging the flow rate until the flow almost ceased. The chart showed that a decrease in the operating pressure resulted in increased well deliverability and a reduced critical gas rate, signifying that the well should revive its production.

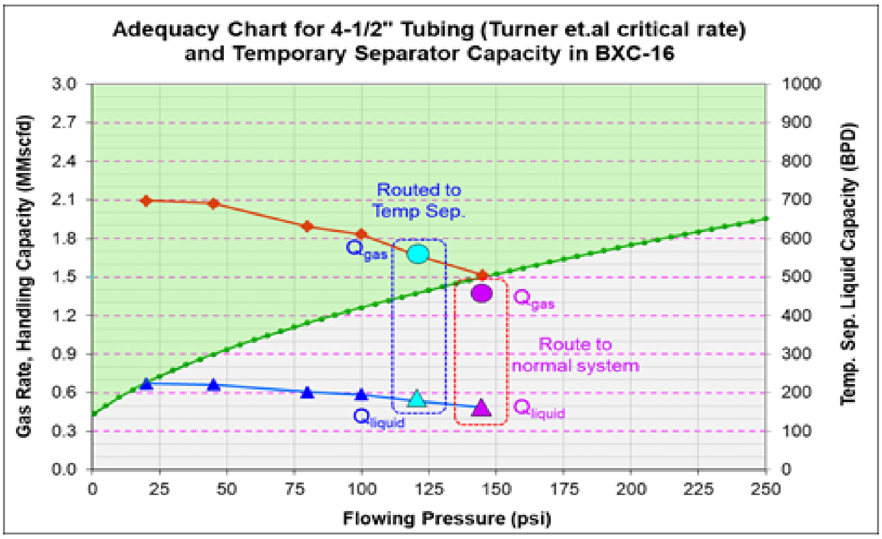

Figure 14. Adequacy chart analysis for well BXC-16 with the temporary separator

Journal of Earth Energy Engineering
Vol. 10 No. 3, November 2021, pp 179-191

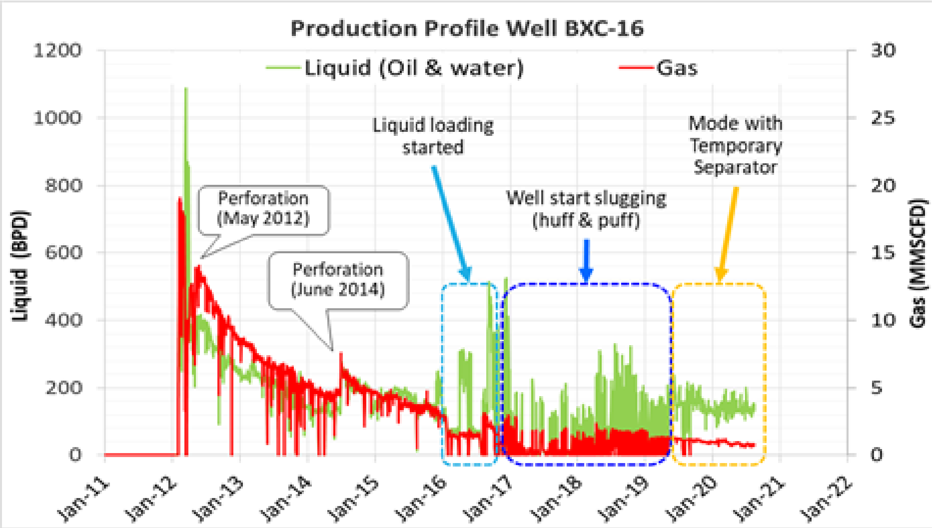

Figure 15. Well BXC-16 production profile with several production modes

Adequacy Chart to Predict Future Liquid Loading

Following the post-optimization process by lowering the pressure of the well, the gas production rate will decline naturally. Consequently, an adequacy chart can be utilized to predict the time needed for the well will reach its critical gas rate by combining it with the decline analysis.

Figures 16 and 17 show examples described with their references, where the well at condition 1 produced 1.7 MMscfd at operating wellhead pressure 120 psi and a critical gas rate of 1.3 MMScfd. The gas production decline analysis can be performed by generating the predicted line through the extrapolation of the history data. In Figure 17, the well gas production history and the predicted decline profile were represented by red solid and dashed lines, respectively. The decline profile usually follows one of the common decline equations, either exponential, harmonic, or hyperbolic, to facilitate estimation of the time required for the well to reach its critical rate and anticipate the future effort needed to overcome the liquid loading problem.

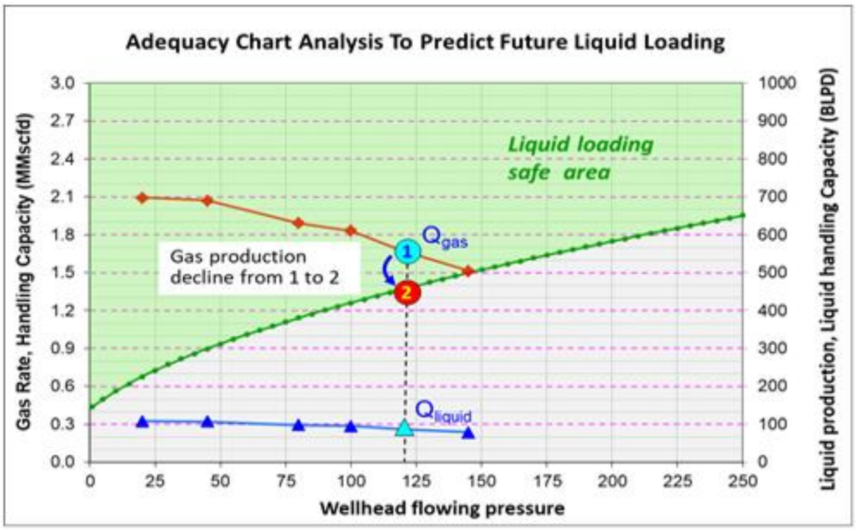

Figure 16. Adequacy chart Analysis to predict future liquid loading

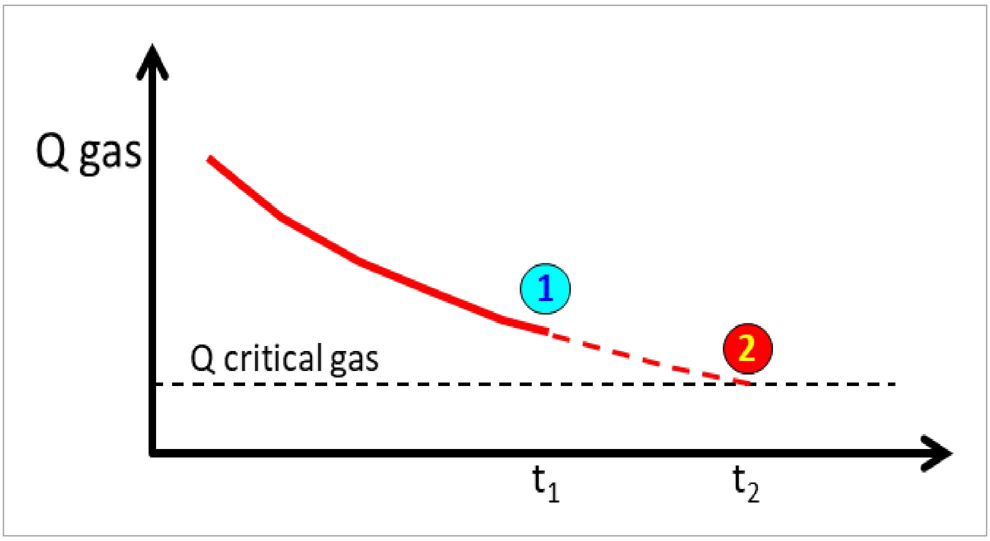

Figure 17. Gas production decline analysis

CONCLUSIONS

Losses due to liquid loading need to be avoided to maintain optimum production from the field, and many technologies and methodologies for its prevention and curation have been introduced and developed. This study encompasses a proposed technology considered as a new and innovative solution to have a quick suitable review on the available lowering pressure unit and well condition. The liquid loading condition will depend on the critical gas rate parameter, which will be determined by the tubing diameter and operating pressure condition to produce different wells will with varying critical gas rates.

Although the pilot project performed in well BLA-01 indicated that the well may continue flowing at a pressure of 15 psi, the production could not be sustained due to wellhead compressor limitation, leading to the suggestion of a larger capacity. Conversely, the gas production in BXC-07 was lower than its critical gas rate and the well was unable to sustain production though it indicated flow at the beginning.

The use of a temporary separator in well BXC-16 is a successful way to optimize liquid-loaded wells by lowering their operating pressure. Although this mechanism has a sufficient handling capacity to manage the gas and liquid production from the well, further optimization is needed to route the vented gas back to the production system to reduce losses and expulsion to the environment.

Based on the field trials above, lowered operating pressure can be described as an appropriate method to revive wells with a liquid loading problem. Also, the adequacy chart analysis is applicable for: (1) All pressure-lowering unit/system equipment, (2) Single or multiple wells, and (3) Predicting the critical gas rate post-optimization with lowered pressure. Therefore, a combination of critical gas rate and decline analyses can be used to predict potential liquid loading problems in wells.

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