Liquid Loading in a Horizontal Shale Gas Well: Prediction, Prevention & Remediation

Liquid loading is one of the major challenges faced by shale gas producers. This phenomenon occurs when the gas in-situ velocity is insufficient to carry the produced liquid, leading to liquid fallback in the wellbore. Liquid Loading can occur during the flowback phase, the phase where the well is producing liquid from hydraulic fracturing, as well as the production phase, and is known to cause premature gas production decline, as shown in Figure 1, as well as production instability and flow assurance issues.

This GATEKEEPER article focuses on the prediction, prevention and remediation of liquid loading, including discussion of liquid loading analysis. Such analysis is essential to perform when designing the optimum well completion, and developing a liquid loading management strategy to minimize the impacts and maximize the profitability of the well.

Liquid Loading Impacts on Well Production

Liquid loading impacts well production in three ways:
1. Liquid loading generates high backpressure to the perforation. This results in high bottomhole pressure and, consequently, a reduction of gas production from the reservoir. When the reservoir pressure is unable to overcome the backpressure, the well is prematurely killed.
2. The liquid fallback promoted by liquid loading may create pressure losses in the near wellbore region due to relative permeability reduction as the perforations are flooded with liquid.
3. The liquid fallback may also create liquid recirculation at some locations in the wellbore, depicted in Figure 2, leading to high risks of flow assurance issues such as corrosion and scaling.

Liquid Loading Prediction

Several studies on liquid loading have been published, including the two most well-known liquid loading models developed by Turner et al. (1969) and Coleman et al. (1991). These models were developed using a liquid droplet mechanism, whereby the minimum gas velocity to carry the liquid (critical gas velocity) is based on the equilibrium between the drag force applied to the liquid droplets and the gravity force.

Brito et al. (2015) studied the liquid film reversal mechanism to develop a robust model for predicting liquid loading instead of using the liquid droplet mechanism. They postulate that liquid loading occurs when the shear stress exerted by the gas flow at the liquid-gas interface is insufficient to generate sufficient drag force to carry the liquid film surrounding the pipe wall. This model predicts the in-situ gas critical velocity along the wellbore, which allows us to determine the liquid loading locations. It requires several data inputs, such as gas and liquid production rates, well geometry, production tubing and casing diameters, and fluid properties.

Figure 3 shows an example of the comparison between the in-situ critical superficial gas velocity ($v_{sG}$) and the actual in-situ $v_{sG}$ of the well. It shows that liquid loading potentially occurs at 1,400 - 10,600 ft MD as the actual in-situ $v_{sG}$ is lower than the in-situ critical $v_{sG}$ at this depth.

It is necessary to predict when the liquid loading will start happening, known as the liquid loading onset, in order to develop a liquid loading management strategy. This can be achieved by performing the liquid loading analysis with various gas production rates based on the production decline analysis (e.g., projected gas production in Figure 1). The liquid loading onset can be predicted by determining the time when the actual in-situ $v_{sG}$ drops to the in-situ critical $v_{sG}$. An example of this analysis can be found in Figure 4.

Liquid Loading Prevention

Liquid loading may inevitably occur as the well’s gas production rate declines over time; however, optimum tubing design and well trajectory can delay the liquid loading onset and maximize the cumulative gas production of the well. The following should be kept in mind when designing the well trajectory and completion:

- Drilling the well toe-up may reduce the liquid loading potential in the lateral section as downward flow of gas and liquid is expected.
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- Smaller tubing diameter will promote higher in-situ actual \( v_{sg} \) and reduce the liquid loading potential. Too small a tubing diameter may cause excessive frictional pressure drop under high gas flowrate.
- End of Tubing (EOT) should land below the depth with liquid loading potential to ensure the actual in-situ \( v_{sg} \) is higher than the critical \( v_{sg} \) at all locations along the wellbore.

**Liquid Loading Remediation**

Several artificial lift methods can be utilized to remediate liquid loading, including plunger lift, foam lift and gas lift.

**Plunger Lift**

Plunger lift is widely used as an artificial lift method for horizontal shale gas well deliquification. Various types of plungers are available in the industry with different fall velocity, rise velocity and liquid fallback tendency. The plunger lift action consists of two cycle periods: the shut-in period and the flow period, as shown in Figure 5. The duration of each period depends on the pressure of the well and productivity of the reservoir.

During the shut-in period, the bottomhole pressure builds up and the plunger travels from the wellhead to EOT. When the bottomhole pressure is sufficient to lift the plunger and the liquid column, the well is produced and the plunger acts as a piston to push the liquid column to the wellhead. The flow period begins when the plunger arrives at the plunger catcher in the wellhead.

During the flow period, the liquid begins to accumulate in the wellbore as the gas velocity is too low to unload the well. Once the backpressure exerted by the liquid accumulation is too high to allow desired gas production rate, the well is shut in and another shut-in period takes place.

**Foam Lift**

Foam lift utilizes foamers to generate foam in the wellbore to eliminate liquid loading. The three major components in a foam lift utilization are the production fluids (gas, water and condensate), foamers and the degree of agitation. The benefits of using foam lift include:
- Reduces the backpressure to the reservoir by reducing the mixture density.
- Increases the gas-liquid interface which generates more effective gas lifting force.

To ensure a successful foam lift application, several aspects need to be evaluated:
1. Foamer type: The foamer should be chemically compatible with the production fluids.
2. Foamer delivery method: Batch or continuous application. The latter is known to provide better control of the foamer dosage, injection rate and concentration. The foamer can be injected through a capillary string, tubing or casing-tubing annulus.

3. Foamer injection location: The injection location should promote sufficient agitation to ensure effective foam generation. A location with highly turbulent and non-stratified flow is preferred.

Gas Lift

Gas lift alleviates liquid loading by injecting gas into the well to reach the critical gas velocity (supplemental gas lift). The schematic diagram of gas lift with a pair-boy completion and an example of liquid loading elimination can be found in Figure 6. Gas is injected through the casing-tubing annulus and mixed with the reservoir stream at the EOT. It can be seen that the actual in-situ \( v_{sg} \) along the well is always higher than the critical in-situ \( v_{sg} \) when gas lift is installed in this example. Dinata et al. (2016) propose a methodology to determine the appropriate gas lift injection location and the optimum gas lift injection rate:
- Injection location should be below the deepest point where liquid loading is occurring to ensure that the injected gas is able to reach all the unloaded locations in the wellbore.
- Gas injection rate should be sufficient to reach the gas critical velocity and should not be so high that it will result in excessive frictional pressure losses.

**Conclusion**

In conclusion, liquid loading impacts on well production can be minimized by (i) performing a liquid loading prediction analysis using a state-of-the-art model, (ii) optimizing the well design and (iii) selecting a suitable remediation strategy. This will maximize the well profitability, and reduce the risks of potential liquid loading issues throughout the life of the well.

**References**


**Nomenclature**

- **EOT**: End of Tubing, ft
- **MD**: Measured Depth, ft
- **\( q_g \)**: Gas Production Rate, MSCFD
- **\( v_{sg} \)**: Superficial Gas Velocity, ft/s

**Figure 5: Plunger Lift Cycles**

**Figure 6: Supplemental Gas Lift Application**

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