Liquid loading in a gas well: A review study

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Abstract: The production ceases from every well as a result of reservoir pressure depletion. As the pressures depletes, the production of gas wells also depletes, a stage comes where liquid effluents could not move upward from the wellbore and starts accumulating around the wellbore. The usual accumulation of liquids around the wellbore creates further problem in reduced production rates. In order to maintain production rates, there a number of possibilities to prevent liquid loading prior to its occurrence. One option is to implement artificial lift method, or in other cases chemicals or foams injections helps to better use the reservoirs remaining energy. In some cases, tubing string sizes could optimize the production. Although, tubing string size selection will help in alleviating liquid loading for a certain time, however this is not an ultimate solution because the reservoir pressure depletes more, the well will start again loading. As the liquids starts accumulating around the wellbore, it becomes very critical to detect it early and to choose an appropriate prevention method. This paper deals with understanding liquid loading problems, prediction of liquid and its identification.

Keywords: *Liquid Loading; Profile of Multiphase; Multiphase Flow;*

1. Introduction

Liquid loading is the incapacity of a gas well to eliminate which are formed in wellbore with the gas. The liquid produced in the well will accumulate there, hence generating a hydrostatic pressure in counter to development of pressure and plummeting output till production from well terminates. To lessen liquid loading effects from the production of gas, a proper diagnosis of these issues should be dealt on time proficiently.

Another fact about liquid loading is very interesting that it presents itself as a low rate/low pressure wells in contrast to high rate/high pressure wells. The variation depends on surface pressure size of tubing string, density and amount of produced liquids with the gas. Thus, it's significant to identify symptoms of liquid loading at initial phases and plan a proper strategy to minimize the negative effects of liquids substantial up the wellbore.

1.1 Multiphase Flow

To properly understand the phenomena of liquid loading and how to effectively deal with it, must have understanding on how gas and liquid act when moving upwards together in the well production string. This perception is known as "multiphase flow". Basically, the multiphase flow is phenomena that represents more than one fluid moving through single medium and in this situation the medium is the gas well production string.
Usually, there are four flow regimes presented in multiphase flow which are:

1. Annular/Mist Flow.
2. Transition Flow.
3. Slug Flow.
4. Bubble Flow.

These regimes of multiphase flow happen due to certain flow velocity of liquid, gas phases and the volume of these segments relative to each other in the medium again in this case the gas well producing.

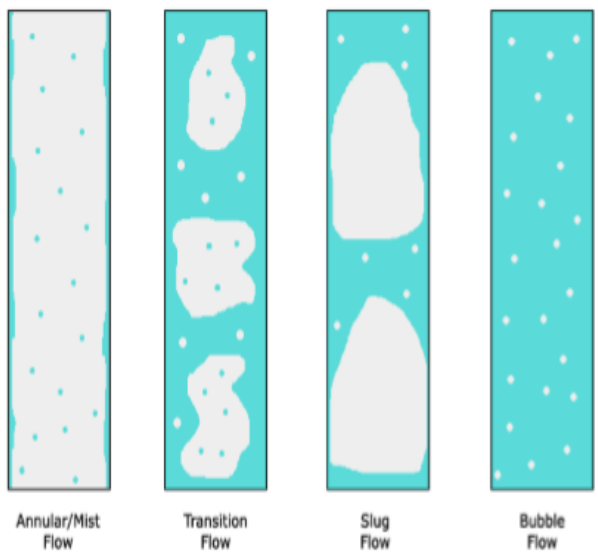

Figure 1. Basic Profile of Multiphase Flow in the Well

1.2 Annular/Mist Flow:

The dominant and the continuous media is the gas phase in the well. The liquid loading is present just as a mist in the gas, mostly a thin layer of liquid moving up the tubular pipe. Hence, the pressure gradient of liquid can be determined from gas.

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1.3 Transition Flow:

In this type of flow, the flow of liquid and gas tends to change from mist to slug. Therefore, there happens the continuous phase changes from liquid to gas or vice versa. The particles of liquids may still present in gas in mist form, but the pressure gradient is determined by presence of liquid.

1.4 Slug Flow:

In this type of flow, large slugs of gas can be found in liquid, but the leading and unceasing phase is liquid. These slugs of gas slugs cause pressure gradient to drop hence, its pressure is measured by both liquid and gas.

1.5 Bubble Flow:

The flow type in this case is such that the liquid is filled in the tubular and gas is present as small bubbles in it. Therefore, it may cause drop in liquid pressure, and decreases pressure gradient along the well. Considering these regimes of flow, one should reminisce that whole in its lifetime rarely there may be the case that only one flow regime is present in gas well. Generally, these gas wells almost have all types of flow regimes throughout their productive life. Correspondingly, in many cases there may be more than one flow regime exist at the same time, meanwhile gas bubble will get expanded when moving up along the production string.

Here, it should be noted that the velocity of flow is directly proportional to cross-sectional area of tubular, so there will be difference in flow regimes above and below the production packer. One more thing to be considered is the flow regime seen at the surface may not be the same as flow regime near the perforations due to bottom hole conditions that may be different down hole. In figure a very simple phenomena of liquid loading in gas well is defined and described in step wise manner. In this figure 2 at the very first stage the liquid and gas are co-produced simultaneously.

The liquid is in small quantity associated with gas and gas has capability to lift it. However, at stage two the gas has very low velocity to lift the liquid to surface hence this liquid starts accumulation inside the wellbore gradually. At the third stage, as shown in figure \3 pressure of flowing well decreases and the liquid in large quantity accumulated inside the wellbore and have killed the well production. Finally at stage fifth it is shown in Figure 5 that the foam or other means of treatment has helped the well to lift the well effluents again and have started producing. Hence the main issues are the selection of appropriate techniques and its implementation in order to optimize the production of existing well again.

As detailed above, with the decrease in gas velocity flow regimes changes from mist to bubble. And the presence of liquid is higher in bubble flow, so amount of liquid produced will increase with the change in flow regimes.

This means, with the decrease in reservoir pressure the rate of gas declines and the amount of produced liquids in the gas well increases and the causing increase in well cost. There will one point, where the increasing amount of liquid will start to accumulate in the well as the flow regime down hole shifts to bubble flow and increasing the bottom hole pressure in the well. In that situation, the well will ultimately be incapable to withstand that pressure and will stop production.

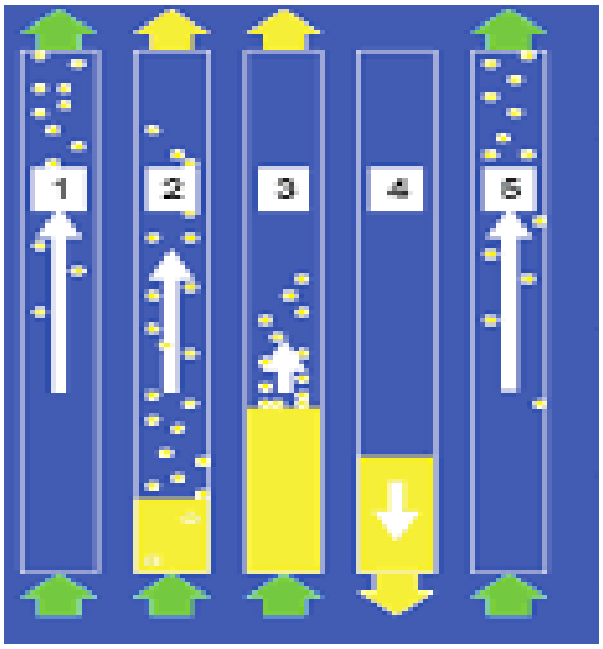

Figure 2. Illustration is the Liquid loading phenomena in gas wells

2. Understanding the liquid loading process

In gas wells, single-phase flow is rarely present. Water can enter the wellbore as free water from the reservoir or as a result of condensation of water from the gas which experiences pressure and temperature changes as it travels through the wellbore.

Wet gas wells typically experience annular flow during normal operation. Liquids can be transported as a film along the inside walls of the tubing, but may also be entrained in the main gas flow in the form of droplets.

The liquid film is transported upward along the tubing walls by the shear forces along the interface with the central gas core. Lowering gas velocities reduces the ability of the gas to transport this liquid film. The liquid film starts to thicken, and part of the film starts to flow downward. In recent experiments it was proven the liquid film starts to flow downwards while the droplets are still produced upwards. This moment is defined as liquid loading. The gas velocity at which liquid loading occurs is referred to as the critical velocity for liquid loading.

This process does not necessarily mean that total liquid transport is downward. The inner part of the liquid film is still forced upward by the gas core, as are the droplets entrained in the gas core. A further lowering of the gas velocity reduces the section of the film that is dragged upward by the gas core, until the net flow is downward and the well is flooding, meaning that water is accumulating at the bottom of the wellbore as shown in Figure.3.

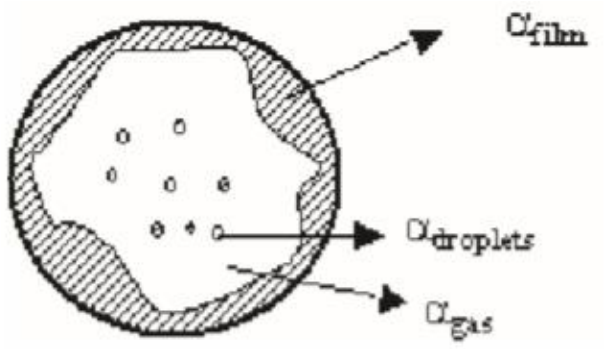

Figure .1 Liquid loading phenomena

This whole process is a balance between inertial forces between the gas core and the liquid film and droplets, which tends to drive the liquid upward, and the force of gravity, causing film thickening and – as gas velocity decreases further – exceeding the available inertial forces resulting in downward liquid flow.

3. Effect of deviation angle

The deviation angle affects this balance in two ways. Firstly, wellbore deviation will mean the direction in which the force of gravity is acting no longer completely opposes the flow direction. This reduces the effect of gravity on the droplets or film and causes liquid loading to occur at lower gas rates. Secondly, however, the liquid film along the walls of the tubing is no longer distributed evenly along the circumference of the tubing. Instead, the film is thicker on the lower tubing wall and thinner on the upper tubing wall. This thickened film layer is less easily transported upward by the gas flow, resulting in liquid loading occurring at higher gas rates. Experiments performed by Keuning [2] and others have quantified this effect, which is shown in Figure 4.

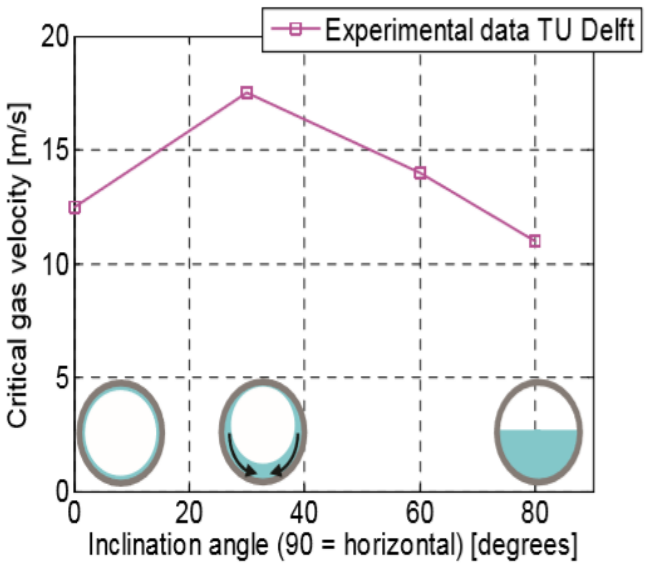

Figure. 2 Measured effect of inclination angle

4. Reservoir effects

The performance of wells is often judged by looking at so-called tubing performance curves (TPCs), which show the pressure drop over the well as a function of the flow rate. Experiments have been performed in flow loops by many authors in order to study the phenomenon of liquid loading.

Looking at the TPCs in Figure .5 obtained in a flow loop by Van 't Westende [3], the effect of gravity on film thickening may be seen at the lower gas flows. In the region to the right of the minimum, pressure drop is dominated by the gas flow, and increasing gas flows cause increased pressure drop. To the left of the minimum, the liquid film starts to thicken because it is no longer transported as effectively. This thickening of the film increases local holdup and therefore gravitational head, and also reduces the area available for the gas flow, creating a higher pressure drop. In experiments, liquid accumulation – flooding – is observed a considerable distance to the left of this minimum point, i.e. at lower flow rates than the minimum. The point at which this happens is important, since in a real well this will result in a column of liquid building up, restricting production. In experiments, this point may occur to the left of the minimum.

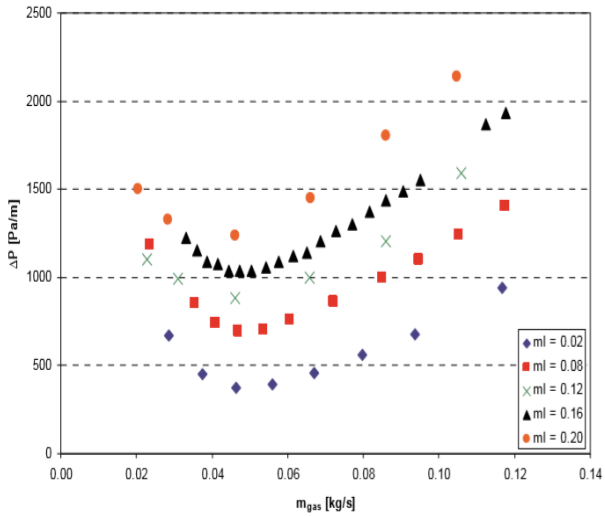

Figure. 3 Pressure drop over the vertical test setup

At this stage it is important to make an important distinction between a well-reservoir system and an experimental flow loop. In experiments, gas is typically supplied by a gas mass source supplying gas at a controlled rate. In such experiments, gas flow rate is independent of the pressure at the bottom of the flow loop. At flow rates slightly to the left of the minimum film thickening has started, but total liquid transport may still be upward, and a column is not building up. Such a loop can operate to the left of the minimum, as long as the flooding point – the point at which total liquid transport is downward – is not reached.

In a well-reservoir system, the situation is different. The flow supplied by a reservoir depends on the pressure difference between the bottom of the well (bottomhole pressure, BHP) and the reservoir itself. As gas is produced, the reservoir pressure decreases, resulting in lower gas flow through the wellbore. At some point the gas flow has decreased to a rate to the left of the TPC minimum, as was seen in flow loop experiments. At this point, the system is unstable: any further decrease in gas flow leads to an increase in bottomhole pressure, which in turn leads to the

reservoir supplying less gas to the wellbore. This instability leads to rapidly decreasing gas flows accompanied by flooding.

Different reservoirs respond differently to pressure changes. A very tight reservoir will have a very high pressure drop over the reservoir compared to the wellbore, and will respond less strongly to increasing BHP. Such reservoirs behave somewhat similarly to mass flow sources, and may experience liquid build-up some way to the left of their TPC minimum. A very permeable reservoir will show much stronger flow decrease for a given change in BHP. Upon reaching the well TPC, the corresponding increase in BHP leads to a very rapid decrease in gas production, accompanied by an immediate build-up of a liquid column.

5. Prediction of liquid loading

In the late sixties, Turner et al. (1969) developed the first model for liquid loading by calculating critical gas velocity. They studied data sets of 106 vertical wells. The pipe diameters were 2.5" and wellhead pressures were above 500 psia. They did two experiments:

– The continuous film model

– Entrained drop movement model

After several experiments, Turner et al. found that the droplet model fits best to their well data. Turner's droplet model can be expressed by force balance on a single droplet. Force balance includes upward drag force F_D, upward buoyant force F_B and downward gravity force F_G. According to the droplet model, droplet will move upward, if $F_D+F_B>F_G$, it will accelerate downward, if $F_D+F_B<F_G$. The balance forces - $F_D+F_B=F_G$ gives critical gas velocity of droplet. Figure. .6 explains force balance of a single droplet. Turner et al. developed an equation for critical loading velocity based on the experiments:

$$v_{crit.} = \frac{k_v \sigma^{0.25} (\rho_l - \rho_g)^{0.25}}{C_D^{0.25} \rho_g^{0.5}} \quad (1)$$

The critical rate can be calculated as in below:

$$Q_{crit.} = \frac{3.06 A p v_{crit.}}{zT} \quad (2)$$

Where kv is 1.3.

The velocity that can suspend the largest liquid droplet at the wellhead is called Turner critical loading velocity. Turner et al. reported that out of 106 wells, 16 are questionable. 66 wells out of 90 best fitted with their model. Then they adjusted the equation 20% upward and got 77 wells best fitted. Note that Turner et al. used 30 as a Weber number.

$$v_{crit.} = 1.2 v_{crit.} \quad (3)$$

$$Q_{crit.20\%} = 1.20 Q_{crit.} \quad (4)$$

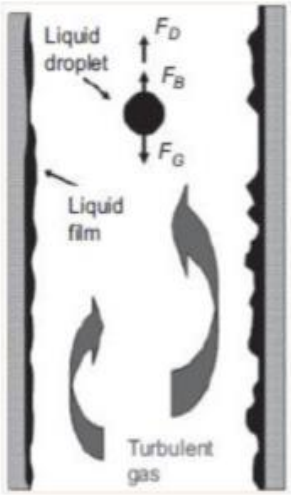

Figure. 4 Force Balance of a Single Droplet (Zhou and Yuan 2009)

However, since Turner's data sets were mostly consisting of high wellhead pressures (P_{wh}>1000 psia), they could not determine that 20% adjustment gives incorrect results for low wellhead pressure wells. Another drawback of Turner's model was an assumption that the shape of droplet is spherical and does not change while flowing in the well.

Coleman et al. (1991) firstly reported that Turner's 20% adjustment does not work with low-rate and low wellhead pressure wells and should be applied without adjustment. Coleman's non-adjusted droplet model is widely used for wells with wellhead pressures less than 500 psia.

Nosseir et al. (2000) by working on Turner's data set, announced that Turner's equation is not based on the flow regimes and this leads to some errors in the calculations. They calculated all Reynolds numbers for each rate and concluded that Turner's assumption for Reynolds numbers between 10^4Re2x10^5 is not correct. Most of the data exceeds this range and shows itself in highly turbulent regime. As a result, they proposed two new equations regarding the critical velocity: one for transition and one for highly turbulent flow regime.

For transition regime:

$$v_{crit.} = \frac{14.6 \sigma^{0.35} (\rho_p - \rho)^{0.21}}{\mu^{0.134} \rho^{0.426}} \quad (5)$$

For highly turbulent regime

$$v_{crit.} = \frac{21.3 \sigma^{0.25} (\rho_p - \rho)^{0.25}}{\rho^{0.5}} \quad (6)$$

Li et al. (2002) unlike Turner's spherical-droplet model, introduced new flat-shaped droplet model. They explained that in a high velocity gas flow, the fore and apt portions of droplet have a pressure difference. This pressure difference changes droplet's shape from spherical to like a convex bean form, which has unequal sides. Fig. 2.7 shows the droplet's shape changes from spherical to flat in a high velocity. Compared with spherical droplets, flat ones need low gas velocity and flow rate due to having more efficient area. For the Reynolds number range 104Re2105, drag coefficient (CD) for Turner's model is 0.44, but for flat

shaped one is 1.0, which means smaller critical velocity than spherical droplet

$$v_{crit.} = 0.7241^4 \sqrt{\frac{(\rho_l - \rho_g)\sigma}{\rho_g^{0.5}}} \quad (7)$$

$$Q_{crit.} = 3060 \frac{Apv_{crit.}}{zT} \quad (8)$$

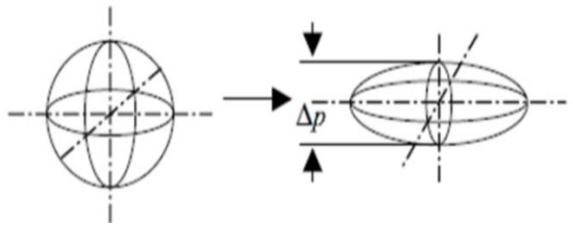

Figure. 5 Entrained Droplet's Shape in a High Velocity Gas Stream (Li et al.2002)

Although, Li et al. introduced the new shaped droplet model and showed Turner's spherical droplet model is not completely accurate, they made the correlation based on the assumption that the shape of droplet is constant and does not convert. They did not consider if droplets coalesce, how it can change their shape. In reality, experiments show that droplets coalesce and separate many times in the wellbore. Consequently, they will need more gas velocity to move upward.

Guo et al. (2006) found that Turner's method is not accurate, because they considered only top of the wellbore instead of bottomhole conditions in their model. However, since the flow in the wellbore is multiphase, bottomhole condition should dominate rather than top hole and because of it their assumption results with the incorrect minimum flow rate prediction. Based on this observation, Guo et al. introduced new phenomena - minimum kinetic energy criterion for calculation of critical rate for multiphase flow in gas wells. They showed that gas should exceed the minimum kinetic energy value in order to transport the liquid droplet to the wellhead. On the other hand, multiphase flow model predicts accurate bottomhole pressure and fluid density that are used in kinetic energy calculation. They proposed a minimum required gas production rate calculation based on this new model:

$$144b\alpha_1 + \frac{1-2b_m}{2} ln\alpha_2 - \frac{m+\frac{b}{c}n-bm^2}{\sqrt{n}}[tan^{-1}\beta_1 - tan^{-1}\beta_2] = \gamma \quad (9)$$

$$\alpha_1 = 9.3x10^{-5} \frac{S_g T_{bh} Q_{gm}^2}{A_i^2 E_{km}} - p_{hf} \quad (10)$$

$$\alpha_2 = \frac{\left(1.34x10^{-2}\frac{S_g T_{bh} Q_{gm}^2}{A_i^2 E_{km}} + m\right)^2 + n}{(144p_{hf} + m)^2 + n} \quad (11)$$

$$\beta_1 = \frac{\left(1.34x10^{-2}\frac{S_g T_{bh} Q_{gm}^2}{A_i^2 E_{km}} + m\right)}{\sqrt{n}} \quad (12)$$

$$\beta_2 = \frac{144p_{hf} + m}{\sqrt{n}} \quad (13)$$

$$\gamma = a(1 + d^2 e)L \quad (14)$$

$$a = \frac{15.33S_s Q_s + 86.07S_w Q_w + 86.07S_o Q_o + 18.79S_g Q_G}{10^3 T_{av} Q_G}\cos(\theta) \quad (15)$$

$$b = \frac{0.2456Q_s + 1.379Q_w + 1.379Q_o}{10^3 T_{av} Q_G} \quad (16)$$

$$c = \frac{6.785x10^{-6} T_{av} Q_G}{A_i} \quad (17)$$

$$d = \frac{Q_s + 5.615(Q_w + Q_o}{600A_i} \quad (18)$$

$$e = \frac{6f}{gd_h \cos(\theta)} \quad (19)$$

$$f = [\frac{1}{1.74 - 2log\frac{2\varepsilon}{d_h}}] \quad (20)$$

$$m = \frac{cde}{1 + d^2 e} \quad (21)$$

$$n = \frac{c^2 e}{(1 + d^2 e)^2} \quad (22)$$

The calculations are followed through eqns. (10) – (22) and got final value. This value is compared with the value of eqn. (9) after substituting the values of eqns. (10) - (22) in (9). The calculations are repeated until right hand side of eqn. (9) is close to value of eqn. (14). Eventually, calculated Q_{gm} becomes minimum flow rate that gas transports the droplet to the surface.

Wang and Liu (2007) offered that for Reynold number ranges between 10^4 and 10^6 and Morton number ranges between 10-10 and 10-12 in gas wells. They determined that most of the droplets are disk-shaped in gas flow and may be carried to the surface because of having more efficient area similar like flat-shaped one. They also calculated that drag coefficient (CD) for disk-shaped droplet is 1.17 and proposed new equations for critical velocity and flow rate:

$$v_{crit.} = 0.5213 \frac{[(\rho_l + \rho_g)\sigma]^{0.25}}{\rho_g^{0.5}} \quad (23)$$

$$Q_{crit.} = 3060 \frac{Apv_{crit.}}{zT} \quad (24)$$

Same as Li et al. model, they also did not consider in their model in case of droplets coalesce and separate and how it can change the minimum flow rate. Zhou and Yuan (2009) showed that for gas wells gas velocity usually is very high and the flow is turbulent. In turbulent flow regime, droplets do not flow just through upward, they flow through all the directions. Droplets may coalesce and make bigger ones, then may separate to small ones and then again they may coalesce. This process is repeated continuously. The process is illustrated in Fig. 1.8. From this observation, Zhou and Yuan introduced a new definition - liquid holdup to represent liquid droplet concentration in gas wells:

$$H_l = \frac{v_{sl}}{v_{sl} + v_{sg}} \quad (25)$$

Where H_l - liquid holdup and V_{sl} and V_{sg} are superficial liquid and gas velocities, respectively.

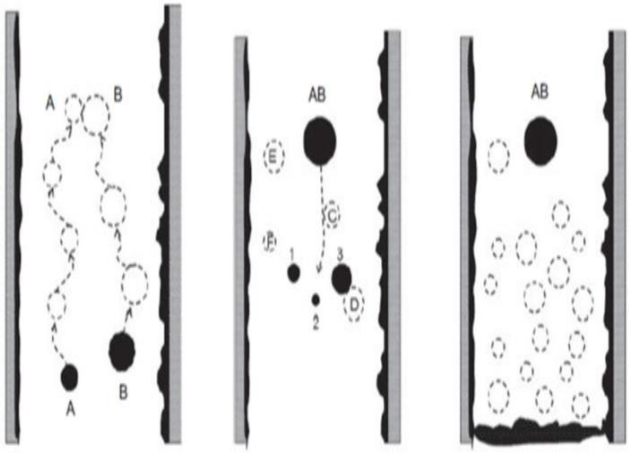

Figure 1.6 Droplets in Turbulent Flow Regime (Zhou and Yuan 2009)

They explained that conventional Turner's critical velocity equation is fitted, if liquid holdup is equal or less than threshold value of liquid-droplet concentration

$(\beta)H_l \leq \beta$

$$v_{crit.-N} = 1.915 \frac{\sigma^{0.25}(\rho_l - \rho_g)^{0.5}}{\rho_g^{0.5}} \quad (26)$$

However, if $H_l > \beta$

$$v_{crit.-N} = v_{crit.} + ln\frac{H_l}{\beta} + \alpha \quad (27)$$

Where $V_{crit\text{-}N}$. - critical velocity for new model, α is a fitting constant. From Turner et al (1969) data, α = 0.6, β = 0.01 were estimated. The maximum H_l = 0.24. According to Barnea et al. (1987), when the liquid holdup becomes higher than 0.24, the multiphase flow changes to slug flow pattern.

Luan and He (2012) by analyzing both Turner et al. (1969) and Li et al (2002) results, determined that Turner's model overestimates, whilst Li's model underestimates the critical velocity of gas wells. Consequently, they introduced a new dimensionless parameter loss factor - S for their new model to include the gas energy loss caused by the move of flat-shaped droplets of Li's model. Thus, the empirical equation of model

$$v_{crit.-s} = v_{crit.-l} + S(v_{crit.-T} - v_{crit.-L}) \quad (28)$$

Where $V_{crit.-T}$ and $V_{crit.-L}$ are the calculated velocities from Turner's and Li's models, respectively.

Luan and He analyzed production data of 300 gas wells in China and observed that S factor ranges between 0.75 and 0.83. For simplification as an upper limit 0.83 is used.

$$v_{crit.-S} = v_{crit.-l} + 0.83(v_{crit.-T} + v_{crit.-L}) \quad (29)$$

$$Q_{crit-s} = 3060 \frac{Apv_{crit.-s}}{zT} \quad (30)$$

Authors, recommended to use their model with low-pressure gas wells, especially wellhead pressures less than 500 psia as Coleman's model.

8. Identification of liquid in gas well (field case)

The methods for identification of liquid in gas well can be characterized as:

1. Direct method
2. Indirect method

The liquid loading through direct method can be identified by monitoring the results of instruments. It is highly precise and spontaneous, with PLT monitoring method and pressure-gradient. Apart from this, the indirect methods involves the use of testing analysis, production and other routine presentation data for identifying liquid loading. Though, this may generate undefined results, and there is need to utilize hybrid of methods to acquire acceptable results. Tubing-casing pressure method, well testing method, critical liquid-carrying method and empirical production change method are the all indirect methods.

6. Pressure-gradient identification method

If there is liquid loading in well, and the bottom hole pressure restores to a stable value after shut-in, abnormal gas-liquid pressure gradients per hundred meters or per meter would occur, with the column weight (density) being higher than pure gas column density. Fig. 1.9 is the Well Sam-61 monitoring curve for hydrostatic pressure gradient. The figure displays that the section above 2430 m is full of gas, if it is between 2430 and 2450m there exist coexistence of gas and liquid, and the section with below 2450m contain liquid. Which proves that the liquid has been loaded in the wellbore interval below 2430 m.

7. PLT monitoring method

Generally, seven parameters are covered in this type of monitoring, i.e., casing collar, turbine flow, natural gamma ray, fluid density fluid temperature and pressure, water holdup. Hence, this can identify more accurately the contents of liquid loading. Fig. 1.10 showing monitoring curve for composite PLT between 2413-2452 m section in well sam-61. There exist two perforation intervals in this section, i.e., 2416.1-2427.6 m interval and 2431.6-2448.3 m interval. Whereas, slight fluctuation in flow curve in the wellbore section below 2446 m, indicate that only a small amount of gas was produced in the formation below, and liquid is filled in most of the wellbore. Between section 2446-2444 m of wellbore, the turbine flow significantly increases, the fluid density of 0.5-1.0 g/cm³, and the temperature drop display that a certain amount of gas is produced and gas-liquid, mainly liquid, exists in this wellbore section. In the wellbore section 2444-2431.6 m, the slight increase in turbine flow and fluid density of 0.2-0.5 g/cm³ reveal that a certain amount of gas produced in this section and gas-liquid, mainly gas exists in this wellbore section. In the wellbore section above 2431.6 m, the wellbore was full of gas.

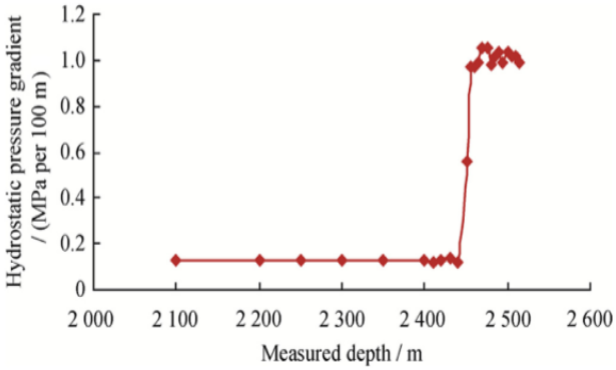

Figure . 7 Hydrostatic pressure gradient monitoring curve of Well Sam-6

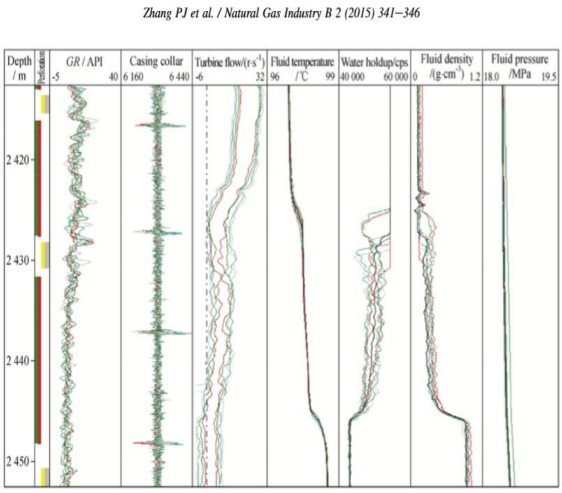

Figure . 8 Composite monitoring of 2413-2452 m wellbore in Well sam-61

1.1 Liquid loading types

There are three types of liquid loading,

1. External liquids
2. Condensate liquid.
3. Formation-water type.

1.1.1 Formation-water type

Under the producing pressure the free formation water flows into wellbore, and when the gas well energy is not enough to remove water out of well the liquid starts to load in the well. The liquid loading performance varies in different types of gas-reservoir. Generally, in case of edge/bottom water reservoirs, water gradually invades into gas-producing reservoirs and finally into the bottom of the gas wells and there will be drop in productivity of the gas wells. Hence, in the middle late stage of gas reservoir development there observe strong negative impact on the production. Most of the Sichuan Basin carboniferous gas reservoir belong to this category. With poor pore structure and internal water, in the low-permeability water-bearing reservoirs, production of water starts from production of well. Although, with the low rate production of water, gradually there will be increase in liquid loading with the gas production is lower than the critical liquid-carrying capacity. So periodic foaming operation is required to drain out the contents of loaded liquid and maintaining production of gas normal. In case of fractured water-bearing gas reservoir, as water rapidly flows into well bottom along fractures, the wells usually have high water production rate; if the gas production rate is high at the early production stage, the liquid in the well would increase rapidly with the decrease in formation pressure and the growth of water production and the output of the gas well would drop to a level to maintain normal production.

1.1.2 Condensate liquid

The water vapor and heavy hydrocarbon components flows in wellbore with the gas with the decrease in temperature accompanying with heat loss in the wellbore. When the gas flow rate is low to carry out condensate liquid to surface, the liquid will flow in the opposite direction of gas and accumulate at the well bottom. For pure gas wells, condensate liquid loading can be judged by comparing the theoretically-calculated condensate water (oil) production and the actual gas (oil) production and. When the theoretically-calculated condensate water quality is greater than the actual water (oil) production the condensate liquid loading is occurred. It is usually found in gas condensate reservoirs.

1.1.3 External liquids

External liquids refer to acidizing fluid, drilling fluid, fracturing fluid, and other operating fluids used for the exploration and development. During drilling process these fluids get into the formations, acidizing, fracturing and other operations and gradually flow back into wellbore in the early stage of production. When the gas flow is not high enough to bring the external liquid to surface, the liquid would load at the bottom of the well.

1.2 Conclusion

Liquid loading is one of the fundamental problem in the gas reservoir. It restricts the production of gas from the well and also causes economical loss and it must be lessen for profitable gas recovery. Thus, it is significant to identify symptoms of liquid loading and predict liquid loading mechanism at initial phases and plan a proper strategy to minimize the negative effects of liquids substantial up the wellbore.

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