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Wet-gas Metering – Implications of Changing Well Conditions on Long-term Flow Measurement

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1 INTRODUCTION

As the Oil and Gas industry slowly adapts to the Digitization paradigm, more data, however poor in quality, is considered better than none at all. Digitization relies on analyzing Big Data coming from across the oil and gas infrastructure and is viewed through a lens of the 4V model – Volume, Veracity, Velocity and Variety [1]. A fifth 'V' for Value is sometimes considered as well [2] – implying that some information is more valuable than others. The problem in the Oil and Gas industry seems to be mainly variety in and veracity of the data.

Wet-gas meters have an important role to play in enabling the Digitization of the industry especially because unlike measurements got from production logging or well testing, the meters are permanently installed and constantly providing data. Within the metering industry, wet-gas metering is often considered less challenging than liquid-dominant multiphase flow metering. Perhaps because of this perception, most wet-gas meters today are based on simple differential pressure devices. There is a trust deficit between the wet-gas meters and reservoir management as the meters are known to provide a Volume of data but their Veracity and hence their Value may be limited.

Wet-gas meters are robust mechanically and serve their purpose most of the time in the early life of a well. However, they are unable to adapt to the changing well conditions in the long-term. In this paper, the wet-gas metering problem is restated from a reservoir engineering point-of-view with the emphasis on the need to rethink the scope and purpose of a permanently installed wet-gas meter.

2 WET-GAS METER SELECTION TODAY

Today, the selection of wet-gas meters is done for a particular instance in the life of a gas well. The expected conditions of pressure, temperature, density and flow rates of the produced fluid are provided by the operator. In response, the expected performance curves of the meter under varying process conditions based on standardized flow loop testing are provided by the manufacturer of the meter. A meter most suited for the application is then chosen and a measurement uncertainty of ±10% is considered reasonable.

The main problem with this selection method is that the immediate past and the long-term future of the reservoir/well are not considered fully. For example, the density and/or the composition of the produced fluid may have changed from the time meter was installed. In other cases, the meter turndown may be barely enough to accommodate the change in the well production rate. These are unstated performance needs from the operator and the result is that meter does not meet the expected performance in the field. Expensive well testing is used to make up for the failure of the meter. Hence, it is important to understand reservoir life cycle behaviour to enable the wet-gas meter to provide accurate gas flow rate. In order to be truly useful to reservoir management, the wet-gas meter must have the ability to adapt to a variety of changing well conditions.

3 RESERVOIR BEHAVIOR

3.1 Reservoir Types

Gas wells are classified into 4 categories [3] – a) Dry gas b) Wet-gas c) Gas (retrograde) condensate and d) Volatile oil. In a dry gas well, the gas has no liquid content under the pressure & temperature conditions at all four locations - reservoir, well bore, wellhead and the separator [Figure 1]. In a wet-gas well, liquids are present at the separator and may be at the wellhead but not at the other two locations [Figure 1]. In a gas condensate well, the depletion curve is to the right of critical point and crosses the dew-point curve under well bore conditions and hence the gas is likely to contain liquids at the well-bore, the wellhead and the separator [Figure 2]. In a volatile oil well, the depletion curve of the well occurs to the left of the critical point and it crosses the bubble point curve under well bore conditions and hence the gas is likely to be liquid only under resevoir conditions [Figure 2].

The wet-gas meter at the wellhead of a wet-gas reservoir described in Figure 1 may have been selected for dry gas conditions but at a subsequent time the depletion curve may cross the dew point curve at the wellhead and the meter is faced with increasing levels of wet-gas. On the other hand, the condensate drop-out at a wet-gas meter at the wellhead of a gas condensate reservoir may have been selected for wet-gas from the beginnning. It is therefore important to include this understanding when the meter is being selected.

The graphs are illustrative and have been adapted from [4] and [5]. Hydrocarbon behaviour may be more complicated in reality.

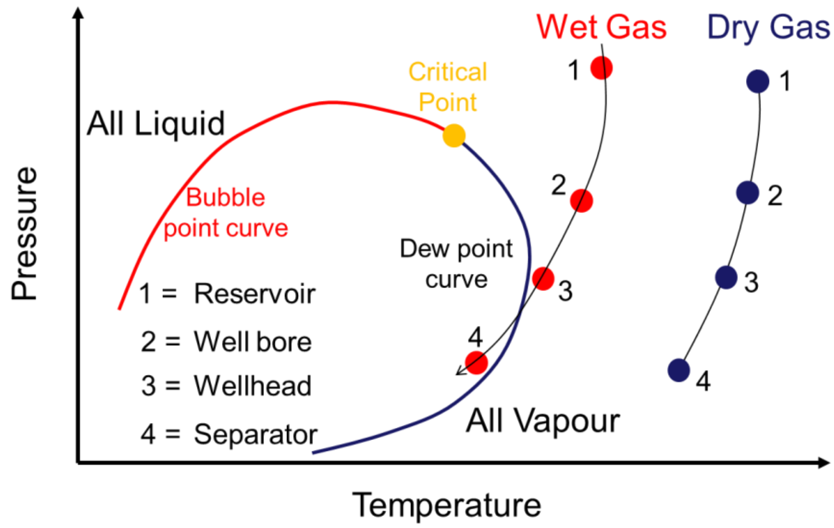

Figure 1. Dry and Wet Gas Reservoirs

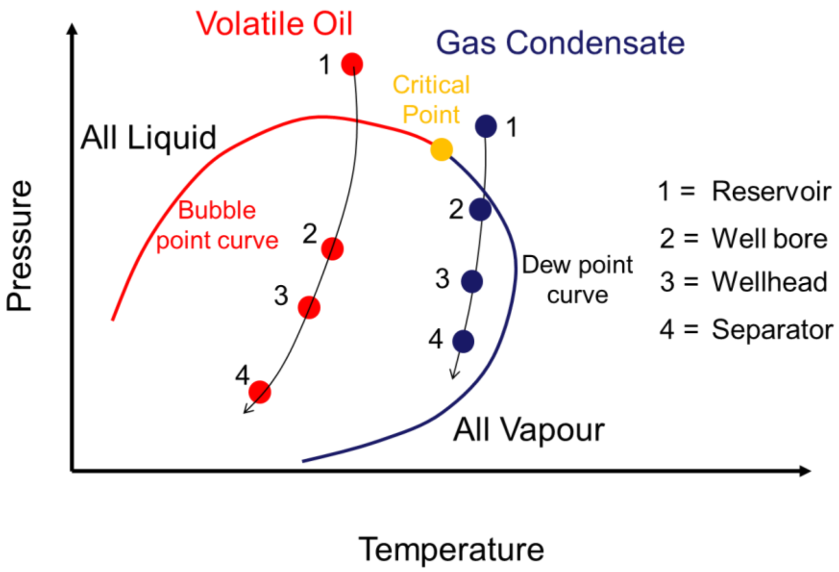

Figure 2. Gas Condensate and Volatile Oil Reservoirs

3.2 Reservoir Behaviour

The production of gas from the reservoir is all about managing pressure drops across the system. The first consideration is the in-flow performance of the well. Figure 3 shows the bottom hole well bore pressure needed to produce a given flow rate of gas into the well bore. As expected, when the bottom hole pressure equals the reservoir pressure, the point where the isobars meet the y-axis, there is no flow of gas from the reservoir. When the bottom hole pressure is brought to zero, the point where the isobars meet the x-axis, the maximum possible gas flow rate is achieved.

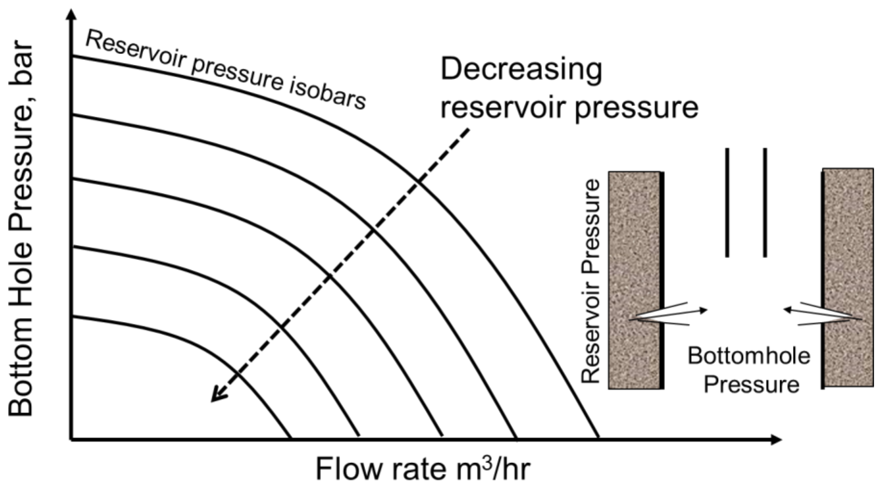

Figure 3. Inflow Performance of Gas Reservoir

The next consideration is the flow through the well bore. Figure 4 shows the gas flow rate achievable with a fixed wellhead pressure for various bottom hole pressures. Obviously, higher bottom hole pressures result in higher flow rates. A higher bottom hole pressure would be needed for a smaller tubing size as there is higher pressure drop on smaller diameter tubing compared to a larger diameter one. The minimum flow rate for the well would be higher in case wet-gas conditions occur at the well bore as the liquid needs more kinetic energy in the gas to bring the condensate out of the well.

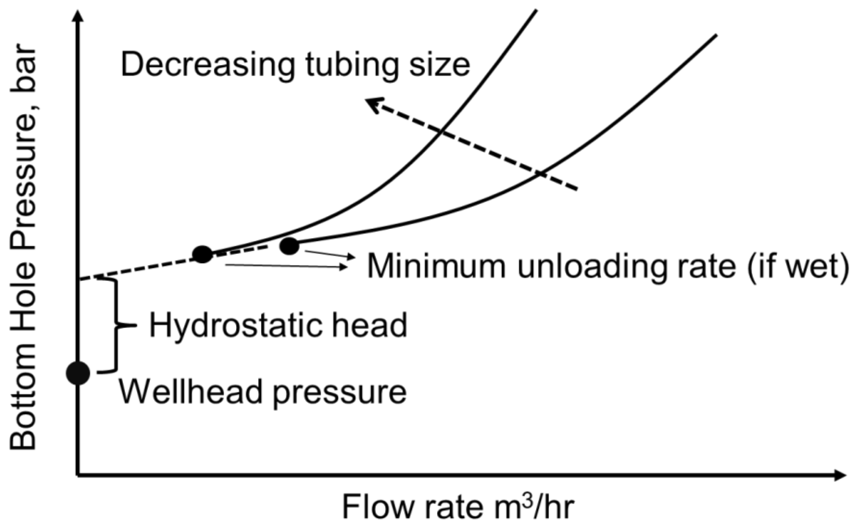

Figure 4. Tubing Flow Performance

The combination of the inflow performance curve and the tubing flow curve provides the reservoir management with the maximum possible production flow rate from the well for a given reservoir pressure [Figure 5].

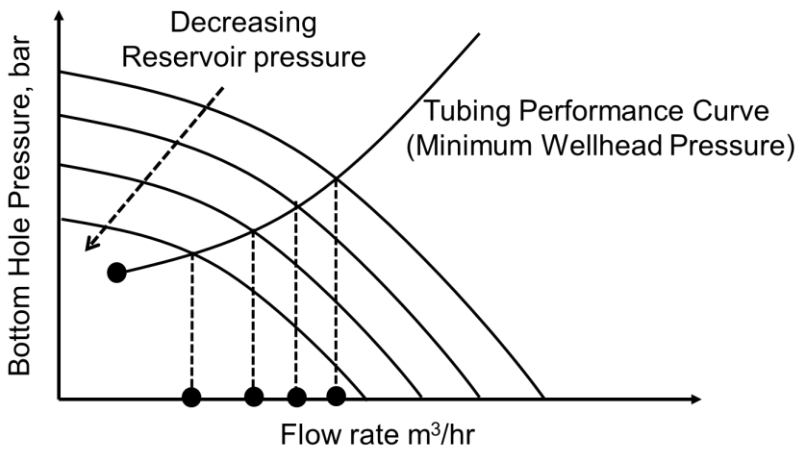

Figure 5. Well Deliverability Curve

Figure 6 shows the well production curve constructed from Figure 5 where the maximum flow rate for a given reservoir pressure is plotted. It is also possible to plot the maximum flow rate against wellhead pressure for various reservoir pressures. The curve would be the inverted image of the Figure 6 where the maximum flow rate decreases with increasing wellhead pressure.

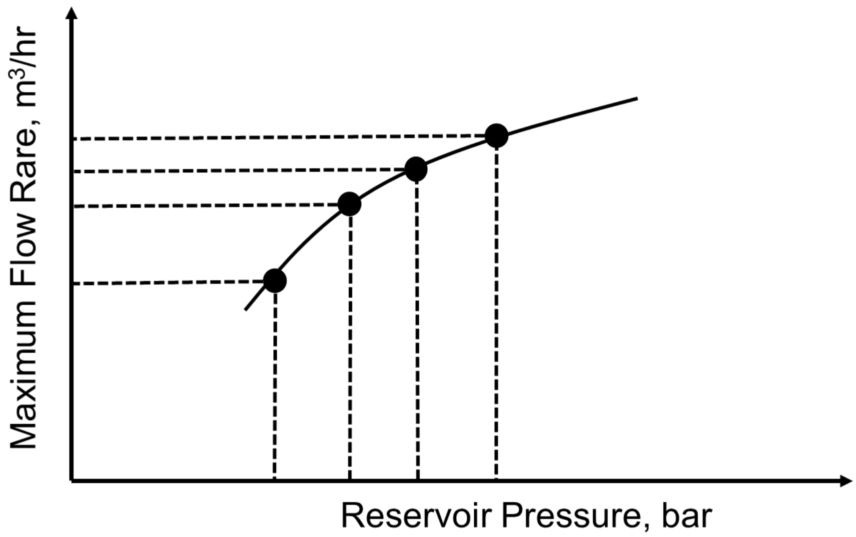

Figure 6. Well Production Curve

The inflow, tubing and production curves of the gas well are used to manage the reservoir production. For example, there may be a minimum contracted gas flow rate needed from the well and reinjection may be needed to increase reservoir pressure and maintain prodcution [Figure 7].

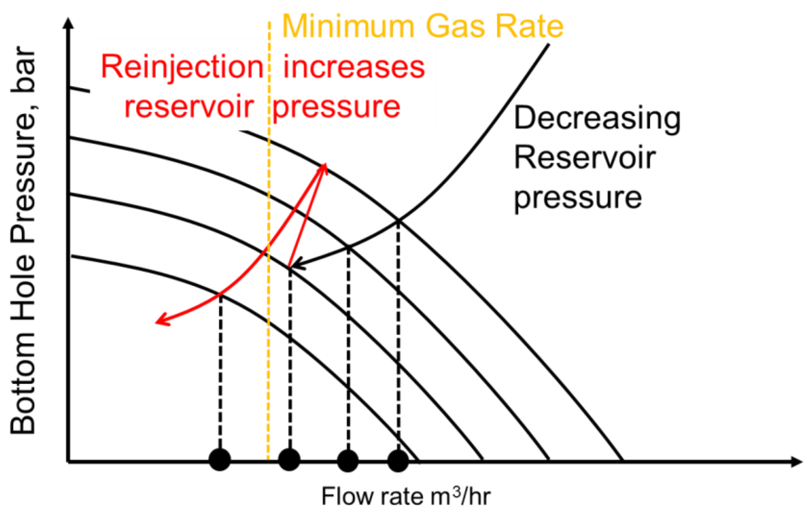

Figure 7. Reinjection for Reservoir Management

From the metering point-of-view, this reservoir management view must be used to understand the pressure, temperature and wetness at the meter location. The meter manufacturer must seek to know the operating point of the well in the life cycle and clarify the longer term implications of the reservoir management strategies on the meter.

3.3 Composition and Flow Variations

Special consideration must be given to gas condensate or retrograde condensate reservoirs. In such reservoirs, as the produced fluid pressure in the well bore reaches the dew point, condensate drops out of the produced fluid [Figure 8]. Along the isotherm line AB drawn vertically downward at temperature T2 in Figure 8, the liquid content first increases as the fluid pressure is decreased. After reaching a maximum at point C, the condensate starts to be evaporate and become gaseous again.

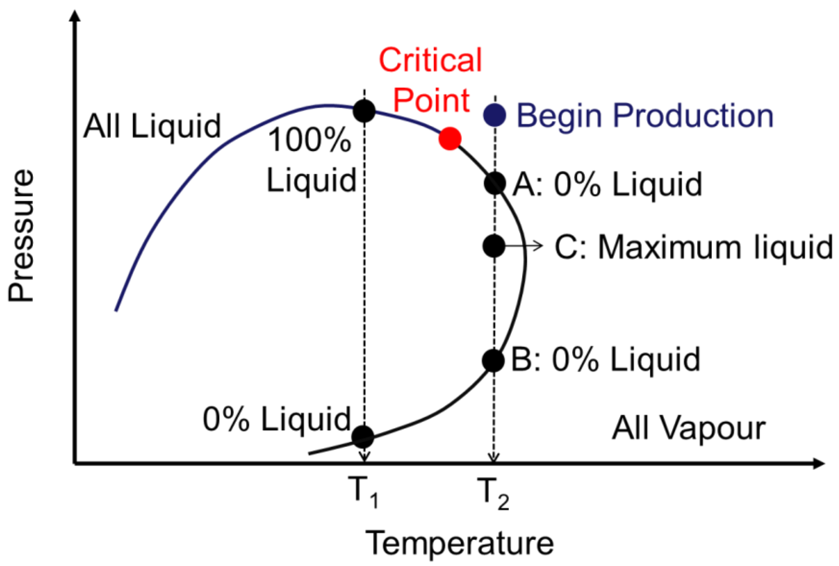

Figure 8. Retrograde Condensate Behaviour

The flow regime at the well bore under these conditions would change from misty flow to a churn flow as increasing condensate drops out of the produced gas [Figure 9] [6]. There is a minimum velocity and hence a minimum flow rate that has to be maintained to lift the condensate to the surface [4]. At the meter location, the wetness may move in either direction depending upon the pressure and temperature. If the pressure at the meter is lower than point C in Figure 8, the wetness at the meter would decrease with time. If, however, the pressure at the meter is above C in Figure 8, the wetness would increase with time. Achieving maximum liquid drop out at surface is well-known management strategy if it is indeed possible for the reservoir in question.

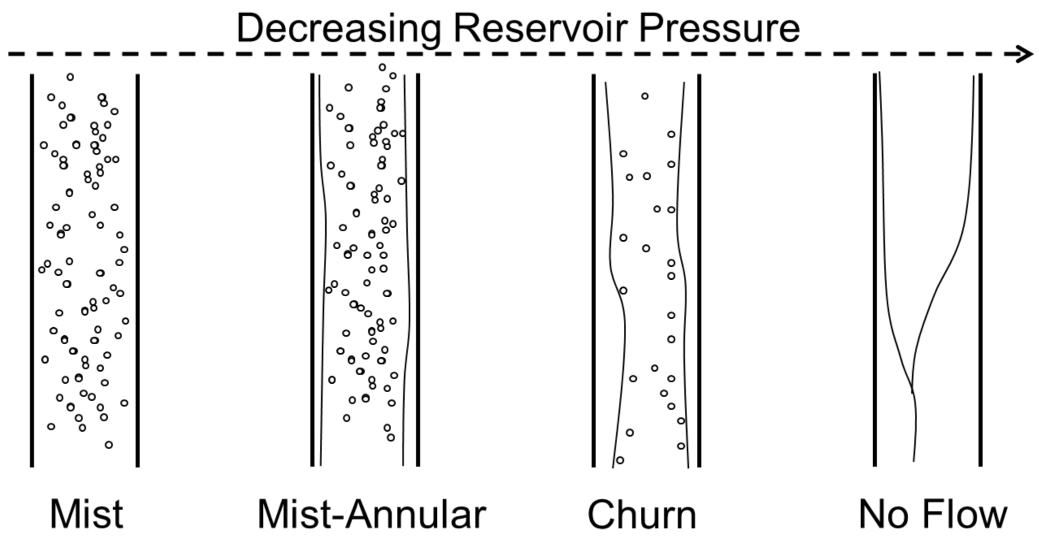

Figure 9. Variation in Flow Regime due to Condensate Drop Out

The other consequence of the condensate drop out is that there is a variation in the composition of the gas across the well bore [3]. It is nominally expected that closer to the top of well bore, the gas in increasingly lighter [3]. However, it has been reported that certain wells exhibit opposite behaviour where the concentration of condensate is higher closer to wellhead [7]. It is reported in [7] that the concentration of hydrogen sulphide is higher at the bottom of the well compared to the top of the well. According to [3], the methane mole fraction increased from 0.76 to 0.84 over a period of a year as the condensate continue to drop out in the well bore. Finally, the condensation of water vapour from the produced fluid result in a change in the composition and wetness of the fluid at the meter. Such compositional variations are not uncommon and have a big effect on the wet gas meter accuracy.

4 WET GAS METERING NEEDS

It is clear that the selection of wet-gas meters must include many more considerations than currently included in the selection. The evolution of wet-gas meter for the future must include

a) Large turndown ratio (>20)
b) Condensate rate measurement
c) Gas density measurement
d) Composition measurement

The turndown offered by wet-gas meters today is not sufficient in wells in the secondary stage of their life. At a minimum, the meters must be able to handle a wide range of chaning flow rates. While many wet-gas meters today offer wetness measurement via a second differential pressure measurement, the uncertainty in condensate measurement is 2-3 times that of gas flow rate. The condensate is more valuable in market and must drive the meters to be more accurate.

Gas density and composition measurement (including water-cut) are both difficult measurements but are needed if the wet-gas meter has to transcend its current scope. A wet-gas meter that is unable to cope with changes in density and composition in the long-term will continue to be considered secondary to well testing. It is time that the wet-gas meter is redefined as a permanently installed production monitor that acts as a hub for several sensors that provide constant information to the reservoir management team.

5 CONCLUSIONS

The paper presented and discussed the shortcomings in the current wet-gas meter selection process. The wet-gas meter is one source of information for the reservoir management team that often does not believe the readings. The paper presented the reservoir management point-of-view and explained that the measurements in context of the life of the well. The selection of meters with a simplistic set of pressure, temperatures and flow rates does not do justice to the complexities of managing gas wells. Changes in density, composition, wetness and flow regimes are rather common and result in high uncertainities in the wet-gas measurements. It is recommended that the wet-gas meter transcend its current purpose and provide a) turndown of >20 b) accurate condensate flow rate c) density measurement and d) composition measurement in order to be truly useful for the long-term and enable the Digitization of the Oil & Gas industry.

6 REFERENCES

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