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## **CHANGING WELL COMPLETION IN A MATURE GAS WELL USING VELOCITY STRING**

### **1. INTRODUCTION**

In a gas field production decrease over time and can eventually stop producing completely because of liquid loading. As the reservoir pressure in a gas well depletes, there may be insufficient velocity to transport all liquids from the wellbore. In time, these liquids accumulate and impair production.

The factors that are causing this problem include declining reservoir pressure, gas velocities and increased water production. Increased water production can also cause a column of water to accumulate at the bottom of the well, preventing reservoir fluids from entering the wellbore. This accumulation of water is called liquid loading of the well.

One method of restoring a well that is liquid loaded back to flow production is installing a smaller diameter tubing string to run inside the production tubing of a well. Installing a velocity string reduces the flow area and increases the flow velocity to enable liquids to be carried from the wellbore. Velocity strings are commonly run using coiled tubing as a velocity string conduit. Safe live-well working and rapid mobilization enable coiled tubing velocity strings to provide a cost effective solution to liquid loading in gas wells.

Regarding advanced rate of depletion in Romgaz gas fields, this method gives viable solutions to face the problems that appear in the exploitation of the wells with appreciable liquid impurities production.

### **2. THEORETICAL ASPECTS**

Many gas reservoirs produce liquids. These liquids include either condensates or water. Gas pipelines will also carry some liquids. The presence of liquids affects the pressure drop calculations. Gas-liquid flow in vertical, horizontal or inclined pipes behaves in a much more complex manner than a single-phase flow. The two most important characte-

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istics in which two-phase flow differs from a single-phase flow are the existence of a slip-page between the gas and the liquid, and the presence of flow regimes. The superficial velocity of gas and liquid are defined as:

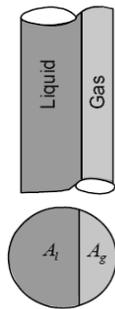
$$v_{sl} = \frac{q_l}{A}; \quad v_{sg} = \frac{q_g}{A} \quad (1)$$

where:  $q_l$  is the liquid flow rate,  $A$  is the cross sectional area of the pipe and  $q_g$  is the gas flow rate. These velocities are called superficial velocities because they are defined based on the entire cross sectional area. That is, the superficial velocity of liquid is the superficial velocity at which liquid will travel in the pipeline if only liquid is flowing.

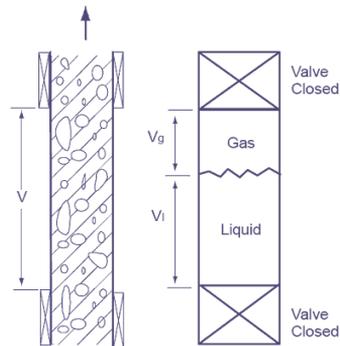
Obviously, because of the presence of other fluid, the liquid and gas occupy only part of the cross sectional area. This is schematically shown in Figure 1. If the liquid phase occupies an area  $A_l$ , and the gas phase occupies an area,  $A_g$ , then the in-situ velocities (actual velocities) of the liquid and gas phases are calculated as,

$$v_l = \frac{q_l}{A_l}; \quad v_g = \frac{q_g}{A_g} \quad (2)$$

where  $v_l$  and  $v_g$  represent the actual velocities at which the liquid and the gas phases are flowing respectively. The fractional cross sectional area occupied by each phase is called the holdup of that phase (Fig. 2).



**Fig. 1.** A simplified representation of two-phase flow in pipe

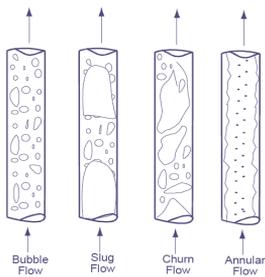


**Fig. 2.** Experimental measurement of hold-up

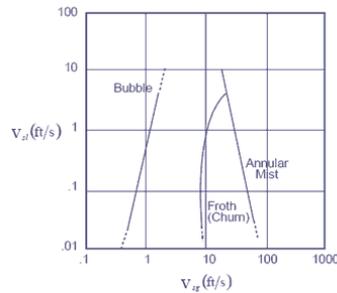
It is very important that correct information on gas and liquid holdups be available for a proper prediction of the pressure losses under two-phase flow conditions. Especially the gravitational gradient can be significantly affected by an incorrect value of the liquid holdup.

Another important difference between the single-phase flow is the presence of flow regimes. Depending upon the relative magnitude of gas and liquid velocities, different flow configurations are observed for vertical and horizontal flows.

For vertical flow, as shown in Figure 3, four flow regimes are observed at different gas and liquid velocities. At very low liquid and gas velocities, the liquid phase is continuous and the gas phase travels as dispersed bubbles. This flow regime is called bubble flow. As the gas velocity increases, the gas bubbles start coalescing, eventually forming large enough bubbles (Taylor bubbles) which occupy almost the entire cross sectional area. This flow regime is called slug flow. As the gas velocity increases even further, we enter a chaotic region. The flow appears very turbulent with each of the phases being intermittently continuous and discontinuous. This flow regime is called churn turbulent or transition flow. As the gas velocity increases even further, the transition occurs and the gas phase becomes a continuous phase carrying the discontinuous phase as the liquid droplets. Some liquid flows as a thin continuous film adhering to the pipe wall. This flow regime is called an annular flow or an annular mist flow.



**Fig. 3.** Flow pattern in vertical and sharply inclined flow



**Fig. 4.** Flow regime map for vertical flow

Based on the variety of the flow regimes exhibited by the two-phase flow, it is obvious that the holdup as well as pressure drop characteristics have to be flow regime dependent. Although not discussed, similar flow regimes also exist for inclined downward and upward flows. It is, therefore, important that flow regime characteristics should be clearly understood before the pressure drop can be accurately predicted. Several attempts have been made to identify the flow regimes for various flow configurations. Typically, a flow regime map is drawn as a function of gas and liquid velocities. Figure 4 shows a typical flow regime map for vertical flow for air-water system. On the x-axis we have superficial gas velocity and on the y-axis we have superficial liquid velocity. The flow regime map shows the transition from one flow regime to another flow regime as a function of superficial velocities. The transition between the flow regimes is plotted as a function of the superficial gas and liquid velocities.

### 3. DESIGNING COILED TUBING VELOCITY STRINGS

The rationale behind installing a coiled tubing string of smaller diameter than the production tubing is to reduce the cross-sectional flow area. The smaller cross-sectional flow area increases the gas velocity in the tubing. The higher gas velocity at the bottom of the tubing provides more transport energy to lift liquid up out of the well. Liquid no longer accumulates at the bottom of the well and production is sustained.

The gas velocity must meet or exceed a minimum or critical velocity to prevent a well from loading up. There are two popular methods for determining the minimum gas velocity: a rule of thumb widely accepted in the petroleum industry and a theoretical correlation presented by Turner *et al.* (1969).

The rule of thumb sets the minimum gas velocity at 3.05 m/sec. Thus, a well can be restored to flowing production if the gas velocity at the bottom of the tubing remains above 3.05 m/sec.

The correlation presented by Turner uses a theoretical analysis of the flow regime. In order to prevent liquid loading of the well, the liquid in the tubing must be suspended as a mist (qualities above 95%) or the flow regime in the tubing must be in annular-mist flow. In these flow regimes, as long as the gas velocities exceed the settling velocity of liquid droplets, high gas velocities force the liquid out of the tubing.

The objective of a velocity string design is to find an optimum coiled tubing size and depth that will restore the well back to flowing production, so that the frictional pressure losses in the tubing are minimal and production is maximized. The well should also continue producing long enough to offset the cost of installing the velocity string.

To design a velocity string that will return the well to flowing production and how long it will sustain production, you compare two curves:

- 1) the reservoir inflow performance relationship (IPR), which describes the performance of gas flowing in from the reservoir.
- 2) the tubing performance characteristic (J-curve), which describes the performance of gas flowing up the tubing.

The reservoir inflow performance relationship (IPR) shows the relationship between the flowing bottomhole pressure and the gas flow rate from the reservoir into the well (Fig. 5). There are various methods available in the literature to construct the reservoir IPR for oil and gas wells. Cerberus constructs the reservoir IPR based on Darcy's equation for oil wells. This can be somewhat of a limitation since many velocity strings are installed in gas wells with high gas-liquid ratios (GLRs).

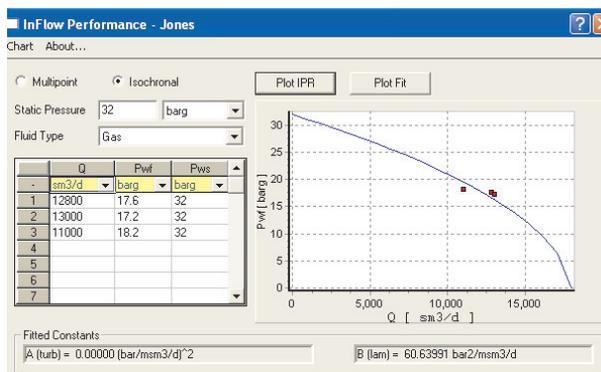


Fig. 5. IPR for a well form Filitelnic gas field

Note that the IPR is determined completely by the properties of the reservoir, especially the reservoir pressure. It is independent of the tubing performance curve.

The size and length of coiled tubing may be dictated by previous pipe installation. Optimal can be externally tapered coiled tubing because of flexibility for optimizing flow. The following design parameters of coiled tubing string should be reviewed:

- Minimum and maximum tensile load, burst and collapse pressure allowed.
- Desired over pull above string weight of each segment before yield load is obtained.
- Based on wellbore trajectory sinusoidal or helical buckling, pickup and slack-off loading evaluation.
- Metallurgy that can ensure suitable material for desired time exposure in the well's downhole environment.

A procedure of typical coiled tubing velocity string hangs off implements:

- Removal of paraffin or other obstruction if needed.
- The way of liquid removal.
- Christmas Tree preparation: closing of lower master valve, bleeding of pressure above lower master valve, removing Christmas tree above lower master valve.
- Installation of coiled tubing hanger, installation of packoff assembly in hanger and locking.
- Rigging up the coiled tubing unit, installation of window and blowout preventers.
- Installing pumpout plug in coiled tubing, opening master valve and running in hole to desired depth.
- Landing coiled tubing, installing slips and packoff, cutting tubing in window; re-cutting after rigging down coiled tubing unit.
- Installation of Christmas tree on coiled tubing hanger, pumping out plug to enable production.

The tubing performance curve describes the performance of a specific tubing size, depth, and wellhead conditions. As such, it is different for each velocity string design. This curve shows the relationship between the flowing bottomhole pressure and the gas flow rate up the well. It is called the *J-curve* due to its shape.

The J-curve (Fig. 6) is divided into two parts by the inflection (loading) point, where the slope is zero. To the left is the hydrostatic contribution. To the right is the contribution from tubing frictional losses. The minimum flow rate corresponding to the minimum velocity also appears on the J-curve.

There are numerous multiphase models available to obtain the tubing performance curve in oil and gas wells. Cerberus uses multiphase models developed for oil wells and their predictions are generally good (errors less than 20%) up to a GLR of about 5000. Note that each model only applies to specific conditions, and select the model accordingly.

A well flows at the flow rate where its IPR and J-curve meet. Compare this intersection point with the minimum gas flow rate on the J-curve to see which of three situations will occur:

- the well will flow, without loading up,
- the well will flow, but will load up and eventually stop producing,
- the well will not flow.

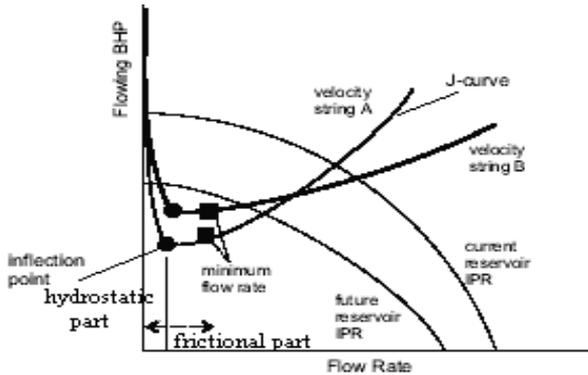


Fig. 6. Theoretical diagram for tubing performance

If the intersection point is to the right of the minimum gas flow rate, the well flows faster than the minimum gas flow rate and no liquid loading occurs.

It is important to first evaluate the performance of the existing production tubing by itself to justify installing a velocity string. To evaluate the existing production tubing by itself, simply create the J-curve for the existing tubing with no C.T. installed and compare it with the IPR. If the well has already started to load up, you should install an appropriate velocity string before the well kills itself.

It is also important to make sure the velocity string design will keep the well flowing long enough to recoup the cost of the installation, as the reservoir pressure continues to drop. To see the future performance of the velocity string, create the IPR for the predicted future reservoir pressure and compare it with the J-curve of the velocity string. Make sure that the actual flow rate at the future pressure is still greater than the minimum flow rate.

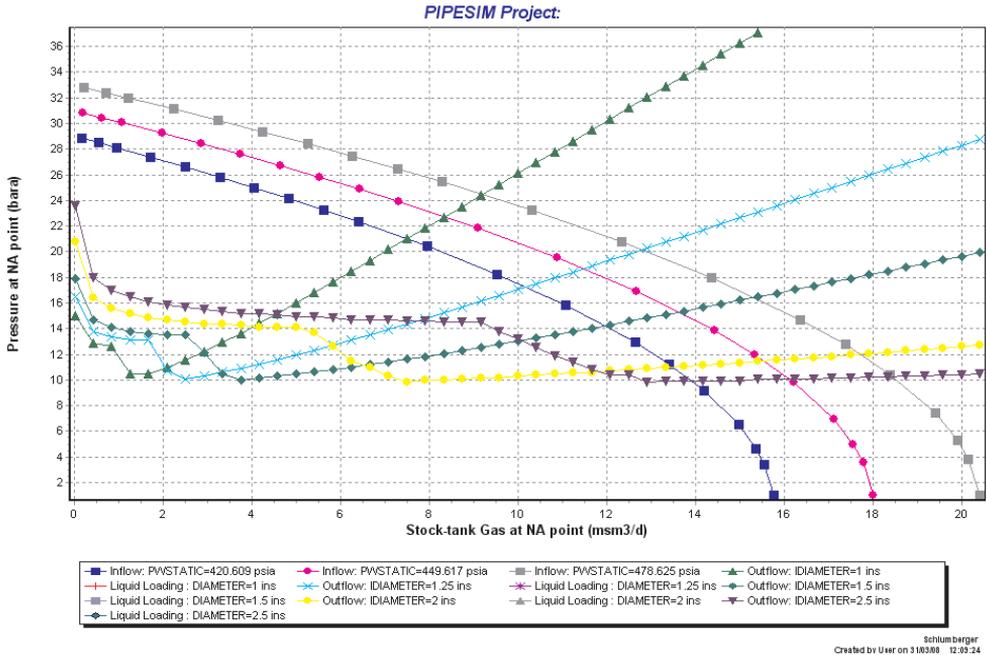
If multiple designs will prevent the well from loading up, the optimum choice is typically a trade-off between current production (a higher flow rate) and sustained production (a lower bottomhole pressure).

#### 4. CASE STUDY

ROMGAZ mostly fields are in an advanced phase of depletion, being considered brownfields (mature fields). For these fields, gas area is boundaries by aquifers, sometimes strong develop.

Our company wants to test the velocity string technology. This begins with possible candidate's selection. There were selected wells with higher relatively static pressures, almost 30 bars, not very depth, about 1000 m, which were predisposed to water loading and could be flooded if no soap has been introduced.

After a close evaluation and PIPESIM (Fig. 7) modeling were selected many wells from Filitelnic field. One of them has the following parameters:  $\Phi$  9 mm 12.9/18,3 12.5/6,9 with 1200 l salt water and a flow rate 10800 scm.



**Fig. 7.** Tubing performance designed in Pipesim

After modeling, a tubing of 1.5 in was selected. The well was completed with this tubing and the following parameters were obtained:  $\Phi$  9 mm 12.3/17,6 12.1/6.8 with 1200 l salt water and a flow rate 11000 stcm.

Romgaz intend to extend this type of well completion to other wells with liquid loading problems.

## 5. CONCLUSIONS

Although Romgaz mostly fields are not waterdrive reservoirs, though in the last phase of gas expansion, these aquifers produce serious problems in exploitations.

Liquid loading of gas wells should be identified and resolved as early as possible. Installation of coiled tubing is now proven alternative. Since this is typically packerless completion coiled tubing and annular pressure can be monitored to ensure that stable flow is occurring. Indication of unstable flow is the fluctuation of annular pressure.

## REFERENCES

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- [2] Mohan G., Kelkar: *Gas production engineering*. Petroskills, 2007