Calculation of the Minimum Required Flow Rates for Water Removal from Flooded Wells under the Conditions of the Yamburgskoye Field

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Abstract. Fluid accumulation is one of the most common occurrences in the gas wells of the Yamburgskoye field, as the field entered a later period of gas well production. Fluid accumulation is not always easy to predict and recognize because a thorough diagnostic analysis of the well data is required, but accurate prediction of the problem is vital for timely action to be taken. Three methods are considered for determining the minimum required flow rates for the removal of water from flooded wells under the Yamburgskoye conditions.

1. Introduction
Fluid accumulation is the most common occurrence in gas wells. And the main reason for this phenomenon is that during the production of a gas well at a later stage, reservoir pressure, gas velocity and fluid throughput will be reduced, and part of the produced water in the wellbore will remain at the bottom of the well, causing fluid accumulation [1], [2].

Fluid accumulation is not always easy to predict and recognize as a thorough diagnostic analysis of the well data is necessary, but accurate prediction of the problem is vital for timely action to resolve it.

Currently, as many large deposits in the north of the West Siberian Plain, the Cenomanian reservoir of the Yamburgskoye oil and gas condensate field is at a late stage of development, which is characterized by low reservoir pressures (dynamics of reservoir pressure of the integrated gas treatment unit 6 (GTU) - Figure 1), a high degree of water cut, low production capacity of the reservoir, collapsing reservoirs [3], [4].

It is known that there are a sufficiently large number of methods for calculating the minimum permissible gas flow rates for the removal of liquid from the well bottom. Most of them are based on empirical dependencies that describe with sufficient accuracy the processes that occur only under certain specified conditions.
### Figure 1. Drop in reservoir pressure in the area of the GTU-6.

#### 2. Method

Comparative analysis established [5], that for the operating conditions of the Cenomanian wells of the Medvezhye field, relatively similar to the operating conditions of the wells of the Yamburgskoye field, a film model of the flow of a gas-liquid mixture in vertical pipes (Tochigin [6], [7]) and an empirical formula obtained by V.N. Gordeev most correctly describes the well behavior. According to this method, the minimum flow rate required to remove fluid from the well is determined by the formula:

\[
Q_{\text{min}} = 3.3 \left[ \frac{g \sigma \rho_1^2}{\rho_2^2 (\rho_1 - \rho_2)} \right]^{0.25} \frac{\pi D^2 P T_0}{R_0 z T} 86.4 ,
\]

where \( Q_{\text{min}} \) – minimum required gas flow rate (thous. m³/day);
\( \rho_1 \) and \( \rho_2 \) – density of liquid and gas, respectively (kg/m³);
\( \sigma \) – coefficient of surface tension for water at \( P \) and \( T \) (N/m);
\( D \) – inner diameter of tubing (m);
\( P, T \) – working pressure and temperature (MPa, K);
\( P_0, T_0 \) – pressure and temperature at standard conditions;
\( z \) – supercompressibility coefficient at \( P \) and \( T \).

In the practice of foreign gas production, the correlation developed by Turner et al. has become widely used to determine the minimum velocity required for the removal of liquid (water) from the well. This formula looks as follow:

\[
v_{\text{min}} = 4.43 (67 - 0.00279 P/z)^{0.25} (0.00279 P/z)^{-0.5} ,
\]

where \( v_{\text{min}} \) – minimum speed required for water removal from the well (ft/s);
\( P \) – working pressure, lb/in² (psi).

In this case, the corresponding value of the minimum flow rate required for the removal of fluid from the well is determined by the formula:

\[
Q_{\text{min}} = 3.067 P v_{\text{min}} A(T + 460)^{-1} z^{-1} ,
\]

where \( Q_{\text{min}} \) – minimum required gas production rate (MCF/D);

\[
\begin{align*}
Q_{\text{min}} &= 3.067 P v_{\text{min}} A(T + 460)^{-1} z^{-1} , \\
\end{align*}
\]
\[ A = \pi D^2/576 \] – cross-sectional area of tubing string inside,
D – inner diameter of tubing, inch;
P, T – working pressure and temperature, (lb/in^2) psi and F [8]

The above relationships (2) and (3) were obtained with respect to wellhead pipe pressure exceeding 1000 psi, which corresponds to 70.31 atm. For the case of operating wells in the Yamburgskoye field (at lower pressures), Coleman's formulas may be more acceptable. Essentially, the formulas proposed by Coleman (for lower pressures) are identical to Turner's formulas, but do not contain the empirical correction factor that Turner used to adapt correlations to the actual data. Coleman's equation for determining the minimum gas velocity required to remove liquid (water) from the well is written in the following form [8]-[10]:

\[ v_{\text{min}} = 1.593\sigma^{0.25}(\rho_1 - \rho_2)^{0.25}\rho_2^{-0.5}. \] (4)

In accordance with the above methods for determining the minimum flow velocity and production quantity values (according to Tochigin, Turner and Coleman) required for water removal from wells for Cenomanian gas wells (GTU-1 – GTU-7) and their operating conditions corresponding to 01.07.2011, calculations and analysis of the results were carried out in order to identify the stock of wells in which the existing production technology cannot provide liquid removal.

As raw data for the calculations, the values of the physical properties of natural gas and water taken from the Cenomanian wells of the Yamburgskoye oil and gas condensate field, presented in Table 1, were taken, as well as the values of the internal diameters of the tubing, wellhead pressures and temperatures according to the operational report for January 2011 [11].

Table 1. Physical properties of natural gas and water taken from the Cenomanian wells of the Yamburgskoye oil and gas condensate field.

| Physical quantity                        | Value | Unit   |
|-----------------------------------------|-------|--------|
| Liquid density \( \rho_{1(\text{st})} \) | 1011  | kg/m^3 |
| Relative density of gas in air \( \rho_{2(\text{rel})} \) | 0.564 |        |
| Gas density \( \rho_{2(\text{St.Cond})} \) | 0.68  | kg/m^3 |
| Coefficient of surface tension at the water-gas interface \( \sigma \), real cond. | 0.068 | N/m    |
| Pseudo-critical mixture pressure \( P_{\text{cr}} \) | 45.75 | atm    |
| Pseudo-critical mixture temperature \( T_{\text{cr}} \) | 190.66 | K      |

3. Results

The sensitivity analysis of the calculation results for the minimum flow velocity and production quantity values required for the removal of water from the wells showed that the change in the surface tension coefficient at the water-gas interface depending on the operating pressure and temperature has a slight effect on the result. The values of the supercompressibility coefficient \( z \) in formulas (1) - (4) were determined using the Platonov-Gurevich approximation of the graph of the change in the supercompressibility coefficient versus the reduced pressure and temperature. The sensitivity of the calculation results to the accuracy of this method for determining the supercompressibility coefficient is insignificant.

Equations (1) - (4) contain empirical coefficients that allow adapting the calculation results to the actual situation of fluid removal from the well. As they are not absolutely accurate, the researchers argue that deviations from the fact can be in the order of 20%, however, for assessment purposes, they can be applied. Comparative analysis was carried out using three methods to improve the accuracy of the results.
It has been established that the most stringent requirements for ensuring the conditions for fluid removal follow from the results of calculations using the Tochigin method, for this reason, it was these results that were given special attention. In addition, on the basis of expert judgment, the safety factor $k_r = 1.20$ was established, correcting upward the calculation results.

The calculation was made for 747 production wells. The results obtained (requirements for production rates and flow rates for each of the wells) were compared with the factual state of operation. It was revealed that 57 out of 747 wells did not meet these requirements (Figure 2).

Figure 2. Share ratio of the Cenomanian production wells GTU-1-7 with provision (1) and without provision (2) conditions for the removal of liquid with a gas flow.

Figure 3 shows the distribution of this group of wells by zones of the gas treatment unit. The zones GTU-3 and GTU-6 account for the largest number of such wells (13 and 15, with a total of 110 and 112 wells, respectively). On zones of GTU-1 and GTU-2 there are 8 and 9 wells of this type (with a total number of 103 wells in one zone). For zones GTU-5 and GTU-7, 6 typical wells for each zone were noticed (with a total of 104 and 122 wells in one zone). Within the zone of the GTU-4, wells operating in non-compliance with the requirements for the removal of liquid with a gas flow, were not identified [11]–[14].

Figure 3. Distribution of the stock of producing wells (GTU-1-7), in which, according to the results of calculations, the conditions for the removal of liquid with a gas flow are not ensured.
Figure 4 graphically illustrates the comparison of the values of the factual and minimum required flow rates for wells, in which the conditions for the removal of liquid with a gas flow in January 01.01.2011 were not provided. For wells grouped into this category, the difference between the factual average daily flow rate and the minimum required flow rate is from 0.05 thous. m$^3$/day. (well 6067 with its factual flow rate of 120.0 thous. m$^3$/day) up to 92.96 thous. m$^3$/day (well 1016 with its factual flow rate of 54.0 thous. m$^3$/day) [11]–[14].

Figure 4. Comparison of the factual (as of 02.01.2011) and the minimum required flow rates for the identified wells, in which the conditions for the removal of liquid with gas are not provided.
The share of the Cenomanian production wells GTU-1-7, characterized by the operation of wells under conditions that ensure the removal of liquid with a gas flow, is classified by the parameter

\[ \Delta Q = Q_f - Q_{\min}, \]  

(5)

where \( \Delta Q \) - excess of the factual average daily flow rate \( Q_f \) over the value of the minimum required flow rate \( Q_{\min} \), thous. m\(^3\)/day. The classification results are shown in Figure 5.

![Figure 5](image)

**Figure 5.** Distribution of the shares of the well stock, in which the conditions for the removal of liquid with gas are provided, according to the \( \Delta Q \) parameter (excess of the factual flow rate over the minimum required).

Evaluating the rate and sequence of replenishment in the process of further development of the category of wells in which the conditions for the removal of liquid along with the gas flow are not provided, it can be assumed that this category will be replenished first of all with a small margin of the value of the parameter \( \Delta Q \). As can be seen from Figure 6, 7.4% of the GTU-1-7 producing wells will tend to self-stalling after their flow rate has decreased by a range of 0-25 thous. m\(^3\)/day; another 10.8% of wells will cease to carry fluid when the flow rate decreases by 25-50 thous. m\(^3\)/day, etc [11]–[14].

![Figure 6](image)

**Figure 6.** Average daily gas production rate of Cenomanian gas wells for each of the GTU-1-7 and for the months of 2011.
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