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CALCULATION METHOD FOR DETERMINING THE GAS FLOW RATE NEEDED FOR LIQUID REMOVAL FROM THE BOTTOM OF THE WELLBORE

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Abstract. As a result of flooding and accumulations of liquid at the bottomholes, the operating conditions of gas wells become complicated, so that they end up self-squeezing and losing of gas production.

A method is proposed for determining the technological parameters of operation of the gas wells with the purpose of removing liquid from the bottom of the wells. Data from the gas dynamics and special studies were used to develop this method, which has been tested on one of the oil and gas condensate fields. It offers the possibility to increase the accuracy of the information provided by the fund and to ensure that the production wells are operated as efficiently as possible with the use of this method. In the case of liquid accumulation in the well that is insignificant, or when water is present in the well, the technique is beneficial in that it allows determining the technological parameters of well operation and ensuring the removal of the liquid from the bottom of the well.

Keywords: Gas flow rate; wellbore; Gas dynamics; liquid removal; Gas moisture

Introduction

As a result of the liquid that accumulates at the bottom of a well during operation, a column forms, which considerably reduces productivity during the final stages of gas field development (Al-Obaidi 2016; Smirnov et al. 2008; Al-Obaidi et al. 2020)[1)]. This can sometimes lead to a spontaneous well-shutdown. It is therefore necessary to maintain an adequate minimum flow rate for removing the liquid from the well when regulating the technological regime.

For the removal of droplets from a gas well, Turner et al (Al-Obaidi 2016; Turner et al. 1969) propose two physical models: the movement of the liquid film along the walls of the pipe and the transfer of a droplet through the gas stream. Calculations that use a film movement model along pipe walls require numerical integration and are more complex than those that use a droplet liquid movement model(Kamensky et al. 2020; Al-Obaidi et al. 1996). Based on actual field data, Turner compared the results of calculations using both methods and found that the droplet-liquid transfer model provided the most accurate predictions. Later, similar work was carried out by Coleman (Smirnov et al. 2008; Coleman et al. 1991). As a result, equations based on experimental correlations of the minimum gas velocity required to remove liquid droplets from a vertical wellbore were obtained (Al-Obaidi et al. 2020; Lee et al. 2008):

Turner equation:

$$v = 5.321\,\frac{(67-0.0031P)^{1/4}}{(0.0031P)^{\frac{1}{2}}} \tag{1}$$

Coleman equation:

$$v = 4.434\,\frac{(67-0.0031P)^{1/4}}{(0.0031)^{1/2}} \tag{2}$$

Here υ is the gas velocity at which all the liquid is carried to the surface, ft / s; P is the gas pressure in the well, psi.

This method fails to take into account temperature, specific gravity of the gas-liquid mixture, wellbore profile (its deviation from vertical), wellbore dimensions (diameter and drawdown depth of the tubing), and condition of the tubing (the actual roughness coefficient determined experimentally) (Al-Obaidi et al. 2020; Al-Obaidi et al. 2017; Al-Obaidi 2016; Al-Obaidi 2007; Lysenko 2000) (Al-Obaidi et al. 2020; Al-Obaidi et al. 2017; Al-Obaidi 2016; Al-Obaidi 2007; Lysenko 2000). It follows from the above equations that the gas velocity at which all the liquid is brought to the surface does not depend on the flow rate of the liquid entering the wellbore, which is not consistent with the physical process. In practice, critical velocities vary considerably depending on the production well, and are dependent on the design of the well bottom and pipe suspension, the density of the formation fluid (product), the presence of mechanical and chemical impurities, among other factors (Al-Obaidi S. et al. 2018; Al-Obaidi S. et al. 2010; Al-Obaidi S. et al. 1996; Al-Obaidi S. et al. 2012).

Researchers at one of the Russian Oil companies have developed a method for determining the minimum flow rate (Equation 3) to ensure the removal of formation fluid from gas and condensate well bottom holes, including (Chang et al. 2021; Al-Obaidi et al. 2019; Al-Obaidi et al. 2020): calculating the gas dynamics of wells in steady-state mode. By increasing the choke diameter in discrete steps, the flow rate is altered, from the lowest concentration at which the formation liquid is not guaranteed to be removed from the bottom of the well to the highest concentration at which the liquid column is removed. Consequently, the wellhead pressure and flow rate are obtained as pairs. When there is a column of reservoir liquid at the bottom of the well on a small diameter choke, there is no cleaning of the bottom of the well, as evidenced by the increased value of pressure losses in the formation-wellhead system (Falcone et al. 2013; Al-Obaidi et al. 2021; Al-Obaidi 2017). In this case, a reservoir liquid column (with high pipe suspension) or a liquid column in the pipe has blocked the perforation interval. Cleaning begins at flow rates where the velocity at the pipe shoe is sufficient to move the liquid. The next step is to calculate the flow rate at the pipe shoe and determine the minimum flow rate that will ensure liquid removal from the bottom of the well.

$$Q = \frac{V \pi T_{st} d^3 P_{wf} t}{\left(4 T_{wf} P_{atm} Z(P_{wf}, T_{wf})\right)} \tag{3}$$

Where Q is the flow rate of the well; V is the flow velocity at the pipe shoe; T_{st} – standard temperature; d is the internal diameter of the pipe; t is the number of seconds in a day; P_{wf}, T_{wf} pressure and temperature at the bottom of the well, respectively; P_{atm} – atmospheric pressure; Z (P_{wf}, T_{wf}) – gas supercompressibility coefficient.

Considering the thermobaric conditions in effect, the formula (3) determines the minimum flow rate based on the technological mode.

The disadvantages of this method include the lack of a clearly defined process for removing the liquid column from the bottom of the well. Consequently, at the time of the investigation, if the liquid accumulation at the bottom has not significantly affected the operation of the well, that is, overlapping the perforation interval or causing increased pressure losses, it is almost impossible to determine the time of liquid removal. The presence of flooded intervals in the geological section opened by the wellbore will result in increased water inflow into the wellbore as the flow rate increases, increasing pressure losses in the reservoir - wellhead system due to the density increase of the gas-liquid mixture (Patkin et al. 2001; Al-Obaidi 2021; Al-Obaidi 1999; Al-Obaidi 1998).

In this work, a method is developed for the determination of the flow rate of a well, based on the moisture content of the gas in the wellhead to allow liquid remove from the lower wellbore.

Methodology

The physical essence of the proposed method can be described as follows. At a given temperature and pressure, moisture is the mass of water vapour dissolved in a unit volume of natural gas. According to this definition, the absolute humidity of the gas W at a given pressure and temperature represents the ratio of the liquid water vapour it contains to its volume, reduced to standard conditions, if it has been drained. According to the gas industry, standard conditions are defined as the condition of the gas at T = 293.15 K and 1.01325 105 Pa (i.e. at 20° C and 760 mm Hg) (Hofmann et al. 2013; Al-Obaidi 1996; Al-Obaidi et al. 2019). Absolute humidity is measured in kg / 1000 m^3 (or in g / m^3). At a given pressure and temperature, moisture content in a gas is defined as the amount of water vapour in a unit volume of the gas, assuming that the gas is completely saturated with water (Hofmann et al. 2013; Al-Obaidi 1996; Al-Obaidi et al. 2019). At a given pressure and temperature, relative humidity is the ratio of the actual water vapour content per unit volume of the gas to its moisture content. The relative humidity is expressed in fractions of a unit or as a percentage.

Gases may be undersaturated, which means their relative humidity is less than one; or they may be oversaturated, which means they have a relative humidity above one (Al-Obaidi 2015; Al-Obaidi et al. 2002). The latter state is unstable, so water vapour (or, water in the gaseous state) will condense, so there will be enough water remaining in the gas to reach the saturation (moisture capacity) of the gas at the pressure and temperature given. It should be noted that terms such as "full saturation" and "moisture capacity" are incorrect. In the gas-water system, it is most accurate to refer to the mass of water vapour as "equilibrium content", but for brevity, "full saturation" or "moisture capacity" is used (Al-Obaidi et al. 2005). The moisture content of a gas depends on the composition of the gas, its pressure and temperature. The following expression can be used to approximate the moisture content W

$$W = \frac{A}{P} + B \tag{4}$$

Where p is the pressure under which the gas is; A = A (T), B = B (T) are functions that depend on the temperature of the gas.

The functions A = A (T) and B = B (T) increase as the temperature increases. There is every reason to believe that beyond a certain distance from the well, nearly constant temperature remains in the productive formation during the development of the field. This is because there is continuous heat moving from the center of the earth to its surface, which compensates for the cooling of the gas caused by the relatively slow pressure drop in the formation (Al-Obaidi et al. 2017; Al-Obaidi et al. 2020; Al-Obaidi et al. 2017). As a consequence, in the productive formation away from the wells, an isothermal process occurs. Under these conditions, the functions A = A (T) and B = B (T) in formula (4) are constants for the entire development period when p is constant. As the reservoir pressure drops, the gas becomes undersaturated and can absorb additional water.

Thus, at an initial reservoir pressure of ~12 MPa and a reservoir temperature of 303 K, fully saturated methane gas has a moisture capacity of W_1 = 0.420

kg/1000 m^3; at 6 MPa and the same temperature, the moisture capacity of the saturated gas is W_2 = 0.667 kg/1000 m^3 of water; and at 2 MPa, W_3 = 1.718 kg/1000 m^3. Consequently, for a pressure drop from 12 to 6 MPa per 1000 m^3 of gas, an additional W2 - W1 = 0.247 kg/1000 m^3 of water can evaporate, and for a pressure drop from 6 to 2 MPa, additional $W_3 – W_2$ = 1.051 kg/1000 m^3 will evaporate. This assumes, however, that the undersaturated gas, whose saturation corresponds to the initial reservoir pressure, is in direct contact with water. In porous formations, such contact always exists: the trapped gas in the rock pores is in contact with the bound water (Al-Obaidi et al. 2006; Al-Obaidi et al. 2021). The average water saturation coefficient in the Cenomanian deposits is 0.3. The question of whether water evaporates into gas from films less than 0.5 microns thick remains unanswered. There is enough water to flow into an unsaturated gas from these thin films, as well as from porous medium in narrow capillaries.

According to the above arguments, we can assume that reservoir gas in the zones far from the wells has complete moisture saturation corresponding to the given reservoir pressure and initial reservoir temperature.

– **Proposed method procedure**

The method involves working out the well in maximum allowable mode to remove any liquid sludge, then shutting down the well and measuring the thermobaric parameters in the reservoir, that is, measuring the pressure and temperature of the gas at the bottom of the shutdown well after they have stabilized. After the well was restarted, the total volume of vaporized and liquid gas at the wellhead was measured. Pressure and temperature of the gas at the bottom of the well are measured as the well operates in several steady-state flow modes with an increase in flow rate from minimum to maximum. In order to determine equilibrium gas moisture content in the vapour phase, bottomhole pressure and temperature are measured. In addition, the reservoir parameters in a shut-in well and the wellbore bottom parameters in a working well are determined simultaneously. As the gas flow rate increases, the moisture at the wellhead is compared with equilibrium moisture content. Whenever the moisture content at the wellhead is less than the equilibrium bottomhole when the well is operated in a certain mode, the flow rate is not sufficient to remove the liquid entering the tubing. The well flow rate is sufficient to remove liquid entering the tubing, but insufficient to remove the liquid condensing at the bottomhole when the moisture content at the wellhead is greater than or equal to that at the equilibrium bottomhole but less than that at the equilibrium reservoir.

In addition, if the moisture content at the wellhead is greater than or equal to the equilibrium reservoir, then the well flow rate is considered sufficient to remove all liquids from the bottomhole.

Results and Discussions

Using an Express method, a monitoring program for flooding processes was implemented in 2008 that includes well logging, chemical composition analysis of wellhead fluid samples, and moisture determination of gas flow at the wellhead (Kirsanov et al. 2003; Al-Obaidi et al. 2020) (Kamensky I. et al. 2020; Al-Obaidi 1996; Coleman et al. 1991);[2)]

Based on the implementation of the specified program, the data included in Table 1 have been processed. Column 4 includes the values for initial reservoir pressures and moisture contents for the gas in the zones of the Yamburg field where the wells are located. Observable are the low bottomhole temperatures in the range of 20 – 23° C (column 6).

Table 1. Results of moisture content measurements at the vertical wellheads of the Yamburg oil and gas condensate field

Tubing size, mm	Well №	Gas production 1000 m^3/d	Reservoir pressure, P_r,ata	Moisture content, W_r, g/m^3	Pressure P_{wf}, ata	Tempraure, T_{wf}, ^oC	Moisture content, W_{wf}, g/m^3	Pressure P_{wh}, ata	Temprature, T_{wh}, ^oC	Moisture content on the well head	
										W_{wh}, g/m^3	W_{exp}, g/m^3
168	7084	420	29,4	1,20	22,7	20,5	0,75	14,1	12,0	0,79	1,07
	7142	251	20,4	1,68	15,3	22,6	1,43	13,4	12,0	0,83	1,32
	7195	196	19,6	1,75	18,2	23,2	1,26	15,0	11,8	0,74	0,88
114	7051	506	38,3	0,96	31,0	19,8	0,64	13,5	5,6	0,54	0,89
	7134	122	27,9	1,27	22,4	22,2	0,98	13,0	10,0	0,75	1,010
	7172	158	21,5	1,60	16,8	22,6	1,31	13,0	10,8	0,80	1,01

Under reservoir pressures of more than 50 ata, the measured borehole bottom temperatures were 1 – 2° C lower than those of the reservoir (usually 28 – 29° C) when borehole measurements (well logging) were carried out in the Cenomanian sediments. In light of the thermodynamic process that occurs in the zone of the borehole bottom location, the decrease in borehole bottom temperatures by 8-10 °C is not hard to explain. In the immediate vicinity of the well bottom, the main pressure drop occurs during gas flow into the well. Natural processes are polytropic, i.e. they lie between the adiabatic process, which proceeds at a finite rate, but without heat transfer, and the isothermal process, which must proceed infinitely slowly, which is not the case in nature (Al-Obaidi et al. 2020; Al-Obaidi 2004).

The following polytropic equation can be used to estimate the temperature decrease at the bottom of the well when gas is flowing there:

$$T^n . p^{1-n} = const. \tag{5}$$

Where n is the exponent of the polytrope.

By writing down the polytropic equation for two pairs of T and P values: T_r, p_r and T_{wf}, p_{wf}, where the subscript "r" represents the reservoir and "wf" represents the bottom, it is easy to solve for the ratio

$$\left(\frac{P_r}{P_{wf}}\right)^{\frac{n-1}{n}} = \frac{T_r}{T_{wf}} \tag{6}$$

Where,

$$T_{wf} = \frac{T_r}{\left(\frac{P_r}{P_{wf}}\right)^{\frac{n-1}{n}}} \tag{7}$$

$$n = \ln\frac{P_r}{P_{wf}} / \ln\frac{P_r T_{wf}}{P_{wf} T_r} \tag{8}$$

The polytropic index n for real processes is in the range $1 < n < c$, $c = C_p / C_V$, where C_p is the heat capacity at constant pressure and C_V is the heat capacity at constant volume at the pressure and temperature of the process (Istomin et al. 1995).

The values for the measured pressures and temperature for the reservoir and bottomhole are shown in Table 1. For each well, the polytropic index can be calculated using the formula (8). As an example, if Well No. 7051 has P_r = 38.28 ata; T_r = 303 K; P_{wf} = 31.06 ata; T_{wf} = 293 K, then the polytropic exponent is 1.19. The well bottom temperatures were significantly higher several years ago at the same pressure drawdowns as those currently operated at the wells listed in Table 1, but with a higher reservoir pressure. According to Formula (7), when Well No. 7051 has reservoir pressure P_r = 70 ata and pressure drawdown ΔP = 7.22 ata, the well bottom temperature calculated using T_{wf} = 298 K is five degrees higher for the polytropic index found n = 1,19.

Due to the decrease in reservoir pressure, there is a sharp drop in wellbore bottom temperatures, causing condensation to precipitate not just in boreholes, but also in their bottom hole zones. Comparing the data on moisture content in the reservoir and at the bottom of the wells (columns 4 and 7), it is obvious that moisture content is significantly higher in the reservoir for all boreholes. When reservoir pressures were high, the picture reversed. The gas was unsaturated as it approached the bottom of the well; the release of condensate began in the wellbore at distances of tens and hundreds of meters from the bottom of the well. Currently, gas is already being released from the bottom of the well in the same wells, increasing resistance to gas movement. Following a pressure drop, the volume of condensate released from the well bottom will increase as the temperature at the bottom of the well decreases.

The equilibrium water vapour content W_r in the natural gas-water system for reservoir pressure and reservoir temperature , W_{wf} for bottom-hole pressure and temperature and Wwh for wellhead pressure and temperature were calculated using the program of V. A. Istomin and V. G. Kvon (Lee et al. 2008; Istomin et al. 1995).

The figures in the table, based on the above reasoning, indicate that the flow rates for all but well 7051 and 7084, within summer conditions with relatively low production rates, were clearly insufficient to completely remove liquid from the bottom of the well. This fact is confirmed by the results of the well logging. This fact is confirmed by the results of the well logging. The water column at the bottom of well 7172 reaches four metres. Part of the productive interval is operating in bubbling mode. The value of gas moisture at the wellhead (1.01 g / m^3), determined by the express method, is greater than the equilibrium water vapour content in the gas-water system for the given pressure and temperature (0.8 g / m^3). At this point, the water vapour is passing through the sensor as a dispersed liquid (mist). The flow rate of this well is 158,000 m^3 / day. Well No. 7134 operates at a flow rate of 122,000 m^3 / day, which does not provide for the removal of condensation from the well. Water is also present at the bottom of well No. 7195.The flow rate of 196,000 m^3 / day is insufficient for removing condensation water. Part of the perforation interval is blocked by a water plug.

Despite the fact that the water level in well No. 7074 is 60 cm above the lower perforation holes, the moisture content measured was slightly below equilibrium. Despite the fact that the measured value exceeds the equilibrium value, well 7142 is operating in anhydrous mode according to the production logging report. An additional check of the presence or absence of water at the bottom of the gas wells is required, etc.

Conclusions

In conclusion, it should be noted that the method of express determination of moisture content was selected due to its simplicity and low cost as compared to other methods of testing gas wells, enabling measurements to be performed on a large number of wells in a short period of time. In terms of measurements accuracy, this method falls into the indicator category, along with the widely used “Nadym-1”. In order to obtain representative results, a full-flow flow meter should be used.

According to the study, based on measurements of the moisture content of gas at the wellhead, technological parameters will be determined that ensure liquid removal from the bottom of the well. Hence, production wells will run more efficiently and information about their operation will be more reliable.

There are positive aspects of this technique such as the fact that it can be applied even when liquid accumulation in the wellbore appears to be insignificant and does not significantly affect the operation of the well, or when there is water flowing into the house.

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